Power Price Spikes: Aberration or Prophecy?

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Introduction

Since mid-May western power markets have experienced a series of convulsive price spikes. On June 28, on-peak spot prices for delivery at Mid-Columbia (Mid-C) peaked at $695 per MWh. This was eight times higher than the highest prices observed in earlier years. While this is a new phenomenon to the West, other regions have had similar experiences. In the summer of 1998 the Midwest had a period of severely hot weather and for a few hours prices reached $10,000 per MWh. In the summer of 1999 there were also price spikes in the Midwest and Atlantic states. These episodes were, however, constrained to a few days; prices soared to dramatic heights and then subsided to previously low levels. In contrast, since mid-May, prices in the Western Systems Coordinating Council (WSCC) have been consistently high which has given rise to accusations of market manipulation and caused California to implement a price cap of $250 per MWh in the wholesale market.

Although it is too early to provide a comprehensive assessment of market performance, certain observations about recent events are worth making:

- The deregulation of power markets in the U.S. is something of bastard child. Wholesale prices have been allowed to seek market levels, but most retail prices remain regulated. As a consequence, wholesale demand schedules are price-inelastic, virtually perpendicular. This means that we depend exclusively on competition between suppliers to keep a lid on wholesale prices. Until adequate demand responses are built into retail loads, the power market will remain the most volatile commodity market in existence.

- Most, if not all, of this summer's higher prices can be explained by market fundamentals. The economy has been exceptionally good and the weather exceptionally warm. These two factors have pushed demand to higher-than-expected levels. In addition, oil and natural gas prices are nearly double their levels of a year ago and the consequence has been to raise the cost floor on electricity prices. The price rise is not restricted to a particular state or utility district; it is region-wide. It is difficult to believe that the entire regional market could have been manipulated, given the diversity of resource ownership.

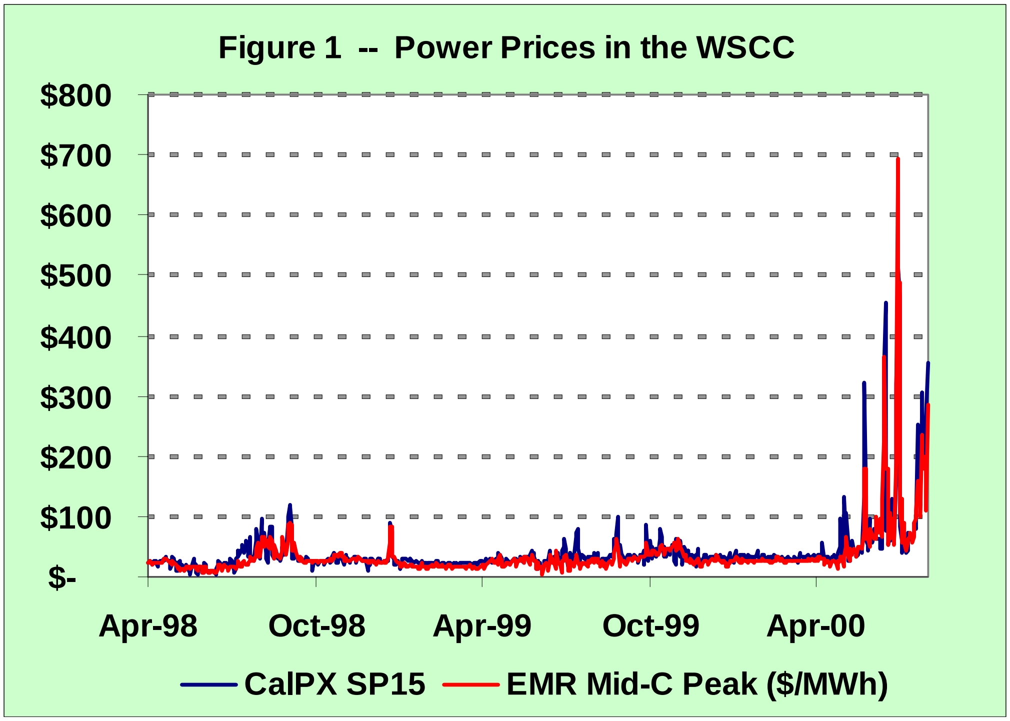
- California's restructured electricity market has also impacted prices throughout the region. Price caps have had the unintended effect of causing buyers and sellers in California to under schedule load and generation. This, in turn, has pushed the California Independent System Operator (CAISO) into panic buying and excessive market intrusions. High price paid by the CAISO have likely raised average prices in the California Power Exchange (CalPX) and the entire region's bilateral transactions.

- Although prophecy is always dangerous, the worst may be over. Markets, even those with regulatory burdens, are self-correcting, and the best thing regulators can do is to stand aside and let the market work. Higher prices will bring forth a variety of novel solutions. Indeed, the present market could bestow substantial benefits on the Pacific Northwest. Our proximity to Alberta and British Columbia natural gas reserves often results in lower than average gas prices. At present, prices at Sumas are $1.50 per million Btu below those in California. This should provide a strong incentive for independent power producers to site gas turbines here, rather than further south.

Price Movements in the WSCC

Figure 1 illustrates daily prices for on-peak wholesale power at Mid-C. On-peak prices represent a block of 16 hours from 6 AM until 10 PM. Typically this commodity is sold in the day-ahead bilateral market in lots of 25 to 50 MW per hour of the block. This price information was collected by survey for the *Energy Market Report*, which is published by Economic Insight, Inc.

