Electricity Regulation in California and Input Market Distortions

Mark R. Jacobsen

Azeem M. Shaikh *

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Abstract

We provide an analysis of the soft price cap regulation that occurred in California's electricity market between December 2000 and June 2001. We demonstrate the incentive it created to distort the prices of electricity inputs. After introducing a theoretical model of the incentive, we present empirical data from two important input markets: pollution emissions permits and natural gas. We find substantial evidence that generators manipulated these costs in a way that allowed them to justify bids in excess of the price cap and earn higher rents than they could otherwise. Our analysis suggests that the potential benefits of soft price cap regulation were likely undone by such behavior.

1 Introduction

During the peak of the California electricity crisis, the Federal Energy Regulatory Commission (FERC) implemented a soft price cap in an effort to stem rapidly increasing prices for wholesale electricity. The idea of the soft price cap was to mitigate high electricity prices by only allowing firms to place bids over the cap if they could be justified on cost-based grounds. The intent was to preserve some aspects of the restructured market-pricing in the area under the price cap, while preventing anti-competitive bidding at prices above the cap. We present a brief literature review and discussion of this type of regulation, followed by a theoretical analysis, and finally an empirical discussion of the

*Department of Economics, Stanford University. We would like to thank Tim Bresnahan, Roger Noll, and Frank Wolak for many helpful discussions. All remaining errors are our own.

effects of the price cap on electricity input markets. We find that the effects on input markets are pronounced, and acted to undermine any beneficial effect the soft price cap may have had.

Our model of soft price cap is most closely related to the long-standing literature in regulatory economics that examines the effects of "cost pass through" regulation. The principle focus in this literature is on electric utilities, where the pass through regulation normally concerns the cost of variable inputs. Since cost appears in the electricity rate base, it is easy to see that inefficiencies could arise: Utilities face no direct loss from the over consumption of inputs. Under uncertainty and other conditions (see for example Isaac 1982) strict incentives to over-consume inputs can appear. The soft price cap allows firms to pass through costs on a portion of their bid. Paralleling the argument above, then, the soft price cap could reduce the incentive of firms to minimize costs and may, as we will discuss in some detail below, create an incentive to inflate costs so that profits on total electricity sales can be increased.

The theoretical model we will describe in the first section attempts to represent the soft price cap regulation enacted by FERC in late 2000 for California's electricity market. As we will model, if demand was such that the market clearing price of electricity was below the $150 level FERC set, generators would face the same uniform price auction for electricity established after restructuring. If the market clearing price exceeded $150, however, generators would be paid-as-bid for bids over $150 and would receive the capped level for all other production. For bids over $150, then, the regulation closely resembles a discriminatory auction. The remaining regulatory feature, which is important to our results, is that these bids must be justified in order to avoid orders for refunds.

Our argument proceeds as follows: We first provide a theoretical model of profit-maximizing bidding behavior and find that, under certain conditions on demand, firms will have an incentive to place bids higher than the price cap and higher than their marginal cost. In combination with the fact that such bids need to be cost justified according to the regulation, firms have a strong incentive to deceptively inflate their justifiable costs to the level of their optimal bids. Our central empirical investigation, then, focuses on two important markets for variable inputs into electricity production: Pollution emissions permits and natural gas fuel. We find very strong evidence of inflation in these prices, allowing generators to justify bids much higher than true costs. In our analysis, we are also able to suggest mechanisms through which electricity producers may have manipulated the costs.

2 A Model of Bidding

Suppose a firm has costs of producing q units of electricity equal to $C(q)$ and faces a stochastic residual demand curve $DR(p, \epsilon)$ where the support of ϵ is $\{e_L, e_h\}$. In other words, our model hypothesizes that there are two states of demand, a low state and a high state, corresponding to the events $\{\epsilon = e_L\}$ and $\{\epsilon = e_H\}$, respectively. The random variable ϵ accounts for uncertainty in the inelastically demanded quantity of electricity, which implies that the two realizations of residual demand are simply horizontal translations of one another. The firm must submit an upward-sloping bid function $S(p)$. Its revenues are calculated according to a soft price cap of level p_C as follows: If the market-clearing price $p^* \leq p_C$, the firm is paid p^* for each unit of electricity sold; if, on the other hand, $p^* > p_C$, the firm is paid the greater of p_C and its bid for each unit of electricity sold. Assume further that the price cap is binding in the following sense: The two states of demand are such that the optimal bid without a price cap (i.e., if generators were paid as in a uniform-price auction), passes through points both above and below p_C. By way of notation, define these points to be $(p_L, DR(p_L, e_L))$ and $(p_H, DR(p_H, e_H))$. Finally, we will maintain throughout the following assumptions on residual demand:

A1. $DR'(p, \epsilon) < 0$, $DR''(p, \epsilon) \geq 0$ for all $\epsilon \in \{e_L, e_h\}$ and $p > 0$

A2. $C'(q) > 0$, $C''(q) \geq 0$ for all $q \geq 0$

A3. $DR''(p, \epsilon)p + 2DR'(p, \epsilon) \leq 0$ for all $\epsilon \in \{e_L, e_H\}$ and $p > 0$

A4. $DR^{-1}(0, e_L) > C'(0)$

A5. $-(p_C - C'(DR(p_C, e_H))DR'(p_C, e_H) \leq (DR(p_C, e_H) - DR(p_L, e_L))$

The first and second assumptions above impose standard regularity conditions on the residual demand curve and cost function of the firm. The third assumption above requires that the standard marginal revenue curve of the monopolist facing demand $DR(p, \epsilon)$ is downward sloping. This assumption, together with the fourth assumption, ensures uniqueness and existence of the solution to the standard monopolist's pricing problem. The final assumption provides conditions on the residual demand for which bidding strictly above the price cap, rather than only along the price cap, will be optimal. In particular, it requires that the residual demand curve be either steep enough (i.e., $DR'(p_C, e_H)$ sufficiently close to zero) or high enough (i.e., $DR(p_C, e_H)$ sufficiently large relative to $DR(p_L, e_L)$).

Before calculating the optimal bid of the firm under these conditions, it is worthwhile to note that there already exists ample empirical evidence in support of A5 during the California electricity crisis. Wolak (2003a), for example, has documented the dramatic increase in the quantity of electricity that cleared in California Independent System Operator's real-time electricity market during the electricity crisis. Wolak (2003b) has further demonstrated that during this same period of time elasticities of the residual demand curve for each of the market's five major participants fell sharply in absolute value. As a result, we feel that the assumptions under which we derive our results below are reasonable approximations of the market during this period of time.

