Waiting for the Boom: A Simulation Study of Power Plant Construction in California

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Abstract

This paper describes a computer simulation model constructed in the summer of 2000. It was used to simulate the general patterns of power plant construction that might appear in an electric system with approximately the same loads, resources and markets as those in California. The paper begins with background on restructuring in California and a review of previous research on construction. The paper then describes the computer model by presenting several simulations with qualitatively different patterns of construction.

The simulations reveal that construction could appear in a steady, even fashion, causing power plants to come on line exactly in time to meet the profitability goals of investors. But this is not the dominant pattern. The more likely pattern shows construction lagging behind the growth in demand, allowing prices to climb to surprisingly high values during peak periods in the summer. When new power plants are completed, they come on line in great numbers causing a bust in wholesale prices.

The boom/bust pattern of construction is common in industries such as commodities and real estate, and there are good reasons to believe that a boom could appear in the electric industry. Electricity consumers would certainly benefit from a boom in construction. Unfortunately, waiting for the boom is a difficult challenge with the current mix of state and federal rules in California. The paper concludes with a summary of recent events that have led to the demise of the California approach to deregulation and to the state’s entry into the power business.
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<td>AB 1890</td>
<td>Assembly Bill 1890</td>
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<tr>
<td>A/S</td>
<td>Ancillary Services (i.e., regulation and reserves)</td>
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<td>believers</td>
<td>a category of investor in the simulation model</td>
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<td>BPA</td>
<td>Bonneville Power Administration</td>
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<td>BTU</td>
<td>British Thermal Unit, a measure of energy in fuel</td>
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<td>CEC</td>
<td>California Energy Commission</td>
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<td>CERA</td>
<td>Cambridge Energy Research Associates</td>
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<td>CC</td>
<td>Combined Cycle generating plant</td>
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<td>CPUC</td>
<td>California Public Utilities Commission</td>
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<td>CTC</td>
<td>Competitive Transition Charge</td>
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<td>DMA</td>
<td>Department of Market Analysis of the ISO</td>
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<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<td>followers</td>
<td>a category of investor in the simulation model</td>
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<td>GW</td>
<td>Gigawatt, a measure of electric power</td>
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<td>IOU</td>
<td>Investor Owned Utility</td>
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<td>ISO</td>
<td>Independent System Operator</td>
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<td>MSC</td>
<td>Market Surveillance Committee of the ISO</td>
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<td>MSU</td>
<td>Market Surveillance Unit of the ISO</td>
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<td>MW</td>
<td>Megawatt, a measure of electric power</td>
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<td>MWhr</td>
<td>Megawatt-hour, a measure of electric energy</td>
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<td>NPPC</td>
<td>Northwest Power Planning Council</td>
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<td>PG&amp;E</td>
<td>Pacific Gas and Electric Company</td>
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<td>PJM</td>
<td>Pennsylvania-New Jersey-Maryland power market</td>
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<td>pre counters</td>
<td>a category of investor in the simulation model.</td>
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<td>PX</td>
<td>Power Exchange</td>
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<td>RTC</td>
<td>RECLAIM Trading Credit (emissions credit)</td>
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<td>SCE</td>
<td>Southern California Edison Company</td>
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<td>SC</td>
<td>Scheduling Co-ordinator</td>
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<td>SDG&amp;E</td>
<td>San Diego Gas &amp; Electric Company</td>
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<td>SWP</td>
<td>State Water Project</td>
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<td>WSCC</td>
<td>Western System Co-ordinating Council</td>
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PART ONE. INTRODUCTION

California began to rethink its electric system in the early 1990s. Its electric rates were among the highest in the country, and it was just emerging from an economic recession. Large manufacturing companies began lobbying for the freedom to negotiate with different power suppliers. They found a receptive audience in the Governor and the California Public Utilities Commission (CPUC). Governor Pete Wilson believed that the utilities had become bloated under regulation. The CPUC believed that the traditional regulatory framework was “fragmented, outdated, arcane and unjustifiably complex.” It voted to open the state’s electricity industry to competition in December of 1995 (CPUC 1995).

California was one of many states rethinking the necessity of vertically integrated utilities with their monopoly privilege and their regulated rates. This approach had allowed the investor owned utilities (IOUs) to expand their transmission and distribution systems and to build the new power plants for almost one hundred years. The traditional view was that the utilities needed monopoly privilege and a regulated return if they were to finance the construction of billion dollar power plants with decade-long lead times. By the 1990s, however, the utilities were no longer looking to invest in large power plants. They were either acquiring generation from independent power producers, or they were looking to invest in the combined cycle (CC) technology shown in Figure 1.

![Figure 1. Schematic for a combined cycle power plant.](image)

CCs were attractive on all fronts. They would burn natural gas much more efficiently than the existing steam boilers, and they released far fewer pollutants. More importantly, they could be constructed with small scale and with short lead time. The argument for large-scale investments was gone. CCs, and cheap natural gas to fuel them, had opened the door to deregulation in California.
Assembly Bill 1890

The shape of California’s new industry was evident in the CPUC decision of 1995. There would be an independent power market, and the large utilities would be allowed to pass along an estimated $28 billion in “stranded costs.” This would be a massive transformation. The parties were looking for a more permanent framework than an order from the CPUC. They turned to the legislature, and the legislators responded with Assembly Bill 1890. Legislators ratified the bill in a rare, unanimous vote in August of 1996:

Not one lawmaker voted against the bill
even though many had only a dim sense of how they were launching
what Sen. Steve Peace has called
the most complex transition of an industry anywhere in the world.

The new bill was signed by Governor Pete Wilson who declared confidently that

We pulled the plug on another outdated monopoly
and replaced it with the promise of a new era of competition.

AB 1890 was crafted in marathon negotiating sessions among the utilities, consumer advocates, power plant developers and other groups comprising a “stakeholder democracy” (CERA 2001). The final bill provided “something for everyone” (Richard and Lavinson 1996). One of its major provisions was 100% recovery of the utilities’ stranded costs. Large customers were given direct access to energy providers in the near term, and small customers were to be protected with a retail rate freeze. AB 1890 also created two new organizations to promote wholesale competition in electricity generation: the Power Exchange (PX) and the Independent System Operator (ISO). The PX would create a financial market for day ahead and hour ahead trading of electric energy; the ISO would create a real time market for electric energy. These new organizations opened for business on March 31, 1998.

The peak demands occur in the summer in California, so the first major test for the new markets occurred in the summer of 1998. Both the energy markets and the ancillary services markets got off to a shaky start in the first summer. But the markets performed better in the summer of 1999, due in part to milder weather. The most severe test came in the summer of 2000. Severe price spikes appeared during heat waves in May and June, running up the total wholesale expenses of the distribution companies that were obliged to purchase electricity on behalf of their retail customers.

There were several reasons for the surge in wholesale prices. First, natural gas prices had doubled from the previous summer, and gas-fired units are typically the most expensive units bidding into the new markets. (The price is set by the highest bid to clear the market.) Consequently, a doubling of gas prices could lead to a doubling of the spot price for many hours of the year. Second, the growth in electricity demand from year to year created a tighter and tighter balance between demand and generating capacity. A
third contributing factor was the surge in the market price of emission credits which drove up the cost of older gas-fired units by as much as 20-30 $/MWhr. These three factors accounted for a substantial part of the price increases in the summer of 2000. But they do not tell the whole story. The remaining factor is strategic behavior by the generating companies. Strategic behavior can take the form of withholding units during periods of tight supply or by submitting bids well above variable costs. Strategic behavior was evident in the summer of 1998, less evident in the summer of 1999. By the summer of 2000, it was staggering. California officials argued that the wholesale markets were “dysfunctional” and the Federal Energy Regulatory Commission agreed.

Never has this commission had to address such a dramatic market meltdown as occurred in California’s electricity markets this summer

James Hoecker,
Chairman, FERC

If California was experiencing a “meltdown,” then San Diego Gas and Electric Company (SDG&E) was “ground zero” for the disaster. Its retail customers were the first to feel the effects of wholesale price spikes; their electric bills increased by 300% from the previous summer. Southern California Edison (SCE) and Pacific Gas and Electric Company (PG&E) felt the impact in a different manner. Their rates were frozen under the AB 1890 transition rules, but they were obliged to purchase electricity on behalf of their customers in the wholesale markets. These companies had around 40% cover, 34% from their own generation and 6% from contracts. They were in a highly vulnerable position, and by the end of the summer, they had accumulated around $6 billion in red ink.

Power Plant Construction

The California crisis has been examined by a several major agencies in California and by the Federal Energy Regulatory Commission. They all agreed that the markets were “unworkably competitive” in the summer of 2000. Furthermore, they all agreed that the lack of new generating capacity was a major reason for the unworkable situation. So, where were the new power plants?

No new power plants came on line in the summer of 1998, the first summer of the PX operation. The lack of new capacity in the first summer may be attributed to decisions in the years before the passage of AB 1890. No new power plants came on line in the summer of 1999 as well. The lack of new capacity in the second summer is reasonable given that new CCs require at least a year or longer for construction. (An investor would have had to start construction almost at the same time as the new markets started operation if the new CC were to be ready by the summer of 1999.) But what about the summer of 2000? New capacity would have been extremely useful for the overall system.
and quite profitable for its owners. Unfortunately, there were no new generating units completed in time to alleviate the tight conditions in the summer of 2000.