The chart illustrates the present conundrum. Quite unexpectedly, prices in late May jumped dramatically, from $48 on May 21, to $178 on May 23. This was remarkable, because May is the month in which prices normally hit bottom—weather is usually moderate and water flows on the Columbia are high. The expectation of low prices was in part to blame for the spike. A large number of thermal units were down for annual maintenance. Moreover, the Southwest was in the early stages of the second hottest summer on record. Temperatures hit 109° in Phoenix on May 22.



The next spike occurred on June 14, when temperatures in San Francisco hit 103°. The Pacific Northwest's record price of $695 was recorded on June 28, the day after temperatures in Portland reached 98°. The second half of July was hot in the Southwest and inland California, and Mid-C prices ranged from $68 to $285. In August the weather has cooled and prices are moderating, but the political fallout, particularly in California, is just beginning.

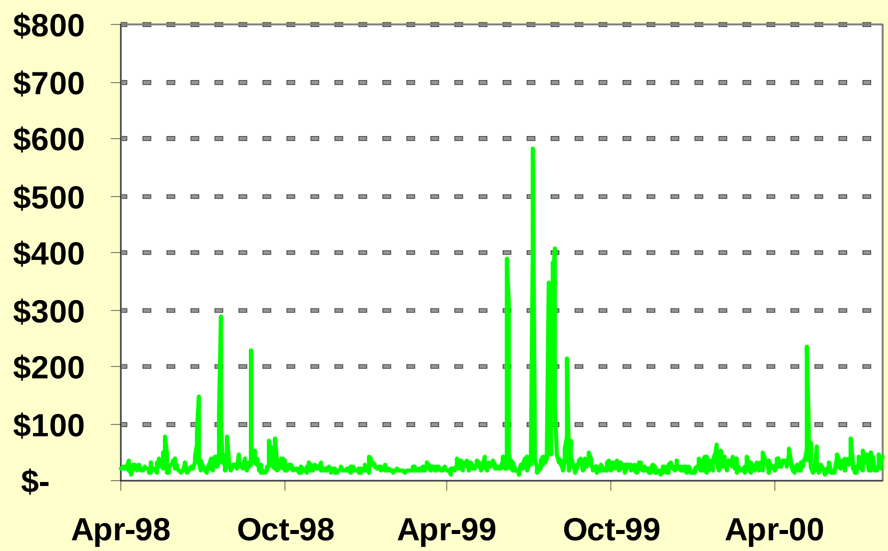
Price Volatility and Frozen Retail Rates

All energy markets tend towards price volatility, because demand and supply schedules are "inelastic" in the short term. Both consumers and producers must make substantial investments in specialized equipment to produce or use a specific form of energy. For example, once a gas furnace has been installed it is costly to switch to heating oil or electricity. Likewise, energy producers are tied to the specific resource and location they have developed. Aside from a large capital investment, it takes years to plan, site, and construct a large power generating facility. In short, both consumers and producers have large fixed investments, which reduce their flexibility and make it difficult to consume less or produce more in the short term.

When electricity demand approaches capacity constraints, the price rise can be substantial, for a number of reasons. First, there is a disconnect between the wholesale and retail power markets. Excepting a few large direct service customers (and for the summer, residents of San Diego) most retail rates are fixed and if they change, they do so independently of daily spot power prices. Thus, retail customers have no incentive to conserve and often are not even aware of wholesale power prices.

The principal buyers of wholesale electricity are utilities. In most jurisdictions utilities have an "obligation to serve," which means that load must be supplied no matter what the short-term cost. Further, customers are connected to the grid and can draw as much power as they choose; it is not possible to tell them that electricity is "sold out, please come back another day." Ultimately, higher costs will show up in higher rates, but by the time they do the crisis is likely to be long past. Regulated electricity markets behave the opposite of how a non-regulated competitive market is expected to perform. With competition, rising marginal costs increase prices, which moderate the quantity demanded. Regulatory lag, however, delays price increases. If the delay is long enough oil and gas prices will drop on their own, easing the pressure on electricity demand, just at the point when rates are allowed to rise. The result may be a long period of over-capacity and a continuing cycle of feast and famine.

Figure 2 -- PJM Western Hub On-Peak Prices



Another factor influencing price volatility is the necessity to balance the grid—to constantly match load and resources. In circumstances where the grid is severely strained (due to unplanned generation outages or higher than expected load) dispatchers must scramble to find replacement resources. In the resulting confusion, they often must pay high prices for last-minute power. The problem is compounded because only a few generating units have the flexibility to respond quickly. In short, the electricity market is especially prone to panic buying and unless institutional arrangements change, the random occurrence of extremely high prices spikes should be expected. The typical pattern for a thermal system is illustrated in Figure 2, which shows on-peak prices for the Pennsylvania-New Jersey-Maryland (PJM) power pool.

Price volatility is easy to understand in thermal systems where there are few opportunities to store electricity. In a mixed hydro and thermal system, such as that in the Pacific Northwest, short-term capacity shortfalls should be infrequent and associated primarily with transmission outages. That is because the region's hydroelectric generation capacity is almost twice that which can be sustained over the course of a year's stream flow. Normally it is easy to meet peak demand particularly during the months of May and June when the Columbia River is flush with snowmelt. But, in the fall and winter, natural stream flow is limited and the region's reservoirs hold only three month's supply.

