The Failure of Risk Management:
A New Perspective on the California Electricity Market

May 2001

By:

Sean Kelley

Christo Leventis

Arthur Weiss

SYNOPSIS

The untimely failure of the state of California's effort to deregulate its electricity market has resulted in the insolvency of its two largest utilities, occasional blackouts, and is causing the state act as a proxy power supplier in place of the failed utilities, spending an expected $13 billion[1] to purchase electricity. In this paper, we examine the California energy crisis as it pertains to conflicting and failed efforts by the state of California and the state's three largest utilities to manage the anticipated and unanticipated risks that accompanied the restructuring of the industry. Our purpose is to demonstrate the importance of considering second-order consequences in using risk management policies when there are multiple constituencies. The primary actors in this tale are the state of California, the utilities (Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric) and their parent companies (PG&E Corp., Edison International, and Sempra Energy), and the few new entrants into the market. The constituencies for whom there was risk in this process were the utilities' shareholders as well as the taxpayers and electricity consumers of California. In the first section, we provide background information on the California energy market and the relevant provisions of the deregulation. In the second section, we describe how the restructured market faced substantially greater risks than old environment. The third section discusses the risk management motivations of both the state and the utilities. In the fourth section we describe and analyze the utilities' reactions to these risks and the state's regulations. Finally, we analyze how the regulations and actions contributed to the breakdown of the nascent "competitive" environment.

[1] "California Controller Battles Governor Over Paying for the State's Electricity Crisis." Wall Street Journal, May 22, 2001.

TABLE OF CONTENTS

SECTION 1: REGULATORY BACKGROUND

Prior to March 31, 1998, California's electric utilities owned and operated all of the businesses necessary to procure, generate, transport and deliver electricity to end users, and provide customer service activities (billing and metering). The market comprised seven investor-owned utilities (IOUs) and numerous smaller publicly-owned utilities (i.e., utilities owned by local governments). By far the three largest IOUs were Pacific Gas & Electric Company, Southern California Edison, and San Diego Gas & Electric Company, which account for 75% of the electricity sold in the state[2]. These utilities were given a legal monopoly over a geographic area in return for providing consistent service to all customers in their area. The state regulators set prices that allowed the utilities to recover their costs and earn a fair return on their investment.

In September 1996, California's legislature enacted AB 1890, laying the foundation for a competitive electricity market which was intended to lower prices paid by consumers and create a broader array of services, while maintaining the integrity of the power system. AB 1890 effectively revoked the IOUs' monopoly status in certain areas of the industry. Although the deregulation went into effect in January 1998, the restructuring would not be substantially complete until March 2002, with the interim four years referred to as the "transition period."

The governmental body that oversaw the regulated environment and now oversees the current market in California is the California Public Utilities Commission (CPUC). Throughout this paper we will refer to the parent companies of the restructured IOUs as the "Parent" or "IOU" and refer to the original utility and the new competitive subsidiaries as the "Utility" and "Non-Utility," respectively. We will refer to the three largest IOUs and their Utilities, respectively, as: PG&E Corporation (PG&E Corp.) and Pacific Gas & Electric Company (PG&E), Edison International (Edison) and Southern California Edison (SCE), and Sempra Energy (Sempra) and San Diego Gas & Electric (SDG&E).

In the overall restructuring process, the regulators were very much concerned with maintaining the consistency of electricity service enjoyed by consumers prior to deregulation. Within this constraint, the mechanics of creating this new competitive environment were

[2] Joskow (2001).

molded by the need to (1) assure the creation of a truly efficient and competitive electricity generation market, and (2) to allow the IOUs to earn a fair return on investments made prior to deregulation.

In 1996, the concentration of electricity-related assets with the local monopolies was not conducive to competition. The initial formation of a competitive market required "unbundling" or splitting the industry into four distinct services. This was to be expedited through mandated divestitures of assets by the IOUs. Under AB 1890, only two of the unbundled services would become competitive businesses, with prices and terms of service set by the market, and with customers free to choose their providers. The first is generation (production of electricity in power plants), a focal point of our analysis. Customer service, which consists of marketing/reselling power-related services, metering and billing, would also become competitive but has not yet attracted many new entrants. The other two services, transmission and distribution, would continue to have rates set by the regulators which allowed the IOUs to earn a specified return on equity. Transmission is the delivery of power from the power plant to sub-stations using high-voltage power lines, while distribution is the use of lower voltage power lines to deliver power from the sub-stations to consumers. In practice, all assets that the Utilities continued to own earned a specified return on equity. The IOUs would be permitted to engage in all four of the unbundled services after deregulation, provided that new entrants were allowed access to transmission and distribution lines. *During the transition period, the IOUs were obligated by law to purchase power for all consumers who did not choose a new provider.* Consumers would see a separation of charges on their electricity bills to reflect this unbundling, but only generation would reflect competitive prices.

The importance of creating a truly competitive market was best stated by the California Energy Commission (CEC), the state's primary energy policy and planning agency in its *1996 Energy Report* (ER 96):

> *" ... restructuring will not be in the public interest if it allows some companies to exploit market dominance and stifle competitive market forces."*

As this quote indicates, the desire to prevent market power was of the utmost importance. The regulators focused on two potential sources of market power: horizontal market power and vertical market power. Horizontal market power was derived from concentrated ownership of a single aspect of production, such as generation. Vertical market power was derived from a single firm's ownership of multiple aspects of production, such as generation and distribution. Addressing this, the IOUs and the CPUC reached an agreement whereby each Utility would divest at least 50% of its fossil fuel-powered generation assets located in the California service area.[3] Most of these assets were acquired by non-utility affiliates of utilities in other parts of the country.

The competitive market in California was expected to create new investment opportunities in areas such as energy trading and principal investing. Similarly, industry restructuring efforts in other parts of the U.S. opened up opportunities for the California IOUs to acquire generating capacity in other regions.[4] In taking advantage of these opportunities, the IOUs restructured their companies, dividing them into a Utility subsidiary and one or more competitive, Non-Utility subsidiaries.[5]

The creation of two new quasi-governmental organizations was intended to ensure the necessary liquidity for an efficient market. These were the California Power Exchange (PX) and the Independent System Operator (ISO). The PX was the primary marketplace where electricity would be bought and sold. During the transition period, the Utilities were required to sell all of their power (either generated or purchased under long-term contracts) to and purchase all of their power needs from the PX. The ISO was charged with "ensuring efficient use and reliable operation of the transmission grid."[6] To this end, the ISO was given control over, but not ownership of, the Utilities' transmission lines, thereby guaranteeing access to these lines for market participants. The ISO's responsibilities included scheduling the

[3] Nuclear, geothermal, and hydroelectric facilities were excluded from the requirement for various reasons, including their importance to the reliability of the power system, and the relatively lower attractiveness to purchasers due to the complexity of operations and regulatory/safety issues.
[4] Due to the technical specifications of the U.S. electricity transmission infrastructure and the physical properties of electricity, it would not be practical to transmit power from most of these plants to California.
[5] Edison International had completed this restructuring prior to deregulation, as it already held generation assets in other markets.
[6] CEC ER 96, page 28.

delivery of electricity and the authority to purchase additional power on a secondary market in the event demand exceeded supply on the PX.[7]

Regulators believed that in order for the IOUs to earn a fair return on investment, they would need to be compensated for generation capacity outlays made prior to deregulation. It was widely believed that the investments in generation would decline in value in the competitive market and that the IOUs would incur various costs in complying with the deregulation. The underlying rationale was that it would be unfair to penalize stockholders and bondholders as a result of the deregulation. These items are referred to as the Utilities "stranded costs" and would be reflected on the firms' balance sheets as "regulatory assets." The "recovery" of these assets was to be accomplished by imposing a "competitive transition charge" (CTC) on all electricity consumers.[9] The competitive transition charge in turn was extracted by *freezing retail electricity prices at 1996 levels during the transition period*.[10] The difference between the frozen rates and the price of electricity prevailing in the market would equal the CTC applied to the regulatory asset from 1998 to 2001. The idea that the CTC would be positive belied the assumption that prevailing electricity prices in the new market would be lower than the frozen levels.

The rate freeze would end for each Utility and their service area, with retail electricity prices set by the market, the earlier of March 31, 2002 or when each Utility recovered the "generation-related component" of its stranded costs.[11] The generation-related component was of stranded costs was estimated at a total of $6.7 billion for the three major IOUs in 1998.[12] These costs could not be recovered past March 31, 2002, at which time any remaining amount would have to be written-off. Thus, increasing the amount of stranded costs seemed initially to be in the best interests of the IOUs. The President of one California IOU stated:

---

[7] Interview with Professor Robert Porter, Northwestern University.

[9] The net present value (in 1996 dollars) of the total amount to be recovered through the competitive transition charge was estimated by the IOUs to be $26.4 billion. CEC ER 96, page 20.

[10] A significant exception to this was a 10% rate cut for residential and small business consumers. The IOUs were compensated for the 10% rate cut through the issuance (by the state) of low interest "revenue reduction bonds" which would ultimately be repaid through a charge to consumers.

[11] Other components of stranded costs are recoverable past March 31, 2002.

[12] CEC ER 96, page 20.

"We are going to have a lot of free cash from the stranded-cost recovery…in the billion dollar range."[13]

The assumption of falling prices was grounded in elementary ideas about the nature of competition. As monopolies, the IOUs had regulated profit levels, negating incentives to control costs and innovate their businesses. Within the pressures of a new competitive market however, all firms must make continued improvements in order to survive. Furthermore, it was expected that prices would approach marginal cost in the competitive market. As stated by the California Energy Commission in ER 96:

"Economic theory indicates that competition will force producers to price services near marginal costs…"

Specifically, the California Energy Commission estimated that the short-term (prior to 2000) wholesale price of power would range between $20 and $24 per megawatt-hour[14] (MWh), compared to the pre-deregulation marginal cost (was effectively the wholesale price) of approximately $25 to $30.[15]

In order to conclude that that prices would fall from their historic levels, it was necessary to assume that supply would exceed demand, as we discuss in Section 4. Of greater concern, it was necessary for this assumption to be true in order to prevent the existence of market power by electricity generators.

These goals and the related assumptions underlying the mechanics of the restructuring were to become key factors in the ultimate failure of the new market.

---

[13] "ENOVA, Pacific Enterprises Unveil New Joint Venture," California Energy Markets, March 14, 1997, p 10. Taken from ELCIN, "The First States", October 1998, p. 2.
[14] A megawatt hour is defined as the production of one megawatt of electricity for a period of one hour.
[15] These figures depended on a variety of factors including natural gas prices. CEC ER 96, page 19.

SECTION 2: NEW RISKS IN THE NEW ENVIRONMENT

The restructuring of the electricity market brought with it a number of risks not previously faced by Utility shareholders and California consumers in the regulated environment. In this section we explore these new risks, some of which were inherent due to the physical properties of electricity and past construction of power plants, and some of which were created by state regulation. Our discussion groups these risks in terms of intrinsic volatility, market power, and supply shortages.

INTRINSIC VOLATILITY

Increased volatility in the price of electricity in the new environment was virtually certain given the physical properties of electricity. As describe below, electricity, unlike a physical product like corn, is a difficult commodity to trade in spot and derivative markets. As Severin Bornstein, director of the University of California Energy Institute, states:

> *"The physical properties of electricity production make the matching of supply and demand especially difficult, while the physical properties of electricity transmission and distribution make it critical that supply exactly match demand at every moment."*[16]

As a result, designing a market that satisfied the CPUC's goals of cheaper power, fair profit and uninterrupted supply was a challenging endeavor.

First, electricity cannot be stored economically, so it must be produced and consumed in the same instant. This exacerbates volatility, since producers cannot hold inventory when prices are low and deplete inventory when prices are high. As a consequence, forward and futures prices are reflective of expectations of future spot prices, rather than being essentially financing instruments with accommodations for storage costs. Moreover, there is only a limited ability to "import" power across regions. The electricity transmission grid is fixed in the short run, and transmitting electricity over long distances results in a 10-20% rate of

[16] Bornstein (2001), page 2.

dissipation.[17] Thus, participants in electricity markets face a commodity that is difficult to trade over time and over different geographic regions.