Why didn’t investors bring new power plants into service in time to benefit from the high prices in the summer of 2000? Will they bring the new power plants on line for subsequent summers? Will new construction appear in a steady fashion to allow generating capacity to keep pace with the growth in demand? Or should we expect construction to appear in waves of boom and bust, as happens in industries like real estate and commodities?

These are important and difficult questions, but they have not received the attention they deserve. Hirsh (1999) describes the common view in the early 1990s -- the new system would erase the utilities’ obligation to serve, and it would scrap the state’s role in resource planning. “In the new system, competition among suppliers would produce a match between supply and demand without intervention from the state.”

According to the San Jose Mercury News (November 30, 2000), the topic of power plant construction was missing from the debate on AB 1890:

California’s deregulation effort was based on an unquestioning faith in the power of the free market. Despite official state forecasts that electricity demands would increase, for example, there was virtually no discussion of whether California’s generating capacity would keep pace.

The topic of power plant construction has also been neglected in the many studies issued since the summer of 1998. If construction is mentioned at all, the reports typically lament the lack of sufficient construction, but they provide little insight on whether the markets are designed to ensure an adequate and stable pattern of construction. Rather, the standard suggestion is to call for “expedited” siting and construction.

Previous Research

I examined research on power plant construction by the key agencies in the western United States in the summer of 1998. The review focused on computer models that could shed light on the dynamics of merchant plant construction (Ford 1999A). One key agency used a model with endogenous construction, but it relied on “perfect foresight” to calculate construction. With this approach, construction appears automatically in the model, just in time to provide a profitable return for investors.

The California Energy Commission (CEC) is a key agency in the west with a long history of modeling for planning and forecasting. As the California markets were opening for business, the CEC’s forecast of market prices avoided the question of power plant construction altogether (Klein 1997):

After 2002 the market clearing price is set outside of the model to be equal to the price of a new entrant...this is
done based on the logic that the market clearing price will rise in response to increased load but once it is high enough to attract new entrants, new entrants will come into the market and drive the market clearing price downward back to its previous level.

These words may convey a feeling for the ups and downs of a construction cycle, but the CEC staff had a different vision of the future. Their 1997 forecast showed long-run market prices climbing to around 27 $/MWhr, exactly their estimate of the fully levelized cost of a new entrant. Their forecast did not describe the construction in any explicit manner.

The CEC view of power plant construction has changed over time as investors applied for permits to construct thousands of MW of new capacity. By the fall of 2000, developers had received approval to construct 6 new power plants, and they had another 34 announced projects inside California. The CEC staff believed that the large number of proposed power plants argued for “a new approach based on specific assumptions about the timing and quantity of new resource additions” (Grix 2000). They adopted two scenarios for resource additions, and they calculated the price implications for each scenario over the time interval from 1998 to 2010. Market prices can be quite high in the summer, and new generators’ profitability depends largely on the prices in the summer quarter. The CEC’s short-term results (1998-2001) indicated that market-clearing prices during the summer may not reach a level necessary to sustain new market entry “until reserve margins drop below historic levels usually regarded as necessary for reliable service.”

The CEC’s long-term results depend on their scenario for investor behavior once profitable levels are achieved within a scenario. The staff specified construction based on a plausible fraction of the power plants in various stages of development. One scenario called for “rapid development” of the proposed plants; the other called for “cautious development.” The interesting result was a bust in market prices in both scenarios. The CEC staff concluded that future generating resources are not likely to be added in a smooth, even pattern. Rather, they will “more likely occur in a cyclical pattern resulting in periods of excess and lean generation capacity.” In other words, construction is likely to appear in a wave of boom and bust.

I drew similar conclusions in a simulation study of power plant construction for the western United States (Ford 1999A). The simulations revealed that power plant construction could appear in waves of boom and bust, causing major changes in market prices during different phases of the construction cycle. Under some circumstances, the cycle could take the extreme form of a limit cycle. In this unfortunate situation, the industry would face repeated periods of undersupply, and regulators would be forced to intervene with price caps.
PART TWO. THE CEC STUDY

The CEC study was conducted in the summer of 2000. The staff was interested in learning if an endogenous theory of power plant construction would expand their insights beyond the findings from the scenarios study. They called for a new model to provide a more detailed portrayal of power plant permitting and construction. It was to simulate construction and market prices in a summer peaking system with approximately the same demands, resources and markets as those in California.

The model was based on the system dynamics approach used in my previous study of the western United States (Ford 1999A). It was designed for highly interactive use to promote communication and discussion. Such models are sometimes called management flight simulators because they allow one to “experience” the dynamics and they encourage experimentation. This approach may appear unusual to many readers, so I will include several images taken directly from the control panel of the model. My purpose is to convey a sense for how the model has been used to promote discussion and understanding of power plant construction.

Permitting and Construction

Figure 2 shows the stocks and flows for investor decisions on permitting and construction. The development process begins with the formal application for a construction permit. The agencies review the proposal and award the permit in 12 months. At this point, the approved proposal enters a “site bank” with a shelf life of 24 months. If the project does not begin construction within 24 months, the permit expires. These time intervals are some of the model inputs shown on the screen in Figure 3.

![Figure 2. Stocks and flows for permitting and construction.](image-url)

Power plant proposals in California are predominantly gas-fired combined cycle (CC) units. The controls on the left side of Figure 3 define the average attributes of the CCs. The base case assumptions match the assumptions by (Grix 2000): a CC owner pays $2.50 per million BTUs for gas and faces a variable cost of 19 $/MWhr. With
levelized fixed costs of around 12 $/MWhr, the investor would face a total, levelized cost of around 31 $/MWhr.

Other controls allow the user to set the growth in demand and the price of natural gas. The base case begins with a peak demand of 46 GW and gas priced at $2.50 per million BTU. Demand grows at a steady rate of 2%/yr, and the price of natural gas remains constant over time. These assumptions are different from recent trends in California, and the differences are intentional. The model was designed for general understanding, not for forecasting. Consequently, staff called for a relatively simple scenario with constant assumptions. This approach allows simulation results to be traced to the cause and effect relationships inside the model.

Electricity demand varies from one hour to the next, and the California markets set different prices for each hour of the day. The model simulates prices over the 24 hours in a day, using a typical day in each quarter. The simulated price for electric energy represents the weighted average of the PX day-ahead price and the ISO real-time price for energy. The energy price is adjusted continuously as the model finds the price that will bring forth the generation needed to meet the demand. All units are bid at variable cost, except for a user specified block of strategic capacity.

Figure 3. Inputs Screen.
Strategic capacity is expensive, gas-fired capacity whose owners are assumed to bid “strategically” during peak hours in the summer quarter. The base case calls for one GW of strategic capacity. This is a controversial input to the model, so the interface provides extensive advice for the model user. The advice button explains that setting this capacity to zero guarantees that all generators bid their units at variable cost, and the simulated market clears at the price expected from a competitive market. On the other hand, the user may assume four times as much strategic bidding by setting the slider at the maximum value. The “impact” button provides information on sensitivity tests and how the simulated prices compare with the ISO studies of strategic behavior. The model assumes that the strategic bids are spread across a wide range, from the variable cost of the region’s most expensive unit to the price cap.

The price cap is another important input to the model. The operative cap in California has been the ISO real-time cap. The ISO opened for business with a cap of 250 $/MWhr. It raised the cap to 750 $/MWhr in October of 1999. The cap was lowered to 500 $/MWhr in July of 2000 and lowered again to 250 $/MWhr in August of 2000. The price cap “slider” in Figure 3 allows the cap to range from a low of 100 $/MWhr to a high of 1,000 $/MWhr. The low value was based on the variable cost of the model’s most expensive unit. The high value is higher than any previous ISO cap, but it matches the cap imposed on the PJM system. Figure 3 shows the slider at 250 $/MWhr, the cap adopted in August of 2000. This is a “hard cap” which controls the height of the price spikes in the model. The model does not distinguish between “hard” and “soft” price caps.

Investor Behavior

The focus of the model is investor behavior. We assume that all investors look into the future to assess the profitability of a new CC. If the siting and construction lead-time is 24 months, for example, investors look 24 months into the future to anticipate the profitability of a new unit when it begins operation. Some models look into the future by simply selecting a number stored in the computer for some future point in time. This “perfect foresight” approach may be possible in a computer algorithm, but it not possible in the real world. Investors can only make educated (and possibly sophisticated) estimates of future prices. The CEC model is based on an explicit theory of how they make such estimates.

Let’s start with the demand for electricity. It is assumed to grow in a steady, predictable manner. Investors observe the growth in demand over time, so they are in a good position to anticipate the demand when their new units would begin operation. Next, investors know the capacity at the start of the simulation, and they know that none of the existing capacity will be retired during the simulation. Investors also know that each year is an “average year” (as far as the weather is concerned), so they are in a good position to estimate the relative balance of peak demand and generating capacity. Investors have access to production costing tools, so it makes sense to assume that they can produce reasonable estimates of the average annual market price based on their assessment of the balance of demand and capacity. As demand grows from one year to
the next, the balance shifts in favor of generation, and the investors’ estimates of future prices climb upward. Investors become increasingly interested in starting construction as their forecasts of future prices climb toward the full cost of a new CC. The typical cost may be 31.3 $/MWhr, but some investors have better access to natural gas or to financing. The model assumes that the advantageous investors will be ready to invest with the estimated market price reaches around 30 $/MWhr. At this point, a small fraction of the plants in the site bank will start construction. After 12 months, the construction is completed, and the new CCs begin operation.