If the Pacific Northwest experiences a very cold winter this year, the modest runoff could mean that the region will have to import large volumes of electricity from the Rocky Mountains and Southwest. No one, of course, knows what power demand will be in the cold months or what price it will fetch. Thus, there is a natural response on the part of utilities that control reservoirs to preserve the asset for the possibility of harder times. One consequence of this behavior is a leveling out of summer prices. Instead of the extreme peaks and valleys observed in the PJM, the WSCC is experiencing a period of sustained high prices. But, the central question is: Does this summer's price runup reflect "gaming" on the part of suppliers or does it reflect economic fundamentals.

The Fundamentals

The level of economic activity is an important determinant of electricity demand. For years, many analysts argued that there was a one-to-one correlation between economic growth and electricity demand growth. While such a relationship is still evident in developing nations it is not the case for the United States and other developed countries. Nonetheless, there still is an important relationship between economic growth and electricity consumption, particularly when the growth is rapid and largely unexpected. As an economy tops out it reaches capacity constraints in manufacturing and services. One consequence is that older and less efficient equipment is more intensively used. In addition, it has been suggested that the rapid growth of the Internet has provoked a surge in electricity demand because more computers have been installed and because they are powered on for much longer periods of time. The manufacture of certain computer components also requires a large, uninterrupted flow of power.

The U.S. is experiencing truly exceptional economic growth. In the last four quarters, real U.S. Gross Domestic Product (GDP) has increased at annual rate of 6.0%.[1] Much of the economic growth has been concentrated in the western United States. During the same period, employment in the West increased by 2.9%; in the remainder of the U.S. the increase was only 1.7%.[2] When more precise statistics are available, the West's economic growth in the last twelve months will most likely be shown to have exceeded 8%. All other things equal, such economic growth could easily increase electricity demand by 4 to 5%, while most forecasters have assumed modest growth of around 2%.

The other important determinant of electricity demand is weather, and it has not been the least bit cooperative. Weather patterns in Oregon, Washington, and Montana have been normal, California's temperatures have been slightly above normal, but in the Central Rockies and the Southwest it has been exceptionally hot. In Arizona, Nevada, New Mexico, Utah, and Colorado, the months of May, June, and July have been among the ten highest since records began in 1895. The four-corners states, upon which California relies for much of its imported power, so far have had the second hottest summer on record.[3]

The nature of this year's hot spell has also been different than that experienced in other regions; it has been a prolonged period of moderately high temperatures. In June and July of 1999 the CAISO experienced two hot spells, from June 29-30 and from July 12-14. In total, there were 31 hourly episodes where load was greater than 40,000 MW. This year, there have been 83 hourly episodes in the same time period, with load greater than 40,000 MW. The episodes were spread over 18 days.

High natural gas prices cannot be blamed for the price spikes, but they are making a significant contribution to the rise in average prices. Natural gas prices at the southern California border have risen from an average of $2.22 per million Btu in the Summer of 1998 to $4.65 per million Btu this year, reflecting higher wellhead prices and scarcity of pipeline capacity into California. As a consequence, the "floor" price of off-peak power has doubled. This can be

