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Abstract

This paper analyzes the extent to which the conditions in the emissions permit market for oxides of nitrogen (NOx) operated by the South Coast Air Quality Management District (SCAQMD) in the Los Angeles metropolitan area interacted with competitive conditions in the California electricity market to enhance the ability of electricity suppliers with some or all of their generation units located in SCAQMD to exercise unilateral market power. We present evidence consistent with the view that NOx emissions permits were a convenient vehicle for enhancing the ability of suppliers to exercise unilateral market power in the California electricity market. We find that generation unit owners with some of their plants located in the SCAQMD paid statistically significantly higher prices for 2000 and 2001 NOx emissions permits than other participants in the SCAQMD emissions market, despite the fact the prices they paid for 1998 and 1999 vintage permits were no different from other SCAQMD participants. We then present evidence consistent with the view that wholesale electricity suppliers did not operate and bid their generation units requiring NOx emissions permits in a manner consistent with higher emission permit prices being a cause of increased production costs. Taken together, this evidence suggests that NOx emission permit prices during 2000 and 2001 were primarily used by these generation unit owners to cost-justify higher bids into the California electricity market that would set higher prices for all electricity they produced.

1. Introduction

The purpose of this paper is to analyze the extent to which the conditions in the emissions permit market for oxides of nitrogen (NOx) operated by the South Coast Air Quality Management District (SCAQMD) in the Los Angeles metropolitan area interacted with competitive conditions in the California electricity market to enhance the ability of electricity suppliers with some or all of their generation units located in SCAQMD to exercise unilateral market power. Several studies have demonstrated that NOx emission permit prices could be significant factor contributing to increased fossil-fuel-based electricity production costs, and therefore substantially higher wholesale electricity prices, during the third and fourth quarters of 2000 (see Joskow and Kahn (2002) and Borenstein, Bushnell and Wolak (2002), hereafter BBW). These studies do not address the question of whether the substantially higher average NOx permit prices during this time period were the result of other factors besides an increase in the demand for permits. For units located in the SCAQMD region, these studies treat the prices paid for NOx emission permits multiplied by the rate at which NOx emissions occur per MWh of electricity produced by the generation unit as part of its variable costs of production. This assumption implies that emissions permit costs should therefore impact the operating and bidding behavior of generation units located in the SCAQMD region in the same manner as input fuel price changes.

We explore the validity of an alternative explanation for the behavior of NOx emission permit prices during the third and fourth quarters of 2000 and the operating and bidding behavior of generation units located in the SCAQMD region. We present evidence consistent with the view that NOx emissions permits were a convenient vehicle for enhancing the ability of suppliers to exercise unilateral market power in the California electricity market. We find that generation unit owners with some of their plants located in the SCAQMD paid statistically significantly higher prices for 2000 and 2001 NOx emissions permits than other participants in the SCAQMD emissions market, despite the fact the prices they paid for 1998 and 1999 vintage permits were no different from other SCAQMD participants. We then present evidence consistent with the view that wholesale electricity suppliers did not operate and bid their generation units requiring NOx emissions permits in a manner consistent with higher emission permit prices being a cause of increased production costs. Taken together, this evidence suggests that NOx emission permit prices during 2000 and 2001 were primarily used by these generation unit owners to cost-justify higher bids into the California electricity market that would set higher prices for all electricity they produced.

This analysis proceeds in three stages. We first analyze the behavior of NOx emission permit prices in the SCAQMD area from 1997, the year before the California wholesale market began operation to mid-2001, when all market participants and state and federal regulators generally agreed that the NOx emissions permit market was effectively suspended for electricity generation facilities. This analysis divides SCAQMD market participants into five groups: (1) generation unit owners with all of their units located in the SCAQMD region, (2) generation unit owners with some of their units located in the SCAQMD region, (3) generation unit owners with all of their units located outside of the SCAQMD region, (4) investor-owned utilities, and (5) all other market participants. After controlling these differences in purchasers of NOx emissions permits, we find that firms with some of their units located in the SCAQMD region and others located outside the region paid substantially higher prices for 2000 and 2001 vintage permits than other SCAQMD market participants, even though the prices they paid for other vintages of NOx permits were no different than those paid by other market participants. Controlling for the date of these transactions in the regression relating the NOx price to the identity of the purchaser does not alter this empirical result.

The second stage assesses the extent to which NOx prices are treated as actual production costs by generation unit owners in the SCAQMD region. To do this, we compare the hourly generation unit-level output of the 92 fossil fuel units used in BBW to the expected (over the 100 Monte Carlo simulations) hourly output of each of these units from the BBW benchmark pricing simulations that treat the sum the following three components: (1) NOx emission costs (the generation unit's NOx emissions rate times the NOx emissions price if the unit is located in SCAQMD), (2) fuel costs (the generation unit's heat rate times the price of the input fossil fuel), and

(3) variable operating and maintenance costs as the actual variable costs of production of the unit. We find that even after controlling for generation unit-level fixed effects, the difference between the actual hourly output of the unit and the expected hourly output from the BBW benchmark pricing algorithm is substantially higher for units located in the SCAQMD region in 2000 relative to 1999 and 1998. Regressions that added the level of NOx emissions costs (the unit level NOx rate times the NOx emissions price for units in SCAQMD) found units with higher NOx emissions costs had systematic larger values of difference between actual hourly production and the level production from the BBW benchmark pricing in 2000 relative to 1998 and 1999. These results imply that even though unit owners in the SCAQMD faced substantially higher NOx emissions costs in 2000 relative to 1998 and 1999, these units were run far more intensively relative to the levels that would have been predicted from the BBW competitive benchmark pricing dispatch algorithm that assumes these NOx emission costs are part of a unit's actual variable costs of production.

Our third line of inquiry builds on the results in Wolak (2003), which quantifies changes in the firm-level incentive of the five large wholesale electricity generation unit owners in California–AES/Williams, Duke, Dynegy, Mirant and Reliant–to exercise unilateral market power in California Independent System Operator's (CAISO) real-time market from 1998 to 2000. Wolak (2003) argues that expected profit-maximizing bidding behavior in the CAISO real-time energy market will result in the hourly real-time price, P_h, less the marginal cost of the highest cost unit in supplier j's portfolio of units operating in hour h, MC_{jh}, and the elasticity of the residual demand curve facing firm j during hour h evaluated at hourly market price, ϵ_{hj}, satisfying the following equation:

$$(P_h - MC_{jh})/P_h = -1/\epsilon_{hj}. \tag{1}$$

where $\epsilon_{hj} = DR_{jh}'(P_h)\,(P_h / DR_{jh}(P_h))$ and $DR_{jh}(P_h)$ is the residual demand curve facing supplier j during hour h. Using the bids submitting to the CAISO's real-time energy market by all electricity market participants besides supplier j, Wolak (2003) computes the average value of $-1/\epsilon_{hj}$ for each year and for each of the five large merchant generation owners in the CAISO control in order to quantify differences in the extent to which supplier j is able to raise market prices in excess of MC_{jh}

across the first three years of operation of the California market. In this paper, we use equation (1) to compute a behavioral estimate of the value of MC_{jh}. Specifically, we use the assumption of expected profit-maximizing behavior on an hourly basis implicit in equation (1) to recover an estimate of MC_{jh} as follows:

$$MC_{jh} = P_h\,(1+ 1/\epsilon_{hj}). \tag{2}$$

We then relate this hourly value of MC_{jh} to the unit-level fuel cost (heat rate times the price of the input fuel) and unit-level NOx emissions permit costs (the units NOx rate times the NOx emission permit price) for the highest cost unit owned by supplier j operating during hour h. The regression of this implied MC_{jh} on fuel costs and NOx permit costs yields the coefficients on unit-level fuel costs for each firm that are statistically insignificantly different from one for all five suppliers, which is consistent with the view that fuel costs are an actual variable cost of producing electricity. In contrast, the coefficients on NOx emissions permit costs are jointly statistically significantly less than from one for all suppliers with units in SCAQMD, consistent with the logic that NOx emissions permit costs do not have as direct an impact on the variable cost of producing electricity as input fuel costs.

These three sets of results cast doubt on the validity of a maintained assumption in much of the analysis of the costs of California electricity crisis, which is that NOx emissions permit costs were a significant component of the variable cost of producing electricity during the crisis period for units located in the SCAQMD. Instead, these results argue in favor of excluding substantial fraction or all NOx emission permit costs from the variable cost of units in the SCAQMD region when computing the competitive benchmark prices necessary to determine the magnitude of unilateral market power exercised during the California crisis period.

Our results also underscore the importance of coordinating the design of any environmental market with the resulting product markets that cause these emissions, otherwise design flaws in one market can allow firms to leverage these market inefficiencies to other markets. In the final section of the paper we provide some recommendations for dealing with this issue.