The analyst classifies investors based on their view of the CCs under construction. Investors may be described as
- **believers,**
- **pre counters,** or
- **followers.**

The *believers* are assumed to factor the CCs under construction into their forecasts only when the new CCs have completed construction. In other words, this investor will believe the new CC is “for real” when he sees it in operation.

The *pre counters* look at power plants under construction differently. They count the new capacity into their forecasting process as soon as construction is initiated. By “pre counting” the capacity, they reveal their confidence that any unit that starts construction will finish construction.

The *followers* are quite different. Their commitment to construction does not occur until others have initiated some construction. Then they are drawn into construction based on a “herd mentality factor” and their own assessment of profitability.
Base Case Simulation

The user controls the mix of investors with the linked controls near the bottom of the inputs screen. The base case considers a situation with 100% believers: investors will believe the new CCs are “for real” once they begin operation. Figure 4 shows the new CCs in various stages of development in the base case simulation. The simulation runs for eight years, with time shown as 1st year, 2nd year, etc. These general labels make it difficult for the reader to interpret the simulation results as a forecast for a particular year (i.e., 2001, 2002, etc.). This difficulty is intentional. The model was built for general understanding of patterns, not for forecasting a precise number in a particular year.

Figure 4. Construction results mid-way through the base case, a simulation with 100% of investors as believers.

The first two years is an active period in terms of proposed projects. By the end of the 2nd year, investors have around 7 GW under review and another 7 GW in the site bank. Construction commences near the end of the second year, and the new CCs enter operation near the end of the 3rd year. Figure 4 shows the simulation mid way through the 4th year. By this time, investors have over 8 GW in the site bank, 3.4 GW under construction and 3.2 GW in operation. Their assessment of future profitability has fallen sharply (as shown by the “believers’ expected profitability” in the lower right
At this point, investors are no longer interested in starting new construction; their strategy is to finish the construction of the 3.4 GW and hope for market conditions to improve.

Figure 5 shows the CCs in construction for the remainder of the base case simulation. This screen shows that construction is completed by the end of the 4th year, and the installed CC capacity climbs to 6.6 GW. The construction is confined to a pronounced wave in the 3rd and 4th years. By the end of the simulation, investors see a return to profitable conditions (the “expected profitability” in the lower right display is at 97% of the target.) They have plenty of capacity in the site bank are about to launch a second wave of construction.

Figure 5. Construction results for the entire base case, a simulation with 100% of investors as believers.
Figure 6 shows the main screen of the model at the end of the initial simulation. The demand for electricity for a typical day in each quarter is shown along with the available generating capacity on a scale from 0 to 60 GW. Planned maintenance is scheduled in the off-peak seasons, and all thermal units are ready for scheduled operations in the summer. Figure 6 portrays the tightness of the summer conditions by the comparison of the peak demand with the available capacity. The simulation shows tight conditions by the 2nd summer, even tighter conditions by the 3rd summer. The tight conditions are eliminated in the 4th summer by the wave of new construction. No further construction is completed during the second half of the simulation, but the peak demand continues to grow. By the end of the simulation, the system has returned to the tight conditions observed at the beginning of the simulation.

Figure 6. Capacity and demand in the base case simulation.
The quarterly prices for the base simulation are shown Figure 7. This is the main screen of the model with a different graph from the graph pad in view. It shows average market prices observed over each previous quarter and each previous year on a scale from 0 to 60 \$/MWh. The summer quarterly prices are most prominent in Figure 7; they average around 32 \$/MWh in the 1st summer, 36 \$/MWh in the 2nd summer and 47 \$/MWh in the 3rd summer. These high prices are due, in part, to price spikes during the peak hours in the summer. The spikes tend to appear in about 1-2% of the hours of the quarter. They are caused, in part, by strategic bidding, and they are controlled by the price cap (which is set at 250 \$/MWh).

Figure 7. Market prices in the base case simulation.

The growth in summer prices is largely responsible for lifting the average annual price toward the total cost of a new CC. By the 3rd year, the average annual price reaches 30.8 \$/MWh, only slightly below the 31.3 \$/MWh cost of a new CC. Figure 7 shows that high summer prices are eliminated for the second half of the simulation. The summer prices fall below the value seen in the very first summer when the new CCs enter operation. The drop in summer prices pulls down the average annual price to well below the total cost of a new CC. Average annual prices range from around 24 to 26 \$/MWh during the second half of the simulation. This is the “bust” in the boom/bust simulation. Demand continues to grow at 2%/yr, and the market experiences a gradual increase in
prices. By the final year, summer prices have climbed back to the value observed at the start of the simulation.

**Thinking About Boom and Bust**

The base case simulation shows the classic pattern of boom and bust. There is no construction early in the simulation as investors wait for their estimates of market prices to climb sufficiently high to cover the full cost of a new CC. By the time they view new CCs as profitable, there are plenty of pre-approved projects waiting in the site bank. They initiate construction on some of these plants, but they do not commence operation soon enough to prevent high summer prices in the third summer. Investors continue to initiate construction of additional plants while their previously initiated plants are under construction. Their enthusiasm for the construction boom is not diminished until some of the CCs enter operation. By this time, however, they are stuck with too much capacity under construction.

This pattern of behavior strikes some as irrational. After all, why would a rational investor initiate construction on new power plants when the number already under construction is more than is probably needed to keep pace with the growth in demand? Of course the important question is not whether this behavior is rational. It’s whether this behavior is realistic.

We have little experience with competitive markets in the electric industry, so we don’t have direct evidence of a boom/bust pattern shown here. We do have signs of a huge accumulation of power plant proposals all around the country, however. For example, a recent review for the Electric Power Research Institute (EPRI 2000) “anticipated that approximately 212 GW of new gas-fired capacity additions” could appear over the next five years.” This would be approximately “two to three times more than would be needed to keep pace with demand growth. The supply-demand balance would be shifted significantly, and market prices would probably fall substantially below the level needed to support new construction.” The EPRI review concluded that different regions of the country “could move from boom to bust in just a few years.”

The EPRI warning may seem incredible, but it probably comes as no surprise to readers with experience in the commodity industries. A commodity is defined as an undifferentiated product, often supplied by many small, independent producers. Examples include minerals such as copper, forest products such as lumber and agricultural products such as hogs. The common pattern among the commodities is a highly persistent cycle in production, prices and investment (Meadows 1970; Ford 1999; Sterman 2000). The restructuring of the power industry has made electricity similar to other commodities in that many independent companies will be able to enter the competitive market and produce electricity that is undifferentiated from electricity produced by others. But electricity is fundamentally different from other commodities because it cannot be stored in inventory as a buffer between producers and consumers. Electricity production and consumption must occur simultaneously across the electrical system.
The electric industry is more usefully compared with an industry like commercial real estate. In real estate, there are no product inventories to serve as a buffer between producers and consumers. New buildings are like new power plants – they provide their owner with the opportunity to rent space in a competitive market. If the space isn’t rented on a particular day, the ability to earn income on that day is lost forever. Power plants provide their owner with the opportunity to sell electricity into a competitive market. If the sale is not executed on a particular day, the ability to earn income on that day is lost forever. Investors in the two industries face long lead times for siting and construction. They erect their facilities on site, and the site location may be extremely important to their competitive advantage. Developers face high fixed costs, and they look to high capacity utilization to recover those costs. Finally, both industries may experience large swings in prices, especially during periods with tight vacancy rates or with tight reserve margins.

Learning from the Real Estate Industry

The lesson from the real estate industry is to expect persistent cycles of boom and bust. One of the best accounts of the real estate construction cycle is Homer Hoyt’s (1933) detailed account of *One Hundred Years of Land Values in Chicago*. He describes five major construction booms, each of which is followed by a bust in prices. Surges in population were the key factor contributing to the booms, but Hoyt looked beyond the obvious, external factor. He focused on the way investors reacted to the population surges. Developers did not build in advance of growing demand. This allowed prices to surge upward, and developers would “scramble to build at many locations around the city…. so that when all these plans came to fruition, an astonishing number of new structures had been erected.”

Hoyt closed his book by speculating that “the real estate cycle may be a phenomenon that is confined chiefly to young or rapidly growing cities.” However, the recent evidence from cities like Dallas and Boston (DiPasquale and Wheaton 1996) tells a different story. The external factors triggering the booms have changed, but the response of developers is still the same. Their construction lags behind demand allowing a surge in real estate prices. Then a wave of over-building causes vacancy rates to soar and prices to plummet. Interviews of developers who suffered from the bust in real estate prices have revealed that a variety of psychological factors obscured their vision of the construction cycle.