We will proceed to calculate the firm's optimal bid under the assumptions above through the following sequence of lemmas. For the sake of continuity, all proofs will be reserved for the Appendix.

Lemma 1: Any optimal bid must be a step function with at most one step. In particular, any optimal bid is composed of two line segments: The first connects the price-quantity pairs $(h_1, 0)$ and $(h_1, DR(h_1, e_L))$, where $p_L \leq h_1 \leq p_H$; the second connects $(h_2, DR(h_1, e_L))$ and $(h_2, DR(h_2, e_H))$, where $h_1 \leq h_2 \leq p_H$.

Figure 1 illustrates a candidate bid curve $S(p)$ as described in Lemma 1. Using this result, it is possible to decompose the profit maximization problem faced by the firm into two parts: In the first stage, the firm chooses the height h_1 at which the first step begins, after which it chooses the height h_2 of the second step subject to the constraint that $h_2 \geq h_1$.

Lemma 2: For h_1 and h_2 as in Lemma 1, $\frac{\partial h_2}{\partial h_1} > 0$ and $h_2 \geq p_C$.

Lemma 2 states that as the firm withholds more supply in the low state of demand (i.e., as the height of the first step, h_1, increases), the firm will decrease its supply in the high state of demand (i.e., the height of the second step, h_2, rises).

In order to state the third lemma, denote by θ_L and $\theta_H = 1 - \theta_L$ the probabilities associated with the events $\{\epsilon = e_L\}$ and $\{\epsilon = e_H\}$ respectively. Denote by π_L and π_H the profits of the firm conditional on these two events. Expected profits π are therefore given by $\theta_L \pi_L + \theta_H \pi_H$.

Lemma 3: For any $\theta_H > 0$, $\frac{\partial \pi}{\partial h_1}$ evaluated at $h_1 = p_L > 0$.

Lemma 3 simply states that so long as the high state of demand occurs with positive probability, the firm's optimal bid will involve some amount of withholding at low prices relative to the world in which there is no price cap. More important for our later analysis is the following implication of Lemma 2 and Lemma 3: Lemma 3 implies that so long as the high state of demand where the price cap is binding occurs with positive probability, a profit-maximizing firm will choose $h_1 > p_L$; Lemma 2 in turn implies that as a result h_2 will optimally be chosen to be greater than p_C.

We can restate this result in words as follows: Under these conditions, a profit-maximizing firm bidding subject to a soft price cap will have a strict incentive to bid in excess of the price cap. If firms are required to justify any bids in excess of the price cap on cost-based grounds, as they were during the California electricity crisis, this incentive will have implications beyond the electricity market for markets that provide inputs into electricity production. In the remainder of the paper, we will present extensive empirical evidence that this incentive led firms to manipulate marginal costs in order to justify profit-maximizing bids in excess of the price cap.

We preview our results below by providing two ways in which firms might have acted on the incentive described above and manipulated the costs of inputs into electricity generation. Suppose, for example, that a firm is allocated or purchases a large number of pollution permits at zero or very low cost. Suppose further that the firm can influence the market-clearing price of pollution permits making it high relative to the value of the permits. Our analysis above suggests that firms could use these high prices in order to justify profit-maximizing bids in excess of the price cap. As another example, suppose that market indices for fuels used in electricity production are computed using self-reported purchases prices for fuel deliveries. Suppose further that a firm can manipulate these indices by reporting high purchase prices without fear of regulatory sanctions. As in the case of pollution permits, our analysis suggests that firms would report higher prices in an effort to drive up market indices, which could then be used to justify profit-maximizing bids above the price cap. We will provide empirical evidence in support of each of these two mechanisms.

3 Input Market Distortions

As suggested, our analysis of the incentive created by the soft price cap will revolve around the markets for two important inputs into electricity generation, NO_X emissions permits and natural gas. As a result, it is worthwhile to first examine the specific way in which natural gas and NO_X permit prices were treated as part of justifiable costs under regulation.

We first consider the components of the \$150 cap. A \$50 portion is attributed to natural gas fuel costs, and is computed using a sample heat rate of

10 MMBtu/MWh and a gas price of \$5 per MMBtu. A further \$40 is added using an emissions permit price of \$40/pound and a sample emissions rate of 1.0 pounds/MWh. The remaining \$60 is allowed for recovery of fixed costs and operation and maintenance. FERC cites the source of the emissions permit price used as the Cantor Fitzgerald Market Index for October of 2000. This index is a weighted average of best current bid, best offer, and recent trades in Cantor's permit auction. Cantor's index was used in lieu of actual permits prices because permits were not purchased by each firm on a continuous basis. The price for natural gas, on the other hand, is taken from Gas Daily, a market index weighted heavily toward the self-reported costs of large gas purchasers. This difference is not inconsequential and will reappear again in our data analysis: The incentive to inflate the costs passed through to electricity prices is the same for both inputs, but the way generators took advantage of this will differ slightly according to the particular index used by FERC.

A series of orders early in 2001 established, at least at that time, FERC's position on what constituted justifiable costs, and created an even clearer incentive of the type we describe: It was decided that a "rate screen" would be set up for each month, establishing justifiable costs for a typical generator. The figure provided by these monthly orders was meant to proxy for the marginal cost of a standardized natural gas electricity generating unit; the final justifiable price would differ by generator according to unit-specific input consumption rates (e.g. heat rates and pollution rates). What is of specific interest here, however, is the direct use of a self-reported gas price index and the monthly market clearing NO_X price in the rate screen. FERC computed these justifiable cost formulas for five months, again using the Cantor Fitzgerald price index to determine NO_X costs and the Gas Daily prices for natural gas. We compile the essential components of these orders into Table 2.

Table 1: Input Prices and Resulting Rate Screens

Month	NO_X Price	Gas Price	Rate
1/2001	22.50	12.50	273.00
2/2001	41.72	19.11	430.00
3/2001	18.00	14.51	300.00
4/2001	33.27	13.83	318.00
5/2001	24.32	11.98	267.00

We will show that the natural gas and emissions permit prices represented above are likely to have been heavily inflated by electricity generators in an effort to capture higher rents, as suggested by our theoretical model.