The remainder of the paper proceeds as follows. In the next section we describe the important institutional details of the SCAQMD NOx emissions permit market. We also present a number of summary statistics on the behavior of permit prices, the number of transactions and average transaction volume over time and across vintages. Section 3 describes the interactions between the California electricity market and SCAQMD NOx emissions permit market. Specifically, we outline how NOx emissions permits might be used by suppliers with units located in SCAQMD to enhance their ability to exercise unilateral market power in the California electricity market. Section 4 describes the data used and motivates the econometric models estimated for the three lines of empirical inquiry summarized above. This section also describes our empirical results and performs some limited sensitivity analysis. Section 5 states our conclusions and some caveats associated with them. It also suggests directions for future research.

2. The South Coast Air Quality Management District and the RECLAIM Market

The South Coast Air Quality Management District (SCAQMD) is the regulatory agency in charge of controlling air pollution throughout the Los Angeles Basin. The SCAQMD region includes Los Angeles, portions of San Bernadino, Orange and Riverside counties (see Figure 1 below). The challenge facing SCAQMD is to ratchet down emissions of criteric pollutants in the Los Angeles Basin, particularly Nitrogen Oxides (NOx). One component of this effort is the Regional Clean Air Incentive Market (RECLAIM). The RECLAIM market began operation in 1994. Included in this market are any firms in the jurisdiction of SCAQMD emitting more than 4 tons of NOx and/or SOx annually. Certain “essential public services”, such as public transit, fire stations, and landfills are exempted from this market and remain under command and control regulation of their NOx and/or SOx emissions.

The market began with 390 participants and this number eventually fell to the current level of 364 by way of entry and exit from the program (some facilities reduced their emissions beyond the scope of RECLAIM’s jurisdiction and others moved their facilities outside the SCAQMD). Each actor in the market receives an allocation of RECLAIM Trading Credits (RTCs). Each RTC is the equivalent of one pound of emissions in a given year (the vintage of the RTC). These vintages are for one year from a start date determined by the "cycle" in which a firm is randomly placed. Cycle 1 lasts from January 1 to December 31 of the same year whereas Cycle 2 is the period from July 1 of the vintage year to June 30 of the following year. Firms are assigned to one of these cycles at random. RECLAIM market participants can trade RTCs for either cycle to obtain the RTCs to cover their NOx emissions. The cycle assignment of a firm determines the time at which it must rationalize its emissions with the RTCs it holds for that year. This must be done either as of December 31 or June 31 of the year depending on the assignment. The rationale behind the cycle system was to facilitate the creation of a liquid market and to reduce large price swings as all facilities near the end of their compliance period at the same time. We present evidence below that suggests these goals may not have been obtained in 2000.

Each firm in RECLAIM receives an allocation of RTCs of different vintages which may be traded. The allocation level for the initial vintage year was determined based on historical emissions levels. Specifically, firms were allowed to set baseline levels on the basis of actual emissions in one of the years between 1989 and 1992, in what some observers of the RECLAIM market have called a concession necessitated by the political climate of the early 1990s recession years. These annual allocations were then reduced at facility specific rates until they reached desired 2003 SCAQMD emissions levels. These rates of allocation reduction are based on the relative control that each industry would have necessitated under the SCAQMD air quality management plan that existed prior to RECLAIM.

The total quantity of RTC allocations was to be reduced from these initial allocations at an annual rate of 8.3% until 2003 (Coy et al., 2001). Given the initial allocations and rates of reduction achieved over time, the total allocations of RTCs to all RECLAIM firms was larger than the actual emissions level until 1999. Figure 2, taken from Coy et al. (2001), shows the time pattern of annual allocations of RTCs and annual amount of emissions produced.

The most dramatic emissions reductions were demanded by SCAQMD from electricity generating facility and oil refineries. Initially the allocation of RTCs to these two industries was 56% of NOx RTC allocations. The NOx RTC allowance for power plants was to be reduced by 81%

by 2003 relative to their initial allocation and refineries were given an allowance in 2003 that is 67% lower than their initial allotment (Coy et al. 2001, p. 10). A key issue to note here is that these changes in allocations do not actually reflect the necessary reductions that firms in these two industries had to make. As mentioned earlier, the initial allocations of RTCs may have been too generous. Because initial RTC allocations were set so high relative NOx emission levels at the start of the RECLAIM market, these two industries had to make reductions in emissions of 67% for power plants and about 48% for refineries by 2003 (Coy et al 2001, p. 10).

In the three months following any RTC trading period (Cycle 1 or 2 in any year) a firm must rationalize all of its emissions with the required number of emissions permits. If a firm emits more than their initial allocation level they have two choices. First, they can reduce their emissions by installing the necessary emission reduction technology using a number of technologies available. Coy et al. (2001) describes a number of these technologies. The other option available, and the only one available in the short term, is to purchase RTCs from other actors in the RECLAIM market. In theory, the ability to trade RTCs allows all RECLAIM entities to achieve the aggregate emissions level mandated by SCAQMD at a significantly smaller cost than command and control methods. This occurs because firms with the lowest marginal cost of pollution reduction will select to do so given the opportunity cost of holding on to RTCs (the resale value of their RTC assets if they implement emissions reduction technology).

Trades to obtain the necessary RTCs fall into one of three categories: (1) intercompany trades, (2) trades involving non-RECLAIM facilities and (3) intracompany trades usually across facilities (Burnside and Eichenbaum 1996). Trades can either be directly negotiated or can flow through one of the two major brokers that handle RECLAIM transactions: Cantor Fitzgerald and the Pacific Stock Exchange.

The RECLAIM market appears to have behaved in a distinctly different manner prior to 2000 and 2001. These differences are consistent with the fact before 2000, it was unlikely that generation unit owners could use RTC permit prices to enhance their ability to exercise market power in the California electricity market. It simply would not have been credible to argue that NOx emissions permits were worth anything substantial given the difference between the total allocation of RTCs and the amount used in all years before 2000 shown in Figure 2. In contrast, for 2000 and 2001, supplier could very credibly to argue that the constraint on NOx emissions permits in SCAQMD was indeed binding so that RTCs of these two vintages would have be of significant value to electricity generation unit owners.

The price increase for the 2000 and 2001 vintage RTCs that occurred starting in 2000 is dramatic. Both annual mean prices and monthly transaction volume weighted average prices show dramatic increases in 2000 and 2001 (see Figures 3 and 4). For example a vintage 2000 RTC traded in 1999 had an average price of \$2.25 per lb of NOx compared to \$21.11 in 2000 and \$23.19 in 2001.

Because most participants in the RECLAIM market that do not primarily generate and sell wholesale electricity face substantial competition for their output from firms located outside of SCAQMD we would expect them to have strong incentive purchase additional RTC permits beyond their initial allocation at the lowest price possible during 2000. In contrast, wholesale electricity generators may want to raise RTC permit prices to enable them to cost justify higher bids to supply electricity during this same time period. These divergent incentives facing RTC permit buyers during 2000 could show up in an increased variance in transactions prices during this time period. Figure 5 shows that the standard deviation of RTC transaction prices for 2000 and 2001 vintage permits increased substantially in 2000. The timing of this increase in variability of transactions prices lends strong support to the view that wholesale electricity suppliers owning facilities both inside and outside of the SCAQMD faced the opposite incentive from other buyers in the RECLAIM market during this period when RTCs could be used to raise wholesale electricity prices in California.

If we assume that RTCs were used to cost justify higher bids into wholesale electricity market for small amount of additional electricity that would set the market-clearing price for the entire state of California or the SP15 congestion zone, we would expect generation owner to purchase the smallest quantities possible to be able to cost justify the higher bid price for electricity rather than buying large quantities of RTCs at these inflated prices. Comparing average transactions volumes for 2000 and 2001 vintage RTCs, we find a dramatic drop in the average transaction size in 2000 and 2001 relative to previous years. Figures 6 shows the decrease in average transaction volume which is consistent with our hypothesis for how NOx emission permits were used by generation unit owners in 2000. Figure 7 shows additional logic consistent with this strategy, because the number of RTC transactions of these two vintages also increased significantly in 2000. By 2001 the average number of RTCs per transaction had fallen to 11,900 from a peak, in 1998, of 134,000.

The figures presented above argue against the view that the market for 2000 and 2001 vintage RTCs was liquid in the sense that large quantities of RTCs could be bought and sold without causing large changes in the price of RTCs of these vintages. These figure argue in favor of the view that the market for RTCs is extremely thin and that had any generation unit owner or other market participant attempted to sell a substantial fraction of their initial RTC allocation during 2000, this would have lowered the prices of RTC permits of these vintages to the levels that existed in previous years.