The question for this article is whether power plant investors will follow the same pattern seen in real estate. For example, will their construction lag behind the growing demand for power? This part of the construction cycle is already evident in California, and the evidence is clear. New power plant construction has not occurred quickly enough to prevent the surging prices in California. Now, what about the power plants now under construction and under review? Should we expect to see a pattern of over-building similar to the over-building in commercial real estate?
Over-building could make sense if investors do not have access to information on power plant construction. But most states report the proposed power plants working through their permitting agencies in one form or another, and investors have access to the state reports. But the question remains, will the investors pre count the power plants under construction when formulating their own estimates of future market prices? One complicating factor that could cause companies to discount reports of plants already under construction is the disparity between construction lead times. The lead-time for installing new peaking units or for refurbishment of existing units is much shorter than the construction lead-time for a new CC. Skepticism about completion of announced power plants is also to be expected in a state with a history of environmental activism and serious air pollution problems. Investors may be skeptical of plants in the construction pipeline if construction could be delayed or canceled when opposition groups present new evidence on power plant impacts. The uncertainty in power plant construction is particularly important when investors must look to the summer months to capture the benefits of high prices (including price spikes) during peak periods.

There is a strong case for viewing power plant investors as influenced by the same combination of factors that have led to over-building in other industries. But the CEC study did not limit the simulations to a single view of investor behavior. The model was constructed to promote experimentation with many different assumptions, so let’s consider a new situation where investors react quite differently to power plants under construction.

**Alternative Simulation**

Figure 8 shows a simulation with all investors reacting as pre counters. *Pre counters* is an informal term to describe investors that count the CCs under construction in their forecasting of future prices as soon as they begin construction. With this assumption, all investors have full knowledge of the construction activity and they adjust their estimated prices downward as soon as construction is initiated. The construction in this scenario will be identical to the first two years of the simulation. Once some construction has begun, however, investors will limit annual starts to around 1 GW, the amount needed to keep pace with growth in demand. This construction is quite small compared to the 10 GW of approved projects in the site bank. Some readers may wonder how the companies competing for a share of the California market would find a way to limit their construction to only one tenth of the approved projects.

The limited construction is simulated endogenously in the model by the diversity of costs among the investors. For example, a company with an advantage in fuel costs may initiate construction when its forecast reaches 30 $/MWhr. Once this company initiates construction, the CC is in the “pipeline” for all to see. At this point 100% of the investors take the new CC into account and adjust their price forecasts downward. The model demonstrates that this combination of assumptions would allow the CCs under construction to equilibrate at around 1GW, exactly the amount needed to match the growth in demand.
Figure 8. Capacity and demand in a simulation with all investors as pre counters.

Figure 8 shows the demand compared to the available capacity in the new simulation. As before, the tightness of the summer conditions is visually apparent when the demand peaks during a typical day for each summer. The first three summers are the same as the initial simulation. The important differences show up in the 4th summer — it’s just as tight as the previous summer. The same situation appears again in the 5th summer, and in all subsequent summers.
Figure 9 shows the price implications of this theory of investor behavior. Once again, the most important implications appear in the summers. Summer prices are pushed to high levels by the tight balance of capacity and demand (and the ensuing price spikes). The distinctive feature in Figure 9 is that high summer prices appear in the 3rd summer and remain for each and every summer. We see average quarterly prices of around 45 $/MWhr year after year after year. These high summer prices cause the average annual market price to hover around 30 $/MWhr, somewhat below the average cost of a new CC. This equilibrium level is achieved inside the model by the simulated actions of the investors.

![Figure 9. Market prices in a simulation with all investors as pre counters.](image)

The prices in Figure 9 show the classic pattern to be expected in a future with rational expectations. Construction does not appear in waves of boom and bust, but occurs in a tightly controlled pattern that exactly matches the growth in demand. Average annual prices find their way to approximately the levelized cost of a new entrant. Then they remain at that level if there are no important disturbances in the system.
Multiple Views of Investor Behavior

The previous simulations classify all investors as either *believers* or *pre counterst* to help the reader appreciate how the model simulates investor behavior. These two simulations provide useful benchmarks as we explore the patterns of power plant construction that would appear with a mix of different investors. Figure 10 provides a side by side comparison of the construction results from five simulations. The 1st and 2nd cases have been described previously. The 3rd, 4th and 5th cases show the installed CC capacity in simulations with a mix of investors.

![Figure 10. Comparison of new CC capacity in five simulations.](image)

The five simulations are identical during the first two years --- no new CC capacity comes on line because all investors are watching and waiting for their forecasts of market prices to hit the threshold values. All five simulations show new CCs coming on line mid way through the third year. At this point, the results head in dramatically different directions. The qualitative differences are the focus of the model. The first case is the classic boom/bust described previously. It shows a rapid rise in CC capacity to 6.6 GW in the fourth year of the simulation. The 2nd case assumes that all investors are *pre counters*, and this assumption leads to a qualitatively different pattern. It shows perfectly linear growth in CC capacity once investors enter the market.
Now consider the third case with an equal mix of believers and pre counters. This simulation shows a construction boom in the third year and a rise in CC capacity during the fourth year. Both the believers and the pre counters participate in the early phase of the boom. But once a significant number of CCs are in the construction pipeline, the pre counters withdraw from the market. The believers continue to invest in new CCs, and it’s their actions that lead installed capacity to grow to around 5 GW by the fifth year of the simulation. Installed capacity is flat for the next three years, as investors wait for improved profitability. Investors see improved profitability near the end of the simulation. A second wave of construction occurs in the seventh year, and capacity climbs to around 6.7 GW by the end of the simulation. Once again, construction is dominated by the believers even though they hold only 50% of the permits for construction.

The 4th case assumes a 75%/25% mix of believers and followers. The followers need to see something in the construction pipeline before they commit to construction, so we would expect to see this simulation lag behind the base case during the early phase of the boom. Later, when the “herd mentality” factor takes hold, we expect to see a greater degree of over-building. Figure 10 confirms our expectation. Installed capacity grows to around 7.5 GW by the fifth year of this simulation. The 5th and final case assumes that all three types of investors are competing for a share of power plant construction. The 5th simulation shows believers and pre counters beginning construction in the third year, with the followers following close behind. The pre counters withdraw from the competition early in the boom, and the remainder of the simulation is dominated by the combined actions of the believers and followers. Total installed CC capacity by the fifth year is almost identical to the value shown in the base case simulation.

Implications of the Dominant Pattern of Behavior

The dominant pattern of behavior is evident from four of the five simulations in Figure 10. Installed CC capacity grows rapidly in the third and fourth years reaching a plateau of around 5 to 7.5 GW depending on the assumed mix of investors. All four simulations show that construction would appear in an exuberant boom which delivers more than enough new capacity to keep pace with growth in demand.

The CEC model reveals the implications of the construction boom in Figure 6 and Figure 7. Figure 6 shows that the tight balance of demand and capacity would be erased after the construction boom, and Figure 7 shows the high summer prices would be erased as well. California would benefit from adequate generating capacity and lower wholesale rates. This would be an attractive long-term future for the distribution companies and their consumers. The challenge is surviving the tight conditions in the 3rd year of the simulation while waiting for the boom.

On the other hand, the boom/bust pattern could pose serious problems for the generating companies. The low prices in the second half of the simulation shown in Figure 7 would pose serious cash flow problems for companies investing primarily in California. However, most of the generating companies are large corporations like
Calpine (with investments around the country) and Duke (with investments around the world). For these companies, the challenge is to balance the losses during the bust period in California with the profits in boom periods elsewhere.

**Implications of the Extreme Pattern of Behavior**

One simulation stands alone in Figure 10. It’s the simulation with each and every investor categorized as a *pre counter*. It shows CC capacity growing by 1 GW per year after the 3rd year of the simulation. This turns out to be exactly the amount needed to keep pace with the growth in demand. The CEC model reveals the implications of this view of investor behavior. We see linear growth in new capacity, tight supplies in each and every summer and higher prices in each and every summer.

Although it is possible to simulate this future in a computer model, it is difficult to imagine that such a future would be tolerated for long. Of course, the generating companies would prosper under these conditions. But the retail companies would not do well under such a future, especially if their retail rates were frozen by state rules. If the retail companies were allowed to pass the high prices along to their customers, it’s hard to imagine that customers would tolerate such a future. One might imagine that customers would tolerate a single summer with low reserve margins and high prices. But it is hard to imagine that they would tolerate six summers in a row. The more likely response is the sort of “rate payer revolt” described by Governor Davis in his appeal to FERC for rate caps and refunds.

**Summary**

This paper describes a computer model to simulate the general pattern of power plant construction in a system like California. The simulations reveal a tendency for new capacity to be added in an exuberant building boom. The results appear in simulations with widely varying assumptions about investor behavior, and they are consistent with building booms observed in industries like real estate. The results suggest that the new markets could deliver long-term benefits if California is able to survive the near term challenges of a tight supply of electricity.
Part Three. Post Script

The simulation study was completed in the summer of 2000. This was certainly a challenging summer with wholesale prices four-five times larger than the previous summer. Retail rates increased three fold in San Diego, while SCE and PG&E accumulated $6 billion in red ink serving retail customers at rates frozen by the AB 1890 transition rules. California normally expects a reprieve from price spikes when the summer is over. Peak loads in the fall and winter can be 30% below the summer peaks, and market prices are normally expected to fall. Under such conditions, the large IOUs might have made some progress paying off the $6 billion in red ink. Under such conditions, California’s consumers would have enjoyed reliable supply (without the threat of interruptions). Perhaps a boom in power plant construction would deliver major additions in generating capacity in time for the next stressful period – the summer of 2001.

Unfortunately, the ISO experienced difficult conditions throughout the fall and winter months. Reserve margins remained dangerously low, and the ISO issued numerous Stage 1 and Stage 2 alerts. The ISO was forced to issue the first Stage 3 Alert in California history on Dec 7, 2000. The first rolling blackout in California’s history occurred on Jan 17, 2001. By this time, stage 3 alerts (and rolling blackouts) had become a regular part of the California economy.