Electricity generation is also a capital-intensive business. Since generation is a flow process with high fixed costs relative to variable costs, managers have an incentive to run plants flat-out if they are run at all. This incentive partially explains why the regulators and the IOUs expected that prices would fall post-deregulation; marginal costs for the plants are low indeed compared to average costs. This led regulators to believe that generators would run most plants all out, all the time. Since marginal costs are low, a generator would want to produce as much electricity as possible to spread their significant fixed costs over a large volume base. Under conditions where a generator could not influence price, idle capacity would be costly.

With the exception of differentiation in time and distance, electricity is a true commodity, and the format of the Power Exchange as dictated by the California Public Utilities Commission sought to treat it as such. The PX used a uniform pricing model whereby the highest price bid by a supplier became the market-clearing price (MCP) paid to all suppliers. In the event demand exceeded supply, the MCP would be the lowest "demand bid" necessary to reduce demand. A demand bid is submitted by power buyers, and is the maximum price they will pay for power, or the price at which they will reduce their consumption. During the transition period, demand bids were not possible as the Utilities were required to purchase all power demanded by consumers. Under the assumption of excess total generating capacity, the bidding rules provided strong incentives for generators to bid their marginal cost at the PX, or risk being left out of the market.

In a competitive market, the uniform price should be the highest marginal cost of all the plants that are supplying power. Costs are highly variable between plants, due to unplanned heterogeneity in operational efficiency, construction of different plant types historically, and the existence (and planned expansion) of high marginal cost peak-load gas-fired turbine plants. As market demand increases, additional less-efficient plants will be turned on as price conditions dictate, effectively raising the highest marginal cost in the

[17] *Ibid*, page. 7.

market and therefore the market-clearing price – up to a point. Figure 9 illustrates the marginal cost curve of fossil fuel facilities.[18]

This price effect becomes especially pronounced as demand approaches capacity. In times of high demand, supply becomes highly inelastic, since most or all power plants are already running, including the least efficient, most expensive plants, whose high marginal costs will set the market clearing price. Since having generators exceed capacity for an extended period of time risks incurring costly damage, once all plants are running flat-out, no more power can be had. Once no more power can be had, all power becomes incredibly expensive, and the supply curve is essentially vertical. See Figure 1[19] for an illustration of an electricity market near full capacity at a single point in time (demand curve 1), and for an electricity market with a supply shortage (demand curve 2).

Power demand exhibits very high hour-to-hour, season-to-season, and to a lesser extent, day-to-day variance. Electricity usage can reach intraday crests in late afternoon or early evening that are more than 50% higher than overnight troughs, but customers face the same price regardless of when it is consumed. The same holds true with seasonality – in California, more power is consumed in hot summer months to fire air conditioners, yet consumers pay the same price as when electricity is less dear in the winter. This price uniformity was statutorily enforced in both the old regulated environment and the new deregulating market (from 1998-2002). As a result, demand is completely price inelastic in the short run since consumers are not affected by the changing costs in electricity. The only options available to reduce demand in peak periods are interruptible supply agreements signed by large commercial and industrial customers, which the ISO has the power to exercise, and blackouts.

Prior to deregulation, the implicit wholesale electricity price faced by integrated utilities was also determined by the marginal cost of production. However, in this case the cost was averaged over the marginal cost curve. For example, if demand on a particular day was such that three plants with equal capacity and marginal costs of \$20, \$30 and \$40 per MWh, respectively, were on-line, then the old implicit average wholesale price would be \$30. The total cost for 10,000 MWh would be \$900,000. The PX price however would be \$40 for

[18] Copied from Bornstein, Bushnell and Wolak (2000)
[19] The demand and supply diagrams labeled Figures 1 and 2 are adapted from Bornstein (2001).

all units, for a total cost of $1.2 million. As demand increases and intersects the MC curve at its steeper end, the difference between average marginal cost of the facilities on-line and the PX price becomes more extreme. This leads to an expectation of increased volatility relative to the old regime.

Despite the potential for severe price inelasticities and for supply / demand imbalances, maintaining equilibrium is critical. If demand exceeds supply in one part of the grid, it will adversely affect transmission over the entire grid. Since consumers do not alter their demand in response to price, and this demand must be met if any customer is to receive power, the demand curve for power is effectively vertical.

<u>*MARKET POWER*</u>

During the transition period, the price inelasticity of demand by consumers, the price-independent obligation of the Utilities to provide constant power service, and the inelastic supply at peak demand combined to make conditions ripe and incentives high for power generators to exercise market power. As illustrated in Figure 2, as demand approaches the limits of supply, the steepness of the supply curve implies that a small decrease in supply results in a large increase in price. Under these circumstances, it would be possible for a single generator to profoundly affect prices through supply and bidding decisions. More specifically, a generator could make super-normal profits by restricting supply through reducing output, selling to markets outside of California, or colluding to raise bids for power on certain high marginal cost plants. The extraordinary prices the supplier could enjoy on all its assets in operation could exceed the high opportunity cost of reducing output, selling to a lower priced market, or risking having potential power remain unsold. Naturally, regulatory bodies would be suspicious if a plant was idle for no reason, but plants do need to engage in maintenance routinely. The CPUC receives a list of idle plants and for what reasons they are idled, but does not have the ability to regularly confirm that plants are engaging in truly necessary or more optional maintenance. A large price increase reached through collusion could also be masked under the high marginal costs at high levels of demand.

Various regulatory actions were aimed at preventing the possession of market power and gaming on the PX by power generators. These were: the forced divestitures of generation assets, the capped rate of return on equity for Utility-owned generators, and the requirement that the Utilities sell all of their power and purchase all of their power needs from the PX. The divestitures were intended to prevent the abuse of horizontal market power by the IOUs in the long run by increasing the number of firms in the market. The capped rate of return on equity for these assets reduced the incentives for the IOUs to game the PX during the transition period. The third action was intended to further mitigate the potential horizontal market power by maximizing the amount of power traded on the PX, making it more robust, and effectively shrinking the size of each supplier relative to the market.

These steps were focused on making sure that the *Utilities* could not manipulate prices in the PX or outside markets over an extended basis to deter competition or inflate their own profits. While the CEC's ER 96 report expressed concern about the ability of *all* firms to exercise market power, the legislation was directed at the Utilities. These actions were reflective of risk management efforts by the state on behalf of consumers/taxpayers.

Ironically, the ability of *generating* firms to actually exercise market power was augmented as an unintended consequence of this legislation. First, the new owners of the generation assets had the ability to sell their power to markets outside of California, so a generator would sell elsewhere if the supply exceeded demand in California and price conditions in California were inferior to the price to be gained from selling outside the state. The regulators gave the right to generators to sell at any time, even when supply was tight, which is exactly when this action could abet market power exercise.

Second, PX demand bids that served to hold prices in check in the event of a supply shortage would not function during the transition period, since the Utilities could not curtail their purchases at any price. They were obligated to deliver whatever amount of power was demanded.

Third, a large percentage, which we estimate at greater than 30%, of California's generation supply would not be competing on the PX during the transition period because it has been designated as either "must-run" or "must-take"[20]. These facilities operated under specialized pricing arrangements and were owned or contracted by the Utilities.[21] This

[20] Our estimate is based on the capacity of nuclear facilities, hydroelectric facilities, and long-term contracts. This figure is likely to be understated by additional facilities that we did not recognize as "must-take" or "must-run."

[21] "Must-run" facilities are units necessary for reliability of the system, and "must-take" facilities include nuclear, hydroelectric, and power under contracts with QFs. “Must-run” facilities sold their power at prices set

reduced the size of the competitive market, increasing the size of each firm's capacity on the PX relative to the Utilities' capacity. This had the effect of increasing the probability of a new entrant successfully gaming the PX.

Lastly, the IOU's generation assets were sold to only five firms, for a total of eight firms that controlled the vast majority of the generation capacity. Minimizing the number of outside parties who sold power into California did not compel anti-competitive action, but it certainly increased the possibility of tacit collusion on a repeated auction such as the PX. The small number of firms also increased the opportunity for individual firms to exercise market power by predicting demand and withholding supply. Though any generator could gain a large price increase at the risk of not selling some power, a generator with aggregate capacity greater than the anticipated supply surplus could be *guaranteed* a positive outcome by withholding supply. Based on historical peak demand data, there were at least three new entrants for whom this was the case.[22]

To illustrate this last point, let us assume that there exists capacity of 50,000 MWh, and predicted peak demand for one hour on one day of 47,000 MWh, with a range of 46,000 to 48,000 MWh. The anticipated surplus is therefore 3,000 MWh, with a range of 2,000 to 4,000 MWh. If a generator with 5,000 MWh of capacity were to reduce output on this day to 1,000 MWh, it could then be *assured* of setting the MCP. This price would (in the absence of demand bids) rise to astronomical levels, and offset the lost revenue during hours of the day with less demand. This bid may not seem outrageous if the 1,000 MWh were the highest marginal cost units owned. Conversely, a firm of 3,000 MWh of capacity would not be assured of setting the MCP, and would risk selling none of its power. In actuality, a generator is able to carry out this scenario because power is bid into the PX the day before it is needed. Thus a generator does not have to actually reduce its power supply, it merely has to enter a bid pertaining to fewer megawatts. If the result is a shortage of power necessary to meet demand, the ISO must then purchase additional power at the MCP.

In a regime where generators are able to exercise market power, prices to purchasers become much more volatile. When supply and demand are in relative balance, it is probably not profitable for generators to engage in supply reduction, but when power is most needed

---

by the CPUC, while "must-take" facilities received the PX price but were required to bid their power into the PX at $0. CEC ER 96, page 24.

[22] Blue Ribbon Panel Report, Kahn, Crampton, Porter, Tabors (2001), page 9.

and most expensive, market power could be exercised. Thus, peaks in price in the deregulating environment will be much more pronounced than under conditions resembling perfect competition.

SUPPLY SHORTAGES

The premise that demand would not approach generating capacity in California was critical to maintaining an acceptable level of volatility. It is therefore instructive to examine this strength of this assumption.

It is clear that demand has followed an upward trend over the past few years. Figure 3 shows total annual electricity demand (in thousands of megawatt hours) in California from 1983 to 1999. Over this period, demand grew by a compound annual rate of 2%, with much of the higher growth rates taking place in the late 1980s (although a significant spike is visible in 1998). The main drivers of electricity demand are widely believed to be population growth and economic growth. Figures 4 and 5 show the relationship between population/output and electricity demand.

As can be seen, there is a seemingly strong relationship visible with both variables. This is confirmed by a simple regression analysis that we performed (see Table 11 for the full results), which shows that population is a predictor of annual demand at a significance level of 5%, and output at a level under 1%. In addition, the R^2 of the regression was over 90%. In this case, forecasting total annual electricity demand requires accurate estimates of economic and population growth, and it seems likely that these data would be relatively easy to find (at least over the long term).

However, the risk to the Utilities' shareholders and to consumers is not annual demand itself, but rather peak demand since electricity cannot be stored. On certain days of the year, usually in the summer when air-conditioning usage is highest, demand reaches its highest hourly point, and it is at these moments that capacity issues are most crucial. Peak demand is clearly related to annual demand (the correlation over the years 1988 and 1999 between the variables is 90%). However, trying to predict it using population and state output is not as easy as with annual demand. The results of a regression attempting to do this are summarized in Table 12. Unlike the above model, the independent variables are insignificant (with no trace of multicollinearity among the variables). Peak demand also exhibits more volatility than annual demand. Although both variables grow at an average rate of about 2% a year, the coefficient of variation of annual demand is 1.68 versus 3.17 for peak demand.