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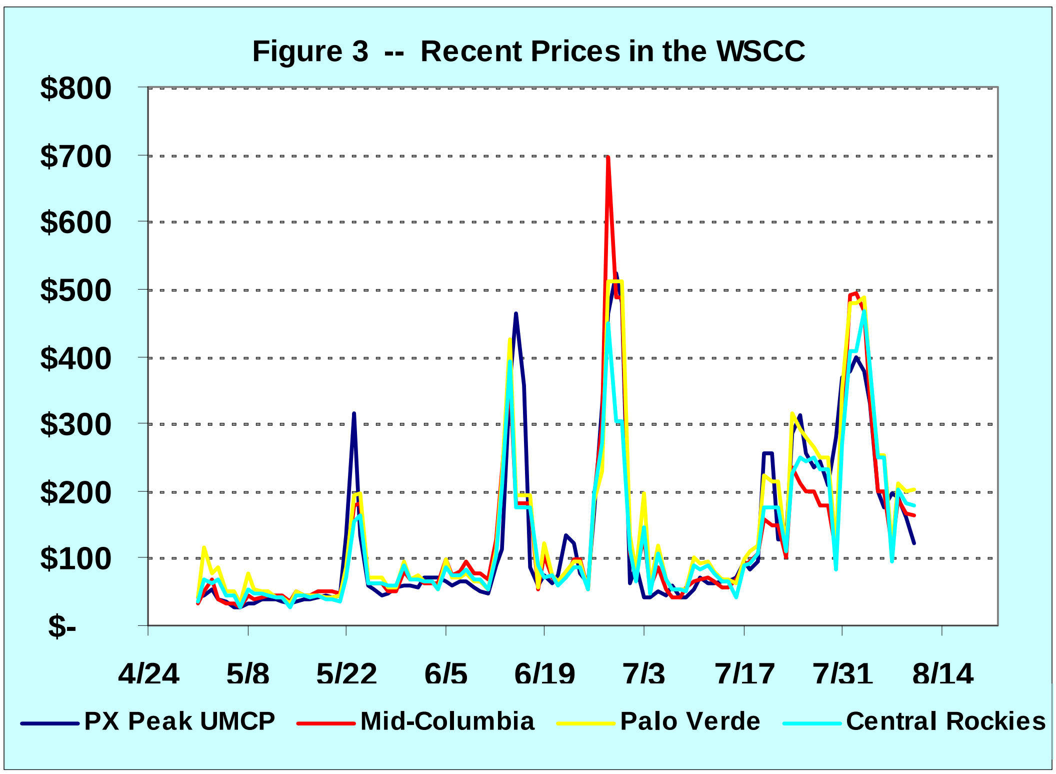
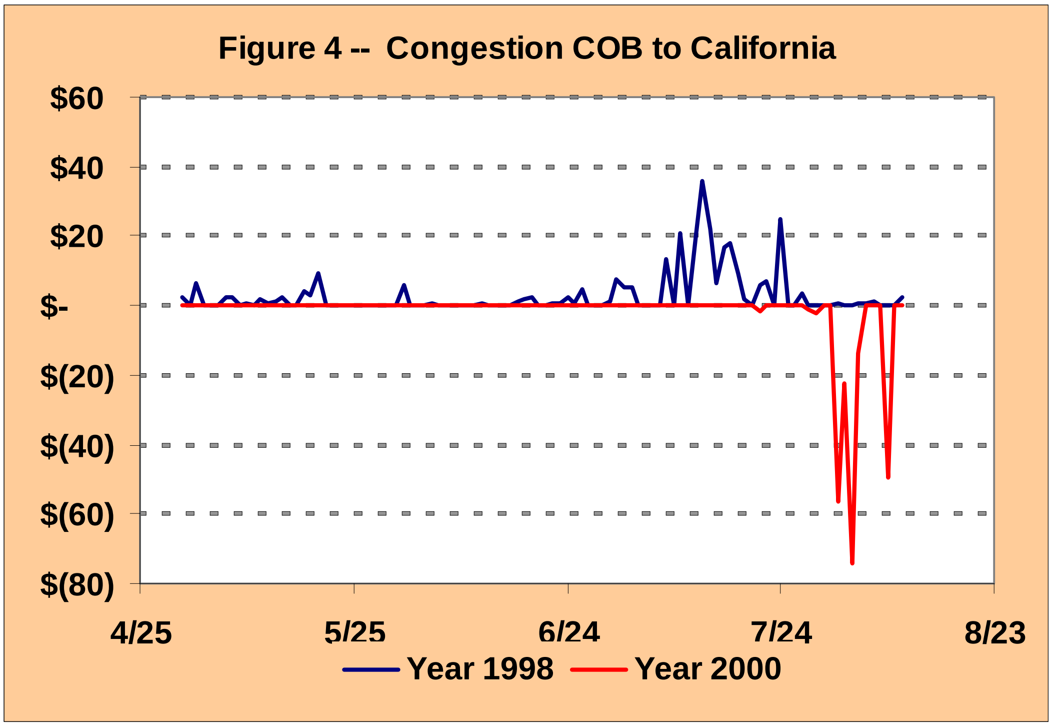
[1] U.S. Department of Commerce, Bureau of Economic Analysis.
[2] Bureau of Labor Statistics. The western U.S. includes all of the WSCC states, plus Alaska and Hawaii.
[3] NOAA, Climate Prediction Center, "Historical Temperature Rankings, 1 May 2000 through 31 July 2000."

illustrated by bilateral weekday off-peak prices at Palo Verde published by the *Energy Market Report*; in the summer of 1998, they averaged $13.50 per MWh, while this summer the average is $51.17 per MWh.

This summer's high prices have been a region-wide phenomenon. Overall, the WSCC has a wide diversity of generators. No one operator controls a key part of the infrastructure. The entity with the largest annual generation is a federal agency, the Bonneville Power Administration, which controls about 12% of the generation in the WSCC. While it can be argued that market power can be exercised from time to time in particular zones, it is difficult to imagine how the entire WSCC market might be manipulated for days on end. Figure 3 illustrates prices in the Pacific Northwest, California, Arizona, and the Rockies.



Another interesting phenomenon of this summer's market has been the reversal of transmission congestion between the Pacific Northwest and California. Since California normally imports power, transmission lines are usually congested in the southbound direction, from Oregon to California. Congestion is apt to be particularly high from May through July, when Northwest stream flow is at its peak. When transmission lines are congested, prices will decline in the surplus region and rise in the deficit region. The CAISO makes this explicit by calculating price increments and decrements by zone. Figure 4 illustrates the CAISO's congestion differential between COB and Northern California. In 1998, congestion caused prices in the Pacific Northwest to be lower than in California. This year, there has been no congestion or the differential has been reversed; that is, transmission lines have been congested in the northbound direction, from California to the Pacific Northwest. This is reflected in Figure 3, which demonstrates that the highest prices have been in this region, rather than further south.