Wholesale prices remained high during the fall and into the winter. The prices were reported in the range of 300 to 400 $/MWhr revealing the “softness” in the 150 $/MWhr price cap imposed by FERC. By the end of the year 2000, the red ink at SCE and PG&E had grown to $12 billion. The utilities’ warned that they were on the edge of bankruptcy, and generators were not paid for previous generation. The electricity crisis had grown into a credit crisis, and reluctant generators continued to sell electricity into the California market under emergency orders by the Secretary of Energy.

The West Coast Crisis

The winter of 2000/2001 revealed that electricity supply is more than a California problem. It’s a problem for the entire WSCC, especially the northwest states whose electric system is tightly interconnected with California. The northwest system is dominated by hydro-electric generation in the Columbia River system which can vary by over 50% from one year to the next. The northwest utilities have lived with this variability for the past 60 years, and they have developed a variety of mechanisms for managing the system and planning the capacity additions needed under “dry” conditions. But the utilities have much less experience with deregulation. Although the northwest states have not followed the same approach to deregulation as in California, they have seen the same lack of power plant construction. The lag in construction is documented in a recent report by the NPCC (2000) and in testimony by Steve Oliver from the Bonneville Power Administration (BPA 2000). He testified that
the most significant challenge – though by no means the only challenge – is the shortage of generation supply at a time when the region’s economy is growing and that development of new generation has lagged due to the numerous uncertainties that still surround the transition to competitive markets. He also raised a concern that may persist even after the transition is completed:

The two-to-three year time lag in the market’s ability to respond to price signals with new generation supplies may reflect an inherent challenge for competitive electricity markets.

Oliver warned that Bonneville is vulnerable to market price volatility over the next five years because it has commitments to serve firm loads beyond the firm generating capability of the federal resources. “These commitments were made in an effort to widely distribute Federal benefits in the region.” By the end of January, BPA announced that its wholesale customers should expect a 60% increase in rates.

California Enters the Power Business

On January 4, 2001, Carl Wood, the Chairman of the CPUC, announced that “deregulation is dead” in California. On January 8, 2001, Gov. Davis described California’s deregulation scheme as “a colossal and dangerous failure.” The Governor lobbied aggressively for an effective price cap to limit the wholesale prices, but FERC did not view a hard cap as part of the solution. The CPUC raised retail rates by 10% in early January, and the legislature met in special session on the crisis. It moved immediately to dissolve the governing boards of the PX and the ISO and to postpone the scheduled sale of the IOUs hydro-electric assets to private generators. The legislature then tapped the State Water Project (SWP) to buy power in the spot markets on behalf of the cash starved utilities. The IOUs red ink (from under collections) has been estimated at around $13 billion, and the State is looking for major steps to prevent their bankruptcy. The options under consideration included state purchase of the IOUs transmission assets, the state purchase of the IOUs hydro-electric assets, and State equity ownership in the IOUs. By March of 2001, the state was concentrating on the purchase of the IOUs transmission assets.

The State is looking to long term contracts to reduce the dependence on the volatile spot markets. It has called on the SWP to negotiate long-term contracts under a $10 billion program authorized by the legislature. The legislature initially asked for long term contracts at 55 $/mwh, but the asking price was soon increased to 74 $/MWhr. (This approach had encountered opposition from consumer groups and economists, but the State is proceeding deeper into the power business as of March, 2001.) The current plan calls for the State to resell the contracted power to the large IOUs who would be allowed to sell the electricity to their consumers at cost. To ensure that the State is not stuck with “stranded costs” (in the event of a decline in spot prices), the legislators are considering a prohibition on residents and businesses from seeking cheaper rates through

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direct contracts with power generators. Meanwhile, everyone is anxiously watching the progress of power plant development.

**Power Plant Construction**

Figure 11 summarizes CCs in various stages of development as of Jan 25, 2001. No new CCs have come on line. There are 6 plants under construction with a combined capacity of 4,308 MW. Three of the plants, with a combined capacity of 1,308 MW, are scheduled to begin operation by the summer of 2001. The other three plants are scheduled to be on line by the summer of 2002. Figure 11 shows that 3 proposals have received construction permits, but are not yet under construction. These would provide 1,970 MW with 500 MW scheduled to be on line by the summer of 2002. An additional 12 proposals with a combined capacity of 6,584 MW are under review by the CEC. The CEC also tracks proposals that have been “announced” but which have not yet formally entered the review process. As of late January, 10 proposals with a combined capacity of 5,920 MW and been “announced” and were “expected to apply.”

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Figure 11. New CCs in development in California in January of 2001.

Figure 11 shows almost 13,000 MW of capacity in various stages of development. The total would be almost 19,000 MW if one counts the projects which have been announced and are “expected to apply.” Figure 11 shows serious construction underway and the potential for an exuberant construction boom (if a majority of the proposed plants actually enter construction). The challenge for California is to restructure the electric business while encouraging the developers to follow through on the proposed projects. The State is accepting bids for longer-term contracts through the SWP. The terms and
conditions of these contracts will be crucial to ensuring that developers follow through on the proposed projects. For example, longer-term contracts could give the developers some protection against the risk of the boom/bust pattern simulated in this paper.

Waiting for the Boom

The simulations reported in this article suggest that power plant construction will appear in a major boom of over-building. Policy makers, utility executives, developers and consumers are all wondering about the timing of the boom. The question on everyone’s minds is how long must we wait to see enough new generating capacity to lower market prices and improve reliability? One forecast warns of a 5,000 MW deficit in California and a 10,000 GW in the west for the year 2001 (CERA 2001). It also warns that “the west is unlikely to add sufficient new supplies until 2003 at the earliest.” If we take summer of 2000 as the first year of soaring prices, this warning suggests that we must endure three successive years of difficult conditions. A similar warning appears in a recent speech by Steven Hickok, BPA’s Chief Operating Officer. He explained that the “lights are on” in Portland only because 3,000 MW of industrial load was shut down. He offered encouragement for the long term: “the fundamentals for electric power in the Northwest are excellent.” But he acknowledged that the current structure is “producing ugly spikes” which he believed will be part of the difficult circumstances to be faced for the “next two to three years.” (Hickok 2001)

Forecasting is hazardous business, and the simulation model described in this article was designed for general understanding, not for year-by-year forecasting. Nevertheless, the model does show certain dominant patterns which can help us think about the duration of difficult times. With the assumption of a 12 month construction interval, for example, the boom/bust simulation suggests that the system will experience one year of difficult conditions before feeling the benefits of a construction boom. Construction intervals may now be closer to 24 months (EPRI 2000), so I have repeated the boom/bust simulations with the longer interval. The new simulations (which are not shown here) suggest that the system would experience two difficult years before seeing the benefits of a construction boom. If we consider the year 2000 as the first of the two difficult years, the new simulations alert us to prepare for difficult conditions for the rest of 2001.

Further Research

The CEC model simulates an electric system with approximately the same loads, resources and markets as those in California. Recent events have taught us all that the lack of power plant construction is more than a California problem; it’s a west coast problem. One of the important areas for further research is to expand the model’s scope to include the northwest loads and resources and their interaction with California.
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End Notes

1 The initial debate was loosely organized around the “yellow book” and “blue book” issued by the CPUC (Hirsh 1999). The quotations from Governor Wilson and the CPUC are taken from the December 9, 2000 issue of the Los Angeles Times.

2 A combined cycle power plant is a dual cycle plant with a heat recovery unit to take advantage of the energy in the exhaust gas to create steam. The steam spins a steam turbine to generate additional electricity. The schematic was provided by Nooter/Eriksen, a supplier of heat recovery steam generators.

3 The change in scale during the early 1990s is particularly evident from a comparison of the marginal generating resource identified by the Northwest Power Planning Council (NPPC 1996). In 1991, the marginal resource was an integrated coal gasification, combined cycle generating plant. Its levelized cost was 60 $/MWhr, and its capital cost was 2,520 $/kw. By 1996, declining gas prices led the NPPC to designate the marginal resource as a gas-fired combined cycle unit. Its levelized cost was estimated at 30 $/MWhr, and its capital cost at 684 $/kw. In 1991, a typical (420 MW) plant would require the utility to raise over $1 billion. By 1996, a typical CC (228 MW) would cost only $160 million.

4 A Fortune article from June 24, 1996 announced that California, Massachusetts and New York had all recently unveiled plans to create competitive markets by early 1998 and that “no one can say with confidence precisely how the various states’ programs and the electricity marketplace will evolve,” but that “all paths should eventually lead to lower prices, and businesses with market clout will enjoy substantial declines right away.”

5 The quotations from Sen. Peace and Gov. Wilson are taken from the December 9, 2000 issue of the Los Angeles Times.

6 The utilities’s stranded costs were paid down from funds collected by a “competitive transition charge” (CTC) on the retail bill. In a typical bill in 1998, the CTC amounted to over 34 $/MWhr well above the 24 $/MWhr to cover energy purchases from the PX (Ford 1999, p. 652).

7 The retail rate was frozen at 10% below the previous level to reinforce the promise that competition would bring lower rates. The rate reduction was to be accomplished (without threatening stranded cost recovery) by using up to $10 billion in revenue bonds issued by the State Infrastructure Bank.