We can look back in time at actual forecasts of peak demand and assess their accuracy. The California Energy Commission (CEC) has been making long-term forecasts for a number of years. Table 1 shows the CEC's expectations for peak demand over 1995-2000, as forecast in their 1988 electricity report. As can be seen, the forecast errors do not seem meaningful on the surface, averaging a 3% overshoot. However, with peak demand even small forecast errors are critical when supply is short. Figure 7 shows total reserve capacity (as a % of total capacity) on the day each year with the highest peak demand. Also shown is spinning reserve capacity, which is defined as that which can be brought on line in less than 10 minutes. There is a clear downward trend in the amount of spare peak capacity over the last decade, especially in the important spinning capacity area that is the first defense against blackouts. With peak capacity falling to under 5% in 2000, it is clear that forecast errors of magnitudes such as those made by the CEC in 1988 for 1995 (5.4%) and 2000 (6%) are enough to cause shortages.

Given this, it is important to analyze whether new capacity would be likely to enter the market. As discussed above, prices in the market are determined by the intersection of demand curve and the cumulative marginal cost curve of the generators. When total capacity exceeds demand by a considerable margin, there is no incentive to build new plants, as the price prevailing in the market is not high enough to cover the total costs of entry (marginal cost plus fixed and capital costs). However, when demand shifts out (as it does on average by 2% per year), prices will eventually rise to the point that capacity introductions become profitable. This process is illustrated in Figure 6 below. As demand shifts out from D1 to D2 due to the growth factors cited above, the price rises from P1 to P2. As long as the average total cost of a new plant is below the expected price level of P2, new entry will occur. Entrants will build capacity in anticipation of demand growth, and in the long run equilibrium, electricity prices will equal the minimum average total cost of entry. In ER 96, the CEC forecasted that demand would begin to exceed supply “in the early years of the new century”, and that new capacity would not be added until then. They further expressed confidence that this would be sufficient to provide adequate incentives to build new plants.

The complacency regarding new supply introduction was driven by a poor application of the relationship between forecast demand and the capacity investment decision. In particular, the above model works well when demand growth is steady and predictable. While this may be true of long-term demand, peak demand is a different animal, exhibiting much more variance. Add to this the lead-time of plant construction (typically over two years), and the large, lumpy capacity increments involved, and the investment decision becomes even more difficult. Here, we point to anecdotal evidence that Utilities in the pre-deregulation United States tended to add capacity in herd-like investment waves, where each firm's decision was predicated on the actions of others[23]. The incentives for new generators to build capacity, as detailed above, are radically different from those that the integrated IOUs faced before deregulation, as we discuss in Section 4.

Other reasons for the difficulty of adding new supply in the 1990s that are peculiar to California have been well-documented in the press and academic research[24]. These include the NIMBY (not in my back yard) attitude of local communities, the lengthy regulatory approval process and strict environmental regulations. We don't deny that these factors exacerbated the supply crunch, but we argue that the economic fundamentals of the market make demand predictions difficult to make over the short term, and therefore complicate the forecasting of new capacity introduction. We believe that the various parties to deregulation, including regulatory bodies and the IOUs themselves, did not take these economic and environmental issues into account when forecasting the likely supply situation a few years ahead of deregulation. This resulted in the overly-complacent attitudes to risk visible from all participants in deregulation.

[23] GE vs. Westinghouse in Large Turbine Generators (A), HBS case 9-380-128

[24] e.g. A State of Gloom, The Economist, 20th January 2001, Joskow (2001), page 4.

EVIDENCE OF VOLATILITY AND MARKET POWER ABUSES

A major study completed in August 2000 deals with these two issues[25]. The authors attempt to analyze what market prices would have been in the absence of market power abuses, to see whether prices exceeded competitive levels. To do so, they develop a model of industry marginal cost, then measure to what extent prices vary more than this, and estimate how much of this is due to market power. A graph excerpted from this paper illustrates the extent to which prices were more volatile than the imputed marginal cost during peak months in the summer of 1999 (reproduced in Figure 8). Clearly, the market-clearing price shows huge volatility relative to marginal cost. In terms of market power, the authors find that prices exceeded the expected competitive level by an average of 18.3% over the 15 month period studied. Moreover, most of this effect is concentrated in the summer months when demand pushed the price further up the marginal cost curve and it became easier to manipulate the market.

The Blue Ribbon Panel report on pricing in the deregulated California market cites this and other studies when it concludes that:

> *"A substantial number of responsible studies have concluded that the extreme price spikes in recent years, at times when demand would in any event have pressed hard on available capacity, were magnified by some large generators "gaming" the system…"*[26]

The final word on market power comes from the CPUC itself, which in May 2001 announced plans to launch legal action against the generators. According to CPUC president Loretta Lynch, generators systematically shut down plants when the state grid manager issued statutory power alert notices that strong demand was likely. She was quoted in the LA Times as saying:

> *"I would argue in fact . . . it's the coordinated behavior of a cartel…".*

[25] Borenstein, Bushnell and Wolak, (2000).
[26] Blue Ribbon Panel Report, Kahn, Crampton, Porter, Tabors (2001).

SECTION 3: THE DECISION TO HEDGE

We now examine the risk management incentives facing the Utilities. The state's risk management incentives are clear and lay in looking after the public good. The whole purpose of deregulation was to benefit consumers of electricity through lower prices, and much of the restrictions placed on the Utilities were designed to ensure that the nascent competitive market was not stifled at the outset by the incumbent firms. We examine the state's actions in greater detail in later sections.

Modern financial theory has hypothesized that risk management increases the value of the firm through reducing the variance of its cash flows[27]. However, firm value does not merely increase through reducing risk exposure. After all, in a perfect Modigliani-Miller world, the firm's shareholders can usually diversify away the risk of commodity price increases themselves, and so at the very least would be indifferent to management doing it for them. This is equivalent to saying that risk management does not reduce the firm's cost of capital. Hedging can therefore only increase the value of the firm if it increases expected cash flows. To do so, we have to relax the restrictions of MM proposition I, and introduce transaction costs and taxes. In this case, risk management adds value through three main areas: reducing the expected costs of financial distress, increasing a firm's debt capacity and allowing it to benefit from a convex effective tax schedule. In view of subsequent events (increased debt capacity and reduced taxes are less relevant for a firm in bankruptcy and making losses), we focus on the first reason.

The costs of financial distress include both direct costs such as legal fees, and indirect costs such as reduced ability to take advantage of positive-NPV projects, difficulty in dealing with suppliers, and inefficiencies caused by court oversight of decision-making in bankruptcy. To take an example from subsequent events in the California crisis, PG&E, found it more difficult to do business on the PX during 2001, as generators were unwilling to supply it due to its worsening financial position.

> *"As a result of the California energy crisis and its impact on the Utility's financial resources, … the Utility became unable to pay the full amount of*

[27] Strategic Risk Management, Smithson, Charles and Clifford Smith, p. 393 The New Corporate Finance, McGraw Hill 1993

invoices received for wholesale power purchases … The Utility had no credit under which it could purchase wholesale electricity on behalf of its customers … and generators were only selling to the Utility under emergency actions taken by the U.S. Secretary of Energy".[28]

It seems clear that the likelihood of increasingly volatile input prices would lead to higher expected costs of financial distress. The probability that the firm will be unable to cover its fixed financing obligations is increased as its income volatility increases. In the case of the IOUs, the problem is especially acute, since downstream prices were capped, and in addition, the Utilities had a legal obligation to supply all power demanded by their customers, so could not shut down when their operation was unprofitable.

The situation is not as simple as it seems: Utility losses on power sales were added to their stranded cost accounts. This means that in general, the firms would be able to recover their losses from consumers through the rate freeze. Three conditions must apply for this to work: wholesale prices have to fall (so that fixed downstream prices actually benefit the Utilities), the companies must be able to absorb losses in the meantime, and they must also be confident of recovering the stranded costs before the mandatory write-off in 2002. If any of these conditions are violated, then volatility in prices becomes a significant concern for the viability of the Utilities, and the firms' shareholders would benefit from risk management.

If the Utilities expected wholesale prices to exhibit no price drift but merely to become more volatile, then we might expect that they would have an incentive to engage in risk management. However, this belief was not universally held. It is clear from the way that deregulation was set up that industry participants felt that wholesale prices were likely to fall. If the utilities were of the opinion that wholesale prices were likely to fall more than the market expected, then the case for hedging becomes less clear-cut. As Rene Stulz argues[29], managers don't usually use hedging contracts to merely minimize volatility of expected cash flows, as financial theory would predict. They tend to engage in selective risk management, trying to reduce the probability of 'lower tail' outcomes while maintaining risk exposure where the firm has a comparative advantage in bearing risk. We might argue that the IOUs'

[28] PG&E 2000 10K page 48.
[29] Stulz, Rene, Rethinking Risk Management, in The New Corporate Finance p. 411.

incentives to manage risk may be less than at first apparent. In that case, we are assuming two things: firstly, that the utilities' forecasts for future spot prices were different to those of the market, and secondly, that the firms felt that they had a comparative advantage in predicting the future direction of prices.

Clearly, if the utilities expected that wholesale prices would fall over time, it would not make sense to enter into 25 year forward purchase contracts for most of their forecast demand at a price higher than they expected to prevail in the spot market, even if they did foresee the risk of increased volatility of input prices. Instead, we would expect the firms to run shorter-term renewable hedges on a reduced amount of their exposure. We look at this issue in greater detail in the next section, but it seems clear that the IOUs did not use what little hedging capability was open to them. Part of the reason for this could be driven by a feeling that they had a comparative advantage in predicting price drift. They may have felt that, as the incumbents in the market for the past century or so, they would have a good feel for how much more efficient generation could become in a competitive environment. However, arguably the competitive market was a completely new animal that the old regulated Utilities could not have had expertise in. In the end, we may never know the exact motivations behind the companies' actions, but it is clear that there could be good reasons for firms not to hedge all their exposure given their expectations of future price movements in the market. On the other hand, in order to justify the increased risk the IOUs assumed, as described next in Section 4, the managers would have to have been supremely confident in their expectations, or else simply ignorant of the risk that they were assuming.

PART 4: RISK MITIGATION AND AUGMENTATION ACTIONS

In this section we analyze how decisions made by the IOUs and limitations imposed by the state with respect to three areas impacted the risk profiles of the IOUs. Those areas are: the use of financial hedging instruments, the divestiture of generation assets, and the opportunity for new investments. We will see that the CPUC severely limited the ability of the Utilities to manage electricity price risk in the new environment, both through regulation and incentive structures. Even within the bounds of what they *could* do however, we find that the Utilities took actions that, on the surface, seem to increase their financial risk. Lest we give the impression that the state of California was being indiscriminately malevolent, let us review one of the state's goals: the creation of a competitive market. In order to create a competitive wholesale market for electricity, generation assets were first divested by the IOUs resulting in a market with multiple competitors. In order to maintain this fragmentation, initially the Utilities were required to purchase electricity from the new electricity marketplace, the California Power Exchange (PX), instead of contracting directly with generators in the spot or forward markets. Engaging in this contracting, the CPUC feared, was tantamount to the IOUs effectively repurchasing their plants. Although the contracts would be arms-length, the IOUs' ability to tie up supply might affect competition in the downstream businesses. Thus the state was managing *its* risk in implementing rules that were intended prevent the Utilities from possessing market power.

In return, the CPUC allowed the Utilities to manage their "risks" through the retail rate freeze which was imposed. These "risks" were not risks in the sense that losses could occur, but rather the "risk" was that past investments would not earn the return promised by the state prior to deregulation, an important distinction as we will discuss. Such was the risk mentality as deregulation dawned on the electricity market: the state was concerned with consumers, while the IOUs were concerned with their shareholders.