3. The RECLAIM Market and California's Restructured Electricity Market

Several features of the California electricity market are crucial to understanding how generation unit owners might use the RECLAIM permit market to enhance their ability to raise wholesale electricity prices. This section describe those features of the California electricity market. We then briefly summarize the performance of the California electricity market from April 1, 1998 until the winter of 2001 and how the events in the electricity market impacted events in the RECLAIM market. This discussion will provide context for our subsequent analysis of the behavior of RECLAIM permit purchase prices in 2000 and 2001 relative to 1997 to1999, and the impact these RECLAIM prices had on how generation units owners decided to operate generation units and bid them into the CAISO's real-time energy market.

3.1. Market Structure and Market Rules in California Electricity Market

California's generation capacity is largely gas-fired. According to the California Energy Commission (2001) more than 50% of the capacity in California is oil or natural gas-fired steam and combustion turbine facilities, with all but a few peaker generation units being natural gas-fired. Of these gas-fired units, roughly 60% are under the jurisdiction of the SCAQMD and, as such, are included in the RECLAIM market. Many of these facilities have very high heat rates, which puts them at upper end of a state-wide marginal cost curve computed based on input fuel costs and variable operating and maintenance costs. If the price of RECLAIM permits is nonzero then more units inside SCAQMD could be at the upper end of the statewide marginal cost curve because they might need to incorporate the price of emissions permits into their operating costs in order to produce more electricity than their initial RTC allocation will allow. Because there is considerable disparity in NOx emissions rates across units within the RECLAIM area, with some emitting 0.10 lbs of NOx per MWh of energy produced and others emitting more than 5 lbs of NOx per MWh of energy produced, increases in NOx emissions prices can alter least cost dispatch of generation units in the SCAQMD. For example, suppose the natural gas-fired unit with a NOx rate of 0.10 lbs/MWh has a higher heat rate than the unit with a NOx rate of 5 lbs/MWh. If the price of RECLAIM permits is high enough then a least cost dispatch would require the higher heat rate unit to be dispatched in instead of the lower heat rate unit.

A second important feature of the California market is that for all hours in our sample period, California set a market-clearing prices for electricity over geographic areas larger than the area covered by the SCAQMD emissions market. For the vast majority of hours there was a single state-wide price, but when there was transmission congestion across northern and southern California, separate market prices were set for these two geographic regions, called the south of Path 15 (SP15) and north of Path 15 (NP15) congestion zones. On February 1, 2000 a third congestion zone was added in southern California called the ZP26 congestion zone. The SP15 congestion zone as of February 1, 2000 for the CAISO control area is still significantly larger and contains much more gas-fired generation capacity than the geographic region covered by SCAQMD.

For this reason, a wholesale supplier with units located both in and outside of the SCAQMD service territory may have an incentive to bid up the price of NOx permits in order to increase the apparent production costs of a permit-using unit that it expects will set the market-clearing price of electricity for the entire state or the SP15 congestion zone that contains SCAQMD. There are a number of merchant power producers in California that own generation units both in and outside of SCAQMD. The logic underlying this strategy is illustrated in Figure 8, which plots the systemwide marginal cost curve with zero RECLAIM permit prices and the systemwide marginal curve with positive RECLAIM prices. There are two sources of increased profits that result from higher RECLAIM prices. The first is the increased profits earned by generation units that do not have NOx costs, because they are not located in the RECLAIM area but are still paid the market-clearing price. This is the area labeled "Additional profits to units without NOx costs" in Figure 8. The second source of increased profits associated with higher RECLAIM prices result from the fact that marginal costs increase much more for a given dollar increase in RECLAIM prices for units with higher NOx emissions rate. In the example in Figure 8, the marginal costs of the highest cost generation unit operating increases by twice as much as the variable cost of the other unit with NOx emission costs because it has a NOx emissions rate that is half the value of the highest cost unit operating. This unit earns the area labeled "Additional profits to unit with lower NOx emissions rate" as a result of the increase in the NOx price.

The logic in Figure 8 also shows why a supplier with all of its units located in SCAQMD might still want to increase the price of NOx permits if these units have significantly different NOx emissions rates. Figure 9 plots the cumulative distribution by generation capacity of NOx emissions rates within the SCAQMD region. If, as is the case for several California wholesale suppliers, the firm has generation capacity at the low end and high end of this NOx emissions rate distribution, the strategy outlined above may be profitable. Even if the supplier had to pay the permit price in order to produce any electricity from its units, if the price of electricity was set by the unit with the highest variable cost of production (including NOx emission permit purchases), the supplier would earn additional profits on all of its units with lower NOx rates because any RECLAIM permit price is multiplied by a lower NOx rate in computing the variable cost of the units owned by this supplier. Consequently, these variable costs would not increase by as much as the market-clearing price, which is set by the supplier's unit with the highest combination of NOx emissions rates and heat rates. Moreover, as noted above, for high enough RTC prices, the unit with highest variable cost unit is the one with the highest NOx emissions rate.

Regardless of the RTC purchasing strategy of electricity a supplier with some or all of their units located in SCAQMD, we would expect that as the price of NOx permits rises all firms interested in raising electricity prices would withhold lower cost units from the market in order to make it more likely that their high cost units (that include very high NOx permit costs) would set the price received by all of their units. Consequently, one implication of higher NOx permit prices in a non-competitive electricity market is a bias in favor of operating high NOx permit cost plants in order to raise market prices. In contrast, in a competitive electricity market, we would expect that competition among generators to serve demand would lead to high NOx emissions cost units being dispatched less frequently given their competitive disadvantage relative to other generation units.

Section 4 of the paper uses RTC transactions data from the RECLAIM market on the price paid, quantity purchased, buyer identity and seller identity along with data on generation unit-level bidding behavior in the California Independent System Operator's (ISO) real-time energy market and data on the hourly output of generation units to investigate the validity of the hypothesis that suppliers with some or all of the their units located in the SCAQMD region used the RTC market to raise the price of wholesale electricity.

3.2. Enabling Initial Conditions in California Electricity Market

The successful use of RTC permit prices to raise wholesale electricity prices requires a number of initial conditions in the California electricity market. Specifically, without market conditions that made it unilaterally profitable for suppliers to withhold power from the California market, either through bidding significantly in excess of the variable costs of supplying electricity from their generation units or refusing to supply electricity from their units at any price, it would have been much more difficult to use RTC permits in the manner we hypothesize.

Had the day-ahead and real-time California electricity markets been workably competitive, with a sufficient number of suppliers able to provide the CAISO control area's incremental day-ahead and real-time electricity needs at all locations within SCAQMD and the rest of California, suppliers required to purchase RTCs to produce electricity would find themselves at a competitive disadvantage relative to other suppliers in the CAISO control area. This would lead to their units being dispatched much less frequently than units that did not have to purchase RTCs. Moreover, those units with the highest NOx emissions rates would be at the greatest disadvantage relative to other suppliers with units in SCAQMD and would be dispatched only when the demand for electricity in SCAQMD or in California is extremely high. Because suppliers requiring RTCs to produce electricity are at such a cost disadvantage in a workably competitive wholesale electricity, they would have extremely strong incentives to pay as little as possible for NOx emissions permits, precisely the opposite incentive they face in market where suppliers have the ability to exercise a substantial amount of unilateral market power.

Wolak (2003) uses the bids submitted by all market participants to CAISO's real-time energy market to show that the amount of unilateral market power exercised by the five large generation unit owners was substantially higher during 2000 relative to 1998 and 1999. BBW estimate the magnitude of systemwide market power exercised in the California electricity market from June 1998 to October 2000. They find a substantial increase in the aggregate amount of market power exercised beginning in May of 2000. Figure 3 of BBW finds that relationship between the hourly value of the Market Level Lerner Index, $MLL_h = (P_h - PB_h)/P_h$ (where PB_h is the expected value of the BBW competitive benchmark price for hour h) and hourly quantity of electricity produced by all of the fossil fuel units located in CAISO control area is stable across the summers of 1998, 1999 and 2000. For all three summers, there is a monotonically increasing relationship between the hourly value of MLL_h and the hourly amount of electricity produced by within-CAISO-control-area generation units. BBW demonstrate that a major reason for the substantially larger amount of market power exercised during the summer of 2000 relative to the summers of 1998 and 1999 is that there were many more hours when a substantial fraction of fossil fuel generation capacity within the

CAISO control area was needed to meet the state's demand for electricity. Specifically, for the summers of 1998 and 1999, during roughly 50 percent of the hours the amount of energy produced from these units was greater than or equal to 5000 MWh. For the summer of 2000, during roughly 50 percent of the hours the amount of energy produced from these units was greater than or equal to 10,000 MWh. As BBW note this increase in the intensity of use of the within-CAISO-control-area fossil-fuel capacity during the summer of 2000 was primarily due to a substantial decline in the availability of imports. The average hourly value of imports in 2000 was roughly half the level of hourly imports during 1998 and 1999.