8 The ISO would also create markets for ancillary services (A/S), adjust prices for transmission congestion and ensure system reliability. The ISO would operate, but not own the transmission system.

9 The ISO Market Surveillance Unit (ISO MSU 99) reported that the real time market found a balance over 99% of the time without hitting the price cap. But it also observed “significant exercise of market power” during certain periods of the summer of 1998. The MSU observed “systematic under scheduling” in the PX and it reported that ISO real time prices were significantly higher than PX prices when loads exceeded 42 GW. The market surveillance committee (ISO MSC 1999) reported that the PX energy price was 38% above a “pure competitive benchmark” for the month of July in 1998. Puller (2000) studied PX day ahead prices from April 1998 through December of 1999. He found “direct evidence of market power: units systematically have unused capacity when price is above marginal cost”, and he found “evidence that the new generation owners suppress output.”

10 For example, the price of replacement reserves cleared at 9,999 $/MWhr on July 13, 1998. This extraordinary price was capped at 4 digits by the generators’ mistaken impression that the ISO software would not accommodate higher bids. (The software was actually capable of accepting a 17 digit bid.) The ISO applied immediately to FERC for a “damage control” cap of 500 $/MWhr. Ten days later, it asked to adjust the cap to 250 $/MWhr to match their cap on energy. A more general, systematic problem in the
first year’s experiment with A/S markets was inverted prices for different levels of ancillary service. (Low quality services were costing more than high quality services.) The ISO called for a “rational buyer procedure” which was implemented in August of 1999.

11 The ISO MSU (1999) reported that the market performance from October 1998 to June 1999 was “what we expect from a workably competitive market.” The MSC reported that actual PX prices in July of 1999 were 20% above a “pure competitive benchmark,” an improvement from the 38% observed in July of the previous year. The MSU attributed the improved behavior, in “no small part to the fact that this period was characterized by low levels of total ISO load.”

12 The price spikes were quite severe during heat waves of June 14-16 and June 26-30 (ISO DMA 2000).

13 The ISO DMA (2000) reports that market costs during the peak hours for 8 days in June of 2000 amounted to $2.5 billion. Their “special report” on the price spikes in May and June reported the average price for energy and ancillary services in the summer of 2000 at 166 $/MWhr, up from 36 $/MWhr in the previous summer.

14 The price of natural gas in southern California averaged around $5 per million Btu through the summer of 2000. But even higher prices were to come. According to Krapels (2001), natural gas prices in southern California had climbed to the stunning value of $25 per million Btu by December of 2000.

15 Nitrogen oxide emissions are released from the uneven combustion of natural gas contributing to ozone (smog) in the air sheds of southern California. A RECLAIM market for nitrogen oxides emissions credits (RTCs) had been established with the total allowed emissions to be lowered over time. Early in 2000, the allowed emissions was high, and the cost of a RTC was only around 1-2 $/lb (Joskow and Kahn 2000). A typical plant emits up to 1 lb for each MWhr of generation, so the RTC could add up to 1-2 $/MWhr to the operating cost. As the total allowed emission was lowered further, however, the RTC market hit “cross over.” RTC prices climbed to 20-30 $/lb, adding up to 20-30$/MWhr to the operating cost of an older unit.

16 “Staggering” is strong word which I use intentionally. My review of the studies by the groups closest to the California markets reveals truly “staggering” differences between the observed prices and the prices that would be charged if markets were to clear based on the variable costs of the most expensive unit. According to the Market Surveillance Committee (ISO MSC 2000A, p. 2), for example, market prices in June of 2000 were 182% above a “pure competitive benchmark.” According to the Department of Market Analysis (ISO DMA 2000, p. 18), the cost of energy and ancillary services in the summer of 2000 was around three times higher than the typical marginal fuel cost. And according to testimony by Kahn and Joskow (2000), average prices in June were approximately double a competitive benchmark.

On the other hand, it’s important to observe that many groups use quite different language in describing the market performance. Krapels (2001) provided an aggregate assessment of the effect of gas prices, emission credits and reduced hydro imports and concluded that “most of the price increases can be justified on the basis of marginal cost economics.” He defined the remaining, unexplained component as a “power market anomaly.” In August of 2000, for example, his “power market anomaly” accounted for around 50 $/MWhr out of a total price of 200 $/MWhr.

A CERA (2001) report provides yet another way of describing the extent and importance of strategic behavior. The CERA analysts reported that the “California markets were highly competitive” during their first two years of operation. When it came to the year 2000, however, the analysts took no position because “CERA does not possess the plant outage and transaction data necessary to fully unravel all market behavior in 2000.” Nevertheless, the analysts felt confident enough to dismiss California complaints about strategic behavior as “distracting” from the real problems.

17 FERC described the California markets as “seriously flawed” in their November 1, 2000 order. Their order called for eliminating the requirement that the three IOUs must sell all their power and buy all of their power needs from the PX. It also ordered the PX to change the single price auction so that bids above 150
$/MWhr would not set the market clearing price paid to all bidders. (The 150 $/MWhr limit is sometimes called a soft cap.)

18 The 6% contract cover is the subject of intense scrutiny as company officials, regulators, legislators and federal officials examine the crisis. With 20/20 hindsight, one can argue that the utilities should have acquired substantial cover to hedge against the price spikes of 2000. According to the Los Angeles Times (February 5, 2001), the lack of contract cover has been attributed to a variety of factors, depending on whom one talks to. Perhaps the key factor is the CPUC commitment to a strong PX as a “core principle.” The CPUC believed that allowing the large utilities to buy electricity directly from power producers (at prices known only to them) would weaken the PX. The CPUC was also worried that contracting outside the PX would hobble the small energy service providers that were attempting to compete with SCE and PG&E. By April of 1999, the PX began offering forward contracts up to 18 months into the future. The utilities were given permission to obtain PX contract cover in July of 1999, but they did not choose to obtain the full cover that had been authorized. The lack of authorized cover has been attributed to the design of the PX forwards and to a fear that contract expenses could be “second guessed” by the CPUC. By December of 2000, the CPUC dealt with the “second guessing” problem by signaling that 60 $/MWh contracts would be “reasonable.” Unfortunately by this time, spot market prices were averaging 250 $/MWhr, and the utilities had accumulated nearly $12 billion in debt.

Sioshansi (2000) tells a somewhat similar story, focusing on the lack of contract cover at SDG&E. The San Diego utility sought CPUC approval in advance of signing PX forward contracts. But “for reasons that are not entirely clear, this critical procedural matter requiring the approval of the CPUC was fumbled.” Sioshansi concluded that, “in hindsight, both sides deserve blame in not sorting things out before the summer’s crisis hit.”

19 The utilities refer to the $6 billion as “under collection” on their books. The cash flow is met by drawing down cash reserves or by increased borrowing.

20 The state agencies include the ISO DMA, the ISO MSC, the CPUC and the California Electricity Oversight Board. The following observation from the ISO DMA (2000, p. i) illustrates what all the agencies were finding.

During peak load hours, the combination of tight supply conditions and the limited ability of consumers to reduce consumption in response to prices creates the situation in which any firm that owns a significant share of the generation serving the state can exercise market power to inflate wholesale prices

The ISO DMA report was quite specific about the “tight supply conditions” in which generators could exercise market power. Their summary (p. 50) revealed non competitive outcomes when the supply fell below 120% of demand (where demand is defined as load plus 10% for A/S).

21 The CPUC ordered the IOUs to contract with private companies for 1,400 MW of new capacity in the early 1990s. SCE and SDG&E objected and appealed to FERC. According to the San Jose Mercury News (February 3, 2001), the FERC response was ambiguous, allowing the utilities to eventually buy out the bidders who would have constructed the 1,400 MW of new capacity.

22 Several investigators have commented on the need for a formal capacity payment to supplement the payments for energy (Michaels 1997, McCullough 1998, CERA 2001). They argue that energy payments alone will not allow investors to recover the full cost of a new CC. I believe there is some merit to these arguments, but I believe capacity payments need to be designed to provide a steady incentive, well in advance of the need for new capacity. I simulated the impact of constant capacity payments in a previous article (Ford 1999A) and learned that constant payments could eliminate much of the volatility in the boom/bust cycle. They do drive up total wholesale prices in the short run, but they stimulate increased investment at a crucial stage early in the cycle, so they reduce the propensity for boom and bust.
The previous article demonstrated that retail consumers would be shielded from the short-run impacts of capacity payments based on the stranded cost recovery mechanism used in California. Capacity payments were not the focus of the CEC study in the summer of 2000, and they are not mentioned further in this article.

23 The ISO Market Surveillance Committee’s analysis of the price spikes in June of 2000 is typical of several detailed studies which look at market performance in great detail, but which pay only slight attention to new construction. For example, the MSC’s only suggestion is to “expedite siting and construction” of new generating capacity (ISO MSC 2000A, p. 3). The California legislature has responded to the calls for expedited construction with AB 970. Passed in the Summer of 2000, it calls for a fast track review to reach a decision within 6 months of the applicant meeting air quality rules.

24 “Merchant” power plants are constructed based on expected profitability selling into spot markets (Moore 1999, Thurston 1999).