3.1 NO_X Emissions Market

We begin examination of the data with an analysis of the market for NO_X (nitrous oxides) emissions permits, needed as an input to the production of electricity by three of the largest generators subject to the soft price cap. We provide an overview of the market, describe the conditions in the permit market under which the incentives from Section 1 would apply, and present evidence from emissions trading data.

NO_X emissions in southern California are controlled under the Regional Clean Air Incentives Market (RECLAIM), operated as part of California's compliance with the Clean Air Act. Permits were allocated to 390 sources in the Los Angeles basin at the start of the program in 1993. Each permit is valid in one particular year, with the final vintage valid for use in 2010, and allows one pound of NO_X emissions. Trading among market participants and outside agents is permitted and facilitated by several brokerages. At the end of each compliance year, a firm must hold as many permits as it has emissions on record. The firms were randomly assigned to one of two overlapping compliance years ending in January or June, and permits from the assigned cycle and the next one to end are accepted. This design is intended to alleviate sudden shortages or surpluses at the end of each cycle; other than this overlap, no banking of permits is allowed.

Economic theory on the efficiency of such cap and trade schemes has been well documented (see, for example, Hahn (1989)). In general, if the permit and output markets for RECLAIM participants were both functioning in a competitive manner, the system would reduce emissions to the capped level at the minimum total abatement cost. The price of NO_X permits would reflect the marginal cost of abatement, which would be equalized across all of the firms participating in the market. Furthermore, the price of a NO_X permit would accurately reflect a part of the firm's marginal operating costs, incorporating the emissions price into production decisions. The initial allocation of emissions permits acts as a lump sum payment and would not, absent the distortions discussed here, affect marginal decisions.

The distortion from the competitive benchmark that we consider here is the incentive created by FERC when including marginal permit prices in electricity rates. The mechanism we propose in Section 2 becomes relevant in the permit market as the fraction of permits allocated to the firms at zero cost or purchased at very low cost becomes large: When this is the case, increases in the marginal permit price would mean a higher justifiable bid for electricity generation; firms effectively earn rents on their inframarginal permit holdings. To see this more clearly, consider the counterfactual case in which firms have no inframarginal permits. If this were the case, increasing the price of marginal emissions permits will still increase bids allowed in the electricity market, but only by enough to exactly offset the increase in expenditure on permits.

We now examine empirically the condition that inframarginal permit holdings represent a significant fraction of permits used. In Table 3, these holdings are computed for the three large generators with some or all of their capacity in RECLAIM. Refer to the Appendix for a description of the data and the method used to compute the aggregate permit holdings in the table. The first three lines of data show, by firm, the ratio of pre-electricity crisis permit holdings to actual permits used for the three permit vintages during the crisis. The fraction of generation inside RECLAIM is given on the fourth line. Total inframarginal emissions for each period are then the sum of inframarginal permits held for generation inside RECLAIM and emissions from all generation outside RECLAIM for which permits are not required. On the last line, we provide the emissions-weighted average fraction of inframarginal permits for the whole period.

Table 2: Inframarginal Permit Holdings of RECLAIM Generators

	Firm A	Firm B	Firm C
Valid 6/2000	71%	50%	36%
Valid 12/2000	68%	48%	30%
Valid 6/2001	78%	55%	34%
Inside RECLAIM	100%	49%	19%
Total 6/2000	71%	75%	88%
Total 12/2000	68%	75%	87%
Total 6/2000	78%	78%	87%
Combined Avg.	**74%**	**77%**	**87%**

Notice that the three firms all possessed the majority of their permits before the electricity crisis, soft price cap, and subsequent rise in permit prices. Firms B and C have significant generation outside RECLAIM (for which all emissions would be inframarginal), but also possessed many fewer permits for their units inside RECLAIM before the crisis began. This feature makes their total effective holdings similar to, or in Firm C's case only somewhat higher than, those of Firm A.

Given the large fraction of permits acquired at low cost, large electricity generators stood to gain from an increase in marginal permit prices via the cost-justification it could provide for high bids in the electricity market. And, in a dramatic fashion, permit prices increased during the electricity crisis and period of the soft price cap. Figure 2 shows a sharp increase from prices of only a few dollars a pound to a peak of more than \$50 per pound in January and Febraury of 2001, shortly after the introduction of the soft price cap.

We begin our discussion of manipulation in the permit market with a brief summary of the related literature: The earliest analysis of the permit market in the context of electricity regulation was done as part of the legal proceedings against the non-utility generators. One of the central findings in the testimony is that the RECLAIM market had broken down – that there was no effective price for permits at any one time. The argument continues that electricity producers might have made bilateral trades at very high prices while the true value of permits was much lower. As evidence, they point to the NO_X permit trade data publicly available from the South Coast Air Quality Management District (AQMD) which shows widely different trading prices recorded simultaneously.

Kolstad and Wolak (2003) have recently argued along similar lines, that prices paid by different agents varied, adding that the incentive to inflate permit prices for firms with generation capacity both inside and outside RECLAIM is higher than that for firms only owning generation facilities inside RECLAIM. Recall, however, that the actual inframarginal permit holdings we have computed above would indicate a large incentive for all three large firms. Furthermore, when the soft price cap was in place the opposite incentive might arise: Firms with more capacity inside RECLAIM could use a high NO_X price to justify costs on a larger fraction of their units.

To see the variation in prices that has drawn attention previously, consider the AQMD NO_X trading data shown in Figure 2. The sample includes the period during California's electricity crisis and shows all trades made with positive price during the validity of the permit (recall that at any given moment two overlapping vintages of permits are valid). The trading price is shown on the vertical axis. The horizontal axis displays the AQMD recording date for the transaction. It is easy to see how the conclusion of multiple prices could be reached: Of the 14 trades recorded on March 8, 2001, for example, the price varies between 15 and 50 dollars per pound for identical permits.

The data, however, contain the AQMD recording date but not the actual date the permit deal was made. At the time, the AQMD did not have any requirement for timeliness of filing, so the only deadline would have been the end of the permit year. A combination, then, of slow reporting by firms and clustering of recording by the AQMD on certain days, might explain the appearance of multiple prices for this essentially homogenous good.

