Diagnosing the California Electricity Crisis

A key lesson is that FERC must regulate, rather than simply monitor, wholesale electricity markets. Rather than focusing its attention on monitoring market performance, FERC should instead concentrate on designing proactive protocols for rapid regulatory intervention to correct market design flaws as quickly as possible and order refunds as soon as unjust and unreasonable prices are found.

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I. Introduction

This article provides a diagnosis of the causes of the California electricity crisis, the impact of actions taken by state and federal regulators in response to the crisis, and those that ultimately ended the crisis. The main point of this article is that the California electricity crisis was fundamentally a regulatory crisis rather than an economic crisis. It is also important to emphasize that a number of conditions in California electricity supply industry discussed below contributed to the events that occurred during the summer of 2000. However, it is difficult to see how the market meltdown that occurred in late 2000 and during the first six months 2001 could have occurred without a significant lapse in wholesale market regulatory oversight and several ill-conceived responses to events in California during the period June 2000 to June 2001 by the Federal Energy Regulatory Commission (FERC).

The most important lesson from the California crisis relates to how FERC carries out

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its statutory mandate under the Federal Power Act of 1935 to set just and reasonable wholesale prices in a market regime. There are almost a number of important lessons for governments and public utilities commissions (PUCs) in states that have already formed wholesale electricity markets and those that are currently considering forming these markets. Because FERC has issued a Notice of Proposed Rulemaking (NOPR) outlining a Standard Market Design (SMD) that it would like the entire U.S. to adopt, it essential that FERC and the state PUCs learn the correct lessons from this regulatory failure. Otherwise, it is very likely that these standard market rules, combined with the retail market rules implemented by state PUCs, will increase the likelihood of future regulatory failures like the California electricity crisis.

A correct diagnosis of the California crisis requires a clear understanding of the federal and state regulatory infrastructures that govern the U.S. electricity supply industry. Many observers fail to recognize that wholesale electricity prices are subject to a much tighter performance standard than prices for virtually all other products. Consequently, they miss this key explanatory factor in the California electricity crisis. The retail market policy of the California PUC (CPUC) is the second key explanatory factor. I will describe the important inconsistencies between California's retail market policies and FERC's wholesale market policies that enabled the California crisis to occur.

I will then discuss the conditions in the western U.S. electricity supply industry that enabled the California crisis to occur. Another important factor that is often unexplained by observers who blame the crisis on California's ''flawed market design'' is that for almost two years—during the period April 1998 to April 2000—a strong case could be made that, according to a number of standard metrics, the California market outperformed all of the wholesale markets in the U.S. This article will provide an explanation for these first two years of market outcomes and discuss the conditions that enabled the events of the summer of 2000 to occur.

Many observers fail to recognize that wholesale electricity prices are subject to a much tighter performance standard than prices for virtually all other products.

I will then describe and analyze several regulatory decisions by FERC that allowed a manageable problem to develop into an economic disaster during the latter part of 2000. As part of this discussion of FERC's response to the events of the summer of 2000, I will provide evidence to dispel a number of the misconceptions that circulated beginning in the late summer of 2000 about the causes and consequences of the California electricity crisis. It is important to clarify the factors that led to the circumstances of the summer of 2000, because a number of apparent misconceptions about conditions in California were used to justify FERC's inactivity during the late summer and autumn of 2000, as well as the ill-conceived remedies it implemented in December 2000. A number of factors suggest that these remedies directly led to the economic disaster of early 2001, when all three investor-owned utilities in California threatened bankruptcy, with one eventually declaring bankruptcy, and wholesale electricity prices and natural gas prices rose to unprecedented levels.

I will then discuss the actions taken at the state and federal level that ultimately stabilized the California electricity market. This is followed by a discussion of what I believe are the major lessons for electricity market design that should be learned from the California crisis. The article concludes with recommendations for how FERC should change the way it carries out its statutory mandate to set just and reasonable wholesale prices and how state PUCs should revise their retail market policies to prevent a future California crisis. In this discussion, I describe a worst-case scenario for how another California electricity crisis could occur if these recommendations are not followed.

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Unfortunately, only a few states appear to be moving forward with plans to make their retail market policies consistent with a workably competitive wholesale market.

II. Diagnosing the California Electricity Crisis

For the most part, market participants in California behaved exactly as one would predict, given the federal and state regulatory processes and wholesale market incentives they faced. The unilateral actions of privately owned suppliers to maximize the profits they earn from selling wholesale power, government-owned entities to minimize the costs of supplying their captive customers, and privately owned retailers to maximize the profits they earn from selling electricity to final consumers in this regulatory environment can explain the market outcomes observed in 1998, 1999, and 2000. In order to understand the complete set of incentives faced by these market participants it is necessary to understand the essential features of the federal and state regulatory processes governing the California electricity market.

A. Federal regulatory oversight of wholesale electricity markets

In 1935, Congress passed the Federal Power Act which imposed a statutory mandate on the Federal Power Commission, the predecessor to the FERC, to set ''just and reasonable'' wholesale electricity prices. An accepted standard for just and reasonable prices are those that recover production costs, including a ''fair'' rate of return on the capital invested by the firm. Moreover, if FERC finds that wholesale electricity prices are unjust and unreasonable, the Federal Power Act gives it the authority to take actions that result in just and reasonable prices.[1] Finally, the Federal Power Act requires that FERC order refunds for any payments by consumers for prices in excess of just and reasonable levels.

For the most part, market participants behaved exactly as one would predict, given the regulatory processes and wholesale market incentives they faced.

Without a legal mandate from Congress, about 10 years ago FERC embarked on a policy to promote wholesale electricity markets throughout the U.S. Under this policy, the price a generation unit owner receives from selling into a wholesale electricity market is determined by the willingness of all generation unit owners to supply electricity, rather than an administrative process that uses the firm's production costs and a rate of return on capital invested.

The just and reasonable price standard for wholesale electricity prices required by the Federal Power Act presented a significant legal and regulatory challenge for FERC because markets can set prices substantially in excess of the production costs for sustained periods of time. This occurs because one or more firms operating in the market have market power—the ability to raise market prices through their unilateral actions and profit from this price increase.

1. Rationale for Federal Power Act protection. Spot wholesale electricity markets are particularly susceptible to the exercise of market power because of how electricity is produced, delivered, and sold to final customers. The production of electricity is characterized by binding capacity constraints because a generating unit with a nameplate capacity of 500 MW can produce only slightly more than 500 MWh of energy in a single hour. These capacity constraints limit the magnitude of the short-run supply response of each firm to the attempts of its competitors to raise market prices.

Electricity must be delivered to all customers over a common transmission grid that is often subject to congestion (a form of capacity constraints), particularly along transmission paths to major metropolitan areas and isolated

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geographic locations. Transmission congestion limits the number of generators able to sell power into the congested region. This reduces the potential supply response to the attempts of firms selling into this smaller market caused by congestion into the region to raise local prices through the unilateral exercise of market power.

Finally, the retail market policies that currently exist in almost all states, including California, makes the hourly demand for electricity virtually insensitive to the value of the hourly wholesale price, particularly in the real-time energy market. Generators recognize that uniformly bid higher prices will not significantly reduce the risk that less electricity will be consumed during that hour. Consequently, the only factor disciplining the bidding behavior of electricity suppliers is the aggressiveness of bids submitted by their competitors, rather than the expectation of any tangible reduction total demand in response to higher prices, as is the case most other markets.

When the demand for electricity is high, the probability of transmission congestion is usually very high. During these system conditions, generation unit owners can be confident that at least some of their capacity will be needed to serve the price-insensitive aggregate wholesale demand. These firms are also recognize that any reduction in the quantity of electricity sold because of high bid prices will be more than compensated for by the significantly higher market prices they will receive for all sales they do make. For this reason, the unilateral exercise of market power by these firms through their bidding behavior leads to higher profits than they could achieve if they did not bid to influence market prices.

The time lag necessary to site and construct new generation capacity can result in substantial periods of significant market power in an electricity market. This feature of the electricity industry makes the potential economic damage associated with the exercise of market power extremely large. In California, even under the most optimistic scenarios, the time from choosing a site for a sizable new generating facility (greater than or equal to 50 MW in capacity) to producing electricity from this facility can range from 18 to 24 months.[2] This estimate does not include the time necessary to obtain the permits needed to site the new facility, which can sometimes double the time necessary to bring the new plant on line. In California, there are several examples of significant permit approval delays for power plants sited close to large population centers, with the Calpine Metcalf facility south of San Jose being perhaps the most well-known. Because of this time lag between conception of a new facility and production of energy from that facility, once market conditions arise which allow existing generating facilities to exercise substantial amounts of unilateral market power, as was the case in California during the summer of 2000, these conditions are likely to persist for a long enough period to impose substantial economic hardship on consumers. At a minimum, this interval of significant economic hardship is the shortest time period necessary to site, obtain permits for, and construct enough new generation capacity to create the competitive conditions necessary to reduce the ability of existing firms to exercise their unilateral market power.

When the demand for electricity is high, the probability of transmission congestion is usually very high.

2. *Federal Power Act requirements applied in wholesale market environment*. Because of the very large potential harm from the exercise of unilateral market power by firms in a wholesale electricity market, FERC determined that its statutory mandate under the Federal Power Act implies that unless a firm could prove that it did not possess market power, it was not eligible to receive market-based prices. The supplier could, however, receive prices for any electricity produced

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that are set through a cost-of-service regulatory process administered by FERC. FERC's logic for granting market-based price authority is that only if all firms participating in a market possess no market power will the price set by the market satisfy the just and reasonable standard of the Federal Power Act. This logic is consistent with a standard result from economic theory that states that if all firms are unable to exercise any market power, the market price will equal to the marginal cost of the highest-cost unit produced. As noted earlier, the conditions necessary for all firms to possess no market power are unlikely to hold in a wholesale electricity market.

Because FERC allows any market participant to receive a market price rather than a pre-existing cost-based price set through a regulatory process, FERC requires that each participant demonstrate that it does not have market power or has adequately mitigated any market power it might possess. In other words, each market participant must submit sworn testimony to FERC demonstrating it does not have the ability to raise market prices and profit from this behavior. Those generators unable to demonstrate that they do not have market power or have not adequately mitigated that market power are not eligible to receive market-based rates, but do have the option to sell at cost-of-service prices set by FERC.

Each of the new generation unit owners and power marketers made these market-based rate filings before they began selling into the California market and, in many cases, before the California market began operation in April 1998. Each firm had its authority to receive market prices approved by FERC for a three-year period. Because of the timing of the transfer of assets from the California investor-owned utilities—Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric—to the new owners—Duke, Dynegy, Reliant, AES/Williams, and Mirant—some of these entities did not begin selling into California at market-based rates until a later date.