25 The problem with the “perfect foresight” assumption is explained by ERPI (2000) and by Ford (1999A).

26 The CEC was not totally alone in calling attention to a boom/bust scenario. According to a July 7, 2000 article in the Wall Street Journal, Duke Energy Corp. builds cycles of boom and bust into their own scenario analysis of electricity markets around the world. “There is little doubt there will be over-building. It will happen. The question is when?” says James Donnell, President of Duke’s North American Energy Unit. “If we get the cycles right, we’re successful. If we get the cycles wrong, we’re less than successful.”

27 The previous study demonstrated that the tendency for severe cycles of boom and bust could be reduced by the introduction of a constant capacity payments well in advance of the need for new construction (Ford 1999A).

28 System dynamics was pioneered by Forrester (1961) and is explained in recent texts by Ford (1999B) and Sterman (2000). The method has been applied extensively in the US (Ford 1997, 1999A) and in the UK (Bunn 1992, 1997) and is valued as a “strategic” tool for use in a rapidly changing industry with high uncertainty and high risk (Dyner and Larsen 2001). System dynamics models are normally implemented with “stock and flow” visual software to aid in model construction and testing. The CEC model was implemented with the IThink software from High Performance Systems (http://www.hps-inc.com/).

29 The value of flight simulators for general learning has been described by Morecroft and Sterman (1994). The value of system dynamics (as compared with methods like agent modeling, competitive analysis, game theory, options theory and scenario analysis) has been described by Dyner and Larsen (2001).

30 California has several markets for electric energy. The PX is only one of several markets operated by scheduling coordinators (SCs). The SCs produce market clearing prices and “balanced schedules” which are sent to the ISO. The ISO runs a real-time market to deal with imbalances that may result from surprising changes in the weather (or from deliberate under scheduling in the PX). The model described in this paper simulates a single market, so the simulated price should be interpreted as a weighted average of the hourly prices observed in the PX (and the other SCs) and in the ISO.

California also has several markets for ancillary services. (A/S). These are run by the ISO, whose motto is “reliability through markets.” The model described in this paper ignores the A/S markets and the extra revenue they provide to generators. An endogenous treatment of energy and A/S markets is explained by Deb (2000). A heuristic treatment of energy and A/S markets is explained by Kahn and Joskow (2000). They adjust the demand upward and find the market clearing price of a larger market for electric energy. The resulting price is taken as a proxy for the combined prices of the energy and A/S markets.

31 The 1 GW is based on the amount of capacity bid well above variable cost in the PJM system, a system with approximately the same size as California (PJM MMU 2000).
The model is simulated with “strategic capacity” set to zero to get market-clearing prices in a competitive market. The model is then simulated with different assumptions on the amount of “strategic capacity,” the relative balance of capacity and demand, and the price cap. The increase in market clearing prices may be compared to increases documented by the ISO Market Surveillance Committee.

The PX has an extremely high cap, say 2,500 $/MWhr, but the market operates as if the ISO cap (say 250 $/MWhr) is the relevant cap. This is because buyers do not offer to pay more than 250 $/MWhr in the PX because they may still buy at the ISO’s cap in the real-time market if their bids are not accepted in the PX.

The model was constructed before the decision to impose a soft price cap of 150 $/MWhr. It is hard to know how to represent a soft cap in a computer simulation. Indeed, it is hard to know how the soft cap will work in real markets in the west.

The FERC order of November 1, 2000 called for bids below 150 $/MWhr to be cleared in the usual manner (at a single price). Bids over 150 $/MWhr will be paid their individual bids, subject to future adjustments if FERC learns the generator can not justify the higher bid. The softness in the soft cap arose from the inclusion of opportunity costs in the list of factors that can justify the higher bids. Generators may circumvent the soft cap by pointing to higher prices in external markets. The opportunity to sell in the external market is the “opportunity cost” that justifies the bids above the soft cap.

This and other problems with the FERC order have been explained by the ISO Market Surveillance Committee (ISO MSC 2000B), by the Department of Energy (DOE 2000) and by Stoft (2000). Stoft argues that “The soft cap ceases to function as soon as external prices are higher than 150 $/MWhr. In other words, there is simply no cap when it is needed most.” He notes that FERC has imposed a regional cap in the Eastern Interconnection, and he recommends a similar approach in the west: “to be effective, a bid cap must allow no exceptions and must also be a regional cap to avoid causing reliability problems for California.” Stoft also discusses how price caps may be designed to suppress attempts to exercise market power without eliminating the necessary incentives for developers to invest in new CCs.

Although FERC has acknowledged the “balkanization of the Western grid” in its November 2, 2000 news release, it has been strangely reluctant to impose a region-wide hard cap. When pressed by western Governors, FERC (2000) responded that imposing a regional cap would be “time consuming and contentious.” FERC argued that California’s main problem is the lack of contract cover to moderate the price spikes in the PX. FERC has ordered California to release the IOUs from their obligations to buy in the PX. FERC resists imposing a regional cap because it would “unravel the economic decisions, rewarding those who did not exercise their choice to hedge and penalizing those who did” and because “this will have a chilling effect on hedging in the future.”

The assumption that investors “look” into the future was based on a consensus among experts interviewed in summer of 1998 and in the summer of 2000. The experts agreed that investors will look beyond today’s prices, as advised by Bill Thompson, a senior partner for Black & Veatch: “Builders of new technology had better remember that they’ll be competing at tomorrow’s prices, not today’s.” (Schuler 1996).

On the other hand, some readers may view investors differently. For example, the CERA report on the California crisis describes a typical investor as extremely myopic: “if market prices remain above the cost to produce electricity from a new plant long enough, then a developer may believe that construction costs of the plant can be recovered, along with a profit.” (CERA 2001, p. 11) The report describes the total lead times for siting and construction at 4 years, which leads to them to conclude that the soaring prices in the year 2000 came “four years too late” to support new investment.

The 12 month construction interval was based on interviews in 1998 and 1999. More recent information suggests that the construction interval is around 24 months (EPRI 2000).
There was a boom in the United Kingdom with 8.3 GW of new CCs entering the system shortly after privitization (Newbery 1995). This was a surprisingly rapid addition of generating capacity, but the UK example is not comparable to the boom simulations from the CEC model. The boom in the UK should be interpreted as a strategic move by the retail companies, as explained by Bunn (1994, p. 367): “the extraordinary speed of the ‘dash for gas’ was primarily strategically driven, resulting from an unbalanced competitive structure in the new market.”

Hoyt (1933) saw the same pattern in one community after another, and he described a typical cycle as follows:

*The demand for land increases when there is a surge in population. Gross rents begin to rise rapidly, at the very time as population is growing. Net rents are the key to developers, and they rise even more rapidly during this phase of the cycle. The surge in net rents causes a surge in prices of existing buildings. At this point, investors begin to erect new buildings. Developers scramble to build at many locations around the city, and a great many men work secretly and independently on a great variety of structures in many sections of the city. There is no central clearing house to correlate the impending supply of buildings with the probable demand, so that when all these plans came to fruition, an astonishing number of new structures had been erected. This over reaction sets the stage for the bust. Gross rents fall, and net rents fall even faster. Land values plummet, and foreclosures are everywhere. Nearly all phases of real estate activity are virtually suspended. The lull lasts much longer than the boom, and developers are left only to hope for another surge in population. When it comes, the cycle begins anew.*

These factors are summarized by Sterman (2000). They include a focus on short-term earnings and a sense of over confidence that their own buildings will survive the bust (due to superior location). Other psychological factors include a focus on external events, a tendency for “herding” and “grouptthink” and simple denial that cycles exist.

Some company officials have described the construction interval for a new CC at almost 24 months; others have said 12 months. Single cycle combustion turbines, on the other hand, can be assembled in a much shorter time interval. A CEC news release at the end of October 2000 spoke of 500 MW of new combustion turbines placed on a “fast track” toward operation by the summer of 2001. Investors reading this news might have been inclined to pull back from their own construction plans thinking that the extra 500 MW could eliminate some of the summer price spikes that contribute to profitability. They might have waited to see the new units come on line before making changes in their own investment. In this case, their skepticism would have been justified. According to the *San Diego Union* (January 8, 2001), the 500 MW of new turbines were canceled around one month after the CEC news release.

The January 24, 2001 issue of the *Los Angeles Times* describes a plan by AES Corp. to refurbish its Huntington Beach plant. AES says it is willing to invest $140 million in construction with the goal of bringing an extra 450 MW on line by June of 2001. If they meet their goal, 450 MW would be added to the system in five months.

An article from the *Sacramento Bee* (January 28, 2001) describes the long delays in obtaining a construction permit. The article then describes how further delays can occur even after construction is started. Construction of Calpine’s plant in Sutter County was suspended to allow an appeal to the EPA. Four months passed before the appeal was rejected and construction could resume.

Despite the extensive documentation of plants in various stages of construction, it is still difficult to get a reading on the amount of new generating capacity that will be on line in the coming summer. On October 25, 2000, for example, the ISO Governing Board received a presentation on the “Summer 2001 Preparedness Program” in which “New Generation” was set at 500 MW with a range from zero to 2,400 MW. If the ISO finds it difficult to pin down the contribution of new generation only 8 months in advance of the summer season, power plant developers would face similar difficulties.
The theory of rational expectations, as applied to electric industry modeling, is described by EPRI (2000).