FINANCIAL INSTRUMENTS

If management of the Utilities in California had gone through the thought experiment outlined in Section 3 and did decide that they needed to hedge their operating risks, there are a number of ways they could have approached hedging a negative exposure to a rise in electricity prices (short electricity). The best and most natural hedge would be to own electricity generating assets, but, as discussed in depth above, the IOUs were forced to divest a certain amount of generating capacity in an effort to prevent them from exercising vertical market power and, as discussed below, had incentives to divest more than the statutorily mandated amount. In the absence of enough generating assets to cover their electricity needs, the Utilities could have contracted bilaterally with marketers and generators for off-exchange forward contracts or swaps. As will be discussed below, these contracts are not without limitations from both the Utilities' and the regulators' perspectives

Another natural choice could be the use of exchange-traded electricity derivatives. Sensing a market opportunity, NYMEX started trading standardized electricity futures and options contracts based on two different delivery points in California in 1996. By purchasing (going long) futures or call options for electricity, the Utilities could offset their losses if electricity prices went up (from having to buy expensive power on spot markets) by reaping gains in the derivatives markets (from increases in the value of their future or option contracts).

The exchange-traded derivatives offered the advantages of improved liquidity over generating assets or private contracts but could never be a perfect hedge against the utilities' exposure to electricity and gas prices. First, there was basis risk in the securities. Though the no-arbitrage rule suggests that the futures price at expiration should equal the spot price*,* in the meantime there can be substantial disparity. This is even more true with electricity than with other commodities since, as discussed earlier, electricity can not be stored and is therefore effectively a different product at every singular moment.

Moreover, convergence between the spot and future price may not occur if arbitrage is not possible, which may be the case if delivery is difficult or expensive. Since electricity is costly to transport, even at expiration, there is no reason to believe that electricity at the California-Oregon Border (the contract delivery point) will necessarily cost the same as electricity in the energy-guzzling Bay Area where the Utility might actually need electricity.

This problem is serious, but can be recognized and accounted for in hedging calculations when there is a consistent difference between the two prices, but if the two locations are poorly correlated, the problem is hard to correct. In theory, non-convergence risk can also be mitigated by taking delivery, but in fact that may not have been possible for the Utilities, who had specific requirements about buying and selling power through the PX and not through outside vendors. Finally, the structure of the futures contract is delivery for peak periods over a month, but the prices on the PX are determined on a daily basis. Ample price fluctuation can happen in a month, given the extreme volatility in electricity prices, which means again that the spot and futures price will not converge, leaving the utility exposed.[30]

Futures and options contracts also have term problems. While the utilities faced a high level of price risk for the two to four years[31] until the market was completely deregulated, the maximum contract length offered by the NYMEX was 18 months. This is a frequent problem with futures markets that is typically addressed by performing a "stack and roll" futures transaction. In a stack and roll a company will buy enough of the longest term future to satisfy their total expected hedging need over the period of exposure. In this case, an IOU could have bought four years worth of 18-month electricity futures in year one. Then, as the sets of futures expire, the IOU renews them all except for the amount represented by the first 18 months of exposure. By 18 months before the exposure is set to end, the utility has only 18 months worth of electricity hedged in a future.

Stack and roll techniques are problematic. If the Utilities have greater confidence than the market that prices will decline, and their bet turns out to be correct, the utility could actually benefit from the interim price risk in a stack and roll, though less than if they had elected to remain unhedged. Conversely, there is interim price risk since the contracts needs to be renewed every 18 months. Moreover, a stack-and-roll ensures minimal price risk at the end of the hedged period, but in the interim, bad things can happen, since in the early years of the hedge exposure to price movements in the futures contracts is much larger than the offsetting natural short position. For example, if electricity prices decline quickly and substantially (as was expected), the four years of long future contracts will earn huge losses initially, while gains will be limited to the short position today. The firm must have enormous

[30] Stoft, *et. al.* (1998), page 30.
[31] The maximum length of the transition period

capital reserves to cover these derivatives losses, even if it eventually gains from the consistent low prices. It is this problem that caused the U.S. trading subsidiary of Metallgesellschaft, who employed a stack-and-roll futures position to offset its short petroleum position, to liquidate its contracts when they reached a paper loss of $1.3 billion.[32] Buying call options rather than futures positions can mitigate these effects to a certain extent, but options are also have a significantly higher premium associated with them to reflect this advantage.

Exchange-traded electricity contracts were not used extensively by the Utilities due to tight restrictions placed on them by the CPUC, the Federal Energy Regulatory Commission (FERC) and other regulatory bodies. These restrictions were not without merit. The CPUC's primary concern was making sure the Utilities could not engage in back-door spot price manipulation through commodities markets. They foresaw scenarios where the Utilities manipulated the PX spot market to earn profits in the derivatives markets to the detriment of generators. Moreover, the CPUC was concerned about the Utility's ability to actually deliver or take delivery of electricity if a NYMEX futures contract was held to expiration, given the CPUC's requirement that the IOU's generating assets sell power to the PX and their distribution arm buy from the PX.

Lastly, the question of who pays for the hedging was an important one. In their original filings to the CPUC requesting permission to trade derivatives, SCE was able to recover fees paid to establish derivative positions, but not negative changes in the position's market value, from their stranded cost account. These were not insubstantial sums; when SCE liquidated its natural gas call options in October 2000, it made $190 million dollars.[33] PG&E originally requested that shareholders bear the cost and reap the benefits of hedging, since they also bear the costs and reap the benefits of spot electricity price movements. As SCE pointed out in regulatory proceedings, this gives PG&E a big incentive to manipulate spot prices up to lose money on purchasing spot power, which extends the monopoly period, while earning money from the derivative contract on the side. PG&E's original request for basically unlimited trading in gas and electricity contracts was denied in 1997. The CPUC very recently granted approval for limited trading in gas to offset the PG&E gas, but not

[32] Stoft, *et. al.* (1998), page 30.
[33] SCE 1999 annual report to shareholders.

electricity, business.[34] It is worth noting that the CPUC objected to some very specific qualities of the PG&E request that probably could have been satisfied by the Utility while accomplishing the goal of reducing exposure to an increase in electricity prices.

Another natural hedge would be to engage in long-term supply contracts with generators calling for either delivery of electricity or payment in cash of the difference between the current spot price and a previous agreed upon price. These are effectively privately negotiated forward or swap contracts, the form of which is similar to those used in other deregulated electricity markets, such as the United Kingdom's. Many, including Bornstein (2000), argue that variations on forwards and swaps are the best method for regulators to have Utilities hedge in deregulated environments. They are not a panacea, however. The problem with forwards is that,

> *While long-term contracts reduce variability in the cost of buying power, Long-term contract prices are unlikely to be below spot prices on average...*On average, a purchaser buying power in forward markets (or through long-term bilateral contracts) will not receive lower power costs than a purchaser buying in the spot market [author's italics].[35]

In fact, there could only be a systematically lower price in the forward market if sellers are systematically more risk averse than buyers, or if expectations on future price movements systematically differ between buyers and sellers.[36] In the California case, it could be argued that the utilities had good reason to be more risk averse than generators, since generators could effectively hedge their input price risk, leaving them well-hedged if they engaged in forward contracts with utilities. In contrast, the utilities faced a volatile input price and no means to hedge their sale price. As a result, a utility can substantially reduce variability in their purchase price, but only at the cost of paying a higher price over time. Whether theoretically the Utilities should have engaged in hedging is discussed in Section 3.

In some sense, a market in which Utilities are perfectly hedged with long-term forwards is similar to the regulated world. Utilities earn stable but sub-optimal returns, while

---

[34] SCE and PG&E Annual reports, 2000 and 1999, respectively.
[35] Bornstein (2001)
[36] Bornstein, Bushnell, Knittel and Wolfram, (2000).

generators bear the electricity and input price risk and get a premium for it. This similarity was not lost on the CPUC, which with the FERC barred the use of forward contracts and other forms of off-PX buying before the crisis occurred. No wonder: though the Utilities were barred from holding a certain level of generating assets, they could effectively exercise control over the divested assets *via* a *de facto* sale-leaseback with a third party. The CPUC was concerned that through extensive use of forwards, Utilities could effectively block entrants into the customer service segment by locking up enough generating capacity, and that the volume discounts that the Utilities would likely gain from buying forwards in bulk would effectively prevent entrants from competing on price since they would not be able to secure the same volume discounts – the volume was already accounted for. It was not until 1999 that the Utilities were allow to engage in block forward purchasing contracts through the PX and not until 2000 was SCE actually engaged in bilateral forward contracts. Even then, the vast majority of power continued to be purchased on the spot market.

As discussed previously, the restrictions on forward contracts were intended to prevent exercise of market power by the Utilities and to thereby lower prices and reduce volatility by encouraging competition. Ironically, the restrictions had just the opposite effect. Many have argued that the widespread use of forwards would have a palliative effect on the extreme volatility that has characterized the market since Summer 2000.[37] The prices of bulk forward contracts are inherently more stable than spot prices since the high price volatility of electricity is spread out over a longer time period. Moreover, forward contracts can actually help reduce horizontal market power and discourage gaming by generators in the PX. Generators that sell a large portion of their capacity forward have less to gain through spot price manipulation and have a harder time doing it. The decreased gaming creates a virtuous cycle of reduced volatility since more generators will be willing to enter a market with more stable prices. Entrants will be more able to secure financing if electricity prices are more certain, which will have the effect of reducing the supply crunch, lowering prices, and reducing further the potential for collusion and volatility.[38]

It is interesting to note that although there were regulatory limits on how much buying could be done on a block forward basis, the Utilities were (and still are) well below their

[37] Bornstein (2001); Porter (2001), Nordhaus, Shapiro, Wolak (2000). MSC of the ISO (2000).
[38] FERC November 1, 2000. p21

limits.[39] The Utilities to this day say they do want to engage in forward contracts, but would prefer to do so off-PX on a bilateral basis. It now appears that they now have some regulatory support for their position; FERC has endorsed the notion and the Market Surveillance Committee of the ISO has gone so far as to say they should be required to do so.[40]

In many markets with volatile input commodities, firms can use financial instruments and long-term contracts to hedge their price risks. In California, such actions were largely prohibited in order to hedge consumer risks and ensure a competitive market. It is easy to use the regulators as a tar baby for the colossal gaffe of the utilities being unhedged in the face of such an obviously dangerous input price exposure. However, the regulators, undoubtedly with the Orange County debacle fresh in their minds, were understandably cautious about letting the Utilities hedge with swaps, forwards or derivatives contracts, especially when it was clear to them that the potential for the utilities to impede competition and game spot prices was real. It is true that the prudent and correct use of exchange-traded or over the counter forwards and other derivative contracts would have helped reduce spot price volatility and prevent the financial distress of the utilities and the subsequent electricity investment by the state. It is also true that we cannot be confident that entities that had little experience in trading complex derivatives, especially compared to their likely counterparties, should have been expected to use derivative contracts properly and would not have been the next cautionary derivatives tale like Proctor & Gamble or Metallgesellschaft.

That said, to the extent that low-risk contracts were permitted, the inaction by the Utilities indicated that the available contracts were viewed as unattractive. Indeed, when given the chance to engage in block forward contracts, whether for greed, discomfort, or both, the utilities used them only sparingly, a fact that bestows a fair measure of culpability for the IOUs financial crisis at their own feet.

DIVESTITURES

As previously mentioned, the Utilities were required to divest at least 50% of their fossil fuel-powered generation assets. These divestitures had two primary implications for risk management: they directly impacted the exposure to electricity prices, and affected the

[39] Blue Ribbon Panel Report, Kahn, Crampton, Porter, Tabors (2001), page14.
[40] *Ibid*

length of time the rate freeze was effective. As generation capacity is the perfect hedge against wholesale electricity prices, it is useful to examine the Utilities' motivations in divesting such a large proportion of an asset that, with hindsight, would have reduced their exposure to the volatility of market prices.

The CPUC gave the IOUs an incentive to undertake divestitures beyond the requirements by specifying a 6.77% rate of return on equity that the IOUs could earn on these assets as compared to 11.60% prior to deregulation.[41] We can estimate the magnitude of this incentive by looking at SCE's financial statements.[42] We estimate that at the end of 1997, the last year before the divestitures, the value of SCE's net generation assets was $5.7 billion. Assuming a capital structure that mirrors SCE's overall regulated equity component of 48%, gives a book value of equity in these assets of $2.7 billion. The decreased return on equity results in reduced profits of $132 million per year ([11.60% - 6.77%] * $2.7 billion), or an economic loss in perpetuity of $1.1 billion, based on an 11.60% cost of equity and zero growth. At the end of 1997, the market value of Edison International's equity was $10.2 billion. Thus the "incentive" to divest was at least 11% of the firm's equity value.