The Restructured California Market—Let the Adventure Begin

California was the first state to attempt full-scale deregulation of the electricity industry. The motivation was simple. California's three largest private utilities, Southern California Edison (SCE), Pacific Gas & Electric (PG&E), and San Diego Gas & Electric (SDG&E) had some of the highest electricity rates in the country. Allowing competition between power generators was seen as a means to get prices down. This appeared feasible, because power from gas-fired combustion turbines, and other new sources, could be produced for less than half the cost of the utilities' nuclear power plants and qualifying facility (QF) purchase contracts. From 1996 to 1998 the California Public Utilities Commission and the Legislature crafted a plan to transition the industry from regulation to competition. The plan balanced a multitude of interests: The utilities would be allowed to recover "stranded costs" within a four-year period; in return, they would be required to sell many of their generating facilities and integrate their operating areas into a state wide independent system operator. Ratepayers were given an immediate 10% rate reduction, a price freeze while stranded costs are recovered, and the right to choose alternative suppliers. Environmentalists were assured energy conservation and other programs would be carried on through regulated distribution rates.

The new California power market opened on April 1, 1998, to an extraordinary level of anticipation. Major energy companies were poised to enter the market. What followed was a disappointment for all concerned. Frozen retail rates made consumers apathetic to the marketing efforts of alternative suppliers and the direct access market got off to a slow start.

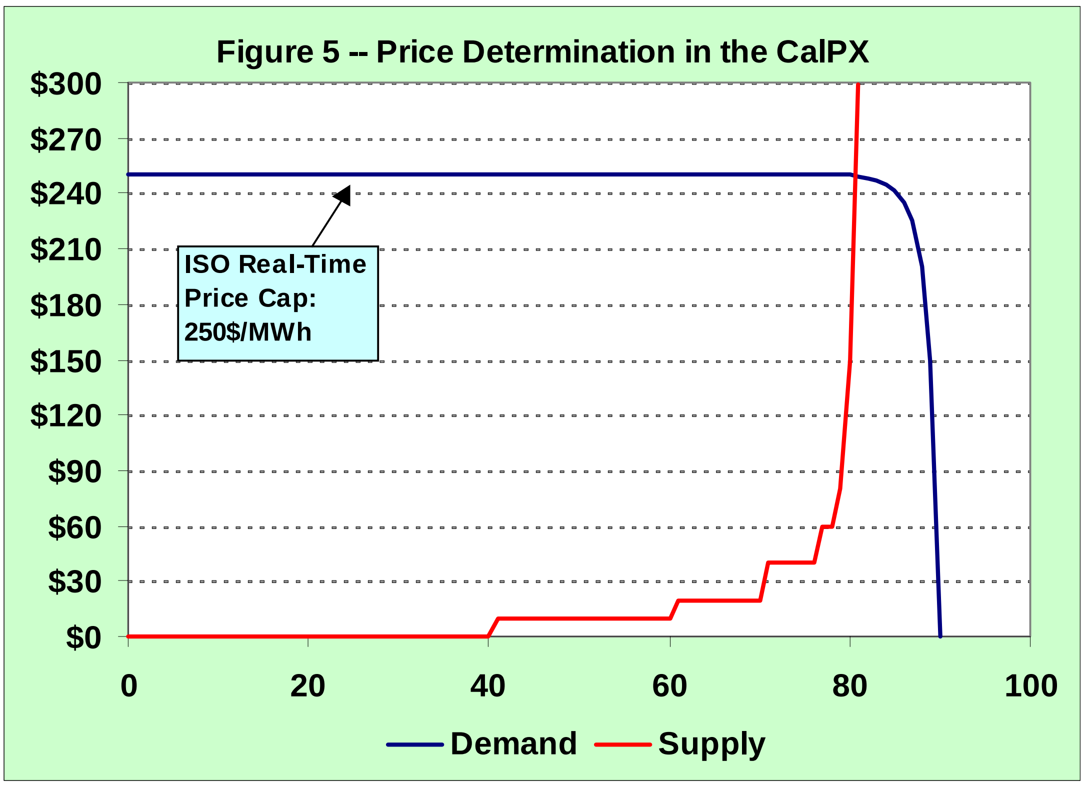
The deregulation plan called for a four-year transition period in which stranded costs could be recovered and the features of a competitive market could develop and take hold. The rate of recovery of those costs (the "Competitive Transition Charge" or CTC) would be determined by the difference between retail rates, less distribution and transmission costs, less the price of energy as determined in the California Power Exchange. The utilities were given four years to recover stranded costs and if not recovered by the end the transition period, they would simply be wiped from the books. The period of recovery was determined on the assumption that average electricity prices in the CalPX would be $25 per MWh or less and that the generating assets sold would bring modest prices.

SDG&E was able to sell its generating units for more than anticipated and, as consequence, was able to recover all of its stranded costs in slightly over one year. This allowed the utility to end the rate freeze and charge its customers a fixed distribution charge plus the monthly cost of acquiring power in the CalPX. This resulted in a rate reduction for SDG&E ratepayers, until the spike in power prices this June. Since then the average utility bill has more than doubled. SCE and PG&E have not ended their rate freeze, so ratepayers are unaffected by this summer's price hike. Instead, higher energy costs imperil the recovery of the utilities' stranded costs.