Calpine, a San Jose based company, is a major developer in the California market with two plants under construction (500 MW Sutter Power and 880 MW Delta Energy) and one plant under review (600 MW Metcalf Energy). But Calpine is not confined to California. According to a company news release (July 24, 2000), Calpine has “established first mover advantage in Texas, California and New England, with programs in place for other key energy markets.” The Calpine operating target is 40,000 net megawatts of base load capacity by the end of 2004.”

Duke Energy Corp. has a 1060 MW proposal (Moss Landing) under review in California. According to a July 7, 2000 article in the Wall Street Journal, Duke builds cycles of boom and bust into their own scenario analysis of electricity markets around the world. “There is little doubt there will be over-building. It will happen. The question is when?” says James Donnell, President of Duke’s North American Energy Unit.

The November 15, 2000 issue of the Los Angeles Times describes the Governor’s warning of a rate payer revolt in his appeal to FERC for price caps and refunds. The likely view of consumers was also described by Sen. Steve Peace, the “architect” of AB 1890:

There is just no appetite among consumers, among voters, to accept the kind of price volatility that FERC thinks is necessary to keep capital in the market.

The ISO DMA (2000) describes the average price for energy and A/S at 166 $/MWhr in summer of 2000 versus 36 $/MWhr in the previous summer.

California aims for 10% reserves, 7% for the WSCC requirement and 3% for regulation. A Stage 1 Alert is issued when reserves fall below 7%, triggering a call for voluntary conservation. A Stage 2 Alert is issued when reserves fall below 5%, triggering a cut off of customers with interruptible contracts. A Stage 3 Alert is issued when reserves fall below 1.5%. It authorizes the ISO to initiate rolling blackouts.

According to a February 14, 2001 article in The Los Angeles Times, California endured 29 straight days with Stage 3 Alerts in late January and early February.

According to a January 24, 2001 article in the Contra Costa Times, the State of California was paying around 300 – 400 $/MWhr for its spot market purchases. Sjoding (2001) reports spot prices of 400 $/MWhr for December of 2000 at the Mid Columbia Hub.

The softness in the soft price cap was anticipated in advance by the ISO (ISO MSC 2000B), by the Department of Energy (DOE 2000) and by Stoft (2000). When wholesale prices remained far above the 150 $/MWhr soft cap, several western Governors pressed for an effective cap. FERC resisted their request, stating that the “process would be time-consuming and contentious” and that it would dampen hedging in the forward markets (FERC 2000). California has turned to Congress where Senator Boxer and Representative Filner have reintroduced legislation for a “Western Regional Rate Cap” (Boxer 2001).

The Pacific Northwest and California markets are connected by 7,900 MW of transmission capacity. With open access to transmission, the west coast market typically acts as one large market (Oliver 2000).

In a year with average runoff, the hydro-electric system might provide around 15,000 average megawatts of energy. This could drop to around 12,000 average megawatts in an unusually dry year or increase to 20,000 average megawatts or more in an unusually wet year.
The NPPC (2000) warned that the region would need the equivalent of 3,000 megawatts of new capacity to reduce the probability of power supply problems during winter months to an acceptable level. They warned that it was unlikely that market prices would be sufficient to stimulate the development of sufficient new generation in that time frame. (The NPPC uses a “probabilistic” warning because of the highly variable runoff in the Columbia River System.)

Stephen Oliver reported that “Bonneville’s annual analysis of the region’s loads and resources has for several years indicated the possibility for regional deficits during years with poor water conditions and times of peak energy usage” (BPA 2000).

The 60% rate announcement is described in the January 26, 2001 issue of the Oregonian. BPA faces higher costs due to unprecedented increases in market prices and extremely low river flows. By March of 2001, BPA estimated that Columbia river flows for the first half of 2001 would be 45% below normal. BPA announced that it would operate the dams exclusively for electricity generation (cutting planned spills to aid salmon migration). This change would reduce the probability of survival of migrating salmon, but it could save an estimated $550 million by September of 2001. The warning of a 250% increase appeared in the April 10, 2001 issue of the Seattle Post Intelligencer. BPA estimated that a wholesale rate increase of that size would often mean doubling the retail rates that northwest consumers pay.

The January 24, 2001 issue of the Los Angeles Times describes the tension between Curt Hebert, President Bush’s recently appointed chairman of FERC, and Gov. Davis. Hebert’s position has been characterized as follows:

For the most part, Hebert, following President Bush, placed blame for California’s problems squarely on its own leaders and said it was up to the state to dig itself out of its hole.

Hebert and the Bush Administration are looking for the CPUC to implement further increases in retail rates. On the other hand, Gov. Davis has pledged to solve the California crisis without further increases beyond the CPUC’s 10% rate hike in early January. The Governor is clearly worried about the threat of utility bankruptcy which would move policy-making into the courts. But he is also worried about the threat of a taxpayer revolt which would move policy-making into California’s notorious ballot-initiative process. According to the Wall Street Journal, the Governor believes that “If I wanted to raise rates, I could solve this problem in 20 minutes.”

Several observers have argued that California should increase retail rates (CERA 2001, Teece 2001), but an uncapped, non-competitive wholesale market is a major obstacle. FERC may decide to remove this obstacle, as urged by the Governors of California, Oregon and Washington. Their challenge is to design a regional cap which will suppress attempts to exercise market power without eliminating the incentives for developers to invest in new CCs.

The IOUs has asked for rate increases of 26-30%, but the CPUC voted to limit the increase at around 10%, approximately the same as the AB 1890 rate reduction financed through state bonds. The Governor pledged to find a solution to the electricity crisis without further increases in retail rates.

With its massive pumps to move water around the state, the SWP is single largest consumer of electricity in California. The SWP began purchasing power in the spot markets on an emergency basis because of the credit problems of the large IOUs.

The transmission system is operated, but not owned by the ISO. A Reuters news release (Feb 14, 2001) describes the state purchase of the transmission system as “a transaction which could put anywhere from $3 billion to $9 billion into the pockets of California’s cash-strapped utilities.”

According to the January 23, 2001 issue of the Contra Costa Times, the State might assume “full or partial” ownership of 4,900 MW of hydro-electric assets owned by the SCE and PG&E. In exchange, the
State would take over their burden of buying the corresponding amount of electricity in the wholesale market.

The proposal for the State to take a “kind of stock option in the two financially battered utilities in return for relief” raises a serious concern for long-term conflict of interest (Los Angeles Times, January 29, 2001). For example, how could the CPUC respond fairly in rate hearings when the State holds an equity position in the IOUs?

According to the March 2, 2001 issue of the San Diego Union, the state purchase of the transmission system could cost around $7.4 billion, approximately 2.3 times book value. The transmission system would then require additional state spending if it is to be expanded to avoid a “tragedy of the grid,” as described in a March 5, 2001 issue of Fortune. The “tragedy” arises from the congested use of a shared resource without clear incentives for individual participants to expand the grid. According to Fortune, the threat of over-loaded power lines poses a much greater threat than shortages of generating capacity.

I have not seen an explanation of $55/MWhr, but this value turns out to be approximately the fully levelized cost of a new CC if natural gas price were to remain at $5 per million BTU (the price in the summer of 2000). Based on the CEC scenarios study (Grix 2000), a new CC would have a levelized fixed cost of around $52/MWhr. The increase to $74/MWhr is described in the Jan 24, 2001 issue of the Los Angeles Times:

Through a series of sensitive negotiations and arcane calculations, officials concluded that they could pay an average of $74/MWhr, rather than the $55/MWhr Davis had insisted upon.

According to the February 3, 2001 issue of the San Francisco Chronicle, Michael Shames, executive director of The Utility Consumer’s Action Network, warned against signing “any contract that exceeds five years.” “Five years down the road, prices will almost certainly be lower.” Similar warnings have been issued by CERA (2001).

A group of prominent economists issued a “Manifesto on the California Electricity Crisis” (Teece 2001). The economists warned that “now is precisely the wrong time for the State to commit to long-term contracts for a large portion of California’s electricity needs….emergency state contracts should last no more than two years, and should be kept small.” The economists warned against government ownership of generation or committing taxpayer funds to large energy projects. The economists believed that “solving the financial crisis will require sharing the pain amongst the various stakeholders,” and they call for further increases in retail rates. As to the concerns for an unworkably competitive market (and the lack of a price cap), the economists found themselves “of different opinions” and they urged further study of market problems.

The legislature will finance the SWP purchases with revenue bounds. “In order for the state to sell the revenue bonds, you have to ensure the bond buyers they will actually be paid” said Sen. Debra Bowen (Orange County Register, January 2, 2000). Sen. Bowen explained “We just want to make sure we don’t leave remaining ratepayers holding the bag if spot prices drop.” The Register observed that “Ironically, such a scenario would leave the state with ‘stranded assets,’ the same concern utilities had when deregulation was enacted and they were forced to sell their generating plants.” This provision at least temporarily “reverses yet another of the key elements of energy deregulation – encouraging competition by allowing customers to buy power from companies other than the major utilities.”

The information was reported in a January 25, 2001 “update” at http://www.energy.ca.gov/maps/siting_cases.html.

News on the contracts has been limited, as the State is reluctant to release information (Contra Costa Times, January 24, 2001). But it appears from the sketchy accounts that the SWP received few bids at the initially suggested price of $55/MWhr. The Dow Jones has reported that Calpine Corp. signed a 10 year
power sales agreement valued at $4.6 billion. Calpine may find that these long-term contracts could protect the Corporation against the adverse impacts of an over-building boom.