The analysis does not recognize the crucial role that demand and other system conditions play in determining the amount of unilateral market power a firm can exercise.

3. *Flaws in FERC's market-based price regulatory review*. A major source of potential error in determining whether a market participant is eligible to receive market-based prices is the fact that it is extremely difficult to determine on a prospective basis if a firm possesses market power. This is particularly likely to be the case for wholesale electricity for the reasons discussed in Section II.A.1. A second source of potential errors is that the methodology used by FERC to make this determination uses analytical techniques for market power assessment based on supplier concentration indices. Market structure indices have long been acknowledged by the economics profession as inadequate for measuring firm-level market power in other product markets. The characteristics of the electricity supply industry makes these indices even less useful for quantifying the extent of market power possessed by an electricity supplier.

The FERC market power analysis was based on concentration indices applied to geographic markets that do not account for the fact that electricity must be delivered to final customers over the existing transmission grid. The analysis does not recognize the crucial role that demand and other system conditions, such as transmission capacity availability, play in determining the amount of unilateral market power that a firm can exercise.[3] Most important, it does not acknowledge the crucial role played by bidding, scheduling, and operating protocols in determining the extent of market power that can be exercised by a firm in a wholesale electricity market. Finally, an important lesson from recent research on wholesale electricity markets is that very small changes in market rules can exert an enormous impact on the ability of

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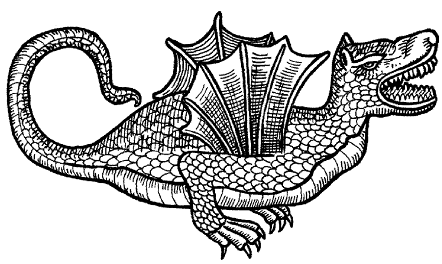
a firm to exercise market power, and the FERC methodology does not account for differences in market rules in assessing the amount of market power a supplier possesses. James Bushnell recently reviewed the FERC market power assessment methodology and suggested an alternate approach that addresses many of these shortcomings.[4]

Besides the extreme difficulty in accurately determining on an *ex ante* basis whether a market participant possesses substantial market power, FERC's methodology for protecting consumers against the exercise of unilateral market power has an even more troubling property. Once a supplier has received market-based price authority it is free to maximize profits, which is equivalent to exercising all available unilateral market power, because FERC's market-based price process has determined that the firm has no ability to exercise unilateral market power. This creates the following logical inconsistency for FERC that it has still not dealt with: It is not illegal for a firm with market-based rate authority to exercise all available unilateral market power, but it is illegal for consumers to pay prices that reflect the exercise of significant unilateral market power because these prices are unjust and unreasonable. Prices that reflect the exercise of significant market power are unjust and unreasonable because, they are not cost-reflective.

Stated differently, according to FERC's market-based price policy it is not illegal for a firm to receive a market price that reflects the exercise of significant market power, but it is illegal for a consumer to pay this unjust and unreasonable price. This logical impossibility is the result of an assumption implicit in FERC's methodology that market power is a binary variable—a firm either does or does not have the ability



to exercise market power. Unfortunately, as the events in California and all other bid-based electricity markets operating around the world have demonstrated, depending on the system conditions, almost any size firm can possess substantial unilateral market power. The issue is not whether a firm possesses substantial unilateral market power, but under what conditions the firm possesses substantial unilateral market power, and whether these system conditions occur with sufficiently high probability that the firm will bid and schedule its units to take advantage of these system conditions to raise market prices and cause substantial harm to consumers.

As we discuss in Section X, protecting consumers from prices that expose them to significant harm is a more logically consistent strategy for FERC to pursue in fulfilling its statutory mandate to set just and reasonable prices in a wholesale market regime. This strategy involves first determining what pattern of prices and for what duration of time causes significant consumer harm, and second, specifying what actions FERC will take in response to these harmful prices.

B. Enabling retail market policies in California

There are two features of the California market that enhanced the ability of suppliers to exercise unilateral market power. The first is that the CPUC shielded all final consumers from wholesale price volatility by offering them the option to purchase all of their demand at a frozen retail price equal to 90 percent of the regulated retail price during 1996. This price reduction was financed by California issuing rate freeze bonds which would be repaid over the first few years of the wholesale market regime. At the start of the California market, all consumers could shop around for lower prices from competing retailers, but at any time in the future they could switch back to their default provider and purchase at this frozen retail rate.

The second enabling feature of the California retail market was the requirement that the three large load-serving entities (LSEs),

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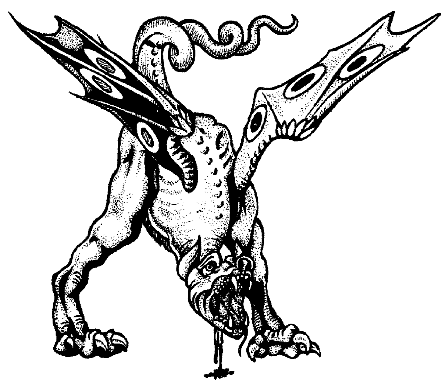
Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E), purchase all of their wholesale electricity needs from the California Power Exchange (PX) day-ahead and hour-ahead markets and the California Independent System Operator (ISO) real-time market. This purchasing requirement was imposed primarily to administer a transparent mechanism implemented by the CPUC to recover the stranded assets of the three LSEs. Under the CPUC's stranded asset recovery mechanism the following equation held on a monthly basis for each investor-owned utility (IOU):

$$\mathrm{CTC} = P(\mathrm{retail}) - P(\mathrm{wholesale}) - P(\mathrm{T\&D}) - \text{Bond Payments}, \quad (1)$$

where P(retail) is the frozen retail rate set by the CPUC, P(T&D) is the regulated price of transmission and distribution services, Bond Payments is the administratively determined amount of bond payments used to fund the reduced fixed retail rate, and P(wholesale) is the average wholesale energy and ancillary services price. CTC is amount of the competitive transition charge, or stranded asset recovery paid to each IOU—PG&E, SCE, and SDG&E—for each MWh of energy consumed in their former service territory, whether or not they sold that electricity to the final consumer.

To implement Equation (1) as a stranded asset recovery mechanism, the CPUC needed a transparent wholesale price of electricity to use for P(wholesale). If it used the average wholesale price that each of the three IOUs paid for their power through bilateral transactions, these firms would have an incentive to negotiate deals with their unregulated affiliates to reduce P(wholesale) as a way increase the amount of CTC recovery they earned, because on a dollar-for-dollar basis, a \$1/MWh lower price for P(wholesale) means a \$1/MWh high value for CTC for that month. The CPUC recognized this problem and therefore decided to use the California PX price as its primary reference price for P(wholesale). To insure that it was a deep spot market, the CPUC required all purchases by the LSEs of three IOUs to be through this market.[5]



In spite of this requirement to purchase their entire load through this spot market and the ISO's real-time market, the CPUC *did not* prohibit the three IOUs from entering into forward contracts to hedge this spot price risk. The CPUC just did not guarantee full cost recovery of these forward contract purchases. I also want to emphasize that the CPUC could not prohibit these three firms from hedging this spot price risk in other ways. For example, all of these firms own unregulated affiliates that are not subject to CPUC regulation. These unregulated affiliates could have purchased the necessary forward contract to hedge the spot risk borne by the regulated affiliate subject to CPUC oversight.

For example, had PG&E Corporation wished to hedge the spot price risk faced by its CPUC-regulated affiliate, it could have used any of its unregulated affiliates to purchase forward financial contracts from suppliers serving the California market. The regulated affiliate could have continued to make purchases from the PX and ISO markets, but difference payments between the sellers of the forward contracts to the PG&E affiliate not subject to CPUC regulation would have hedged PG&E Corporation against this spot price risk. For example, assuming PG&E's load is 10,000 MWh, the unregulated affiliate could have purchased forward financial contracts for 10,000 MWh at a fixed price from a number of suppliers. The difference payments associated with this contract would exactly offset any spot price and CTC payment risk the CPUC-regulated affiliate might face because the requirement to purchase all of its energy from the PX and ISO markets.

It is unclear why the three IOUs did not hedge their spot price risk in this manner or even make full

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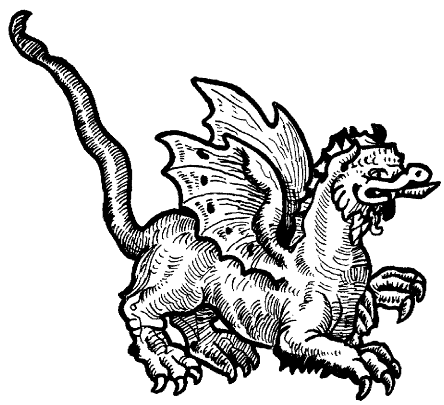
use of the authority given to them by the CPUC to hedge spot price risk though the PX Block Forwards market. One explanation is that they did not believe that wholesale prices would reach a level for a sustained period of time so that Equation (1) produced negative values for CTC on a monthly basis, as it did throughout the summer and fall of 2000. It seems very plausible that the three IOUs believed that if wholesale prices reached this level, FERC would intervene and declare that wholesale electricity prices were unjust and unreasonable. Evidence for this view is that the average value of the difference between *P*(retail) and *P*(T&D) and Bond Payments was roughly between $65/MWh and $70/MWh, depending on the IOU. However, during the first two years of the market, the average value of *P*(wholesale) in Equation (1) was slightly less than $35/MWh, which meant that CTC averaged between $30/MWh to $35/MWh, depending on the IOU.[6]

Wholesale prices on the order of $70/MWh were difficult to fathom unless one was willing to assume substantial unilateral market power was being exercised, which would cause FERC to intervene, or extremely high natural gas prices, which did not occur in California until very late 2000. Consequently, as of the start of the market, and even as late as April 2000, it is difficult to see how the IOUs could have forecasted average wholesale prices above $70/MWh for an entire month, which could explain their lack of interest in hedging this spot price risk.

C. Events leading up to the California electricity crisis

In July 1998, California's energy and ancillary services markets experienced the first episode of the exercise of significant market power. Perhaps the most dramatic illustration of this activity took place in the ISO's Replacement Reserve market. A generator providing Replacement Reserve is paid a $/MW capacity payment to provide standby generation capacity available with 60 minutes' notice. A generation unit owner providing this service also submits a bid curve to supply energy in the ISO's real-time energy market if the unit's capacity bid wins in the Replacement Reserve market. Because a generation unit owner providing this service has the right to receive the ISO's real-time price for any energy it provides from this reserve capacity, the market price for this product averaged less than $10/MW during the first three months of the California market.