Another crucial part of the California deregulation plan was the separation of the forward market from grid management. Other jurisdictions, such as PJM, have combined grid management and the spot market as the pool opened access to marketers and independent power producers. California's decision to create both a power exchange and an ISO was both a political compromise and a regulatory necessity. An objective source of price information was required to measure stranded cost recovery. Placing such an institution within the ISO (which was the melding of the utilities operating controls and transmission systems) ran the risk of distorting prices. As a consequence, the ISO was designed to operate a real-time market and markets for ancillary services necessary to balance the grid, while the

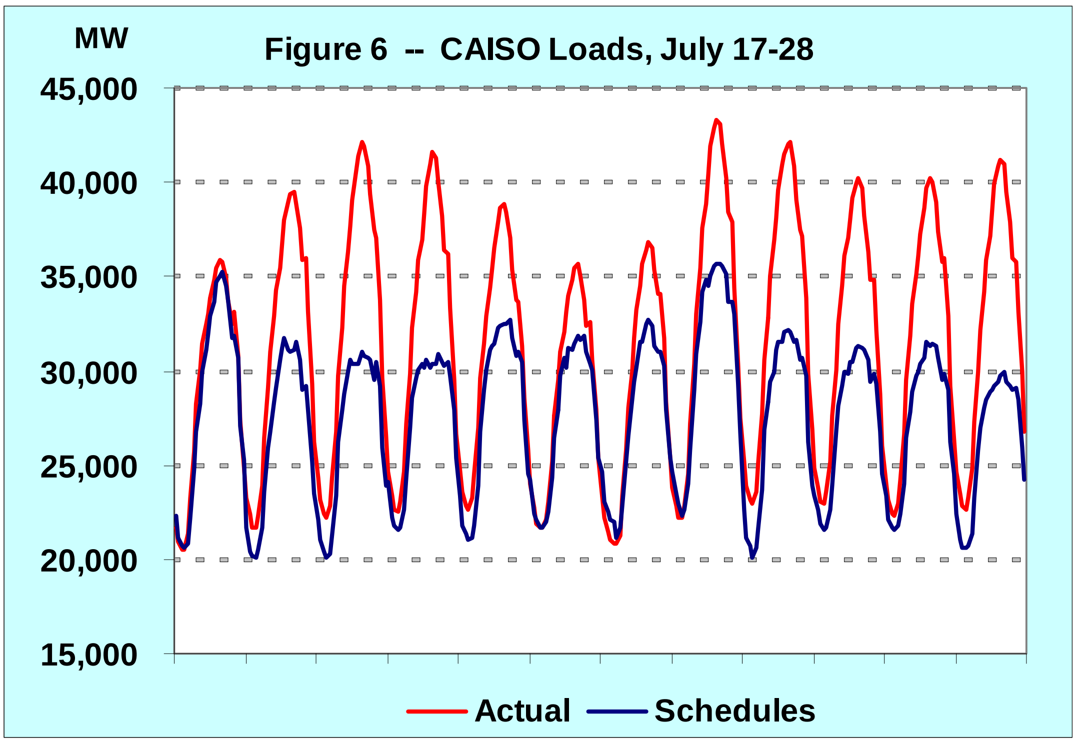
CalPX was given the task of managing the primary market (the day-ahead prescheduled market).

Given the CalPX's regulatory role, it was necessary that the exchange's auction produce a market-clearing price for each period in which power was delivered. The principal buyers in the exchange would be the utilities and, given frozen rates, their load would have no price sensitivity. That is, demand would be expected to be perfectly perpendicular. It was quickly recognized that in certain peak hours, total supply bids might be less than demand and the market would not clear. This problem was resolved by placing price caps on the ISO real-time market, which in turn placed *ad hoc* price caps on the forward markets. The solution is illustrated in Figure 5, where demand is perpendicular until it approaches the ISO real-time price cap; it then bends back and becomes horizontal which ensures that the market clears.



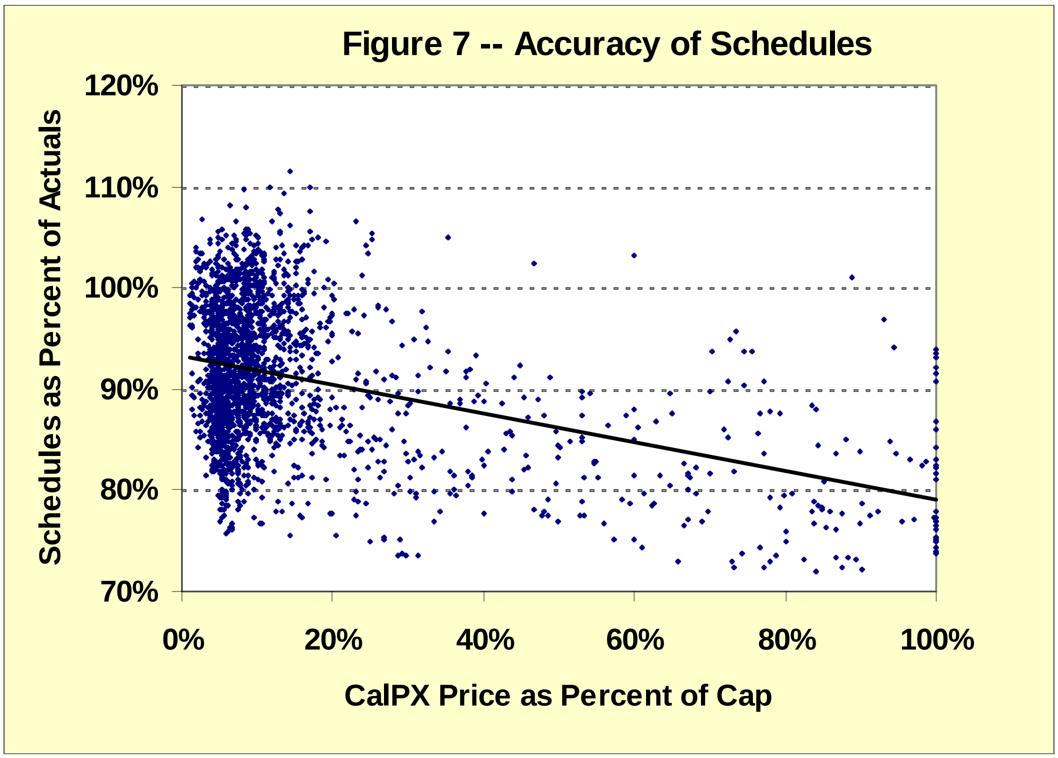
The problem with this trick is that it is just a trick; the apparent demand elasticity in peak periods is artificial, it does not reflect reality. Instead, the market structure provides an incentive for the under scheduling of power for generation and delivery the next day. Both the utilities and power suppliers shift from forward markets to the real-time markets. This substantially compounds the ISO's grid management problems.