The results in Wolak (2003) and BBW are consistent with the view that the lower import availability in 2000 relative to 1999 and 1998 created substantially less elastic residual demand curves for all of five large suppliers to the California electricity market. This made it unilaterally profit-maximizing for these suppliers and other suppliers to withhold capacity from the California electricity market in order to exploit these less elastic residual demand curves during the summer of 2000. Wolak (2003) argues that these simultaneous unilateral actions by all market participants led to the enormous increase in the amount of market power exercised in the California electricity market documented in BBW.

The enormous increase in the extent of market power exercised in the California during the summer of 2000 created a difficult public relations problem for generation unit owners in the California electricity market. Although natural gas prices during the summer of 2000 were slightly higher than those during the summers of 1998 and 1999, it was extremely difficult to explain the enormous increase in electricity prices in California that occurred starting in May 2000. Figure 10 plots the average hourly price in each of the three CAISO congestion zones for each month from April 1998 to December 2000. Consequently, one interpretation of the behavior of prices for 2000 and 2001 vintage RTC permits is that they provided a mechanism for cost-justifying substantially higher bids into the day-ahead and real-time electricity markets in California for those units located in the SCAQMD. Comparing Figure 10 to Figure 11, we can see that the increase in electricity prices during the summer of 2000 that started in May 2000 roughly coincides with the increase in

NOx emissions permit prices. However, even after accounting for NOx emission permit prices shown in Figure 11 in their competitive benchmark price computations, BBW find an enormous increase in the amount of market power exercised in the California electricity market beginning in May 2000.

We now turn to our analysis of the extent to which the increase in NOx emissions prices described in Section 2 and summarized in Figure 11 was used to cost justify higher bids into the California electricity market and therefore increase wholesale electricity prices during the summer of 2000. As noted in Section 2, there are number of factors which suggest that the increased average prices for the 2000 and 2001 vintage RTCs during 2000 were not treated as actual increases in the cost of producing electricity by generation units located in the SCAQMD during the summer 2000. Specifically, the enormous increase in the standard deviation of transactions prices for vintage 2000 and 2001 permits during 2000 and 2001 suggests that some buyers of RTCs were not interested in finding the lowest possible price for these permits.

4. Evidence that RTC Permits Were Used to Raise Wholesale Electricity Prices

This section is divided into three parts, each of which contributes evidence in favor of the conclusion that the RECLAIM NOx emission permit market was used by suppliers with some or all of their units located in SCAQMD to enhance their ability to exercise market power in the California electricity market. We present evidence that suppliers with some or all of their generation units located in SCAQMD paid systematically higher prices for vintage 2000 and 2001 RTC permits than other RECLAIM market participants. We then compute the difference between the actual unit-level hourly output and the unit-level expected hourly output value that results from the BBW competitive benchmark-pricing Monte Carlo simulations for each hour from June 1998 to December 2000. We find that the hourly value of this difference is substantially higher in 2000 (relative to 1998 and 1999)for units located in SCAQMD relative to other fossil fuel units in the CAISO control area. Moreover, we find that this hourly difference in 2000 is higher for units in SCAQMD with higher NOx emissions rates, implying that units with higher emission rates are run relatively more intensively relative to the amount they would be operated had there been a workably competitive wholesale electricity market in California during the summer of 2000. Finally, we use the results of Wolak (2003) to recover hourly estimates of the marginal cost of the highest cost unit operating owned by each of the five large generation unit owners in the California electricity market. We find that consistent with fuel costs being an actual expense incurred to produce electricity, higher values of this marginal cost estimate are directly associated with higher values for the unit's heat rate time the price of natural gas. However, for units located in SCAQMD, after controlling for the impact of input fuel price changes, we find a substantially less direct relationship between this implied marginal cost and the unit's NOx emissions rate times the relevant emissions permit price taken from BBW.

4.1. RTC Transactions Prices and Buyer Identity

This section presents the results of our analysis of the price paid for all RTC transactions with positive prices that occurred for permits with vintages from 1997 to 2001. We also excluded all transactions the occurred after June 1, 2001 for the reasons discussed in Section 2. This yields a total 1,792 transactions. We focus our analysis on these vintages rather than include earlier ones because we believe it was unlikely that participants in the RECLAIM market thought the wholesale electricity market in California would begin operation before January 1, 1997. In fact, there was only transaction in the RECLAIM market by wholesale suppliers of an RTC vintages earlier than 1998.

To present our regression results, define the following notation:

ln(P(t)) = natural logarithm of the price paid for a NOx permit for transaction t.

Wholesale(t) = an indicator variable that equals 1if the parent company of the buyer for transaction t is a non-utility owner of generation units in the CAISO control area

Utility(t) = an indicator variable that equals 1 if the parent company of the buyer for transaction t is one of the three California investor-owned utilities

AQMD(t) = an indicator variable that equals 1 if all of the units owned by the parent company of the buyer for transaction t are located in SCAQMD

InOut(t) = an indicator variable that equals 1if some of the units owned by the parent company of the buyer for transaction t are located in SCAQMD, and others are not

Out(t) = an indicator variable that equals 1if all the units owned by the parent company of the buyer for transaction t are located outside of SCAQMD

Year(J,t) = an indicator variable that equals 1if J is the vintage year of the RTC permit for transaction t

TransYear(J,t) = an indicator variable that equals 1 if J is the year that transaction t occurred.

According to our interpretation of SCAQMD records the wholesale electricity suppliers with all of their units in the region during our sample period are AES/Williams and Themo Ecotech. Suppliers with some of their units in the region are Dynegy and Reliant. Duke and Mirant do not own units located in the SCAQMD region.

Table 1 reports the results from estimating the following regression

$$\begin{aligned} \ln(p(t)) = \alpha_0 + \sum_{J=1998}^{2001} \delta_J\, Year(J,t) + \beta_1 Wholesale(t)*AQMD(t) + \beta_2 Wholesale(t)*InOut(t) \\ + \beta_3 Wholesale(t)*Out(t) + \beta_4 Utility(t) + \gamma_{00} Wholesale(t)*AQMD(t)*Year(00,t) \\ + \gamma_{01} Wholesale(t)*AQMD(t)*Year(01,t) + \lambda_{00} Wholesale(t)*InOut(t)*Year(00,t) \\ + \lambda_{01} Wholesale(t)*InOut(t)*Year(01,t) + \eta_{00} Utility(t)*Year(00,t) \\ + \eta_{01} Utility(t)*Year(01,t) + \delta_{01} Wholesale(t)*Out(t)*year(01,t) + \epsilon_t \end{aligned} \tag{3}$$

Consistent with our hypothesis, the estimates of γ_{00}, γ_{01} and λ_{00} and λ_{01} are all positive, and all but the estimate of γ_{00} are statistically significantly different from zero. Moreover, we find that the joint null hypothesis H: $\beta_1 = \beta_2 = \beta_3 = \beta_4 = 0$ cannot be rejected. These two results imply that after controlling for the vintages of permits being purchased in transaction t, none of the four types of market participants paid higher average prices for 1997, 1998 and 1999 vintage RTC permits. For 2000 and 2001 vintage RTC permits, wholesale electricity suppliers with some or all of their plants located in the SCAQMD district paid higher average prices for RTC permits than all other RECLAIM market participants. Although they are only marginally statistically significantly different from zero, the point estimates of η_{00} and η_{01} are negative, indicating that the three

California investor-owned utilities paid lower prices for 2000 and 2001 vintage RTC permits than did other RECLAIM market participants.

One possible explanation for these results could be a composition effect associated with the date the RTC permits were purchased. For this reason we expanded regression to include seven transaction year indicator variables, TransYear(J,t) for J=1995 to 2001. Table 2 reports the results of this regression. Although the transactions year indicator variables for 2000 and 2001 are estimated to be very large and positive, the estimates of γ_{00} , γ_{01} and λ_{00} and λ_{01} are all positive, different from Table 1, only λ_{00} and λ_{01} are statistically significantly different from zero. The joint null hypothesis H: $\beta_1 = \beta_2 = \beta_3 = \beta_4 = 0$ still cannot be rejected. The point estimates of η_{00} and η_{01} are now positive, but not jointly statistically significantly different from zero.

The results in Tables 1 and 2 show that wholesale suppliers with some units in the SCAQMD and others outside paid on average from 21% to 27% higher prices for 2000 vintage RTCs and from 25% to 30% higher prices for 2001 vintage RTCs than all other RTC market participants. The corresponding ranges for suppliers with all of their units in the SCAQMD region are from 11% to 17% higher for 2000 vintage RTCs and from 13% to 31% higher for 2001 vintage RTCs, although these results are not estimated with same statistical precision as those for the InOut suppliers.