On July 9, 1998, because capacity was withheld from the ancillary services markets—some suppliers did not make capacity available at any price and others bid extremely high prices—the price of Replacement Reserve hit $2,500/MW. In the subsequent days, the ISO cut its Replacement Reserve demand in half, but these attempts were largely unsuccessful in limiting the amount of market power exercised in this market. On July 13, 1998, the price of Replacement Reserve hit $9,999.99/MW. A rumor circulating at the time claimed that the only reason the market participant had not bid higher than $9,999.99/MW was because of a belief that the ISO's bid software could not handle bids above this magnitude. During this same time period, prices in the California Power Exchange day-ahead energy market and ISO real-time energy market reached record high levels.

As result of these market outcomes, the ISO management made an emergency filing with FERC for permission to impose hard price caps on the ISO's energy and ancillary services markets at $250/MW in the ancillary services markets and $250/MWh in the real-time energy market, which FERC quickly granted. FERC also directed the Market Surveillance Committee (MSC) of the California ISO to prepare a report on the performance of the ISO's energy and ancillary services markets. The MSC's Aug. 19, 1998 report noted that the ISO's energy

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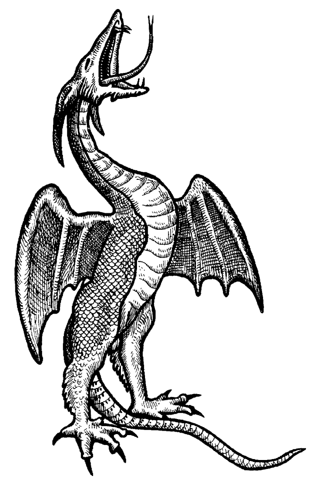
and ancillary services markets were not workably competitive.[7] This report identified a number of market design flaws which enhanced the ability of generators to exercise their unilateral market power in the California electricity market. The report contained a number of recommendations for correcting these market design flaws.

In response to the report, FERC issued an order implementing various market rule changes and asked the MSC to prepare a report analyzing the impact these market rule changes had on the performance of the ISO's energy and ancillary services markets. The March 25, 1999 report provided an analysis of the market power impacts of the redesign of the ISO's ancillary services markets and its reliability must-run contracts.[8] The major focus of this report was whether FERC should continue to grant the ISO the authority to impose ''damage control'' price caps on the ISO's energy and ancillary services markets. The MSC concluded that the California electricity market was still not yet workably competitive and was susceptible to the unilateral exercise of market power because of an over-reliance on day-ahead and shorter-time-horizon markets for the procurement of energy and ancillary services and the lack of price-responsiveness in the hourly wholesale electricity demand. As noted earlier, all customers had the option to purchase at their IOU's frozen retail rate. For these reasons, the MSC strongly advocated that FERC extend the ISO's authority to impose price caps on the real-time energy and ancillary services markets, which FERC subsequently did.

On Oct. 18, 1999, the MSC filed a report with FERC reviewing the performance of the market since the March 25, 1999 report.[9] The focus of this report was a comparison of the performance of the



California electricity market during the summer of 1999 versus the summer of 1998. The measure of market performance used in this report was based on a preliminary version of the methodology for measuring market power in wholesale electricity markets described in the 2002 study by Borenstein, Bushnell and Wolak, hereinafter BBW.[10]

This measure of performance compares average actual market prices to the average prices that would exist in a market where no generators are able to exercise market power. This analysis controls for the changing costs of production for generation owners due to input fuel price changes, forced outages, and import availability. This standard of a market where no supplier possess market power was selected because it is consistent with the perfectly competitive market benchmark and the standard FERC uses to determine whether a market yields just and reasonable prices.

Based on this measure of market performance, as well as other factors, the October 1999 MSC report concluded that the potential to exercise significant market power still existed in California's wholesale energy market, despite the fact that the performance of the California electricity market significantly improved during the summer of 1999 relative to the summer of 1998. The October 1999 MSC report emphasized that a major reason for the superior performance of the market during the summer of 1999 versus the summer 1998 was the much milder weather conditions and corresponding lower peak load conditions during the summer of 1999, and the greater availability of imports from the Pacific Northwest in 1999 relative to 1998.

This report also noted that the two major retail market design flaws allowing generation unit owners to exercise market power in the California energy and ancillary services markets—the lack of forward financial contracting by the load-serving entities and the lack of price-responsive wholesale demand—remained unaddressed. The October 1999 MSC report provided several recommendations for redesigning California's retail

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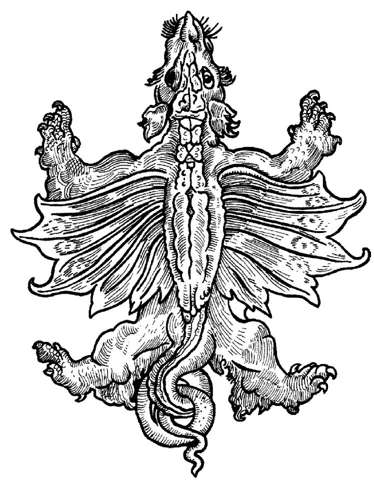
market policies in order to address these market design problems. This report also noted that if these retail market issues were not addressed as soon as possible, generators would have significant opportunities to exercise market power in the California electricity market during the summer of 2000.

In March 2000, the MSC was asked by the Board of Governors of the ISO to provide an assessment of whether the California energy and ancillary services markets were workably competitive and offer an opinion on the appropriate level of the price cap on the ISO's energy and ancillary services markets for the summer of 2000. In its March 9, 2000 opinion, the MSC concluded that these markets were not likely to be workably competitive for the summer of 2000, for the same reasons that it concluded in previous MSC reports that these markets were not workably competitive during the summers of 1998 and 1999.[11] This opinion also summarized an update of the market power measures of BBW through the summer and autumn of 2000.

This opinion also provided a prospective assessment of the impact on average wholesale electricity prices of the exercise of market power for various levels of the price cap on the ISO's real-time energy market during the summer of 2000. Because of a divergence of viewpoints among the members of the MSC about the increased opportunities to exercise market power at a higher price cap during the summer of 2000, the MSC did not offer an opinion on the level of the price cap, but instead explained to the ISO Board the tradeoffs it should take into account in setting the level of the price cap for the summer of 2000.

In spite of the problems that occurred during the summer of 1998, average market performance over the first two years of the



market, from April 1998 to April 2000, was close to the average competitive benchmark price. The average difference between the actual electricity prices and those that emerged from the BBW competitive benchmark pricing algorithm over this two-year period differed by less than $2/MWh. The average electricity price over this two-year period was approximately $33/MWh.

It is also important to emphasize that other wholesale electricity markets operating during this period also experienced the exercise of significant unilateral market power. Bushnell, Mansur, and Saravia compare the extent of unilateral market power exercised in the California market to that in the PJM and ISO-New England wholesale markets.[12] The major conclusion from this three-market comparison is that unilateral market power is common to all of these wholesale markets, particularly when the demand for electricity is sufficiently high that a large fraction of the within-control-area generating capacity is needed to meet this demand. Over their sample period, Bushnell, Mansur, and Saravia find that the amount of market power exercised in California to be quantitatively similar to the amount exercised in the other two ISOs. In fact, over their sample period of the summer of 1999, they found that PJM experienced the greatest amount of unilateral market power.

Although the performance of the California market during its first two years of operation compared favorably to the eastern ISOs, there were two danger signals not present to as great of an extent in the eastern ISOs as they were in California. The first, and by far most important, was the lack of hedging of spot price risk by California's LSEs. The eastern ISOs had virtually their entire final load covered by forward contracts either because of explicit forward contract purchases or because very little divestiture of vertically integrated firms was ordered as part of forming the eastern ISOs. In contrast, California LSEs purchased all of their supplies through day-ahead or shorter-horizon markets. While is it true that the three IOUs retained ownership of enough generation capacity to serve between one-third and two-thirds

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of the hourly load obligations of their LSEs, this left a substantial amount of their daily energy needs for the short-term markets.

Another important factor is California's significantly greater import dependence than the eastern ISOs. California historically relies on imports to meet between 20 and 25 percent of its electricity needs. Moreover, these imports are primarily from hydroelectricity from the Pacific Northwest, and water availability does not respond to electricity prices. A fossil fuel-based system can usually supply more electricity in response to higher prices because more input fuel sources become economic. In case of hydroelectricity, a supplier can only sell as much energy as there is water behind the turbine, regardless of how high the electricity price gets. This implies that LSEs in California should have hedged an even greater fraction of their expected wholesale energy needs than the eastern ISOs because they are much more dependent on hydroelectric energy.

III. The California Electricity Crisis

Low hydro conditions during the summer of 2000 throughout the Pacific Northwest and high demand conditions in the Desert Southwest left significantly less energy available from these regions to import into California. BBW show that the average hourly quantity of imports during the late summer of 1998 was 5,000 MWh, 6,800 MWh in 1999, and 3,600 MWh in 2000. This substantial drop in imports in 2000 relative to 1999 implied that generators located in California faced a significantly smaller import supply response when they attempted to raise prices through the unilateral exercise of market power. BBW found that suppliers to California were able to exercise market power at unprecedented levels during the summer of 2000. Using a similar methodology to that employed by BBW and public data sources on generation unit-level hourly output, Joskow and Kahn quantified the enormous amount of market power exercised during the summer of 2000.[13] Moreover, they provided firm-level evidence of supply withholding to exercise market power during many hours of the summer of 2000.