To test the hypothesis that the market may have actually been producing a single price signal (which might be expected given the high value and relatively low transaction cost), we look at data from Cantor Fitzgerald, the largest active broker in the market. The data contains price, quantity, and date for 130 sequential trades of 2000/2001 vintage permits. The date is the actual date that Cantor made the deal as part of their continuous permit auction. We recognize that these are only a subset of the actual trades made, but argue that they are important for two reasons: First, the Cantor index was the one used to set the soft price cap and proxy prices, so high priced bilateral trades made outside of the brokerage would be of little use in inflating the price of electricity. And furthermore, the price series shown from Cantor contains almost all of the highest price transactions in the market and the majority of trades made by electricity wholesalers, implying that if market manipulation was taking place it was likely done within the brokerage's auction framework.

Figure 3 presents the Cantor trade data using the actual transaction date. Note that while volatile (the dates of two important crashes in permit price caused by AQMD announcements are indicated) the market appears to provide a single price at any particular moment in time. When these same 130 trades are matched with AQMD data and plotted by recording date instead of actual date, the multiple-price effect appears. Note that the AQMD dates used in Figure 4 distort the transactions such that the crashes and recoveries in permit price are no longer visible; what appears when looking only at recording dates is a market supporting multiple prices simultaneously.

This evidence would then support a different mechanism for the inflation of permit prices than has been considered in previous work. Rather than a breakdown in the price signal, it seems more likely that market power in the permit market was used to inflate permit price. McCann (2003) computes that in some months 90% of permit purchases were from three electricity wholesalers – with this concentration and by timing purchases when supply was short, for example, generators could have rapidly driven up NO_X prices using their market power in permits. Sales of permits into Cantor's auction tended to be from a large number of smaller firms, further contributing to the idea of a workably competitive permit supply with market power in permit demand.[1] While we are able to present detailed empirical support of the incentive to inflate NO_X permit prices, further work remains in verifying the mechanism for price manipulation that we suggest.

3.2 Natural Gas Market

As described above, another important input into the marginal costs of generating electricity is the cost of fuel. California, unlike many other states in the United States, depends heavily on natural gas-powered generating facilities. We posit that prices paid for natural gas by different generators in the state should be comparable, modulo small differences for intrastate transmission charges. Whereas interstate transmission charges for natural gas fall under the regulatory jurisdiction of FERC, rates for intrastate transmission are determined by the California Public Utilities Commission (CPUC). These charges typically account for at most \$0.50/MMBtu of the final price paid for natural gas by end-users.

Ideally, we would like to test for the effect of the incentive created by the soft price cap by comparing receipts for purchases of natural gas by generators subject to the soft price cap regulation and generators who did not have this incentive. Unfortunately, the available data do not permit such a direct comparison. Instead, we compare prices for natural gas collected from industry survey data, similar to those used by FERC in setting the rate screens in the soft price cap, with prices for natural gas deliveries reported to FERC by a group of generators not subject to the incentive.

Before proceeding with our analysis, we describe each of these two sources of data in greater detail. Our first source of data comes from the Energy Intelligence Group (EIG), an energy information service, whose prices are commonly used in energy indices. These data provide for each day a volume-weighted average of self-reported spot market prices for all natural gas transactions at each of several different delivery points in California. These prices are comparable to those from Gas Daily, a competing energy information service, that were used by FERC during the electricity crisis. Our second source of data is FERC Form 423 *Monthly Report of Cost and Quality of Fuels for Electric Plants*. On

[1] The use of market power in permits we propose is contrary to that normally considered. Following Hahn (1984), if permit purchases were concentrated in electricity producers, these producers would have the monopsonist's incentive to under-purchase permits in order to lower the market clearing price. Here, however, the incentive is to use monopsony power to increase marginal permit price.

this form, electric utilities, who notably were not subject to the soft price cap incentive, are required to submit to FERC a detailed summary of fuel deliveries received. For each natural gas purchase, these generators must reveal, among other things, whether the transaction is a spot or contract purchase, the quantity received in MMBtu, and the price per MMBtu. For the purposes of Form 423 and our analysis, spot transactions are defined to be those shipments under purchase orders or contracts of less than 30 days in duration.

Since EIG reports estimates of spot market prices for natural gas, we restrict our attention to purchases made on the spot market by generators filing Form 423. Furthermore, we abstract from geographic effects, such as those stemming from possible congestion along north-south intrastate transmission, by restricting our attention to generators filing Form 423 and located in the NP15 congestion zone in the northern half of the state, as defined by the California Independent System Operator.

There are two features of our data that will shape our subsequent analysis and therefore merit further discussion. First, Form 423 fails to record the specific day each delivery of natural gas is received; it only records the month in which the transaction takes place. This feature of the data prohibits us from comparing natural gas prices across days and forces us instead to somehow aggregate data for each month. Second, whereas the data in Form 423 represent actual purchases of natural gas by electricity generators, this is not true of the data collected by the EIG. Rather, they represent only *potential* prices at which natural gas could be purchased by electricity generators. As a result, these two sets of prices, even after aggregation by month, are not immediately comparable.

In order to make meaningful comparisons from the limited data, we note the following implication of there being no price manipulation and proceed to show that this condition is violated in the data: If the prices paid for deliveries of natural gas by different generators are similar, we would expect the distributions within each month of prices paid for deliveries of natural gas to be similar as well. From the data in Form 423, we can recover for each month in our sample an estimate of the distribution of prices paid for deliveries of natural gas by utility generators, who were not subject to the soft price cap incentive. The distribution of prices reported by EIG, however, may differ from the distribution of prices at which actual purchases were made by non-utility generators to the extent that their purchases were not made uniformly throughout the month. Yet, we would still expect the support of the distribution of prices reported by EIG to contain the support of the distribution of actual purchase prices by utilities. If this were not the case, it would be impossible for the distribution of actual purchases by these two sets of firms to be the same.

The critical piece of information needed for us to construct an estimate of this same distribution for generators subject to the incentive generated by the soft price cap is the identities of the days on which purchases were made by these facilities. But observe that a *necessary* condition for there to exist a set of days which would equate the implied distribution of purchase prices by generators subject to the soft price cap with the estimated distribution of their counterparts filing Form 423 is that the support of the latter distribution be contained in the support of the former distribution.