4.2. The Impact of RECLAIM Market on Generation Unit Hourly Production

This section uses the actual hourly generation unit-level output from the CAISO settlement data and the expected hourly generation unit-level output that results from the BBW competitive benchmark pricing Monte Carlo simulation to assess the impact of RECLAIM emissions prices on the production decisions of all suppliers in the CAISO control.

The objective of this analysis is to compare how fossil fuel units located in the CAISO control area operated on an hourly basis to how they would have operated had no California suppliers been able to exercise unilateral market power. The BBW competitive benchmark analysis solves for price and unit-level output quantities that would result from all suppliers in the California ISO control area behaving as if they had no ability to influence prices through their bidding or scheduling behavior. To account for the fact that the vector of hourly unit-level of outputs from all fossil fuel generation units in California is a realization from the joint distribution of unit-level availabilities all for fossil fuel units in California, BBW uses information from the National Electricity Reliability Council (NERC) to construct a joint distribution of unit-level availabilities. For each hour in the sample, BBW then draw 100 realizations from this joint distribution of unit-level availabilities and compute the competitive benchmark price that results. The hourly competitive benchmark price reported in BBW (2002) is the average of these benchmark prices over the 100 realizations from the joint distribution of unit-level availabilities. Computing the competitive benchmark price without accounting for the possibility of unit-level outages will tend to produce a competitive benchmark price that is too low and yield a unit-level output mix that over-uses low cost generation units relative to what is technologically feasible given the variables cost of all units in the CAISO control area. This issue is particularly important for present analysis. Consequently, for each hour from June 1, 1998 to December 31, 2000, we compute the average unit-level output from each competitive benchmark price realizations for each of the 100 draws from the joint distribution of unit-level availabilities.

Define the following notation:

$\mathbf{OUT\_ACT_{hj}}$ = Actual output in MWh of unit j during hour h,

$\mathbf{OUT\_BBW_{hj}}$ = Mean output in MWh of unit j during hour h from the BBW benchmark pricing procedure, and

$\mathbf{y_{hj}} = OUT\_ACT_{hj} - OUT\_BBW_{hj}$.

As shown in Figure 6 of BBW, the actual California market price is set by the intersection of the import supply curve with the aggregate willingness supply curve of within-control-area fossil fuel generation unit owners. Consequently, under the counterfactual scenario that all within-control-area suppliers behave as if they have no ability to influence the market price through their bidding or scheduling decision, the more aggressive bidding (a higher willingness to supply output at the same price), expensive imports will be replaced by within-control-area supply. For purposes of computing the competitive benchmark price, BBW assume that the total demand in the CAISO control area is unchanged. Therefore, competitive benchmark pricing substitutes more aggressively supplied within-the-CAISO control area electricity for more expensive imports. Therefore, the net result is more aggressive bidding of California suppliers under the competitive benchmark pricing with a larger amount of total supply from these units. This is why the average value y_{hj} is negative.

If suppliers with units located in SCAQMD perceive RTC permit costs as actual production costs we would expect that when RTC permit prices increase, those firms with the highest NOx emissions costs–(NOx Emissions Rate)*(NOx Emissions Price)–would operate less frequently. The BBW competitive benchmark pricing process accounts for this fact by specifying that the marginal cost of unit j during day d is equal to

$$\begin{aligned} MC_{jd} &= \text{(Variable Operating and Maintenance Costs for Unit j)} \\ &+ \text{(Heat Rate for Unit j in MWh/MMBTU)*(Price of Input Fuel in day d in \$/MMBTU)} \quad (4) \\ &+ \text{(NOx Emissions Rate in lbs of NOx/MWh)*(NOx Emissions Price \$/lb of NOx).} \end{aligned}$$

This implies that as the price of RTC permits increases units located in SCAQMD will be dispatched less frequently, because they are more expensive to operate.

The goal of the analysis reported below is to determine the extent to which actual plant operation was consistent with high NOx emission prices increasing the expense of operating units in the SCAQMD region, even though, as noted above, under the BBW competitive benchmark pricing scenario we know that fossil-fuel units located in the California ISO control area, including SCAQMD, would on average have to produce more output during each hour. This is particularly true during hours when prices in California reflect the greatest amount of market power. As shown in Figure 3 of BBW, these tend to be the hours when the amount of energy produced by the fossil fuel units located in the CAISO control area is the greatest.

The specific hypothesis we investigate is whether units owned by suppliers with some or all of their units located in SCAQMD produced more electricity relative to the amount that would be produced under the BBW competitive benchmark pricing assuming NOx emissions costs are actual variable costs of production. We use two approaches to investigate this hypothesis. The first uses only the identity of the unit owner and location of the unit and the second also adds information on the NOx emissions costs of the units.

Introducing the two regressions we run requires the following additional notation:

$\mathbf{InGen_{hj}}$ = Indicator variable that equals 1 if unit j is owned by a wholesale supplier that has plants in the SCAQMD only

$\mathbf{InOutGen_{hj}}$ = Indicator variable that equals 1 if unit is owned by a firm that has plants in and outside of SCAQMD and unit is located in SQAQMD

$\mathbf{OutGen_{hj}}$ = Indicator variable that equals 1 if unit is owned by a firm that has plants in and outside of SCAQMD and unit is located out of SCAQMD

$\mathbf{Year(J)_h}$ = Indicator variable that equals 1 if hour h is in year J, for J=1998, 1999, and 2000

$\mathbf{Month(M)_h}$ = Dummy variable that equals 1 if hour h is in month M, M=1,2,...,12

We estimate the following regression for h=1,...,H, where H is the total number of hours from June 1, 1998 to December 31, 2000, and j=1,...,92, the total number of fossil fuel units in California.

$$\begin{aligned} y_{hj} = \alpha_j &+ \sum_{J=1999}^{2000} \delta_J YEAR(J)_h + \sum_{M=2}^{12} \gamma_M MONTH(M)_h + \sum_{J=1999}^{2000} \eta_J OUTGEN_{hj} * YEAR(J)_h \\ &+ \sum_{J=1999}^{2000} \beta_J INGEN_{hj} * YEAR(J)_h + \sum_{J=1999}^{2000} \lambda_J INOUTGEN_{hj} * YEAR(J)_h + \epsilon_{hj} \end{aligned} \tag{5}$$

where α_j is generation unit fixed effect. Table 3 presents the regression results. We find that relative to 1998, wholesale producers with some or all of the their units in SCAQMD ran their units more intensively relative to the levels predicted by a dispatch based on competitive benchmark pricing in 1999 and 2000 relative to 1998. The coefficients estimates for $INGEN_{hj}$, $INOUTGEN_{hj}$ and $OUTGEN_{hj}$ for 2000 are uniformly about twice the magnitude of the corresponding coefficients for 1999, indicating that these units were run relatively more intensively in 2000.

The results in Table 3 are consistent with the following logic. All fossil fuel units owned by other suppliers in the CAISO control area outside of the SCAQMD region were run less intensively relative to the levels that would occur under competitive benchmark pricing. The units owned by suppliers with some or all of their units located in SCAQMD ran their units more intensively relative to the levels that would occur under competitive benchmark pricing and therefore had a greater likelihood of setting high electricity prices with bids that account for the increased RTC permit prices in 2000.

To investigate whether high perceived NOx costs predicted increased deviations in actual hourly unit-level output from the hourly output levels implied by competitive benchmark pricing including NOx costs, we estimated this same regression including the following additional variables,

$$InGen_{jh}*Year(J)_h*(NOxRate_j*NOxPrice_h) \text{ and}$$

$$InOutGen_{jh}*Year(J)_h*(NOxRate_j*NOxPrice_h),$$

where

$NOxRate_j$ = the rate at which pounds of NO_x emissions are produced per MWh of electricity produced

$NOxPrice_h$ = price of NO_x emissions permits in hour h.

These results are given in Table 4. The coefficients on both of these variables are positive and large relative to their standard errors for 1999 and 2000. This result is consistent with the view that units with higher NOx emissions costs were run more intensively that would be justified based on a least-cost competitive benchmark pricing dispatch that included NOx emission costs as a variable cost of production for units located in SCAQMD.

We also estimated each of these regressions separately for each year, which prevents us from estimating unit-level fixed effects. These results are given in Table 5 and largely consistent with the pooled results that include unit-level fixed effects.

The results in Tables 3-5 suggest that fossil fuel unit owners in the CAISO control area significantly distorted their production decisions in order to increase the likelihood that units with high NOx emissions rates would set statewide or zonal market-clearing prices during a larger number of hours of the year during 2000. This logic is consistent with the discussion in Section 3 of Figure 8 about how generation unit owners with some or all of their units located in the SCAQMD region might use NOx emission permit prices to enhance their ability to exercise unilateral market power in the California electricity market.