As you would expect from a value maximizing firm, the IOUs chose to divest far more of their assets than required. As indicated in Table 2, in 1997 fossil fuel-powered assets represented 45% of the IOUs' generating capacity. The divestitures represented 43% of their fossil fuel assets, and 70% of their total generating capacity.

While the above analysis indicates a clear incentive to divest, the ability of the IOUs to manipulate the regulatory asset balance related to the stranded costs of generation presents us with less clear incentives. When the balance of this regulatory asset reached zero, the retail price freeze would be lifted and the Utilities would be free to set market prices. In accordance with the deregulation, the extent to which the market value of the generation assets realized upon sale exceeded their book value reduced the regulatory asset, with the opposite situation increasing the asset's value. Under the assumption that wholesale prices would fall, and therefore a longer period with fixed retail prices was good for the Utilities, they would want to maximize the value of their regulatory asset base. Most of the IOUs' generation plant market value was above book value (as evidenced by actual sales, where the total divestiture proceeds

[41] The new owners of these assets would be able to earn a market rate of return.
[42] SCE was chosen only due to the availability of more detailed information.

exceeded book value by 74%). Since sales would therefore reduce the stranded cost account and the fixed price period, this was a disincentive to divest.

A further issue to be considered by the IOUs in determining the optimal divestiture level is the protection that generation assets give them from volatile wholesale prices. They would weigh the costs and benefits of divestitures; on the benefit side, avoiding a sure loss due to the change in allowed return; on the cost side, a reduced stranded cost recovery period and increased expected cost of financial distress. Since we know that they did divest most of their generation assets[43], we hypothesize that the financial incentive overrode the potential costs in the mind of the IOUs. It is arguable whether an analysis of this sort was reasonable: however, the firms are more likely to have made the decision that they did if they underestimated the cost side of this equation.

The divestiture decision became more complex as the deregulated industry environment unfolded. Once the Utilities realized their exposure to a market which was characterized by the prolonged necessity to 'buy high and sell low', their motivation was to remove the retail price cap and pass through the higher wholesale prices to consumers. As long as their stranded costs remained unrecovered they were prevented from doing this. In this case, the benefits of further divestiture (allowing floating retail prices) probably outweigh the costs (less hedging ability). With hindsight we can see how important this was to the Utilities. In mid-1999 SDG&E became the first to emerge from the fixed rate regime, helped by its decision to divest the majority of its capacity. In August 2000, with the electricity market already out of control, PG&E attempted to do the same through the transfer of its hydroelectric assets to its unregulated affiliate, PG&E Generating, based on its market value. The company believed that this transaction would allow a credit of $2.1 billion to the regulatory asset, representing the difference between the assessed value of $2.8 billion and the book value. This amount would complete the recovery of PG&E's generation-related stranded costs and allow it to remove its price freeze. Unfortunately for PG&E, the regulators disallowed the transaction, and this decision contributed to PG&E's decision to file for Chapter 11.

---

[43] They probably would have divested more if they could: most of their remaining capacity was hydro and nuclear, which as explained earlier is difficult to sell.

With hindsight, it is obvious that maintaining as much generating capacity as possible would have been in the Utilities' best interests, in that generation assets rise in value to offset the decreased value of the electricity wholesale business. However, *ex ante* there existed a strong financial incentive to divest. As the crisis unfolded, the potential to remove the retail price cap through divestitures probably outweighed the value of the assets as a hedging tool. By the time this incentive kicked in, however, the onset of the financial crisis resulted in the state preventing further divestitures.

<u>INVESTMENT AND CAPITAL STRUCTURE DECISIONS</u>

The IOUs' decisions to invest in new opportunities and the means by which they were financed strongly affected the risk profile of the Utilities. Prior to deregulation investment decisions (in a new generating facility for example) were tightly controlled by the CPUC. Also, the return on equity of these firms was set by the CPUC. Under this regime, the only way to produce higher profits was to grow the book value of assets and common equity. Unlike the managers of firms in other industries who, in an ideal world, would not grow their firms unless there existed positive NPV projects, the managers of the IOUs were virtually guaranteed a positive NPV. These returns on equity, which are reset each year, have recently varied from 10.60% to 11.60%. Abuse of this 'phenomenon' was limited however, by the need for regulatory approval of new generation assets and the imposition of capital structure constraints. The data in Table 3 confirms this incentive to grow, or at least maintain the amount of total assets and common equity. The CPUC imposed capital structure defined a maximum long-term debt-to-capital ratio of 46%, and preferred equity-to-total capital ratio, of 6%, with the remaining 48% in the form of common equity.

While the restructured environment created new investment opportunities with no constraints on returns or capital structure, Utilities were still regulated to a large degree. In the new environment, they were able to earn additional profits through performance incentives but faced the possibility of not recovering their stranded costs, or -- worse yet -- recovering losses from power sales should this occur.

Initially, the Utilities were flush with cash from the sale of assets and the rate freeze (since wholesale rates did indeed drop). There was also flexibility in the capital structure constraints.[44] Clearly, there was the opportunity and ability to export capital from the Utilities and put it to better use. It is reasonable to assume that the IOUs felt they had a competitive advantage in the emerging, energy-related businesses, thus providing the potential for above market returns. As we will see, in aggressively taking advantage of these opportunities, the IOUs greatly increased the risk profile of the Utilities, thereby increasing the risk to taxpayers in the event of a bankruptcy. Table 4 shows the varying degrees to which the Utilities responded to the new incentives. Note that the peak balances of assets and common equity occurred in 1995, the year in which AB 1890 was passed by California's legislature. From 1995 to 1999, PG&E's assets and common equity declined by 20% and 36%, respectively.[45] Over this time period SCE's assets and common equity declined by 3% and 39%, respectively. For SDG&E the figures are less dramatic, with declines of 2% and 14%, respectively. We will discuss later how this contributed to the relative financial health of these firms today.

Despite paying out less cash in the form of dividends, all three Utilities either paid out more in dividends as a percent of their cash flows from operations, or augmented their dividend payments by repurchasing their shares from their Parent company, or in one case issuing a loan to the Parent. As shown in Table 5, over the period from 1997 to 1999, PG&E, SCE, and SDG&E distributed 63%, 87%, and 73% of their cash flow from operations, respectively. Comparable figures from 1992 to 1996 were 35%, 38%, and 33%, respectively.

Naturally the combination of fewer assets and larger cash distributions resulted in increased leverage and decreased debt service capability (see Tables 6 and 7). PG&E's average annual cash flow from operations from 1997 to 1999 was 23% lower than the average from 1992 to 1996. For SCE and SDG&E, the comparable figures are 22% and 17% respectively.[46] The leverage ratio of all three firms held steady between 1992 and 1996, with a sudden jump in 1997 which persisted though the onset of financial difficulties in 2000. At the end of each year and for each firm, the leverage ratio was substantially above the 46% maximum set by the CPUC. It was not until 1998, when the divestitures began to be consummated that the firms' ability to service debt suddenly deteriorated, which can be seen in the boxed area of Table 7.

[44] The flexibility was that these standards only had to be met on average.
[45] We measure though 1999 rather than through 2000 since the energy crisis in 2000 tends to distort the interpretation of the IOUs' intentions.
[46] 1992 and 1993 data for SDG&E are not included as it was unavailable.

Meanwhile, the total assets and common equity of the Non-Utility subsidiaries increased substantially. Only Edison's Non-Utility businesses were of a significant size to require reporting as a business segment prior to 1997. In aggregate, the Non-Utility businesses of Edison and PG&E Corp. held assets and common equity of $6.8 billion and $1.5 billion, respectively, in 1996 (see Table 8). By the end of 2000, the total assets of the Non-Utility businesses had ballooned to $32.0 billion, while common equity invested stood at $5.6 billion.

These investments were partially funded by using the large, steady cash flows from the Utilities. Cash was transferred from the Utilities to the Non-Utility businesses using various avenues. One way was paying dividends which where held at the Parent and not distributed to the IOUs' shareholders. Another way was for the Utility to repurchase its own shares from the Parent. In the case of Edison and PG&E, the Utility "prepaid" its income taxes to the parent.[47] In order to estimate the magnitude of these transfers, we compare the dividend payments and share repurchases made by the Utilities to those made by the Parent, remembering that the Parent held 100% of the common stock of the Utilities. The most clear example of this occurred with PG&E Corp. and its utility PG&E. Table 9 shows cash paid to shareholders through dividends and share repurchases, and to the government in the form of taxes. Amounts paid by PG&E were paid to PG&E Corp., while amounts paid by PG&E Corp. were paid to either shareholders or the government. The top row shows, just for reference purposes, the cash flows from operations of National Energy Group, the non-utility (competitive) businesses of PG&E Corp. In looking at these figures, it is important to note that National Energy Group appears to not have any net operating loss carry backs that would account for the unusual tax payments. It can be seen that, while National Energy Group did not contribute any funds to tax payments, dividends, and stock repurchases, with the exception of the 1997 stock repurchase, it actually received more than $1.2 billion through these transactions from 1997-2000.[48] This is in addition to National Energy Group's positive cash flows of $533 million. Table 10 shows a nearly identical situation with SCE and Parent

[47] In the pending case Richard D. Wilson v. Pacific Gas and Electric Company, the plaintiff alleges that PG&E Corporation overcharged the Utility $663 million (from 1997 - 1999) and declines to voluntarily return these funds under a "tax-sharing arrangement under which PG&E Corporation annually files consolidated federal and state income tax returns for, and pays, the income taxes of PG&E Corporation and participating subsidiaries." This figure matches exactly our computation during these three years.

Edison, with a net cash flow to Edison's Non-Utility businesses of $1.1 billion. Our purpose is not to opine on the legality of these transactions, which is currently being challenged in court, but merely to show the profound impact PG&E's capital decisions had on its financial risk.

If the Utilities were stand-alone firms, it would be easy to conclude that the financial risk of the Utilities was larger, and therefore that the shareholders faced additional risk. If it were the case that these were all equity firms, they would merely have to convince investors that they have positive NPV projects if they needed more capital. However, matters are complicated because the existence of leverage in a financial distress scenario creates a high probability of the value of the investment reverting to bondholders rather than shareholders.

The Utilities are not stand-alone firms however, and much of the cash was not sent to the ultimate shareholders, but rather to the Parent company, a direct shareholder. Thus, the risk management implications of these investments are not completely obvious, since the Parent company is not well diversified. The Parent could, if it wished, transfer assets at will between the two subsidiaries to stave off financial distress. Once again, the risk management needs of the state influenced this decision. This resulted in a California state law that ensured that managers would *not* have the incentive to make such transfers in times of financial distress. In order to protect consumers against the volatility of these new Non-Utility businesses, the Utilities were not allowed to guarantee the debt of the Non-Utility subsidiaries, and *vice versa*. There was no recourse for the debtholders across subsidiaries. In order to better understand this, it is useful to think of the debtholders as owners of default-free debt and writers of a put on the assets of the firm with a strike price equal to the value of the debt-- but only on the *Utility's* assets. In this way, the increased financial risk faced by the Utility did not necessarily translate into increased financial distress for the entire firm. Therefore, the IOU managers (acting on behalf of shareholders) would have little incentive to transfer assets back into the distressed subsidiary.

[48] A recent audit by the CPUC indicated the value of such transfers at $838 million from 1997-1999, while our estimate of this time period is $869 million.

Moreover, the ability of the managers to infuse capital into the Utilities was limited. This is because the cash transferred to the Non-Utility businesses was used to purchase illiquid assets, such as power plants, which could not be converted to cash in short order. Also, in the event of a financial crisis, it is questionable whether the IOUs' shareholders would make a new investment in the firm.So the question remains: Did the IOUs increase the risks to their shareholders through their investment and leverage decisions? The answer is that the shareholders only face additional risk to the extent that the debtholders have some probability of gaining access to the Non-Utility assets by court order. Otherwise the Parent could simply transfer cash to the Utilities. The risks to the Utility debtholders were clearly increased. More importantly, the Utility subsidiaries faced greater risk, and thus electricity *consumers* faced greater risk, which is exactly what the regulators sought to prevent. It is interesting to note that PG&E Corp. and Edison engaged in far more “risk-taking” than Sempra, and their Utilities currently face financial distress whereby SDG&E does not.