To test this implication, we compute for each month in our sample period the percentage difference in the minimum price from each of the two sets of data. We compute the same quantity for the maximum price from each of the two sets of data. We use percentage differences instead of absolute differences to help control for any common trend in the two sets of data. These data are displayed in Figure 5. Note that the percentage difference in the maximum prices remains close to zero throughout our sample period. Likewise, before the soft price cap is introduced and after it expires, the percentage differences in the minimum prices remains close to zero. While the soft price cap is in effect, however, the percentage difference between the minimum prices is very large.

A potential concern is that the large differences between the minimums found during these months is being driven by outliers in Form 423. It is possible that the distribution of purchase prices taken from Form 423 places very little probability mass upon the low prices responsible for these observations. To test for this possibility, we non-parametrically estimate for a subset of these months the density of prices paid by generators filing Form 423 using kernel density techniques. For comparison, we juxtapose these estimates with estimates obtained using prices from EIG. A normal kernel is used and the bandwidth is chosen according to Silverman's Rule of Thumb. These results are displayed in Figure 6.

In each of the four months for which we carry out this exercise, it is clear that the estimated densities using the data from Form 423 place large mass on prices much lower than the minimum price found in the EIG data. This observation, together with the percentage differences reported above, suggests that our necessary condition for equality of the distributions of purchase prices across these two sets of generators – those subject to the soft price cap incentive and those not – is strongly rejected during these months. More specifically, we have shown that during this period of time the distribution of purchase prices by generators subject to the incentive created by the soft price cap is located to the right of the distribution of purchase prices by generators not facing this incentive.

Recall that the salient feature of the data collected by EIG is that it is a *self-reported* volume-weighted average of transactions at the delivery point. During this period of time electricity generation accounted for nearly 35 per cent of all natural gas consumption in California, and so reports by electricity generators plausibly influenced these averages by a large amount. Our finding above is therefore consistent with the idea that non-utility generators, in response to the incentive created by the soft price cap, manipulated these self-reports in an effort to increase the marginal costs perceived by FERC without actually incurring them.

4 Conclusion

We present an analytical model of soft price cap regulation during the California Electricity Crisis and demonstrate, under certain assumptions, that the optimal bids of electricity generators will lie above this cap. It is straightforward to verify that market clearing prices, and therefore bids, did indeed lie well above the price cap a substantial fraction of the time. The regulation further stipulates that firms must cost-justify bids over the cap, and we propose they attempted to cost-justify their high bids by artificially increasing prices in two important input markets. Data from the market for NOx emissions permits and the spot market for natural gas provide evidence of substantial input cost inflation, allowing generators to claim higher marginal costs than were actually realized. The mechanism firms used to inflate the cost indices used by FERC differs across the two markets we study, but the source of the incentive is the same and comes out of our analytical model and the features of the regulation.

While regulators unfortunately failed to forsee the problems with the soft price cap, a number of *ex post* complaints alleging permit market and natural gas price manipulation were lodged in April and May of 2001 by the California Independent System Operator, AQMD, and Electricity Oversight Board. As a result, the inclusion of NO_X price in FERC's rate screens and proxy prices was eventually dropped in an order dated June 19, 2001. The use of spot price indices for natural gas was terminated at the same time, and replaced with a broader price index less easily affected by self-reported purchases. While these issues will likely continue in litigation for some time, we believe that the mounting legal evidence against generators with respect to these input markets adds substantial support to the theory and evidence we present above.

While the soft-price cap in California is no longer in force, we think there are valuable lessons to be had from this regulatory experiment. In addition to the failure of pay-as-bid regulation to control electricity prices, highly damaging interactions with input markets, particularly for NOx permits, resulted. The market for NOx emissions in Southern California has been badly crippled, with electricity producers removed from trading altogether and binding caps placed on emissions permit price. Potentially valuable gains in efficiency of pollution reduction were lost due to misguided regulation in the electricity industry.

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5 Appendix

5.1 Proofs for Section 2

Proof of Lemma 1: Note that any supply curve must pass somewhere through $DR(p, \epsilon)$ for each realization of ϵ. Consider the point of intersection with $DR(p, e_L)$. If the point of intersection occurs beneath the price cap, then the shape of the bid curve up until the point of intersection is irrelevant to revenues and thus the firm is indifferent among all possible bids up to that point. If, on the other hand, the point of intersection is above the price cap, then the firm is paid the area underneath its bid curve in both realizations of demand and maximizes its profits by bidding along a straight line up until that point. Having established this, we can argue similarly for the point of intersection with $DR(p, e_H)$. As a result, any optimal bid curve is a step function with at most one step.

The fact that h_1 must be above p_L follows from the definition of p_L and the fact that it is below the price cap. If $h_1 < p_L$, then by bidding instead according to $h_1 = p_L$ and not changing h_2 one could strictly increase profits in the low state of demand and not decrease profits in the high state of demand. Hence, $h_1 \geq p_L$. Similarly, if $h_1 > p_H$, one could increase profits in both states of demand by bidding according to $h_1 = h_2 = p_H$. Since the firm is restricted to submitting upward sloping bids, $h_2 \geq h_1$ by hypothesis. To see that $h_2 \leq p_H$, note that if $h_2 > p_H$, we have a contradiction to the definition of p_H.

Proof of Lemma 2: We first establish that if $h_1 < p_C$, $h_2 \geq p_C$. To see this note that, if $h_2 < p_C$, profits in the high state of demand are calculated as in a uniform-price auction. Yet, assumption A3 and the definition of p_H ensures that at all prices below the p_H, marginal costs exceed marginal revenues. Hence, no $h_2 < p_C$ can be optimal. Therefore, it must be the case that $h_2 \geq p_C$.

Given h_1, h_2 solves the following maximization problem:

$$\max_{\max\{p_C, h_1\} \leq h_2 \leq p_C} [DR(h_2, e_H) - DR(h_1, e_L)]h_2 - C(DR(h_2, e_H)) + C(DR(h_1, e_L))$$

Assuming an interior solution, which is ensured for any $h_1 > p_L$ by A5, the f.o.c. for h_2 is

$$DR'(h_2, e_H)h_2 + DR(h_2, e_H) - DR(h_1, e_L) - C'(DR(h_2, e_H))DR'(h_2, e_H) = 0$$

Using the Implicit Function Theorem, the desired derivative is given by:

$$DR'(h_1, e_L)[DR''(h_2, e_H)h_2 + 2DR'(h_2, e_H) - \\ C''(DR(h_2, e_H))(DR'(h_2, e_H))^2 - C'(DR(h_2, e_H))DR''(h_2, e_h)]^{-1}$$

It follows from A1 - A3 that this expression is strictly positive.