These results suggest that California fossil fuel unit owners withheld supply from low cost units that would be used more intensively under a competitive benchmark pricing dispatch in order to operate units that were thought to have higher operating costs, because they were thought to require the purchase of RECLAIM permits to produce electricity. The higher perceived costs for these units allowed suppliers to bid higher prices for electricity supplied from these units. If this bid was accepted, these units would set the price for the entire CAISO control area or if there was transmission congestion, the price for the SP15 congestion zone.

4.3. Implied Marginal Costs and NOx Emission Permit Costs

This section provides further evidence in favor of the use of NOx permits as mechanism to raise electricity prices by examining the bidding behavior of the five merchant power producers during the period June 1 to September 30 for each year from 1998 to 2000. The specific hypothesis we examine is whether or not these firms behaved as if their marginal cost of supplying electricity to the CAISO's real-time energy market included RTC emissions permit costs.

This is accomplished by regressing an estimate of the marginal cost of the highest cost unit in operating during hour h in supplier j's portfolio of units on the two factor thought to determine this marginal cost: (1) input fuel costs and (2) the RTC emission permit costs.

The logic underlying this analysis is discussed in detail in Wolak (2003). This paper argues that an expected profit-maximizing bidder in the CAISO real-time energy market would submit a bid supply curve such that regardless of the realization of its residual demand curve, the bid supply curve the firm submits would always cross this residual demand curve at a point that satisfies the equation

$$(P_h - MC_{jh})/P_h = -1/\epsilon_{hj}. \tag{6}$$

where $\epsilon_{hj} = DR_{jh}'(P_h)\,(P_h / DR_{jh}(P_h))$ and $DR_{jh}(P_h)$ is the residual demand curve facing supplier j during hour h, and P_h is CAISO real-time price for hour h. This implies ϵ_{hj} is the elasticity of the actual residual demand curve faced by supplier j during hour h. This residual demand curve is equal to the aggregate demand for electricity from the CAISO's real-time market during hour h, QN_h, minus $SO_{hj}(p)$, which is the aggregate willingness to supply electricity of all CAISO market participants besides firm j.

In this paper, we use equation (6) to compute the estimate of the value of MC_{jh} implied by expected profit-maximizing bidding behavior in the CAISO real-time market. Specifically, we apply equation (6) to recover an estimate of MC_{jh} as follows:

$$IMC_{jh} = P_h\,(1+ 1/\epsilon_{hj}), \tag{7}$$

where we write IMC_{jh} to denote the fact that this marginal cost estimate is based purely on the bids submitted by other market participants besides firm j and the market clearing price for hour h. We use the method described in Wolak (2003) to compute the value of elasticity of the residual demand curve at the hourly market-clearing price using the hourly bids into the CAISO's real-time market submitted by all other market participants besides supplier j.

Equation (4) in Section 4.2 also gives an expression for MC_{jh} in terms the product of the unit's heat rate and the price natural gas and the unit's NOx emission rate and the price of RTC permits. This logic suggests estimating the following regression:

$$\begin{aligned} IMC_{hj} = \alpha &+ \sum_{k=1}^{4} \delta_k FIRM(k)_j + \sum_{k=1}^{5} \beta_k HR(k)_{hj} * GAS_h * FIRM(k)_j \\ &+ \sum_{k=1}^{3} \lambda_k NOXR(k)_{jh} * NOXP_h * FIRM(k)_j + \epsilon_{hj} \end{aligned} \tag{8}$$

where the variables are defined as follows:

FIRM(k)$_j$ = indicator variable equal to 1 if j equals k and zero otherwise

HR$_{kh}$ = the heat rate in MMBTU/MWh of the highest cost unit operating in hour h owned by supplier k

GAS$_h$ = price of natural gas in hour h

NOxRATE$_{kh}$ = the NOx emissions rate of the highest cost unit operating in hour h owned by supplier k

NOxPRICE$_h$ = RTC NOx emissions permit price for hour h

We use the daily unit-level natural gas price series and the monthly volume weighted average NOx emission permit price series used in BBW to compute the GAS_h and $NOxPRICE_h$. Figure 11 plots this monthly NOx emission price series.

We determine the identity of the highest variable cost unit operating in hour h from supplier k using the following algorithm. For each hour during our sample period and each of the five suppliers, we have the values of MC_h for each of the units owned by supplier k computed using equation (4) from Section 4.2. Call EMC_{nkh} the estimate of marginal cost of unit n owned by supplier k during hour h. Using CAISO settlement data, we find all units owned by supplier k that produced a nonzero amount electricity during that hour. Among those units we find the one with the highest value of EMC_{nkh}. The heat rate and NOx emissions rate (if applicable) for this unit are the values of HR_{kh} and $NOxRATE_{kh}$ for supplier k for hour h. If the highest cost unit operating during hour h is not in SCAQMD we set $NOxRATE_{kh}$ equal to zero.

Under the null hypothesis that the five suppliers bid to maximize the expected value of their hourly profits from selling in the CAISO's real-time energy market treating both input fuel costs and RTC emission permit costs as variable costs of production, the true values of the β_i (i=1,..,5) should be 1 and the true values of the λ_i (I=1,2,3) should be 1. There are only three λ's because only three of the five large fossil fuel generation unit owners have plants located in the SCAQMD region. They are AES/William, Dynegy and Reliant. The other two large generation unit owners are Duke and Mirant.

Table 6 presents the results of estimating equation (8) over our sample period of June 1 to September 30 of 1998, 1999 and 2000. We select this sample period, because as shown in BBW, this is the time of year when suppliers have the greatest opportunities to exercise unilateral market power. For the same reasons as Wolak (2003), we restrict our sample to hours when a single statewide price was set in the CAISO real-time market. Because firms have little ability to raise prices during hours when the residual demand for their output in the ISO's real-time energy market is negative, we also exclude these observations. Because the real-time market is a market where imbalances are bought and sold, this simply means that the supplier is buying back electricity previously scheduled for delivery in the day-ahead or hour-ahead CAISO scheduling process.

For the case of fuel costs, the point estimates of the all of the β_i (i=1,..,5) are not statistically significantly different from 1. Specifically the size α=0.05 Wald test of the joint null hypothesis H: β_i =1 for (i=1,...,5) cannot be rejected. Substantially different results are obtained for NOx emission permit costs. The size α=0.05 Wald test of the joint null hypothesis that H: λ_i =1 for (i=1,2,3) can be rejected. Moreover, the point estimates of all of the values of λ are less than one and less than the point estimate of β for the same supplier. Because all of the result are qualitatively similar across the five β_i and three values of λ_i, we only reports estimates by the firm number, and not the firm name. To preserve anonymity, the numbers used for fuel costs do not correspond to the number used for NOx emissions permit costs. The bottom of this table presents the results estimating this model assuming all of the β_i are equal and all of the λ_i. These results confirm our conclusion that fuel costs enter the regression equation with a coefficient of 1 and NOx emission costs enter with a value significantly less than one.

Because of a concern that our results were driven by low price observations, where the value of the elasticity of the residual demand curve may be very large so that the implied estimate of the MC_{jh} according to equation (4) is effectively equal to the hourly value of the real-time clearing price, we imposed a further sample selection criterion of only using hours with market price above \$20/MWh. This eliminated roughly 2/3 of the observations from the sample, but gave quantitatively similar results. These estimates are given in Table 7.

We believe the results in Table 6 and 7 provide strong evidence that NOx emissions permit costs were not treated in the same manner as input fuel costs in determining the supplier's variable costs used to compute their expected profit-maximizing bidding strategy into the CAISO's real-time market. Combined with the evidence presented in Sections 4.1 on the significantly higher purchase prices of 2000 and 2001 vintage NOx permits by suppliers with some or all of their units located in the SCAQMD and the reduced average transactions volumes during this period suggests that prices where used to justify higher bids into the California electricity market, but were not treated as actual costs of production on equal footing with input fuel cost changes. The deviations in hourly plant operation behavior relative the competitive benchmark suggests that unit owners were successful at raising wholesale electricity prices by bidding high prices from units located in the SCAQMD region during the 2000. These unit ran more frequently than would be predicted by competitive benchmark dispatch in 2000. Moreover, as NOx emission price rose, these units were dispatched for even more electricity relative to what would occur under a competitive benchmark pricing dispatch treating NOx emissions costs as an production cost.

5. Conclusions, Caveats and Directions for Future Research

Although our results are far from conclusive, they are strongly suggest that NOx emission prices were used by suppliers during 2000 to enhance their ability to exercise market power in the California electricity market. The evidence presented on the NOx emission permit purchase prices, generation unit operating decisions and the bidding behavior of suppliers in the CAISO's real-time market are with the view that the prices of RECLAIM permits were used to raise the prices in California electricity market.