Figure 6 illustrates the ISO scheduled and actual load from July 17 to July 28. The figures illustrate the under scheduling problem. The CAISO is, of course, aware of under scheduling and has its own forecast tool for determining expected load. In order to ensure that the grid is in balance, the CAISO buys substantial volumes of replacement reserves in its day-ahead and hour-ahead markets. These markets are, however, very thin, because only a few generators have the flexibility to operate in real-time markets. Sellers are well aware of the CAISO's absolute necessity to balance demand and supply. If market power is to be exercised this is the perfect arena for a sophisticated seller. In July the load was under scheduled by as much as 28%.



Inaccurate schedules also compound uncertainty. The prescheduled market is an important tool in grid planning. If schedules are left to the last minute it is all but impossible to balance loads and resources in a way to minimize congestion, which reduces the system's effective capacity. Moreover, the under scheduling and concern about reliability forces the CAISO to procure a larger volume of reserve capacity which, in effect, removes energy from the prescheduled market, causing prices to be higher than they would otherwise be. Figure 7 is a scatter diagram that compares scheduled power, as a percentage of actual load, to the CalPX price as a percentage of the price cap. An OLS trend line is included in the diagram. The diagram illustrates the substantial instability in the California system and the tendency for the accuracy of schedules to decline as prices rise to the cap.

In response to the price runup, the CAISO board decreased its real-time price cap twice, from $750 to $500 on July 1 and to $250 on August 7. The evidence garnered so far suggests that dropping the price cap reduces scheduling accuracy. In hourly episodes where the CAISO's load was 40,000 MW or more, the standard deviation of schedules as a percentage of actual load increased from 3.3 to 4.9 when the cap dropped from $750 to $500. If the resulting instability has increased congestion or caused the CAISO to procure more reserve capacity than is necessary, it has likely contributed to higher prices in the WSCC.



Other CAISO procedures contribute to the market's instability and higher prices. The real-time price cap is not really a cap. In an emergency, the CAISO may make "out-of-market" purchases. In effect, they can pay anything, if they have to balance the grid. Just as with price caps, the "out-of-market" purchases contribute to the under scheduling problem and increase prices in the CalPX day-ahead market. It is only natural for suppliers to divert resources to the ISO's market if there is any chance of an emergency because they can get a much higher price. Demand bids in the CalPX are, however, inelastic until prices approach the CAISO cap. Thus, diverting supply from the CalPX to the CAISO markets ratchets up CalPX prices. In effect, the cap may work as a floor as often as it works as a ceiling.

A recent report by the CAISO provides data that illustrates how the CAISO's intrusion into the market ratchets up prices.[4] On June 26 the CAISO purchased 4,500 MWh at $750 per unit. The highest price determined in the CalPX auction for delivery that day had been $288. In response, CalPX auction prices for delivery on June 27 rose to a peak of $650. Meanwhile, on June 27 the CAISO purchased another 6,100 MWh out-of-market for $750 and next day prices in the CalPX rose to a peak of $750. By June 29 (even though the weather had cooled) the CAISO was forced to purchase 12,500 MWh out-of-market at an average price of $680, due to under scheduling.

California's regulatory policy regarding the CAISO and the CalPX is headed in the wrong direction if the objective is lower prices. Price caps should be eliminated and the incentive structure aimed at penalizing scheduling coordinators for inaccurate schedules. As long as the state's utilities are required to purchase power through the CalPX, liquidity should be concentrated in its auction, rather than spread out in a series of sub-markets, where market power is more easily exercised and panic buying is commonplace.

In the longer term, California's price caps and threats of re-regulation will have the opposite of their intended effect. Power suppliers will shun the State and locate generation facilities beyond the control of California's regulators. In addition, longer-term forward and futures markets will not develop. Buyers have little or no incentive to manage risk through forward contracts, if they know prices will be capped. What ought to be a single summer of high prices and some dislocation could be turned into a 21st Century energy crisis.

The California experiment with electricity price caps is not the first time intervention has led to perverse results. Price controls on crude oil and petroleum products in the 1970s led to long lines at gasoline stations and contributed to two major recessions. Likewise, price regulation of interstate natural gas led to factory and school closures in the winter of 1976-77. Consumers do not like the high prices that markets sometimes produce, but the alternatives—shortages and a crippled economy are far worse.