5. IMPLICATIONS AND CONCLUSIONS

The actions of the state and the IOUs in designing the new market and during the evolution of the new market were consistent with their respective *first-order* risk management incentives. The state's primary concern was to create a competitive electricity market for the benefit of consumers. Their risk management focus was therefore to make sure that the new market was truly competitive in order to provide for reduced prices and better services. The legislation focused on the risks of the IOUs' retaining residual monopoly power. Ironically, this legislation contributed to *second-order* effects that ended up harming the public good. Among these second-order effects were the exposure the Utilities faced to highly volatile wholesale prices, and the financial incentives they were given to create risk in the Utilities. The PX, the epicenter of the competitive market has ceased to function, power prices are much higher than marginal cost and highly volatile, and two of the three largest Utilities are insolvent. For the public, this has meant rate increases, blackouts, and the use of state funds to purchase expensive electricity. The danger of price volatility, the potential for supply shortages, and the potential exercise of market power by competitive power generators were foreseeable by all market participants. Although outside factors such as high natural gas prices and lower electricity output in the Pacific Northwest contributed to the price volatility, these events only helped to expose the flaws in the design of the market and the actions of the participants.

In certain respects, the California energy crisis teaches us some of the same risk management lessons taught to the financial community in the wake of the meltdown of Long-Term Capital Management. First and foremost, great caution must be taken when assuming that the future can be predicted based on the past. LTCM used historical securities prices to measure the risk of future price movements. The state and the Utilities used historical trends of electricity supply and demand in designing the PX. They also used historical electricity marginal costs and natural gas prices in predicting electricity wholesale prices in the competitive market. The second lesson is that an over reliance on these assumptions can lead to irreversible commitments, such as investing in illiquid assets (i.e., power plants by the IOUs and large highly leveraged positions in securities by LTCM). The third lesson relates to hubris. In this case, the state and the IOUs were highly confident in their predictions of volatility and supply/demand levels and therefore did not pay adequate attention to their risks. Finally, the California electricity crisis teaches an additional lesson in situations with multiple constituencies: participants must think through the game, and consider the strategic responses to each parties' decisions. There is nothing profound about these lessons. It is astonishing that sophisticated parties consistently fall prey to these mistakes and lose billions of dollars of other people's money.

FIGURES

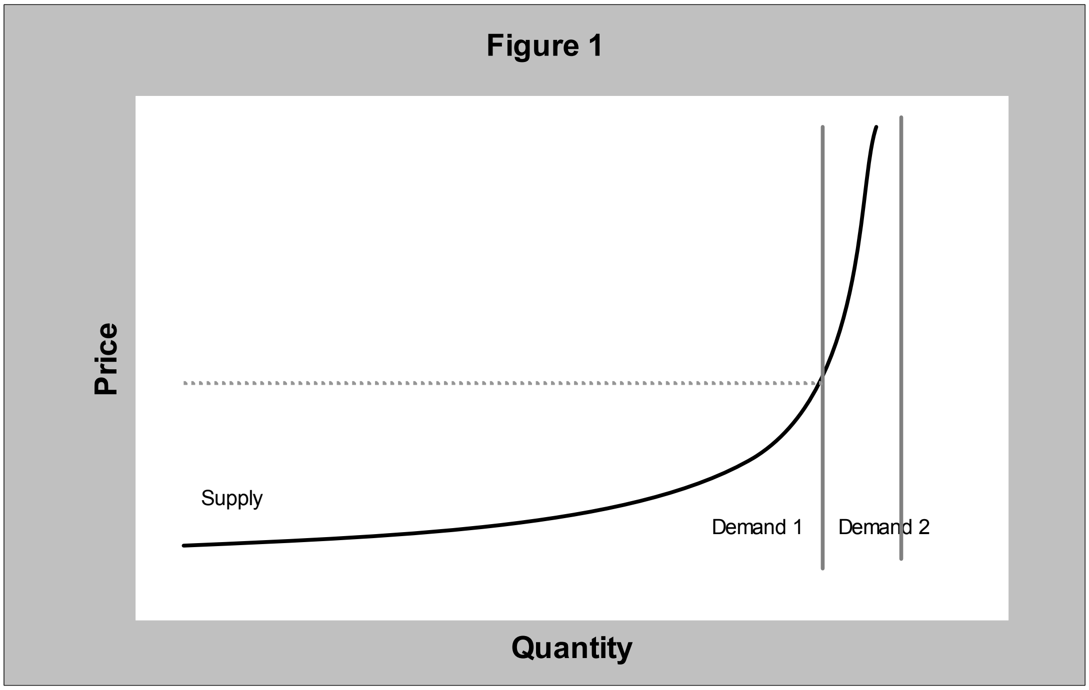


Figure 1
Price
Supply
Demand 1
Demand 2
Quantity

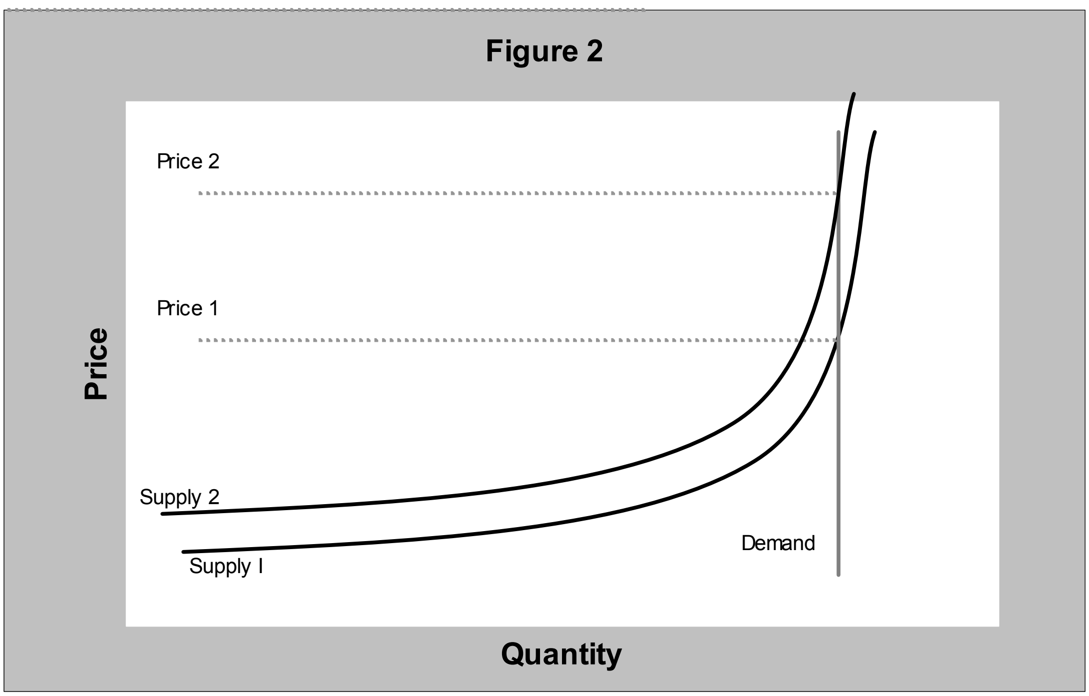
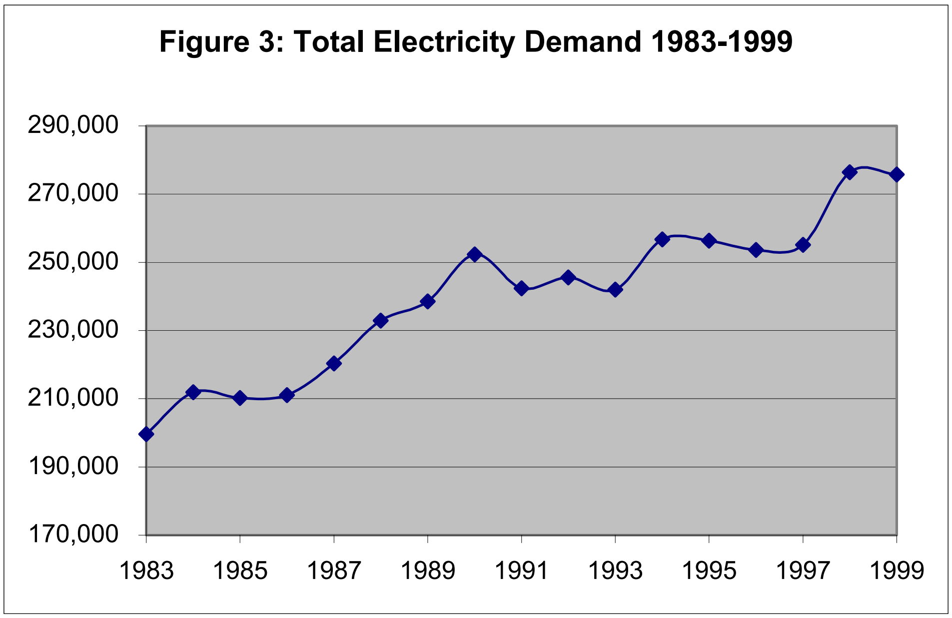
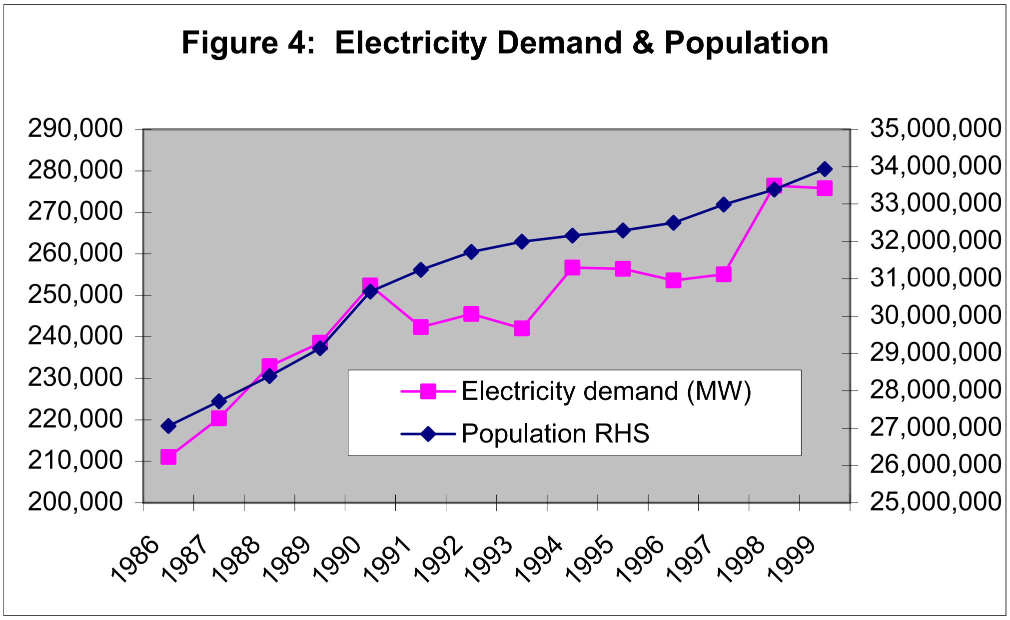


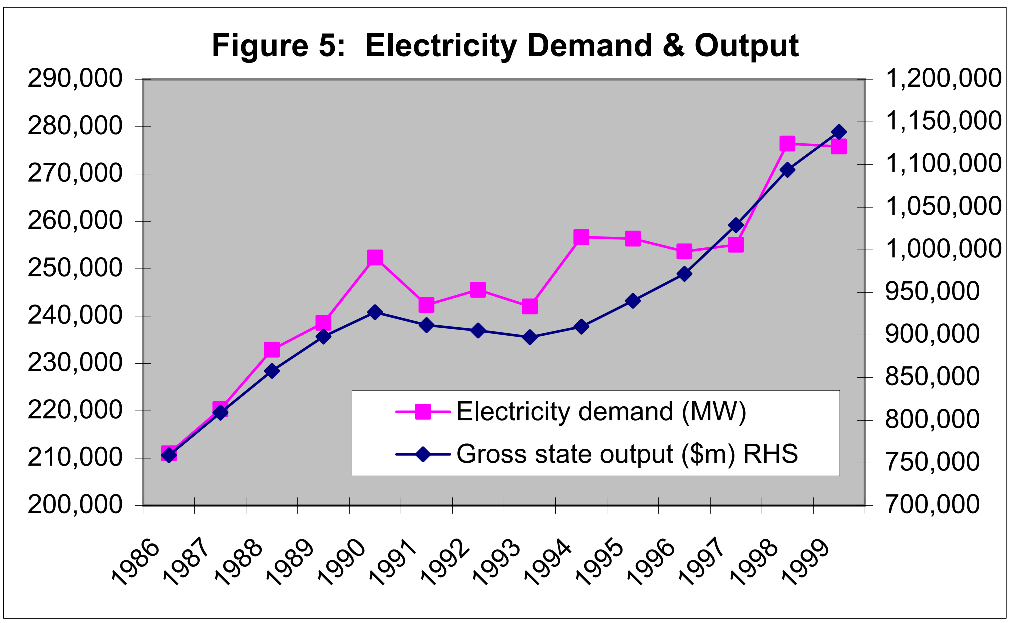
Figure 2
Price 2
Price 1
Price
Supply 2
Supply I
Demand
Quantity



Source: California Energy Commission.