Although there are number of caveats associated with our results, one seems worth mentioning as topic for future research. One reason for high NOx cost units to operate more than would be necessary according to the BBW competitive benchmark pricing dispatch algorithm is because transmission constraints require these units to operate to provide local reliability energy. Consequently, in future work we plan to account for the amount of reliability must-run (RMR)energy required from each of the RMR contract units in the CAISO control area during each hour. In this case we would modify y_{hj} to be the difference between the unit's actual hourly output and the maximum of the BBW benchmark pricing dispatch expected hourly output and the required amount of RMR energy from that unit during that hour.

There are number of features of the RECLAIM market that allowed suppliers to use RTC prices in this manner. In particular, the paid-as bid nature of transactions allowed suppliers interest in raising RECLAIM transactions prices to do so without impacting the prices paid by RTC buyers wanting to keep their purchase prices down. The enormous increase in the standard deviation of transactions prices for 2000 and 2001 vintage permits during 2000 is evidence in favor of this design flaw in the RECLAIM market. This experience argues in favor of periodic trading of RTC permits though an anonymous mechanism using a market-clearing price mechanism. This is another topic for future research.

A final topic for future research is an analysis of the actual use of RTC permits during 2000 and 2001. Given our hypothesis, one might expect that some of the RTC permits might have gone unused during 2000. Determine how many RTC permits each supplier ultimately obtained and compare this to the amount of emissions they produced would be a worthwhile.

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Table 1: NOx Emission Price Prediction Based Given Buyer Characteristics

Dependent Variable = Natural Logarithm of Transaction Price for RTC NOx Emissions Permit		
Variable	Parameter Estimate	Standard Error
Intercept	-1.378	0.044
Wholesale*AQMD	0.099	0.111
Wholesale*InOut	0.104	0.107
Wholesale*Out	0.230	0.280
Utility	-0.437	0.059
Year98	0.489	0.057
Year99	1.097	0.054
Year00	2.171	0.054
Year01	2.281	0.057
Wholesale*AQMD*Year00	0.172	0.136
Wholesale*AQMD*Year01	0.310	0.144
Wholesale*InOut*Year00	0.271	0.120
Wholesale*InOut*Year01	0.298	0.129
Wholesale*Out*Year01	0.091	0.376
Utility*Year00	-0.149	0.092
Utility*Year01	-0.203	0.096
Number of Observations = 1,792		$R^2 = 0.71$

Table 2: NOx Emission Price Prediction Based Given Buyer Characteristics and Transactions Date

Dependent Variable = Natural Logarithm of Transaction Price for RTC NOx Emissions Permit		
Variable	Parameter Estimate	Standard Error
Intercept	-1.407	0.066
Wholesale*AQMD	-0.036	0.076
Wholesale*InOut	-0.018	0.074
Wholesale*Out	0.017	0.192
Year98	0.347	0.043
Year99	0.696	0.043
Year00	1.264	0.045
Year01	1.286	0.046
TransYear95	0.313	0.077
TransYear96	0.010	0.077
TransYear97	-0.093	0.067
TransYear98	0.176	0.064
TransYear99	0.314	0.064
TransYear00	1.031	0.063
TransYear01	1.501	0.065
Wholesale*AQMD*Year00	0.115	0.093
Wholesale*AQMD*Year01	0.126	0.099
Wholesale*InOut*Year00	0.211	0.082
Wholesale*InOut*Year01	0.250	0.089
Wholesale*Out*Year01	0.015	0.258
Utility*Year00	0.130	0.063
Utility*Year01	0.035	0.066
Utility	-0.028	0.040
Number of Observations = 1,792		R^2 = 0.87

Table 3: Actual Hourly Output Versus Least-Cost Hourly Output Deviation Predictions Given Unit-Owner Characteristics and Location*

Dependent Variable = (Actual Hourly Generation Unit Level Output) - (Expected Hourly Generation Unit Level Output from BBW Competitive Benchmark Pricing)		
Variable	Parameter Estimate	Standard Error
OutGen*Year99	23.656	0.463
OutGen*Year00	47.058	0.446
InGen*Year99	19.215	0.478
InGen*Year00	56.034	0.460
InOutGen*Year99	35.032	0.593
InOutGen*Year00	66.690	0.571
Number of Observations = $2{,}29 \times 10^6$		$R^2 = 0.319$

*Regression includes generation unit-level, monthly, and yearly dummy variables.

Table 4: Actual Hourly Output Versus Least-Cost Hourly Output Deviation Predictions Given Unit-Owner Characteristics, NOx Emissions Rate, and Location*

Dependent Variable = (Actual Hourly Generation Unit Level Output) - (Expected Hourly Generation Unit Level Output from BBW Competitive Benchmark Pricing)		
Variable	Parameter Estimate	Standard Error
OutGen*Year99	23.656	0.436
OutGen*Year00	47.058	0.446
InGen*Year99	13.192	0.552
InGen*Year00	54.595	0.482
InOutGen*Year99	33.120	0.678
InOutGen*Year00	65.905	0.604
InGen*Year99*NOxPrice*NOxRate	5.615	0.254
InGen*Year00*NOxPrice*NOxRate	0.058	0.006
InOutGen*Year99*NOxPrice*NOxRate	2.583	0.464
InOutGen*Year00*NOxPrice*NOxRate	0.038	0.009
Number of Observations = $2,29 \times 10^6$		$R^2 = 0.320$

*Regression includes generation unit-level, monthly, and yearly dummy variables.

Table 5: By Year Actual Hourly Output Versus Least-Cost Hourly Output Deviation Predictions Given Unit-Owner Characteristics, NOx Emissions Rate, and Location*

Dependent Variable = (Actual Hourly Generation Unit Level Output) - (Expected Hourly Generation Unit Level Output from BBW Competitive Benchmark Pricing)		
Year 1998–Table 3 Results (N= 472,603, R^2= 0.0240)		
Variable	Parameter Estimate	Standard Error
OutGen	-51.067	0.478
InGen	-21.462	0.493
InOutGen	-26.022	0.612
Year 1998–Table 3 Results (N= 472,603, R^2= 0.0244)		
OutGen	-51.067	0.478
InGen	-23.802	0.540
InOutGen	-28.460	0.665
InGen*NOxPrice*NOxRate	3.489	0.327
InOutGen*NOxPrice*NOxRate	5.626	0.601
Year 1999–Table 3 Results (N= 805,919, R^2= 0.0120)		
Variable	Parameter Estimate	Standard Error
OutGen	-27.411	0.332
InGen	-2.247	0.342
InOutGen	9.009	0.425
Year 1999–Table 4 Results (N= 805,919, R^2= 0.0127)		
Variable	Parameter Estimate	Standard Error
OutGen	-27.411	0.332
InGen	-8.183	0.430
InOutGen	7.083	0.527
InGen*NOxPrice*NOxRate	5.533	0.243
InOutGen*NOxPrice*NOxRate	2.716	0.440
Year 2000–Table 3 Results (N= 1.101×10^6, R^2= 0.0266)		
Variable	Parameter Estimate	Standard Error
OutGen	-4.009	0.294
InGen	34.571	0.303
InOutGen	40.668	0.376
Year 2000–Table 4 Results (N= 1.101×10^6, R^2= 0.0267)		
Variable	Parameter Estimate	Standard Error
OutGen	-4.009	0.294
InGen	33.172	0.337
InOutGen	39.819	0.426
InGen*NOxPrice*NOxRate	0.056	0.006
InOutGen*NOxPrice*NOxRate	0.041	0.010

*All regression include monthly dummy variables.

Table 6: Implied Firm-Level Hourly Marginal Costs Predictions Given Unit-Level Fuel Costs and NOx Emissions Rate Costs and Owner*

Implied Marginal Cost for Highest Cost Unit Operating During Hour h Owned Buy Supplier k (Derived from Assumption of Expected Profit-Maximizing Bidding Behavior)		
Variable	Parameter Estimate	Standard Error
Intercept	-6.190	1.970
Gas*HR1	0.744	0.040
Gas*HR2	0.767	0.055
Gas*HR3	0.922	0.052
Gas*HR4	1.256	0.045
Gas*HR5	0.853	0.074
NOxPrice*NOxRate1	0.627	0.124
NOxPrice*NOxRate2	0.509	0.075
NOxPrice*NOxRate3	0.162	0.092
Number of Observations = 14,256		R^2 = 0.223
Estimation Constraining All Gas*HR and NOxPrice*NOxRate Coefficient To Be Equal		
Intercept	-18.509	0.758
Gas	0.958	0.033
NOxPrice*NOxRate	0.446	0.066
Number of Observations = 14,256		R^2 = 0.203

*Regression includes firm-level dummies and excludes observations where residual demand facing the firm is negative and hours when there is transmission congestion.