Evidence also exists that the substantially higher prices during the summer of 2000 were the result of the unilateral profit-maximizing actions of suppliers to the California electricity market.[14] Building on a model of expected profit-maximizing bidding behavior in a wholesale market that was explicated by this author in 2000,[15] this paper shows that a firm with the marginal cost curve given in **Figure 1** would formulate its expected profit-maximizing bid curve, $S(p)$, as follows given that it faces two possible residual demand realizations—$DR_1(p)$ and $DR_2(p)$. It would compute the profit-maximizing price and quantity pair associated with each realization of the residual demand curve. If residual demand realization $DR_1(p)$ occurs, the firm would like to produce at the output level q_1 where the marginal revenue curve associated with $DR_1(p)$ crosses $MC(q)$, the firm's marginal cost curve. The market price at this level of output by the firm is equal to p_1. The profit-maximizing price and quantity pair associated with residual demand

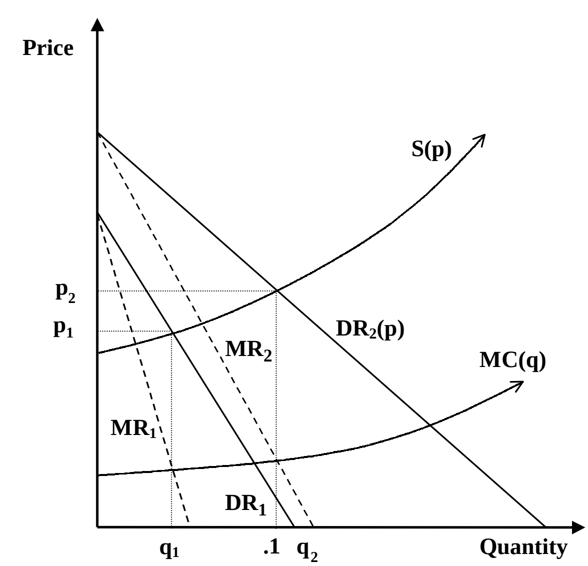

Figure 1: Model of Profit-Maximizing Bidding Behavior

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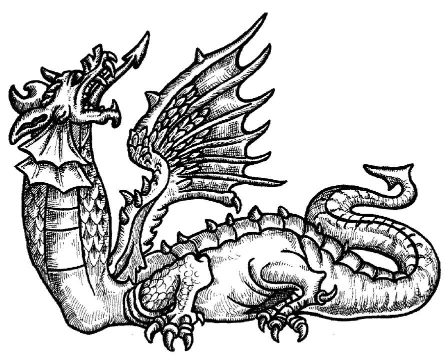
realization $DR_2(p)$ is equal to (p_2, q_2). If the supplier faced these two possible residual demand realizations, its expected profit-maximizing bidding strategy would be any function passing through the two profit-maximizing price and quantity pairs (p_1, q_1) and (p_2, q_2). The curve drawn in Figure 1 is one possible expected profit-maximizing bidding strategy. Extending this procedure to the case of more than two possible states of the world (or residual demand realizations) is straightforward, so long as distribution of the residual demand curves satisfies the regularity conditions given in Wolak (2000). In this case, the firm's expected profit-maximizing bid curve, $S(p)$, is the function passing through all of the *ex post* profit-maximizing price and quantity pairs associated with all of the possible residual demand curve realizations.

This logic has the following implication. Regardless of the residual demand realization, the following equation holds each hour of the day, h, and for each supplier, j:

$$\frac{P_h - MC_{jh}}{P_h} = \frac{-1}{\varepsilon_{hj}}, \qquad (2)$$

where P_h is the market price in hour h, MC_{jh} is the marginal cost of the highest cost MWh produced by firm j in hour h, and ε_{hj} is the elasticity of the residual demand curve facing firm j during hour h evaluated at P_h. Mathematically, $\varepsilon_{hj} = DR'_{jh}(P_h)(P_h/DR_{jh}(P_h))$. Define $L_{hj} = -1/\varepsilon_{hj}$ as the Lerner Index for firm j in hour h derived from this hourly residual demand elasticity. By the logic of Figure 1, it is expected profit-maximizing for supplier j to submit a bid curve in hour h, $S_{jh}(p)$, such that all points of intersection between it and any possible residual demand curve firm j might face in that hour occur at prices where Equation (2) holds for that residual demand curve realization



and resulting market-clearing price, P_h. If supplier j is able to find such a bid curve, then it cannot increase its expected profits by changing $S_{jh}(p)$, given the bids submitted by all of its competitors and all possible market demand realizations Q_h^d during hour h.

By this logic, the value of $L_{hj} = -1/\varepsilon_{hj}$ is a measure of the unilateral market power that firm j possesses in hour h. Using bids submitted by all participants in the California ISO's real-time market it is possible to compute L_{hj} for each supplier j and for all hours. The calculation differs from the usual approach to computing the Lerner index for a supplier that uses an estimate of the marginal cost of the highest-cost unit operating during the hour for supplier j and the market-clearing price for that hour. Using bids into the ISO's real-time market, I only require the assumption of expected profit-maximizing bidding behavior to recover a supplier's Lerner index from the bids submitted by all other suppliers besides supplier j and the market price. The average hourly value of L_{hj} for each supplier for the period June 1 to Sept. 30 is a measure of the amount of unilateral market power possessed by that firm.

Although the conditions required for Equation (2) to hold exactly for all possible residual demand realizations are not strictly valid for CAISO real-time market, deviations from Equation (2) are unlikely to be economically significant. As discussed in Wolak (2000), the market rules may prohibit the firm from submitting a bid curve that is sufficiently flexible to intersect all possible residual demand curve realizations at their *ex post* profit-maximizing price and quantity pairs. Figure 4.1 of Wolak (2003a) gives an example of how market rules might constrain the bid curves a supplier is able to submit for the case of the Australian electricity market.[16] In this market, suppliers are able submit up to 10 quantity bid increments per generating unit each half-hour of the day, subject to the constraints that all quantity increments are positive and they sum to less than or equal to the capacity of the generating unit. Associated with each of these quantity increments are prices that must be set once per

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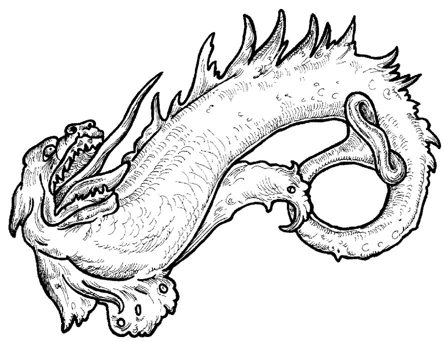
day. In the ISO's real-time energy market suppliers are able submit 10 price–quantity pairs each hour for each generation unit, which affords them considerably more flexibility in satisfying Equation (2) each hour than suppliers in the Australian market.

Using bid data from the California ISO's real-time electricity market, Wolak (2003b) computes, ε_{hj}, the elasticity of the hourly residual demand curve for hour h facing supplier j evaluated at the hourly market-clearing price for each of the five large in-state suppliers to the California electricity market—AES/Williams, Duke, Dynegy, Mirant and Reliant—for the period June 1 to Sept. 30 for 1998, 1999, and 2000. Consistent with the market-wide estimates of the extent of unilateral market power exercised presented in BBW, Wolak (2003b) demonstrates that for all of these suppliers the average hourly value of $1/\varepsilon_{hj}$ was higher in 2000 relative to 1998 and 1999. This result implies that the ability of each of these five suppliers to raise market prices by bidding to maximize their profits from selling electricity in the California ISO's real-time market was much greater in 2000 relative to the previous two years. The average hourly value of $1/\varepsilon_{hj}$ in 1998 was somewhat higher than the same value in 1999, indicating that the unilateral profit-maximizing actions of these suppliers in 1999 were less able to raise market prices than in 1998. This result is also consistent with the market-wide estimates of the extent of unilateral market power computed in BBW for 1998 versus 1999.

IV. FERC's Response to the Summer and Autumn of 2000

On Nov. 1, 2000, FERC issued an order that concluded wholesale electricity prices during the



summer and autumn of 2000 were unjust and unreasonable and reflected the exercise of significant market power. This order also proposed remedies for these unjust and unreasonable prices in the California wholesale electricity market. It proposed replacing the \$250/MW(h) hard cap on the ISO's real-time energy and ancillary services market with a soft cap of \$150/MW(h). This soft price cap required all generators to cost justify bids in excess of \$150/MWh. If this quantity of energy or ancillary services was needed by the ISO, then the firm would be paid as-bid for its sales. This order also proposed to eliminate the requirement that all California investor-owned utilities buy and sell all of their day-ahead energy requirements through the California PX. In addition to several other market rule changes, this preliminary order required that the ISO implement a penalty on all loads of \$100/MWh for any energy in excess of 5 percent of their total consumption that is purchased in the ISO's real-time energy market. FERC also invited comment on these proposed remedies.

On Dec. 1, 2000, the MSC filed comments on these proposed remedies.[17] The MSC concluded that ''the Proposed Order's remedies are likely to be ineffective to constrain market power and, in fact, could exacerbate California's supply shortfalls and, thereby, increase wholesale energy prices.'' The MSC concluded that the proposed remedies would be likely to cause the California PX to declare bankruptcy with little impact on wholesale electricity prices. The MSC and the PX's Market Monitoring Committee, as well as number of other comments, observed that the Commission's soft cap would function very much like no price cap because market participants could use affiliate transactions or other means to make the cost (paid by the affiliate that owns the generation unit) of providing energy or ancillary services to California consumers extremely high. The MSC also argued that the order's penalty on load for purchasing excessive amounts of energy in the real-time market would do

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little to solve the significant reliability problems that the California ISO was facing as result of the enormous amounts of generation and load that appeared in the ISO's real-time energy market, given the profitability to suppliers of withholding power from the California market until the real-time market under FERC's proposed remedies.

On Dec. 8, 2000, the ISO management and board unilaterally implemented the FERC soft cap at a $250/MWh level. This meant that from this date going forward, any generator that could cost-justify its bid above $250/MWh would be paid as-bid for the electricity they supplied in the ISO's real-time market. In its final order directing remedies for the California electricity market on Dec. 15, 2000, FERC reiterated its statement that wholesale electricity prices in California were unjust and unreasonable and reflected the exercise of market power. This order adopted its Nov. 1, 2000 proposed remedies with only minor modifications. Effective Jan. 1, 2001 when all of the remedies ordered by FERC were implemented, the ISO's soft cap was reset at $150/MWh.

On Feb. 6, 2001, the MSC filed with FERC a further elaboration and clarification of its proposed market power mitigation plan outlined in the Dec. 1, 2000 MSC report.[18] This report noted that many of the warnings about the likely impact of the remedies in FERC's Dec. 15, 2000 order given in the Dec. 1, 2000 MSC report had been borne out by the events of January 2001. The Feb. 6, 2001 MSC report noted that the average real-time wholesale energy price (the quantity weighted-average price of real-time energy purchases) during January 2001 was approximately $290/MWh, despite the existence of a $150/MWh soft cap on the ISO real-time energy market.

Moreover, California experienced, for the first-time, two days with rolling blackouts due to insufficient generation capacity available to serve the California market.

It is important to emphasize that these rolling blackouts occurred during a month when the daily demand for electricity is near its lowest annual level. For example, the peak demand in January 2001 was approximately 30,000 MW. The peak demand during the summer of 2000 was slightly less than 44,000 MW. This occurred during August 2000, when the average price of wholesale electricity was slightly less than $180/MWh. Consequently, despite a significantly lower peak demand and significantly less energy consumed daily, real-time prices in January 2001 (when FERC's remedies were in place) were more than $100/MWh more than prices during August 2000, the month with the highest average price during the summer of 2000. Moreover, the California ISO experienced no Stage 3 emergencies and no rolling blackouts during August 2000, whereas it experienced almost daily Stage 3 emergencies and two days with rolling blackouts during January 2001.