Source: California Energy Commission**, U.S. Bureau of the Census**



Source: California Energy Commission, California Technology, Trade and Commerce Agency

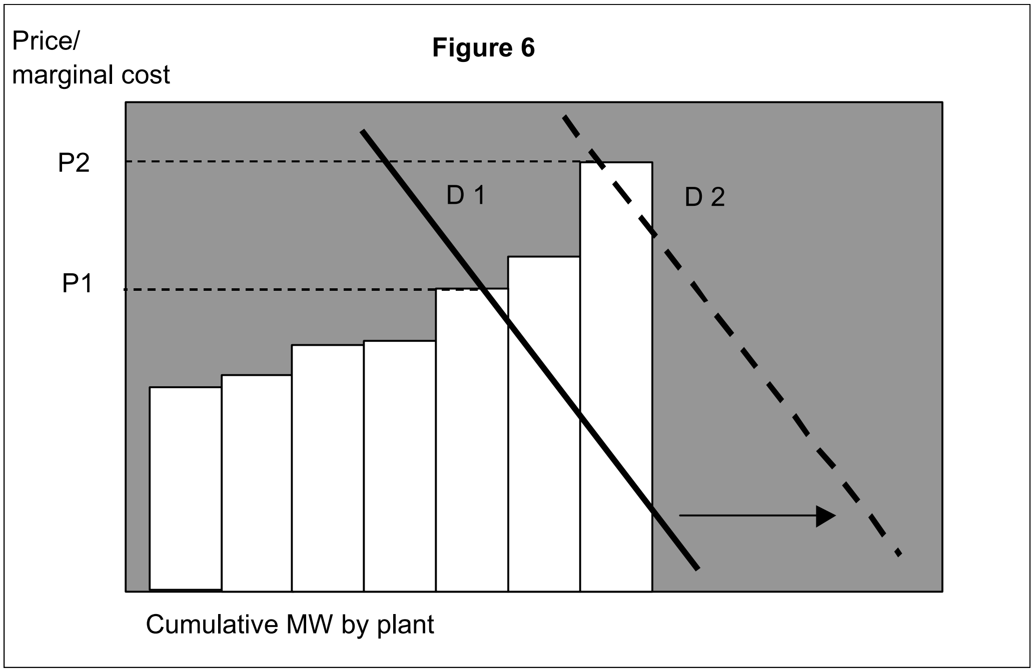


Figure 6

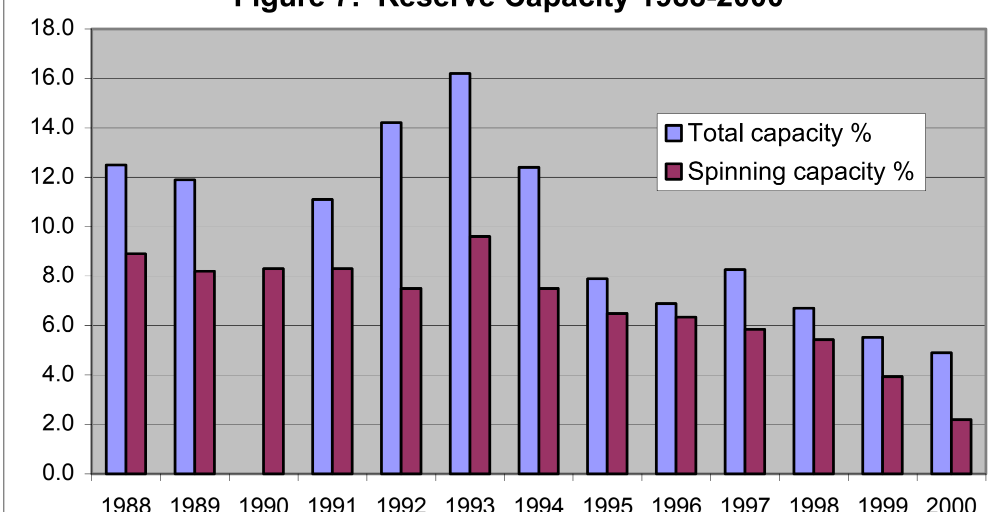
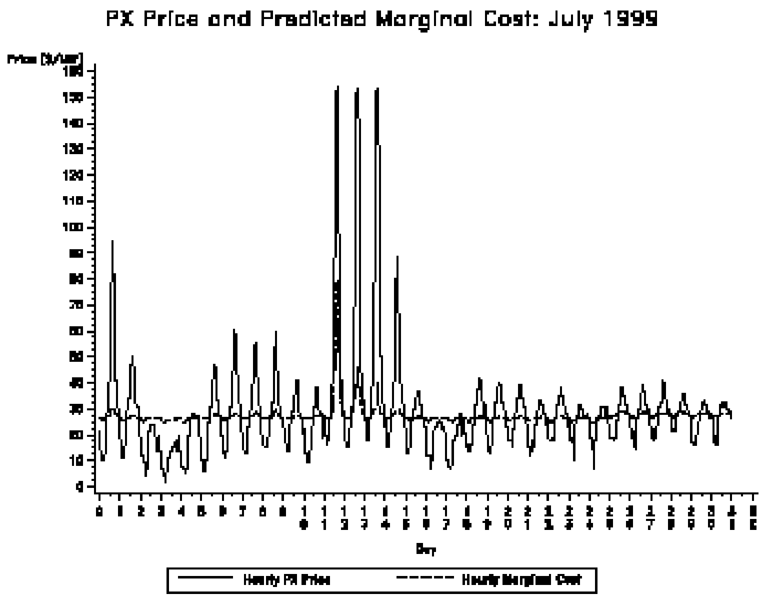


Figure 7: Reserve Capacity 1988-2000

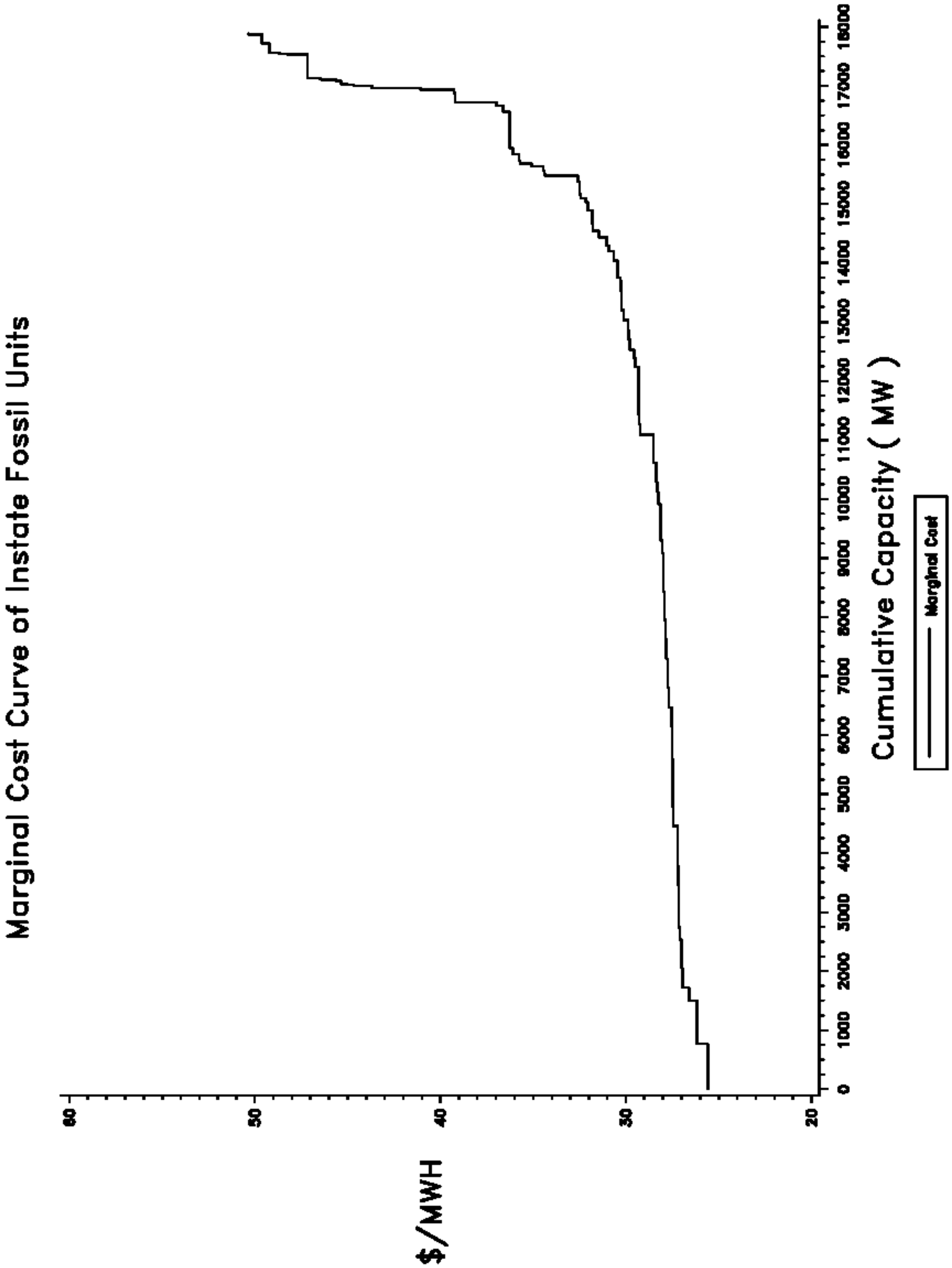
Source: CEC

Figure 8



Source: Bornstein, Bushnell, Wolak (2000)

Figure 9



Source: Bornstein, Bushnell, Wolak (2000)

TABLES

Table 1: CEC Demand Forecasts
(Thousands of megawatt hours)

Year	Actual peak Demand	ER 1988 Forecast	Under (Over) Estimated	% Difference
1995	47,813	50,561	(2,748)	-5.4%
1996	50,189	51,683	(1,494)	-2.9%
1997	52,195	52,757	(562)	-1.1%
1998	54,658	53,914	744	1.4%
1999	53,335	55,033	(1,698)	-3.1%
2000	53,257	56,673	(3,416)	-6.0%

Source: CEC

Table 2: Generation Divestitures
(Thousands of megawatt hours)

	1997 Generating capacity *		Total	% Divested	
	Total	Fossil-fueled	Divested	Total **	Fossil-fueled
PG&E	18,183	6,289	6,934	38%	92%
SCE	21,511	11,188	9,606	52%	86%
SDG&E	3,321	1,973	1,973	67%	100%
Total	43,015	19,450	18,513	43%	89%

* Includes generation under long-term contract.
** Includes voluntary terminations of long-term contracts.
Source: SEC filings and the California Energy Commission.