Proof of Lemma 3: Note that $\frac{\partial \pi}{\partial h_1} = \theta_L \frac{\partial \pi_L}{\partial h_1} + \theta_H \frac{\partial \pi_H}{\partial h_1}$. Since $\frac{\partial \pi_L}{\partial h_1} = 0$ when evaluated at $h_1 = p_L$ by definition of p_L, it suffices to show that $\frac{\partial \pi_H}{\partial h_1} > 0$ when evaluated at $h_1 = p_L$. To see this, note that $\pi_H = [DR(h_2, e_H) - DR(h_1, e_L)]h_2 + p_C DR(h_1, e_L) - C(DR(h_2, e_H)$. Hence,

$$\frac{\partial \pi_H}{\partial h_1} = \frac{\partial h_2}{\partial h_1}[DR'(h_2, e_H) + DR(h_2, e_h) - DR(h_1, e_L) - \\ C'(DR(h_2, e_H))DR'(h_2, e_H)] - DR'(h_1, e_L)h_2 + p_C DR'(h_1, e_L)$$

It follows from the Envelope Theorem for h_2 that the bracketed term in this last expression vanishes. As a result, the derivative is simply $-DR'(h_1, e_L)h_2 + p_C DR'(h_2, e_L) > 0$.

5.2 Permit Holdings Data

The dataset recording NO_X emissions trades is publicly available through the South Coast Air Quality Management District (SCAQMD). According to SCAQMD, the dataset lists all of the permit transactions made during the program. The source of the data is either internal accounting (for initial allocations of permits, for example) or through the recording of details on the form submitted when two parties transfer permits from one to the other.

Throughout the dataset, the accounting of permits held and records of each transfer are coded according to a firm-source ID. Note that each ID is associated with a single pollution source, but that each source can have multiple ID's. This happened, for example, during the divestiture of electricity generators. Many divested sources were assigned a new ID, and the permits from the old ID were typically transferred. In cases where permits remained in more than one account assigned to a particular source, we assume that all permits for that source were valid for emissions. In addition to the parties involved in each permit transfer, the data include quantity and type of permits transferred, a SCAQMD recording date, and the price written on the form by the parties involved.

There are a number of serious shortcomings in this dataset, most related to the prices and trading dates that are reported. The recording date issue is discussed in some detail in the text of the paper, while the price issues are simply related to the non-binding nature of reported prices: The forms submitted to SCAQMD officially transfer the permits from one account to another, but the financial considerations are handled through brokerages or separate contracts meaning reported prices do not necessarily reflect actual payments. Further price reporting complications arise when permits of multiple vintages are traded simultaneously, meaning individual prices by vintage may not even be computed by the parties involved in the package trade, nevermind correctly reported. A final concern that has been noted by several others using the data is that many transactions are made with a zero or arbitrarily fixed price, perhaps involving a transfer to a brokerage and then back to the firm (likely indicating a failed attempt to sell permits) or transfers among sources for a particular firm. In our paper, we are able to abstract from the price variable and instead use aggregate measures of permit holdings, which we argue are less susceptible to the problems in the data. Note that the problems resulting from offsetting trades at arbitrary or zero prices appearing from a failed deal with a brokerage will simply cancel out in our analysis.

Each transaction in the dataset actually appears as a pair, once with a positive quantity value for the firm receiving the emissions permits, and once with a matching negative value for the source of the permits. In many cases the source or destination for the permits is SCAQMD, coded with ID 999999. The most common reasons for this are initial allocations (INIT_ALLOC), adjustments to allocations (ADJ_ALLOC), and audit deductions (AUDIT_DEDU). In cases where the permits are traded between agents, the coding is either CERTIF (presumably meaning certificates), or ALLOC (emissions allocations). When a brokerage sells permits to a firm, for example, the brokerage receives a negative entry for its stock of CERTIF, and the firm receives a credit for that number of emissions allocations. For trades made directly from firm to firm, both the reduction for one firm and the credit for the other are coded as ALLOC.

For the analysis, we are interested in the total quantity of permits held by a firm before the price spike (initial allocations, adjustments, and purchases) relative to the final holdings of the firm for that vintage. To the extent that SCAQMD has accurately recorded the quantities of permits moved from one entity to another, these figures are relatively straightforward to compute. We simply calculate the cumulative total number of permits of a particular vintage transferred to and from each source, and compare it with the total holdings before the price spike. The cumulative total usually includes, chronologically, a substantial initial allocation, some adjustments and audit items, and then a series of credits and debits as the firm trades permits to other firms or brokerages. In the case where a new ID has been assigned, there is no initial allocation, but instead a large transfer from the original ID assigned to that source followed by the usual series of permit trades.

The inaccuracy of the reporting date for permit trades makes it difficult to determine the proper cutoff to use for the beginning of the price spike. In order to ensure that the permits held before the cutoff are either part of initial allocations or purchased at low cost, we conservatively choose June 1, 2000 to divide the data. The true ratio of permits held before the spike could therefore be even higher than we have reported.

A number of concerns still remain, however, primarily related to possible emissions overruns and side-arrangements made with the SCAQMD. The individuality of these arrangements combined with the difficulty of obtaining complete documentation makes it difficult to do a truly comprehensive accounting. The evidence we do have, however, is very strongly supportive of our assertion that the majority of emissions permits used by electricity generators were held before the price increase.