The Feb. 6, 2001 MSC report also described the perverse incentives the FERC soft-cap created for generators with natural gas affiliates selling into California. This report outlines logic that illustrates how these firms can use affiliate transactions to raise the announced spot price of natural gas in California and thereby cost-justify higher electricity bids under the FERC soft-cap. It also presented evidence that the persistent divergence in natural gas prices in California relative to the rest of the western U.S. could be attributed to this activity. Finally, this report described a fundamental difference in the incentives faced by a generation unit owner in wholesale electricity markets versus the former vertically integrated monopoly regime: the enormous potential profit increase to generators selling into an electricity market from declaring forced outages at their facilities. By declaring a forced outage, a generation unit

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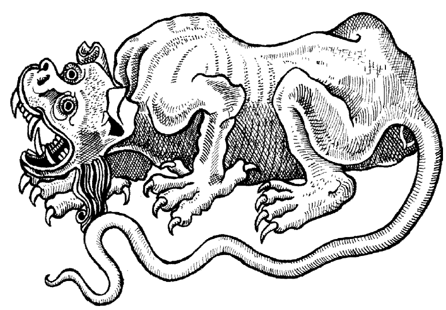
owner is able to create an artificial scarcity of generation capacity and therefore pre-commit itself not to provide an aggressive supply response (because some of its capacity is declared out of service) to the attempts of its competitors to raise market prices through their bidding behavior. Under the former vertically integrated monopoly regime, the generation owner has little incentive to declare forced outages because it still retains the obligation to serve final retail demand. A forced outage requires this firm to operate more expensive units or purchase power from other firms to meet its demand obligations.

This report also noted the practical impossibility of verifying whether a declared forced outage truly means that the plant is unable to operate. An analogy is drawn to the labor market where an employee might call his boss to claim a sick day. It is virtually impossible for the employee's boss to determine whether that employee can in fact work despite his request for a sick day. Similar logic applies to the attempts of the ISO, FERC, or any other independent entity to verify if a declared forced outage in fact means that the plant is truly unable to operate. By this logic, planned or unplanned outages can be very powerful tools that owners of multiple generation units can use to exercise their unilateral market power.

In assessing the plausibility of ''sick days'' as a mechanism for creating an artificial scarcity of available generation capacity, it is important to bear in mind the following facts. The California ISO control area had slightly over 44,000 MW of installed capacity. Consequently, for a capacity shortfall sufficient to cause rolling blackouts to occur when peak demand is 30,000 MW, over 14,000 MW of capacity must be



either forced or planned out. For Stage 3 emergencies to occur, only slightly less capacity must be forced or planned out. All of these calculations assume that no imports are available to sell into the California market. With some imports, these numbers must be even larger. California has over 12,000 MW of available transmission capacity to deliver energy into the California market, with a historical peak transfer of energy into California of more than 10,000 MWh in early 1999, so that unless the amount of energy available to import in California is limited, this use of generation outages to exercise market power is likely to be unprofitable. However, these calculations provide evidence for the view that the unprecedented magnitude of forced outages during the late autumn of 2000 and winter of 2001 was due in part to the increased ability of suppliers to exercise unilateral market power in response to less import availability. This ability to exercise market power was enhanced by the remedies implemented by FERC in its Dec. 15, 2000 order that increased the potential profitability of withholding power until the ISO's real-time market.

V. FERC's Response to Further Evidence of Substantial Market Power

Despite the growing volume of evidence from a number of independent sources on the extent of market power exercised in the California electricity market following the imposition of the Dec. 15, 2000 remedies, FERC took no further action to fulfill its statutory mandate set just and reasonable prices for wholesale electricity in California for almost four months. The average real-time price over this period was more than $300/MWh, even though these months are typically the lowest demand months of the year.

On April 26, 2001, FERC issued an order establishing a prospective mitigation and monitoring plan for the California wholesale electricity market that was implemented by the California ISO on May 29, 2001. This plan

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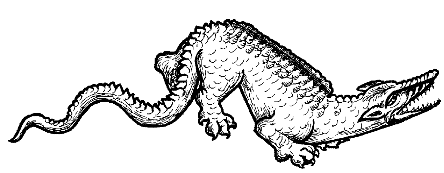
provided price mitigation only under Stages 1, 2, and 3 system emergencies but placed no requirements on the bid prices of generators during other system conditions.[19] Because of the requirement in the FERC order to limit bid prices during periods of system emergencies, the incentives for generators to supply as much capacity as possible were significantly dulled precisely at the time when the capacity was needed most. For many of the same reasons that the soft cap and other market rule changes implemented under the Dec. 15, 2000 FERC order were ineffective at mitigating the significant market power exercised in the California electricity market from Jan. 1, 2001 to June 2001, these market rules did not significantly improve market performance.

In response to increasing pressure from other states in the west as well as California, FERC imposed a west-wide mitigation plan on June 19, 2001. This plan set a west-wide price cap subject to cost-justification similar to the soft-cap that applied all western U.S. generation units. Moreover, power marketers and importers were required to bid as price-takers, which meant they could not set the market-clearing price with their bid and would be paid the market-clearing price for any energy they sold. This west-wide mitigation measure applied to all hours, rather than just system emergency hours. However, the mitigation mechanism only applied to the ISO's real-time market, which by that time was serving less than 5 percent of California's load. In mid-January 2001, the State of California Department of Water Resources had begun purchasing the net-short of the three LSEs, the difference between their total demand for energy and amount they could supply from their own generation units, though bilateral transactions.



In spite of its laudable goals, the mitigation measure was, for the most part, too late, because as I discuss in Section VIII, the State of California had already essentially solved the California crisis, albeit at a substantial cost to California consumers, by substantial purchases of forward contracts during the winter of 2001 that began to make deliveries in June 2001.

VI. The Fundamental Enabler of Supplier Market Power in California

I will now describe the primary factor that allowed suppliers serving the California market to raise prices vastly in excess of competitive levels during the period May 2000 to June 2001. When California sold off approximately 20,000 MW of generation capacity owned by PG&E, SCE, and SDG&E to Duke, Dynegy, Reliant, AES, and Mirant, the five new entrants to the California market, it was done without an accompanying provision that the new owners agree to sell back to these three firms a large fraction of the expected annual output from these units at a fixed price in a long-term contract with a duration of at least five years. These mandatory buy-back forward contracts sold along with the generation units are typically called "vesting contracts." A vesting contract on a 500 MW unit might require the new owner to sell an average of 400 MWh each hour back to the load-serving entity that sold the generation asset at a price set by the regulator (before the asset is sold) for a period of at least five years. There are a number of modifications to this basic vesting contract structure, but the crucial feature of these forward contracts is that they obligate the new owner to sell a fixed quantity of energy each year at a fixed price to the LSE affiliate of the former owner.

Vesting contracts have been a standard part of the restructuring process in virtually all countries around the world and in a number of U.S. markets. Green (1999) discusses the role of vesting contracts in the England and Wales electricity market.[20] Wolak (2000) discusses the Australian electricity market's experience with vesting contracts. In the New England market a number of IOUs had energy buy-back arrangements with the purchasers of the divested units that resembled vesting contracts. Although vesting contracts are not essential to the success of a restructured electricity market, an active forward market where the vast majority of energy is bought and sold substantially limits the incentive supplier have to exercise market power in the spot market. In markets where active forward markets did not previously exist, such as in countries where the process started with a state-owned monopoly, vesting contracts are a transition period to an active forward market. In markets were an active forward energy market already exists, there is less need for vesting contracts to stimulate the level forward market participation necessary for a workably competitive spot market.[21]

Forward contracts set up an extremely powerful incentive for the seller to produce at least the contract quantity from its generation units each hour of the day. The new owner must purchase any energy necessary to meet its forward contract obligations that it does not supply from its own units at the spot market price and sell it at the previously agreed upon contract price. Consequently, the supplier only has an incentive to bid to raise the market price if it is assured that it will produce at least its forward contract obligations from its own units. However, this supplier cannot be assured of producing its forward contract obligation unless its bids for this quantity of energy are low enough to be accepted by the ISO. If each supplier knows that other suppliers have forward contracts and are eager to supply at least their forward contract obligations from their own units, then all suppliers will have strong incentives to

bid very close to their marginal cost of production for their forward contract obligation. This aggressive bidding brought about by the desire of suppliers to cover their forward contract positions will set market prices very close to competitive levels in all but the highest-demand periods when at least one supplier is confident that it will be needed by the ISO to produce more energy than its forward contract quantity regardless of how high it bids.

In contrast, if suppliers have little or no forward contract obligations, their incentive to bid substantially in excess of the marginal cost of supplying electricity from their units can be much greater. That is because they will earn the market-clearing price on all electricity they produce. Because these suppliers have no forward contract obligations to meet, they are net suppliers of electricity with the first MWh of electricity they produce. To understand this dramatic change in the incentive to raise prices caused by having no forward contract obligations, consider the 500 MW unit described earlier. Suppose this supplier actually produces 450 MWh of energy. In a world with 400 MWh committed in a forward contract, if the supplier manages to raise market prices by $1/MWh, this will increase its revenues by the difference of 450 MWh (the amount energy it actually produces) and 400 MWh (the amount of its forward contract obligation), times $1/MWh or $50. In contrast, in a world with no forward contract obligation, if this firm manages to increase the market price by $1/MWh, it earns an additional $450 in revenues, because it receives this price for all of its sales. In this simple example, the lack of any forward contract obligation for the supplier resulted in a 9 times greater incentive to raise market prices by $1/MWh, than would be case if the firm had a forward contract obligation to supply 400 MWh. Extending this example to the case of a supplier that owns a portfolio of generation units, one can immediately see the tremendous increase in the incentive to bid in excess of marginal cost during certain system conditions

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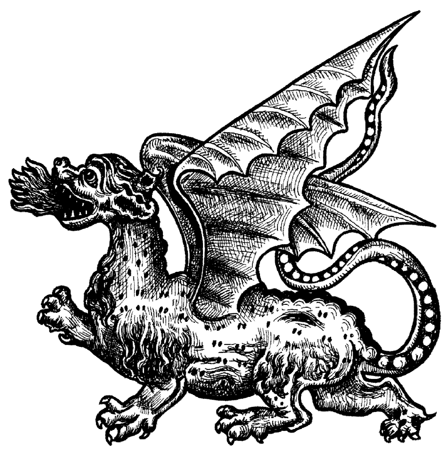
caused by the lack of sufficient forward contract commitments. The five new entrants to the California market had very limited forward contract commitments to the three large LSEs in California. Besides limited sales in the PX Block Forwards market to the three LSEs, virtually all of the energy the five merchant generation companies sold to the three LSEs was purchased in the day-ahead PX and real-time ISO markets. Consequently, any increase in these short-term market prices could be earned on virtually all of the energy produced by these suppliers.