Table 3: Utility Assets and Common Equity Prior to Deregulation
(Dollars in millions)

	1996	1995	1994	1993	1992
Total Assets					
PG&E	$26,129	$26,850	$27,809	$27,162	$24,188
SCE	$17,737	$18,155	$18,075	$18,098	$15,968
SDG&E	$4,160	$4,472	$4,353	$4,702	$4,046
Common Equity					
PG&E	$8,364	$8,599	$8,635	$8,446	$8,283
SCE	$5,045	$5,143	$5,038	$4,932	$4,774
SDG&E	$1,404	$1,520	#N/A	$1,516	#N/A

Source: SEC filings.

Table 4: Utility Assets and Common Equity
(Dollars in millions)

	2000	1999	1998	1997	1996	1995	1994	1993	1992
Total Assets									
PG&E	$21,988	$21,470	$22,950	$25,147	$26,129	$26,850	$27,809	$27,162	$24,188
SCE	$15,996	$17,657	$16,947	$18,059	$17,737	$18,155	$18,075	$18,098	$15,968
SDG&E	$4,734	$4,366	$4,257	$4,654	$4,160	$4,472	$4,353	$4,702	$4,046
Common Equity									
PG&E	$1,116	$5,477	$6,054	$7,253	$8,364	$8,599	$8,635	$8,446	$8,283
SCE	$780	$3,133	$3,335	$3,958	$5,045	$5,143	$5,038	$4,932	$4,774
SDG&E	$1,059	$1,314	$1,124	$1,387	$1,404	$1,520	#N/A	$1,516	#N/A

Source: SEC filings.

Table 5: Distribution of Utility Cash Flows from Operations
(Dollars in millions)

	1997-1999	1992-1996	1999	1998	1997	1996	1995	1994	1993	1992
Cash dividends / Cash flow from operations										
PG&E	25%	30%	20%	17%	42%	33%	27%	30%	31%	32%
SCE	83%	34%	45%	112%	101%	45%	34%	32%	31%	26%
SDG&E	44%	33%	20%	50%	67%	36%	30%	32%	#N/A	#N/A
Share repurchases / Cash flow from operations										
PG&E	38%	4%	42%	61%	0%	0%	25%	-2%	3%	-8%
SCE	4%	4%	0%	7%	6%	0%	4%	0%	5%	13%
SDG&E	0%	0%	0%	0%	0%	3%	0%	0%	#N/A	#N/A
% of CFO distributed via dividend or share repurchases										
PG&E	63%	35%	62%	78%	42%	33%	51%	28%	34%	23%
SCE	87%	38%	45%	119%	106%	45%	38%	32%	36%	39%
SDG&E *	73%	33%	102%	50%	67%	39%	30%	32%	#N/A	#N/A

* The 1999 figure includes a loan to Sempra Energy, which was repaid in 2000.

Table 6: Utility Cash Flows from Operations
(Dollars in millions)

	2000	1999	1998	1997	1996	1995	1994	1993	1992
PG&E	($699)	$2,200	$2,628	$1,768	$2,581	$3,336	$2,947	$2,793	$2,560
SCE	$829	$1,533	$1,008	$1,708	$1,778	$1,954	$1,822	$1,671	$1,809
SDG&E	$174	$520	$535	$380	$529	$624	$566	#N/A	#N/A

Source: SEC filings.

Table 7: Utility Capital Structures and Debt Service
(Dollars in millions)

	2000	1999	1998	1997	1996	1995	1994	1993	1992
Leverage ratio*									
PG&E	72.2%	51.6%	52.4%	51.3%	45.8%	46.0%	47.7%	49.9%	47.6%
SCE	82.9%	59.3%	59.4%	58.2%	46.0%	47.8%	46.8%	48.5%	48.9%
SDG&E	52.4%	50.0%	55.8%	54.5%	46.0%	42.6%	N/A	N/A	N/A
Debt service**									
PG&E	0.12x	1.91x	2.23x	3.44x	3.07x	3.59x	3.08x	2.90x	1.79x
SCE	0.67x	1.14x	1.25x	2.63x	2.87x	6.15x	2.30x	2.45x	2.89x
SDG&E	6.52x	12.98x	11.38x	12.55x	18.48x	80.63x	N/A	N/A	N/A

* Computed as Long-term debt / (Long-term debt + Common equity + Preferred equity). Based on book values.
** Computed as Cash flow from operations / (Current portion of long-term debt + Short-term debt).
Source: SEC filings.

Table 8: Total Assets and Common Equity of Non-Utility Subsidiaries
(Dollars in millions)

	2000	1999	1998	1997	1996	1995
Total Assets						
National Energy Group (PG&E Corp.)	$13,303	$8,245	$10,284	$5,410	NMF	NMF
Edison Non-Utility	$18,730	$18,842	$7,946	$6,926	$6,836	$5,773
Common Equity						
National Energy Group (PG&E Corp.)	$2,056	$1,409	$2,012	$1,644	NMF	NMF
Edison Non-Utility	$3,605	$4,122	$1,676	$1,245	$1,508	$1,505

Note: Non-Utility assets and common equity accounts were not available for SDG&E.
Source: SEC filings.

Table 9: Distribution of Cash Flows from PG&E to National Energy Group (Dollars in millions)

	Total	2000	1999	1998	1997
Cash flow from operations of National Energy Group	$533	($77)	$87	($327)	$850
Dividends paid					
PG&E	$2,098	$475	$440	$444	$739
PG&E Corp.	$1,895	$436	$465	$470	$524
Cash retained by Parent	$203	$39	($25)	($26)	$215
Common stock repurchases					
PG&E	$2,801	$275	$926	$1,600	$0
PG&E Corp.	$2,421	($63)	$639	$1,095	$750
Cash retained by Parent	$380	$338	$287	$505	($750)
Cash paid for income taxes					
PG&E	$2,957	$0	$1,001	$1,115	$841
PG&E Corp.	$2,314	$20	$723	$770	$801
Cash retained by Parent	$643	($20)	$278	$345	$40
Total cash retained by parent	**$1,226**	**$357**	**$540**	**$824**	**($495)**

Source: SEC filings.

Table 10: Distribution of Cash Flows from SCE to Edison Non-Utility (Dollars in millions)

	Total	2000	1999	1998	1997
Cash flow from operations of Edison Non-Utility	$2,242	$774 *	$442	$619	$407
Dividends paid					
SCE	$3,929	$395	$686	$1,130	$1,718
Edison	$1,798	$492	$443	$412	$451
Cash retained by Parent	$2,131	($97)	$243	$718	$1,267
Common stock repurchases					
SCE	$174	$0	$0	$74	$100
Edison	$2,365	$386	$92	$714	$1,173
Cash retained by Parent	($2,191)	($386)	($92)	($640)	($1,073)
Cash paid for income taxes					
SCE	$1,582	$306	$433	$405	$438
Edison	$415	$3	$27	$87	$298
Cash retained by Parent	$1,167	$303	$406	$318	$140
Total cash retained by parent	**$1,107**	**($180)**	**$557**	**$396**	**$334**

* This figure is based on the twelve months ended September 30, 2000.
Source: SEC filings.

Table 11
Regression: Log of Electricity Demand

	Constant	Year	Log of Population	Log of Output
coefficient	2.47	0.00	0.61	0.49
std error of coef	3.03	0.00	0.28	0.14
t-ratio	0.81	-0.91	2.23	3.39
p-value	0.43	0.38	0.05	0.01
beta-weight		-0.30	0.59	0.70
Standard error of regression		0.01		
R-squared		0.94		
Adjusted R-squared		0.92		
number of observations		14		
residual degrees of freedom		10		
t-statistic for computing 95%-confidence intervals		2.23		

Table 12
Regression: Log of Peak Demand

	Constant	Year	Log of Population	Log of Output
coefficient	-6.33	0.00	0.50	0.44
std error of coef	5.11	0.00	0.58	0.25
t-ratio	-1.24	0.48	0.87	1.79
p-value	0.25	0.65	0.41	0.11
beta-weight		0.23	0.31	0.45
standard error of regression		0.01		
R-squared		0.90		
adjusted R-squared		0.86		
number of observations		12		
residual degrees of freedom		8		
t-statistic for computing 95%-confidence intervals		2.31		

BIBLIOGRAPHY

Regulatory Documents

California Energy Commission, "*1996 Electricity Report*"

California Energy Commission website and databases, energy.ca.gov

California Power Exchange Corporation website, calpx.com

Federal Energy Regulatory Commission "Order Proposing Remedies for the California Wholesale Electric Markets" Docket No. EL00-95-000, Washington, DC, November 1, 2000.

California Public Utility Commission Application 96-11-037 (application of PG&E to use energy-related derivative financial instruments), August 8th, 1997

California Public Utility Commission Resolution E-3506, November 5th 1997

California Public Utility Commission. "Comments of Southern California Edison Company (U338-E) on Plan for Voluntary Divestiture Submitted in Response to the Commission's December 20, 1995 Policy Decision", March 19, 1996

Company Documents

Form 10K SEC Filings from 1992-2000 of the following companies:
PG&E Corp.
Edison International
Southern California Edison
San Diego Gas & Electric
Sempra Energy

Financial & Statistical Supplement for Edison International for the following periods:
Third quarter 2000, 1999 and 1997

White Papers

Borenstein, Severin, James Bushnell and Frank Wolak, "Diagnosing Market Power in California's Restructured Wholesale Electricity Market", August 2000

Borenstein, Severin, "Power. The Trouble with Electricity Markets (and some solutions)", January 2001

"Cooking the Books", The Utility Reform Network, October 18, 2000

Hauter, Wenonah and Tyson Slocum, “It’s Greed, Stupid! Debunking the Ten Myths of Utility Deregulation”, Public Citizen’s Critical Mass Energy and Environment Program, January 2001

Joskow, Paul. "California's Electricity Market Meltdown", April 2001

Kahn, Alfred, Peter Crampton, Robert Porter, Richard Tabors, “Blue Ribbon Panel Report: Pricing in the California Power Exchange Electricity Market” (a study commissioned by the PX)

Stoft S., T. Belden, C. Goldman and S Pickle, “Primer on Electricity Futures and Other Derivatives”, January 1998

"The First States: The Learning Curve on Stranded Cost Recover Policies", Elcon, October 1998

Wolak, Frank. "An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market", January 2000

Press Articles

“A State of Gloom”, The Economist, January 20th 2001

“California Controller Battles Governor Over Paying for the State's Electricity Crisis”, John Emshwiller, Wall Street Journal, May 22, 2001

“California Blame Game Yields No Score”, John Emshwiller, Wall Street Journal, May 22, 2001

"Electricity Deregulation. A Nasty Shock", The Economist, January 6, 1996

"Opening the Grid", Journal of Commerce, April 29, 1996

"Power Prices, Hedging in the Market and the Lessons from California", Power Economics, November 30, 2000

“While a Utility May Be Failing, Its Owner Is Not”, Richard Oppel and Laura Holson, New York Times, May 2001

Miscellaneous

GE versus Westinghouse in Large Turbine Generators (A), Harvard Business School case 9-380-128

Conversation with Professor Robert Porter, Northwestern University Department of Economics, April 20, 2001

Lowenstein, Roger. "When Genius Failed. The Rise and Fall of Long-Term Capital Management" Random House, 2000.

Smithson, Charles and Clifford Smith. “Strategic Risk Management” in The New Corporate Finance. New York, McGraw Hill 1993.

Stulz, Rene. “Rethinking Risk Management”, in The New Corporate Finance. New York, McGraw Hill 1993.