Figure 1: Candidate Optimal Bid with Price Cap

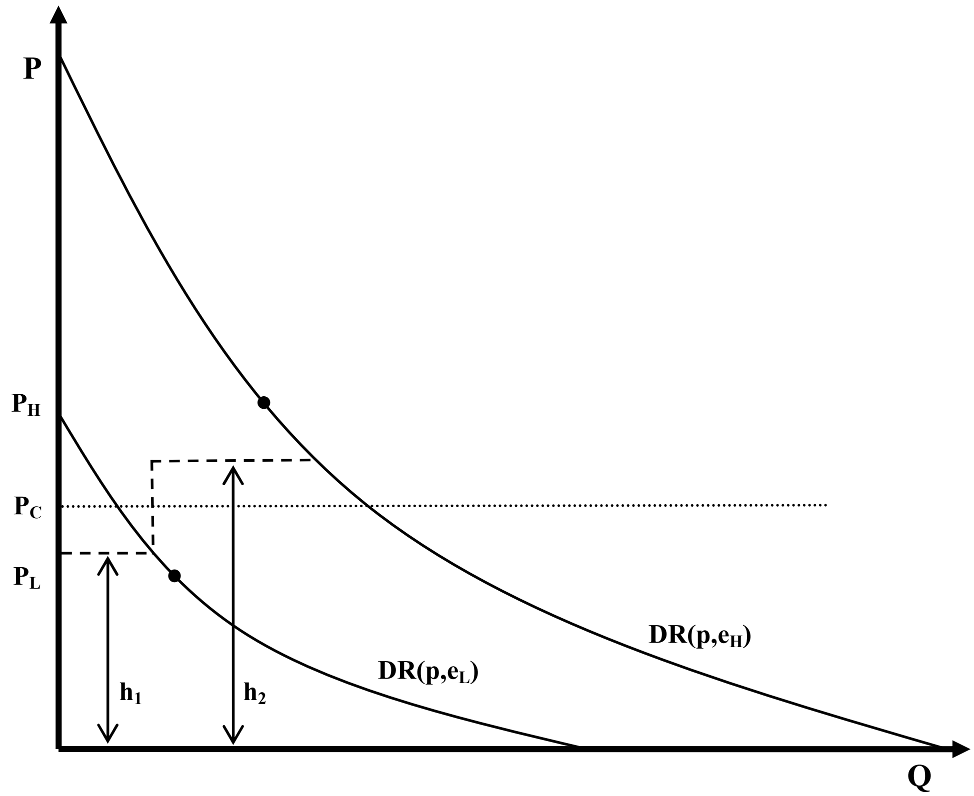

Figure 2: NOx Prices by Recording Date

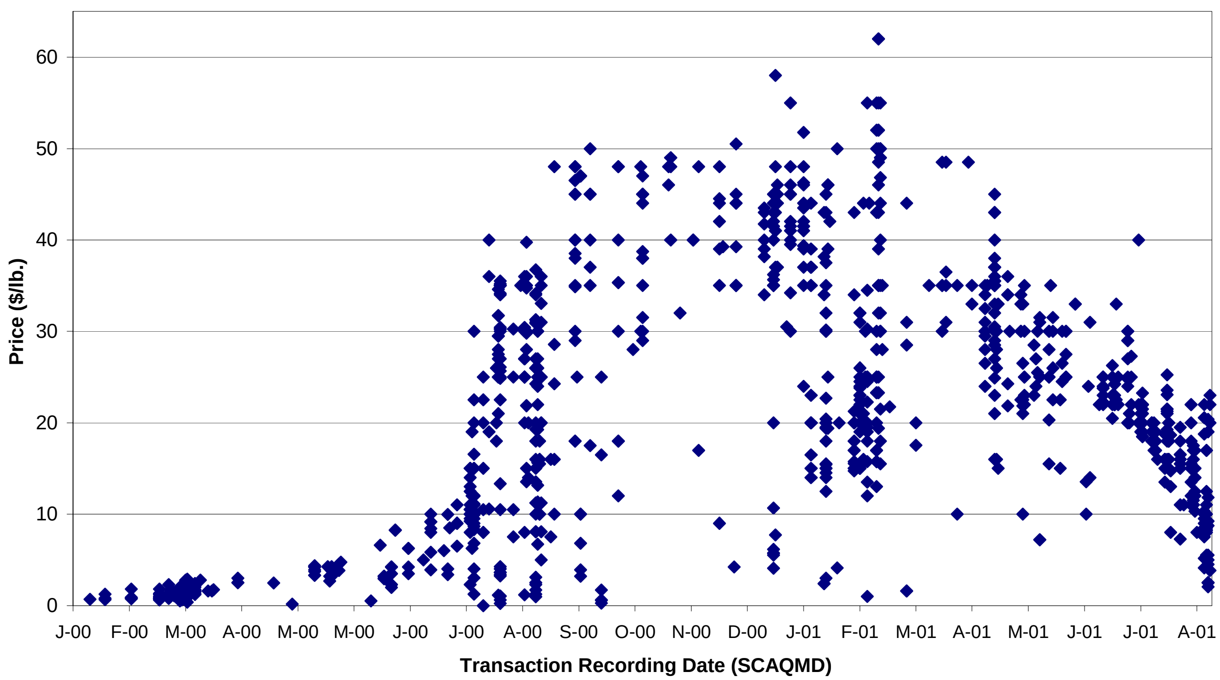

Figure 3: Cantor Trades of 2000/2001 Vintage NOx Permits

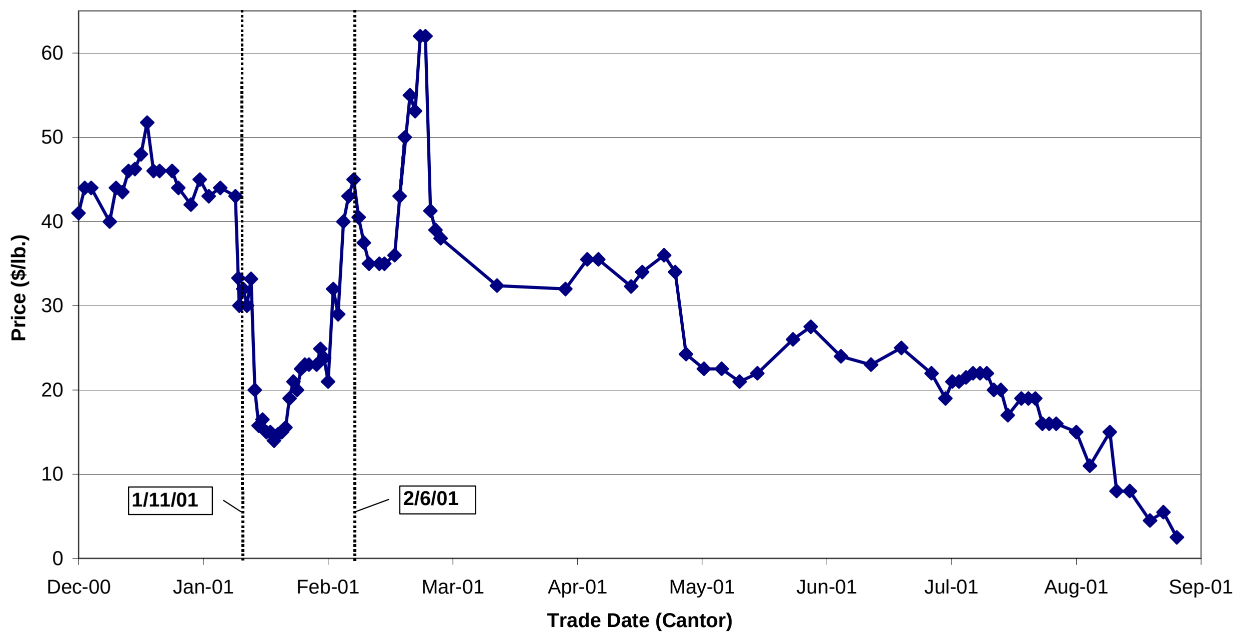