This same incentive for suppliers to raise spot prices in the eastern ISO is limited to extreme demand conditions, because all of the large LSEs in these markets either own sufficient generation capacity to meet most all of their final demand obligations or have forward contracts with other suppliers for a substantial fraction of the expected output of from their units. Consequently, the exercise of significant market power only occurs during very high-demand conditions, which one or more suppliers is net long relative to their forward contract position. This is consistent with the evidence presented in Bushnell, Mansur and Saravia presented for PJM and New England, two ISOs with substantial forward contract coverage of final demand. Although it is difficult to get precise estimates of the final demand covered by forward contracts, estimates for the PJM, New York, and New England Markets suggest that between 85 and 90 percent of annual demand is covered by forward financial obligations either in the form of generation ownership or forward financial contracts. In California during the period May 2000 to June 2001, this figure was close to 40 percent, which is the approximate average percentage of the



total demand of the three large investor-owned utilities that could be met from their own generation units.

The very limited forward contract obligations to the three LSEs by the five new fossil-fuel capacity entrants combined with low import availability during the second half of 2000 created an environment where, as shown in Wolak (2003b), the unilateral profit-maximizing bidding behavior of these suppliers resulted in prices vastly in excess of competitive levels. If California had forward contract coverage for final demand at the same levels relative to annual demand as the eastern ISOs, it is difficult to understand how California suppliers would have found it unilaterally profit-maximizing to withhold capacity to create the artificial scarcity that allowed them to raise market prices dramatically starting in the summer of 2000. In addition, even if the five suppliers had been able to raise market prices, California consumers would have only had to pay these extremely high prices for approximately 10 percent of their consumption rather than for close to 60 percent of their consumption.

The lack of forward contract obligations to final load in California created a much faster rate of harm to consumers in California than in other states in the west. These states only used the spot market for approximately 5 percent of their annual electricity needs. The substantially larger spot market share in California meant that the same $/MWh electricity price increase resulted in wholesale energy payments increases in California that were more than 10 to 12 times higher than the wholesale energy payments increases in the rest of the western U.S.

VII. Regulatory Dispute that Led to California Crisis

The discussion in the Sections V and VI provide evidence consistent with the view that the California electricity crisis that occurred in the latter part of 2000 and first six months of 2001 was primarily the result of the conflict

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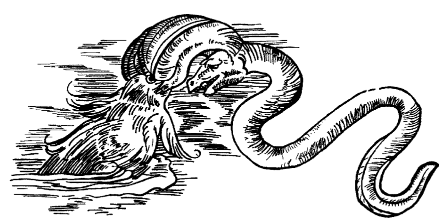
between the Federal Energy Regulatory Commission and the state of California over the appropriate regulatory response to the extremely high wholesale electricity prices in California during the summer and autumn of 2000. The state of California argued that wholesale electricity prices during the summer and autumn of 2000 were unjust and unreasonable and it was therefore illegal under the Federal Power Act of 1935 for California consumers to pay these wholesale prices. However, not until it issued a preliminary order on Nov. 1, 2000, did FERC first formally state that wholesale prices in California were unjust and unreasonable and reflected the exercise of significant market power by suppliers to the California market. Although FERC reached this conclusion almost four months after California, the ultimate conflict between FERC and the state of California does not appear to be over whether wholesale prices in California during the summer and autumn of 2000 were illegal under the Federal Power Act. Instead, the ultimate regulatory conflict that led to the California crisis appears to be over the appropriate remedy for these unjust and unreasonable prices.

As should be clear from the events in California from June 2000 to June 2001, the process FERC uses to determine whether a firm is eligible to receive market-based prices does not guarantee market prices that satisfy FERC's statutory mandate under the Federal Power Act. First, the dichotomy implicit in the FERC process that a firm either possesses market power or does not possess market power does not reflect the realities of wholesale market operation. Depending on conditions in the transmission network and the operating decisions of all market participants, almost any firm can



possess substantial market power in the sense of being able to impact significantly the market price through its unilateral actions. Second, it is extremely difficult if not impossible to determine on a prospective basis the frequency that a firm possesses substantial market power given the tremendous uncertainty about system conditions and the incentives they create for the behavior of other firms in the market.

Because FERC granted market-based price authority to all sellers in the California market using an inadequate methodology without any accompanying regulatory safeguards, given the discussion in Section VII, it is not surprising that a sustained period of the exercise of significant market power and unjust and unreasonable wholesale prices occurred because of the substantially lower import availability in 2000 and the over-dependence of California's three large LSEs on the spot market. FERC's remedies implemented in its Dec. 15, 2000 order are more difficult to understand. Despite filings by a large number of parties arguing that these remedies (also proposed in the Nov. 15, 2000 preliminary order) would be ineffective at best and most likely harmful to the market, FERC still implemented them without significant modification. As I noted earlier, in its Dec. 1, 2000 comments, the MSC concluded that the Proposed Order's remedies would most likely be ineffective at constraining the exercise of market power and, in fact, could exacerbate California's supply shortfalls, and thereby, increase wholesale energy prices. Unfortunately, this is precisely what happened following the implementation of these remedies in January 2001. The California Power Exchange went bankrupt, PG&E declared bankruptcy, SCE came close to declaring bankruptcy, and rolling blackouts of firm load occurred in January, March, and May of 2001.

As noted in the Dec. 1, 2000 MSC report, FERC's soft price cap policy contained in its Dec. 15, 2000 final order amounted to no price cap on wholesale electricity prices, because all suppliers had

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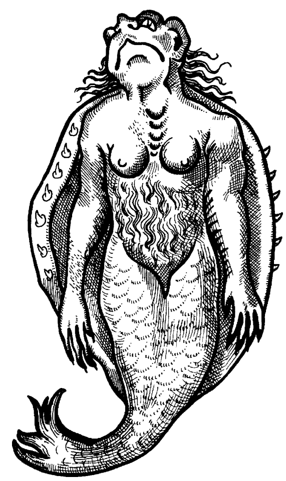
to do was to cost-justify their bids in excess of the $150/MWh soft price cap, something they found increasingly easy to do because at the time FERC only did a very limited review of the prudency of these cost justifications. Rather than remedying the unjust and unreasonable prices of the summer and autumn of 2000, as noted earlier the Dec. 15, 2000 remedies appear to have produced real-time wholesale prices from Dec. 1, 2000 to the end of May 2001 that were substantially higher than average wholesale prices during any preceding or following six-month period, along with the rolling blackouts and bankruptcies and near-bankruptcies described above.

VIII. The Solution to the California Electricity Crisis

I now address the question of the solution to California electricity crisis. As described above, the lack of forward contracts between California suppliers and the three large LSEs created strong incentives for suppliers to withhold capacity from the market in order to increase spot prices. By this logic, if enough California suppliers had a substantial amount of their capacity committed in long-term contracts to California LSEs, the incentive California suppliers had to withhold capacity from the market would be substantially reduced and the accompanying very high average spot prices created by this artificial scarcity would be largely eliminated. For this reason, the Dec. 1, 2000 report of the Market Surveillance Committee proposed a joint/federal state regulatory mechanism to implement what amounted to *ex-post* vesting contracts between California's LSEs and suppliers to the California market at fixed prices set by FERC. This regu-



lated forward contract remedy was not adopted by FERC in its Dec. 15, 2000 final order. Consequently, if the state of California wished to purchase the quantity and mix of forward contracts necessary to commit suppliers to the California market during the summer 2001 and following two years, it would have to pay prices that reflected the market power that suppliers expected to exist in the spot market in California over the coming two years. Profit-maximizing suppliers would not sell their output in forward contracts that covered this time period at a fixed price that is below the average price that they expected to receive from selling this energy in the spot market over the duration of the contract.

Thus, the only way for California to lower the price it had to pay for a forward contract was to increase the duration of the contract or the fraction of energy purchased in the later years of contract. By committing to purchase more power from existing suppliers at prices above the level of spot prices likely to exist in California more than two years into the future, California could obtain a lower overall forward contract price. However, this was simply a case of paying for the market power that was likely to exist in the California spot market during the period June 2001 to May 2003 on the installment plan rather than only during this two-year time period.

A simple numerical example illustrates this point. Suppose a supplier expects that it will be able to sell electricity in the spot market at prices that average $300/MWh for the period June 2001 through May 2002, $150/MWh for the period June 2002 through May 2003 and $45/MWh for all years following May 2003. Consider a forward contract that offers 1/20 of its energy in the first year, 1/10 in the second year and 17/20 in years 3 to 10. Only if California officials were willing to pay at least $68.25/MWh ($= 0.05 \times 300 + 0.1 \times 150 + 0.85 \times 45$) for this forward contract would a profit-maximizing generator to be willing to offer it.

This example shows that the forward contracts California

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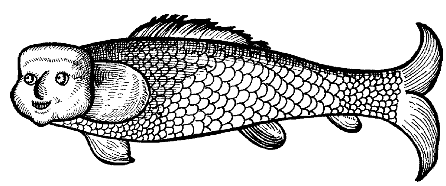
signed during the winter and spring of 2001 did not allow it to avoid paying for the considerable market power that market participants expected to exist over the coming two years when the contracts were signed during the winter of 2001. One might ask why the forward prices for deliveries in 2003 and beyond during the winter of 2001 were significantly lower than prices for deliveries in the two intervening years. This occurred because suppliers recognized that new generation units could be sited and put into service before the start of the summer of 2003, so the market for electricity deliveries made after that date is very competitive. Even during the winter of 2001, existing firms faced significant competition to supply electricity at time horizons beyond the start of the summer of 2003 from many potential entrants using combined-cycle gas turbine technologies that are almost twice as efficient at converting natural gas into electricity as most existing gas-fired facilities in California.[22]

During the late winter and early spring of 2001, the state of California signed approximately $45 billion in forward contracts with durations averaging approximately 10 years. These forward contracts committed a significant amount of electricity to the California market during the summer of 2001 and even more in the summer of 2002 and beyond. While a few of the forward contracts signed during the winter of 2001 began making deliveries in late March and the beginning April and May of 2001, a substantial fraction of these contracts began delivering power to California June 1, 2001. The vast majority of the remaining contracts delivering power during summer of 2001 began July 1, 2001 and Aug. 1, 2001.

The FERC price mitigation plan described in its June 19,



2001 order was implemented June 20, 2001. This plan established a west-wide price cap and required power marketers to bid as price takers in the California market. However, all sellers other than power marketers were still allowed the opportunity to cost-justify and to be paid as-bid for their electricity at prices above this west-wide price cap.