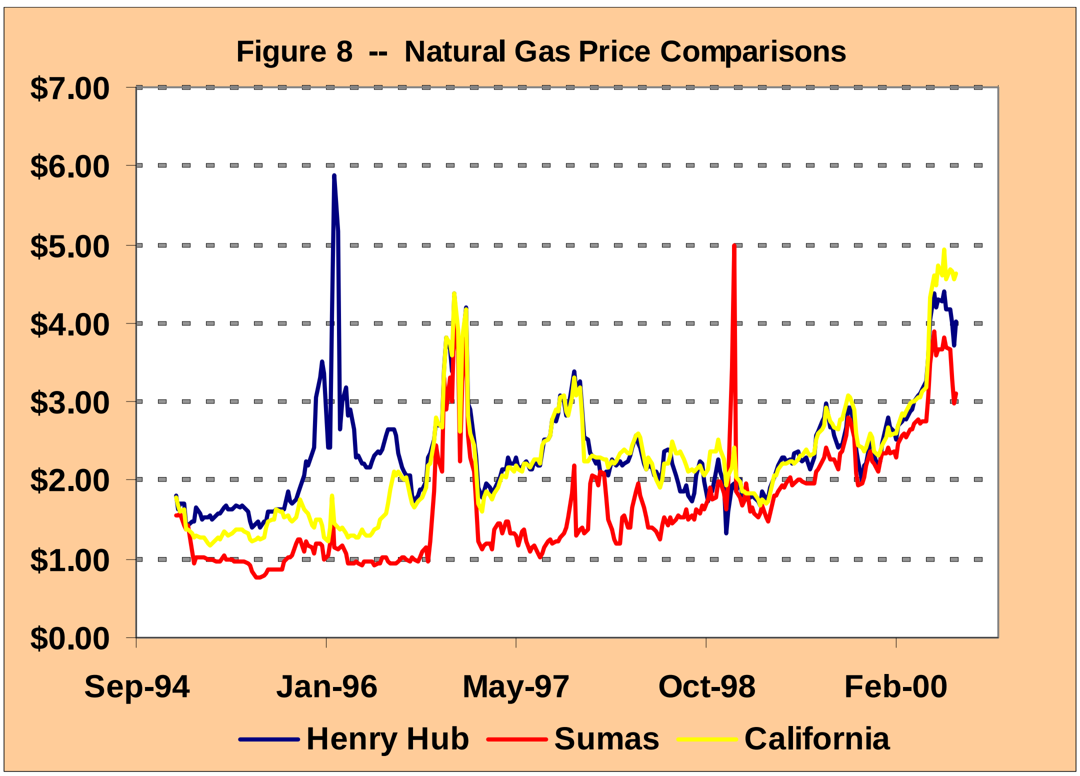
Finally Some Good News

Bonneville Power projected that the Pacific Northwest could expect an average energy deficit of 2,500 MW this operating year and even greater in the event of a drought.[5] This has always been a dilemma for the region, because the

[4] CAISO, Department of Market Analysis, *Report on California Energy Market Issues and Perfomance: Ma-June 2000*, August 10, 2000, www.caiso.com.
[5] Pacific Northwest Power Planning Council, *Northwest Power Supply Adequacy/Reliability Study: Phase 1 Report*, Paper No. 2000-4, March 6, 2000.

odds of very low water runoff are quite low. No one wants to construct a capital-intensive generation facility if it is to be utilized less than half the time. However, the demand for power in California, combined with discounted natural gas prices will provide significant incentive for independent power producers to construct gas-fired turbines in this region.

Figure 8 illustrates the relationship of natural gas prices at the California border compared to the export price at Sumas, Washington. More often than not, the Sumas price tracks prices in Alberta rather than prices in mid-continent or in California. This is because Canada's gas producing regions frequently have inadequate pipeline capacity to markets in the U.S. Over the years, a classic cycle has been built into the market. Prices in Alberta decline relative to those in Oklahoma, Texas, and other gas producing areas. This provides an incentive to increase pipeline capacity. Once the pipeline bottlenecks are removed, Alberta prices rise until a new constraint is reached. The Pacific Northwest is usually tied to the Alberta price cycle, which means this region has a clear economic advantage for gas-fired power generation.



Parting Shot

As a new hire of the U.S. Treasury in 1973 I was sent to a large energy conference scheduled a few weeks after Arab OPEC had declared an embargo on

U.S. oil imports. It was my introduction to the energy industry and the politics that permeate it. At the conference Professor Morris Adelman of MIT offered sound, if unheeded, advice. He had been to a baseball game in which the batter was notorious for swinging at anything, either a ball or a strike. The bases were loaded and the pitches had been going wild. At that point a fan shouted in a booming voice: "Don't just do something, Lefty, stand there." That was Professor Adelman's advice to government bureaucrats, get out of the way and let the market work.

Markets, particularly energy markets, are cyclical. Today's high prices were preceded by very low prices three years ago and will almost certainly be followed by a glut and declining prices. During the last cycle of the energy market, policy makers as well as consumers panicked and locked themselves into high-cost energy projects, with wrenching economic and financial consequences. The stockholders of merchant plants are enjoying this increase in profits, so let them also take the risk of overbuilding and associated losses. Indeed, the more profits power producers reap during a period of insufficient supply, the more likely that consumers will enjoy a prolonged period of low and stable energy prices in the future.