Figure 4: Same Cantor Trades, Using AQMD Reporting Dates

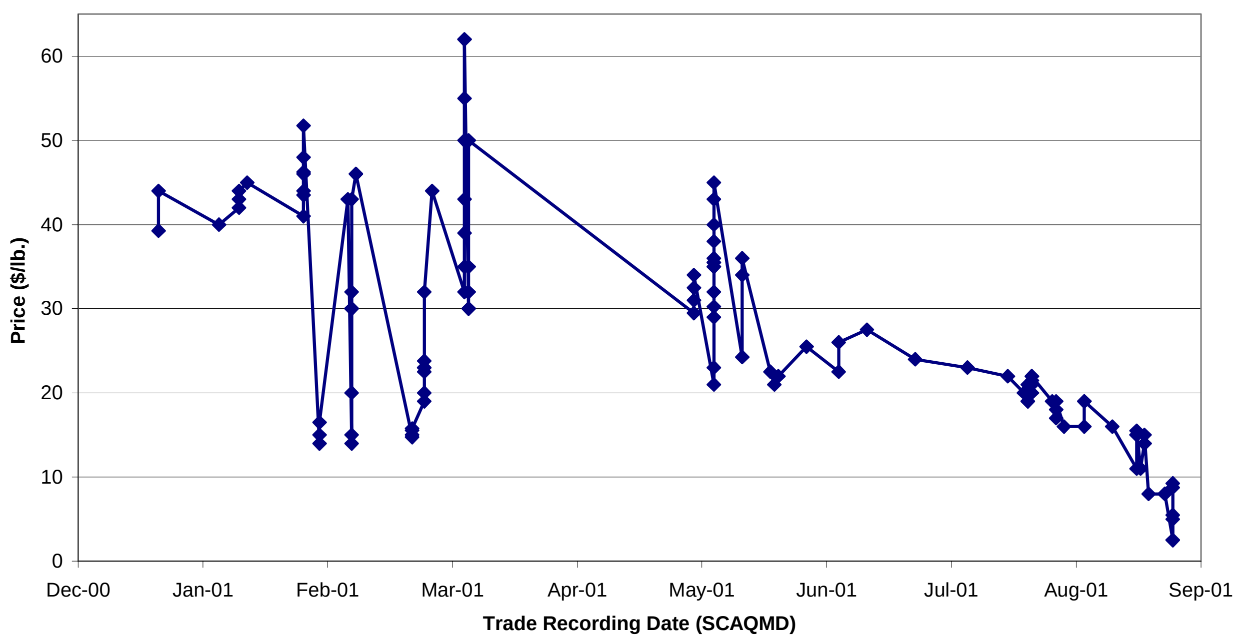

Figure 5: Percent Differences (Relative to Form 423) of Min and Max of Supports

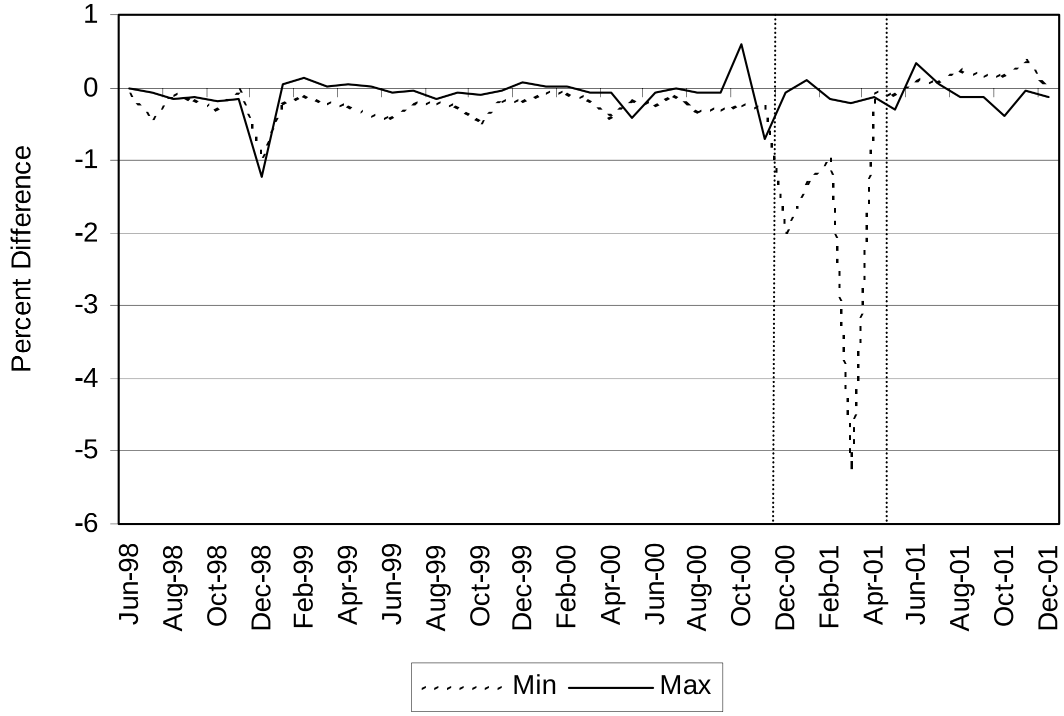

Figure 6: Density Estimates of Natural Gas Prices