To assess the relative impact on spot market outcomes of this price mitigation plan relative to the forward contracts purchased by the state of California, it is important to bear in mind the following facts. First, the FERC price mitigation plan only applied to sales in the California ISO real-time market. During this period less than 5 percent of the energy consumed in California was paid the ISO real-time price. The vast majority of sales during the summer of 2001 were made through the long-term forward contracts signed during the winter of 2001 and medium-term commitments to supply power negotiated by the California Department of Water Resources. Second, according to the California ISO's Department of Market Analysis, average prices for incremental energy were slightly below $70/MWh during July 2001 and less than $50/MWh for the remaining months of 2001. Throughout this entire time period the west-wide price cap was slightly above $91/MWh. Third, according to the July 25, 2001 Market Analysis Report of the ISO's Department of Market Analysis, the extent to which real-time prices exceeded the competitive benchmark price during the period June 1, 2001 to June 19, 2001 was substantially smaller than it was any previous month during 2001.[23] The result is consistent with the logic that the forward contracts beginning delivery on June 1, 2001 provided incentives for more aggressive spot market behavior. Finally, it is important to note that demand during each month of 2001 was approximately 5 percent less than demand during the same month of 2000 because of significant conservation efforts by California consumers. All these facts suggest that the June 19, 2001 price mitigation plan was

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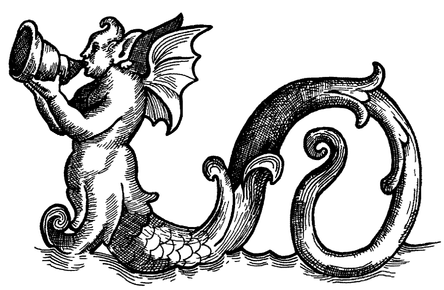
not a binding constraint on real-time prices during the vast majority of hours of the second half of 2001.

Monthly average real-time incremental energy prices from Jan. 1, 2002 to Sept. 30, 2002, the end of price mitigation period, averaged between \$50/MWh and \$60/MWh, which provides evidence that this price mitigation plan was not the binding constraint on prices for the vast majority of hours of the first nine months of 2002 as well. Average prices for near-term (forward market horizons longer than day-ahead) energy during the period July 1, 2001 to Sept. 30, 2002 were significantly lower than average incremental real-time energy prices over this same time period. This result provides evidence that the long-term contracts signed during the winter of 2001 caused suppliers to exhibit more competitive behavior in the near-term energy market during this time period. More recent analyses of market outcomes by the Department of Analysis of the California ISO which accounts for the impact of the forward contract obligations of the large suppliers, finds additional evidence consistent with the view that these forward contract obligations increased the competitiveness of the near-term and real-time electricity markets during the period July 2001 to September 2002.

Although the above evidence suggests that the FERC June 19, 2001 price mitigation order had, at most, a very limited impact on the competitiveness of the medium-term and real-time spot markets for electricity in California relative to the impact of forward contracts signed by the state of California during the winter of 2001, it did have substantial impact on the behavior market participants. Following the



imposition of the June 19, 2001 order, FERC clearly demonstrated a greater willingness to support the actions of the California ISO operators and Department of Market Analysis in their attempts to restore order to the California market. Following the implementation of the June 19, 2001 order, FERC was much more willing to take tangible actions in support of the ISO's efforts to make suppliers comply with FERC's must-offer requirement as well as a number of other provisions of the ISO tariff. These actions demonstrated to California market participants that FERC was now taking a far more active role in regulating the California market. This more active presence by FERC in California appears to have subsequently benefited system reliability and market performance.

IX. Lessons Learned from the California Electricity Crisis

Several lessons from the California electricity crisis follow directly from the diagnosis of the causes and solution to the California electricity crisis given in the previous section of this article. The most important lesson is that any restructuring process should begin with a large fraction of final demand covered by long-term forward contracts. Only a very small fraction of total demand should be purchased from the medium-term and real-time markets, particularly given the way that retail electricity is priced to final consumers throughout the U.S. To the extent that the wholesale market in a geographic region is highly dependent on imports and highly dependent on hydroelectric power, the fraction of total demand that should be left to the medium-term and real-time market is even smaller. For this reason, the forward contract coverage of final load at the start of the market in California should have been even greater than what exists in any of the markets in the eastern U.S. because none of them are as dependent on imports and hydroelectric energy as California.

The second lesson is that state and federal regulators must coordinate their regulatory efforts to protect consumers. Because FERC appears to have disregarded much of the input from California regulators and policymakers and other independent monitoring entities intimately acquainted with the performance of the California market during autumn of 2000 in formulating its Dec. 15, 2000 order implementing remedies for the California market, this order had many unintended consequences that only made matters worse, rather than remedying the extreme market power exercised in the spot electricity market in California. This outcome underscores an important component of this lesson that is particularly relevant for states that have not yet re-structured. State regulators cannot protect consumers from market power in the wholesale market without the cooperation of FERC, because it is the only regulatory body charged with setting just and reasonable wholesale electricity prices. To provide the necessary assurance to states that another regulatory crisis between FERC and state regulators will not occur at some future date, I believe it is necessary for FERC to implement a formal mechanism that guarantees it will fulfill its statutory mandate to set just and reasonable wholesale prices in the most timely manner possible should market outcomes that reflect significant market power arise in any wholesale electricity market that it regulates. I am extremely skeptical that the national political process will allow further restructuring of the electricity supply industry unless FERC is able to provide a greater degree of assurance to state regulators that it will provide the same or a superior level of protection to consumers relative to what they received in the former vertically integrated utility

regime. The tremendous resistance to FERC's Standard Market Design NOPR expressed by politicians and policymakers in the majority of U.S. states appears to be due in part to the perception that FERC cannot or will not provide this level of protection to electricity consumers.

An important corollary to the necessity of coordinating federal and state regulatory policies is that a successful wholesale market design must take into account the existing retail market design. Federal wholesale market polices must be coordinated with state-level retail market policies. The details of state-level retail market policies can have potentially enormous unintended consequences for wholesale market performance. For example, designing a wholesale market assuming the existence of active participation by final consumers, when virtually all U.S. retail markets do not support such participation, will not create a workably competitive wholesale market. Consequently, a national policy for a standard wholesale market design should at least recognize that certain conditions in the retail market are necessary to support a workably competitive wholesale market. For example, one retail market precondition for FERC approval of a wholesale market design would be that all customers above some peak demand level, say 200 kW, have hourly meters at their facility, and face a default wholesale price equal to the hourly spot price of electricity at their location. FERC may also wish to consider pre-conditions on the retail infrastructure to support participation by small-business and residential customers in the wholesale market, but some preconditions on the retail infrastructure for large, sophisticated electricity customers is essential.

A third lesson from the California crisis is that FERC cannot set *ex ante* criteria for a supplier to meet in order for it to be allowed to receive market-based prices without *ex post* criteria for assessing whether the subsequent market prices are just and reasonable. As discussed above, it is impossible to determine with certainty on an *ex ante* basis whether a supplier owning a

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portfolio of generation units has the ability to exercise significant market power. Consequently, I see no way for FERC to avoid devising a transparent methodology for determining what constitutes a just and reasonable price in a wholesale market regime. Despite over four years experience with wholesale markets in the U.S., FERC is still unwilling to define what constitutes unjust and unreasonable prices. This FERC policy creates unnecessary regulatory uncertainty and increases the likelihood of another California electricity crisis, where there is a disagreement between FERC and state regulators over the extent to which wholesale prices are unjust and unreasonable and the appropriate regulatory remedies for these prices. FERC's policy does not serve the interests of electricity suppliers either. A major complaint of electricity suppliers at the present time is that they want assurance that any price they are paid will not be subject to an *ex post* refund obligation. Setting an *ex post* standard for what constitutes a just and reasonable market price along the lines of the 12-month competitiveness index that is part of the California ISO's Market Design 2002 proposed market power mitigation measures satisfies this goal.[24]

If one is willing to acknowledge that suppliers attempt to exploit all of the unilateral market power that they possess and that conditions in the transmission network and the production and consumption decisions of other market participants determine whether a firm possess substantial market power, then it follows that a supplier cannot be immunized against the ability to exercise market power on an *ex ante* basis. By this logic, the issue is no longer whether any supplier possesses market power, but whether the unilateral actions of

all market participants exercising all available market power results in prices that impose significant harm to consumers. In other words, do wholesale prices reflect the exercise of a substantial amount of market power for a sustained enough period of time to impose sufficient harm to consumers to justify regulatory intervention? This is the fundamental question that FERC must answer in order to provide a transparent definition of what constitutes unjust and unreasonable prices in a wholesale market regime. Specifically, FERC should be required to define the extent of market power exercised, the geographic market over which it is exercised and the time interval over which it is exercised that results in unjust and unreasonable wholesale prices worthy of regulatory intervention. A transparent definition of unjust and unreasonable prices in a wholesale market regime that can be applied to any wholesale market considerably simplifies the process of regulating wholesale markets. If this transparent standard (that can be computed by all market participants) for prices is exceeded, then regulatory intervention should automatically occur.

This perspective on just and reasonable wholesale market prices suggests a logical inconsistency in FERC's current approach to enforcing the just and reasonable price provision of the Federal Power Act. Specifically, in a number of public statements and orders, FERC has stated that it is important to find the bad actors and punish them for causing unjust and unreasonable prices. While it is important to find market participants that have violated market rules and take back their ill-gotten gains as well as penalize them for any market rule violations or illegal behavior, these statements by FERC seem to suggest that bad behavior on the part of a market participant is necessary for unjust and unreasonable prices worthy of refunds to occur. However, as emphasized in the above discussion, the unilateral actions of all privately owned market participants to serve their fiduciary responsibility to their shareholders and the unilateral actions of all publicly

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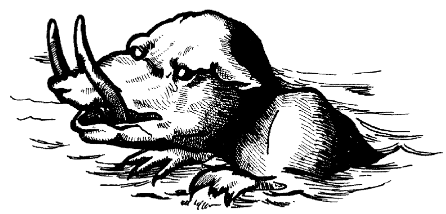
owned market participants to serve the interests of their captive customers can result in market outcomes that reflect the exercise of enormous market power. In short, there is no need for any malicious behavior by any market participant for a wholesale electricity market to produce unjust and unreasonable prices. Moreover, the Federal Power Act does not specify that prices must be the result of malicious behavior by a market participant in order for them to be deemed unjust and unreasonable. The Federal Power Act only requires that if FERC determines that prices are unjust and unreasonable, regardless of the cause, then it must take actions to set just and reasonable prices and it must order refunds for any payments in excess of just and reasonable levels.

The Federal Power Act does not say that these refunds must be paid only by firms that violated market rules or engaged in illegal behavior. This is the fundamental logical inconsistency that FERC faces in attempting to introduce wholesale markets without an explicit statutory mandate to do so. Firms can be required to refund wholesale market revenues despite the fact that no market participant engaged in any illegal behavior or violated any market rule, because their unilateral profit-maximizing actions jointly resulted in unjust and unreasonable market prices. This means that the legal actions of market participants in compliance with the market rules can result in market prices that are illegal and worthy of refunds. I believe the best way for FERC to deal with this problem is once again to set a transparent standard for what constitutes unjust and unreasonable prices in a wholesale market regime and set a pre-specified regulatory intervention that will occur if this



standard is violated along the lines of the California ISO's proposed 12-month competitiveness index for market power mitigation. This will minimize the potential for future FERC versus state regulatory conflict that can create another California electricity crisis.

X. Recommended Changes in FERC's Regulatory Oversight of Wholesale Markets

A final lesson from the California crisis is that FERC must regulate, rather than simply monitor, wholesale electricity markets. As should be clear from the previous sections and the description of the early warning signs of the exercise of market power in the California market discussed above, there was no shortage of effective market monitoring in California from the start of the market in April 1, 1998 to the present time. The Department of Market Analysis of the California ISO, the Market Monitoring Committee of the California Power Exchange, the Market Surveillance Committee of the California ISO, as well as a number of state agencies, all documented the exercise of market power in California. However, none of these entities had the authority to implement any market rule changes or penalty mechanisms to limit the incentives firms had to exercise market power or violate California ISO market rules. Only FERC has the authority to implement market rule changes and make regulatory interventions to improve market performance. Rather than focusing its attention on monitoring market performance, FERC should instead concentrate on designing proactive protocols for rapid regulatory intervention to correct market design flaws as quickly as possible and order refunds as soon as unjust and unreasonable prices are found. What allowed the California crisis to exist was not a shortage of observers with radar guns recording the speed of cars on the highway; it was the lack of traffic cops writing tickets and imposing fines on cars that exceeded the posted speed limit.

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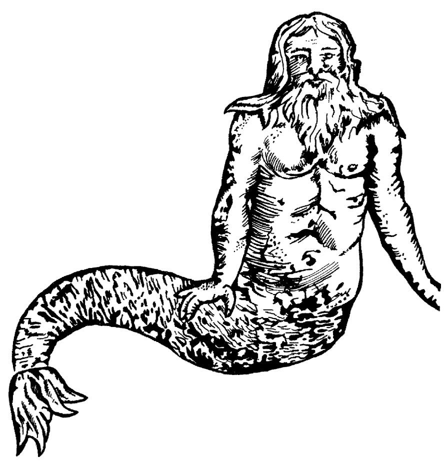
On the topic of the necessity of FERC regulating rather than simply monitoring wholesale markets, I would like to use FERC's soft price cap policy during the period January 2001 through June 2001 to illustrate this point. As discussed above, the soft cap policy stated that if a generator could cost-justify a bid in excess of the $150/MWh soft price cap, then it could be paid as-bid for its energy if it was needed to meet demand. However, regulation that simply says a firm must justify its costs in order to be reimbursed can yield the same outcome as no regulation at all. The recent revelations that energy traders in California misreported transaction prices during the crisis period suggests that it would be easy for an electricity supplier to obtain an invoice for its natural gas input fuel purchase at prices in excess of the actual cost to its energy trading affiliate. Consequently, without a rigorous prudency review of how input costs are actually incurred and disallowances for imprudently incurred costs, there is little limit on the prices that firms might be able to cost-justify. In fact, during the period Jan. 1, 2001 to June 30, 2001, electricity suppliers often cost-justified and were paid as-bid prices substantially in excess of $300/MWh under the FERC soft-cap policy. For this reason, anytime FERC caps the bids that a firm might submit based on its costs of production, it must perform a prudency review of these costs and be prepared to disallow any cost that cannot be adequately justified.

A final point related to the importance of FERC regulating rather than simply monitoring is the necessity of very accurate data on the physical characteristics of plants, input fuel prices, other input prices, and many other aspects of the operation of the wholesale market to carry out this task. For example, in order to perform a satisfactory review of the prudency of costs a firm would like to recover, FERC must have the best available data on these variables. Moreover, in order to compute the best possible estimate of what constitutes a just and reasonable wholesale market price FERC will need, at a minimum, the best available information on the operating characteristics of generation units, input fuel prices, and the physical state of the transmission network. Finally, in order to provide tangible evidence on how well it is doing in delivering economic benefits (in the form of lower prices) to consumers that they would not have received in the former vertically integrated utility regime, FERC will need to be able to determine what prices would have been under the former vertically integrated utility regime. This will require the same information. Consequently, particularly during the initial transition to a wholesale market regime, FERC should substantially increase, and certainly not reduce, the amount of data that it collects from market participants if it would like to be an effective and credible regulator.■



Endnotes:

1. To illustrate the wide-ranging authority, the Federal Power Act gives to FERC to set just and reasonable prices, I reproduce the following text from the Federal Power Act: ''Whenever the Commission, after a hearing had upon its own motion or upon complaint, shall find that any rate, charge, or classification, demand, observed, charged or collected by any public utility for transmission or sale subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affected such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification rule, rule, regulation, practice or contract to be thereafter observed and in force, and shall fix the same by order.''

2. The California Energy Commission processes all applications for licensing of thermal power plants that are 50 MW or larger. Plants smaller than 50 MW are licensed by city and county agencies and, as a result, may face a shorter time from conception to operation.

3. Schmalensee and Golub in 1984 first noted the crucial role played by transmission constraints in market

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power assessment in wholesale electricity markets. Richard Schmalensee and Benett Golub, *Estimating Effective Concentration in Deregulated Wholesale Electricity Markets*, RAND J. ECON., Spring 1984, 15 (1), at 12–26.

4. James Bushnell, *Looking for Trouble: Competition Policy in the U.S. Electricity Industry*, Center for the Study of Energy Markets (CSEM), Working Paper 109, 2003, available at http://www.ucei.berkeley.edu/PDF/csemwp109.pdf.

5. Wolak (1999) discusses the stranded asset recovery mechanism in detail and its impact on retail competition in the California market. Frank A. Wolak, *Report on the Redesign of the California Real-Time Energy and Ancillary Services Markets*, Oct. 18, 1999, available at http://www.stanford.edu/~wolak.

6. Another explanation is that the three IOUs felt that if wholesale prices rose above \$65/MWh to \$70/MWh, the CPUC would be forced to raise retail rates above this level under the ''filed rate doctrine,'' which roughly states that any wholesale price that has been filed with and approved by FERC must be passed through in retail electricity prices.

7. Frank A. Wolak, Robert Nordhaus, and Carl Shapiro, *Preliminary Report on the Operation of the Ancillary Services Markets of the California Independent System Operator (ISO)*, Aug. 19, 1998, available at http://www.stanford.edu/~wolak.

8. Frank A. Wolak, Robert Nordhaus, and Carl Shapiro, *Report on the Redesign of the Markets for Ancillary Services and Real-Time Energy*, March 25, 1999, available at http://www.stanford.edu/~wolak.

9. Wolak (1999), *supra* note 5.

10. Severin Borenstein, James Bushnell, and Frank A. Wolak, *Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market*, AM. ECON. REV., Dec. 2002, 92 (5), at 1376–1405.

11. Frank A. Wolak, Robert Nordhaus, and Carl Shapiro, *Analysis of ''Order Proposing Remedies for California Wholesale Electric Markets (Issued Nov. 1, 2000),''* Market Surveillance Committee of California Independent System Operator, Dec. 2000, available at http://www.caiso.com/docs/2000/12/01/2000120116120227219.pdf.

12. James Bushnell, Erin Mansur, and Celeste Saravia, *An Empirical Assessment of the Competitiveness of the New England Electricity Market*, Center for the Study of Energy Markets (CSEM), Working Paper, May 2002.

13. Paul Joskow and Ed Kahn, *A Quantitative Analysis of Pricing Behavior*

in California's Wholesale Electricity Market during Summer 2000: The Final Word, ENERGY J., Dec. 2002.

14. Frank A. Wolak, *Measuring Unilateral Market Power in Wholesale Electricity Markets: The California Market 1998 to 2000*, AM. ECON. REV., May 2003, at 425–430. Hereinafter ''Wolak (2003b).''

15. Frank A. Wolak, *An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market*, INT'L ECON. J., Summer 2000, 14 (2), at 1–40. Hereinafter ''Wolak (2000).''

16. Frank A. Wolak, *Identification and Estimation of Cost Functions Using Observed Bid Data: An Application to Electricity Markets*, in M. Dewatripont, L.P. Hansen, and S.J. Turnovsky (eds.), ADVANCES IN ECONOMIC AND ECONOMETRICS: THEORY AND APPLICATIONS, Eight World Congress, Vol. II (New York: Cambridge University Press, 2003), at 133–169. Hereinafter ''Wolak (2003a).''

17. Wolak, Nordhaus, and Shapiro, *supra* note 11.

18. Frank A. Wolak, *Proposed Market Monitoring and Mitigation Plan for California Electricity Market*, Feb. 6, 2001, available at http://www.stanford.edu/~wolak. Hereinafter ''Wolak (2001a).''

19. Stages 1, 2, and 3 are various levels of system reserve deficiencies, with a Stage 3 emergency being when the ISO forecasts less than 1.5 percent available reserves on the system or less than the largest contingency within the service area.

20. Richard Green, *The Electricity Contract Market in England and Wales*, J. IND'L ECON., 1999, XLVII (1), at 107–124.

21. In this regard, the difference between the origins of California ISO and the eastern ISOs is informative. The eastern ISOs were formed from tight power pools where presumably active forward markets had ample time to develop during the power pool regime. In contrast, the California ISO was formed by combining the control areas of three vertically integrated IOUs that primarily used their own units to serve load.

22. Subsequent events in the California market bear out this logic. More than 3,000 MW of incremental capacity (net of unit retirements) has been put into service in the California ISO control area between the winter of 2001 and the summer of 2003.

23. Anjali Sheffrin, *Market Analysis Report*, July 25, 2001, available at http://www.caiso.com/docs/2001/07/26/2001072608203878555.pdf.

24. In the April 19, 2002, MSC comments on the ISO's proposed market power mitigation measures, Wolak, Barber, Bushnell, and Hobbs discuss this 12-month competitiveness index and how it should be used as mechanism for determining consumer harm worthy of regulatory intervention. Frank A. Wolak, Brad Barber, James Bushnell, and Benjamin F. Hobbs, *Comments of the Market Surveillance Committee of the California ISO on the Proposed Oct. 1, 2002 Market Power Mitigation Measures*, April 19, 2002, available at http://www.caiso.com/msc.