Table 7: Implied Firm-Level Hourly Marginal Costs Predictions Given Unit-Level Fuel Costs and NOx Emissions Rate Costs and Owner*

Implied Marginal Cost for Highest Cost Unit Operating During Hour h Owned Buy Supplier k (Derived from Assumption of Expected Profit-Maximizing Bidding Behavior)		
Variable	Parameter Estimate	Standard Error
Intercept	9.906	3.943
Gas*HR1	0.721	0.069
Gas*HR2	0.840	0.065
Gas*HR3	1.083	0.082
Gas*HR4	1.394	0.065
Gas*HR5	0.903	0.114
NOxPrice*NOxRate1	0.475	0.185
NOxPrice*NOxRate2	0.509	0.108
NOxPrice*NOxRate3	0.267	0.142
Number of Observations = 5,995		R^2 = 0.217

*Regression includes firm-level dummies and excludes observations where residual demand facing the firm is negative, hours when there is transmission congestion and prices less than $20/MWh.

Figure 1: South Coast Air Quality Management District Region

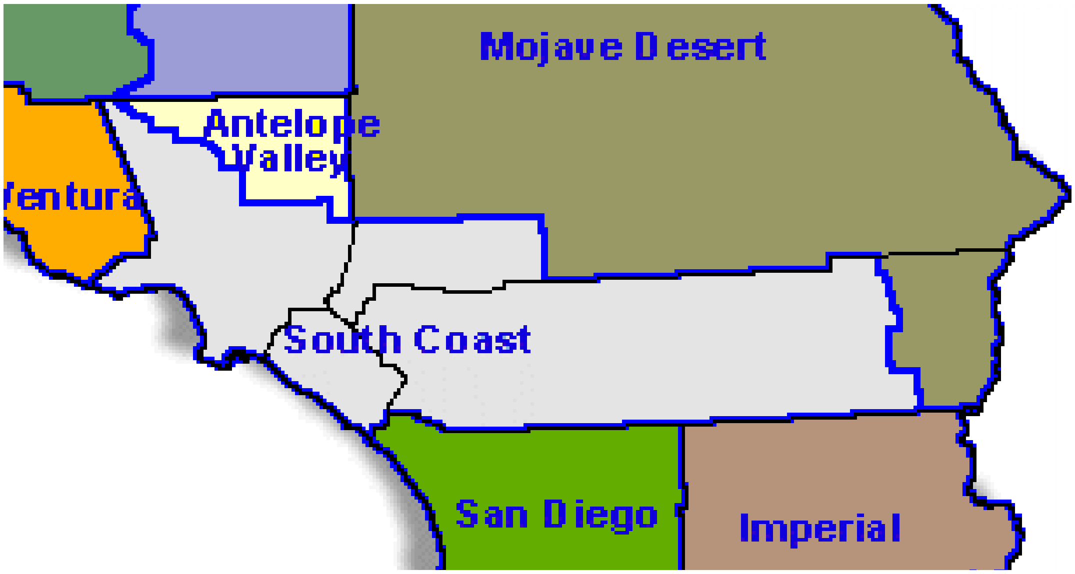

Figure 2: Total RTC Supply and Reported Emissions

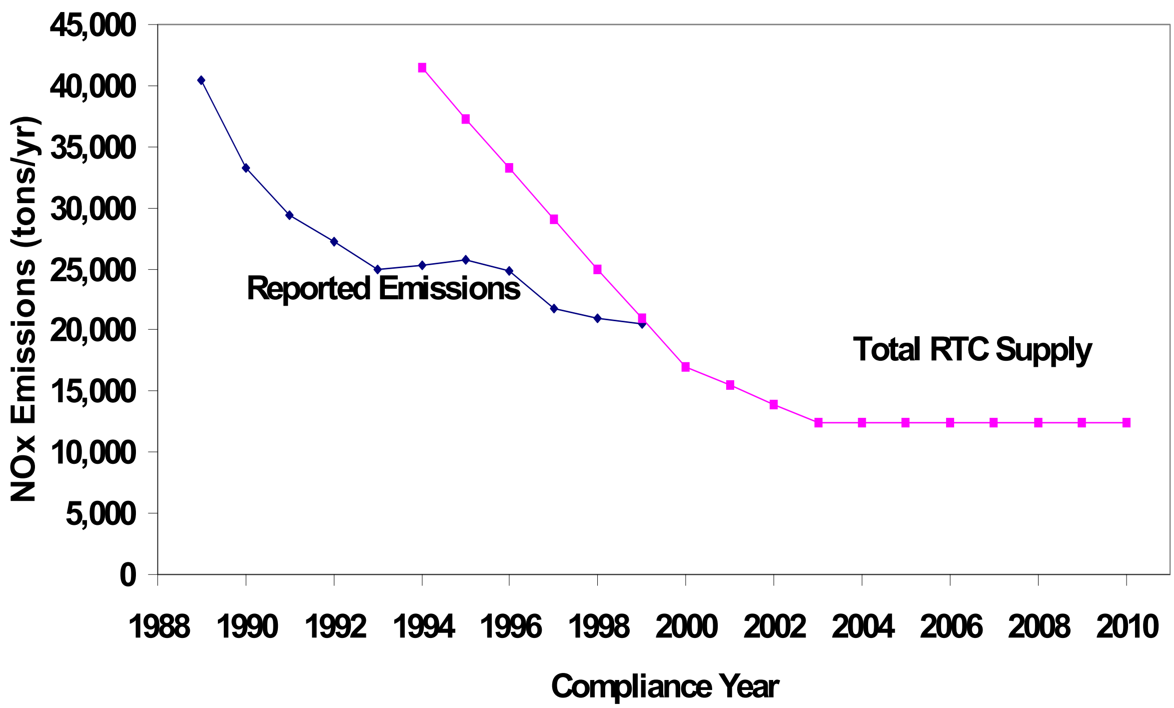

Figure 3: Mean RTC Price for 2000 and 2001 Vintages

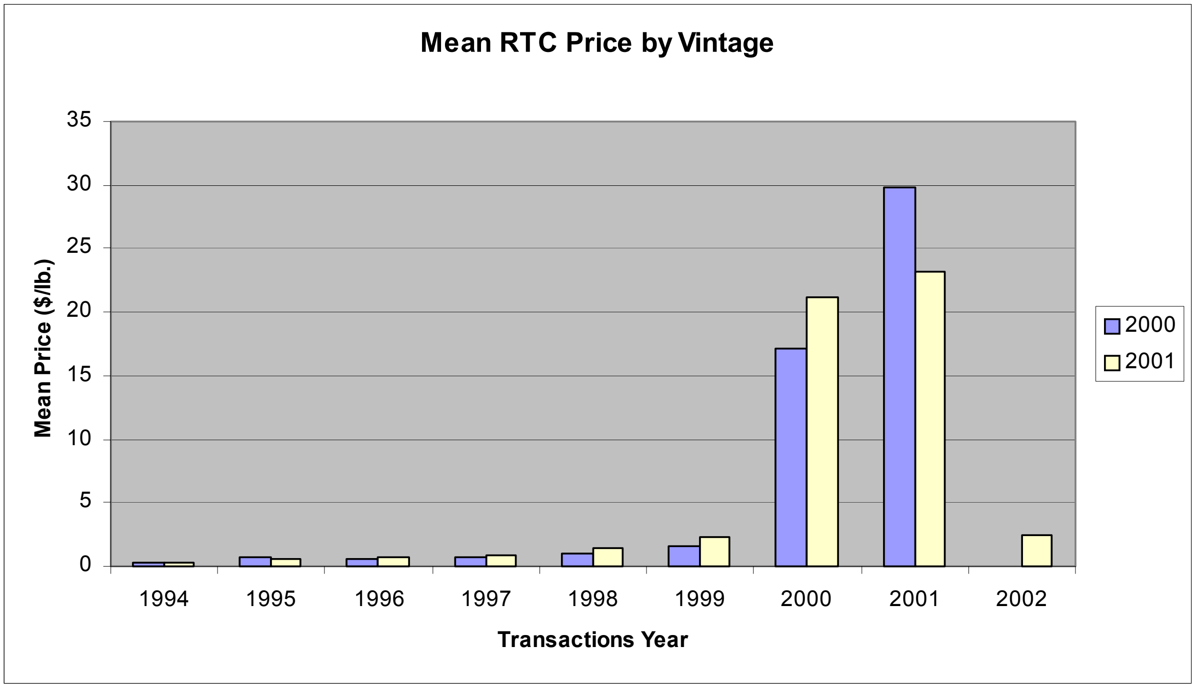

Figure 4: Transaction Volume Weighted Average Prices by Vintage

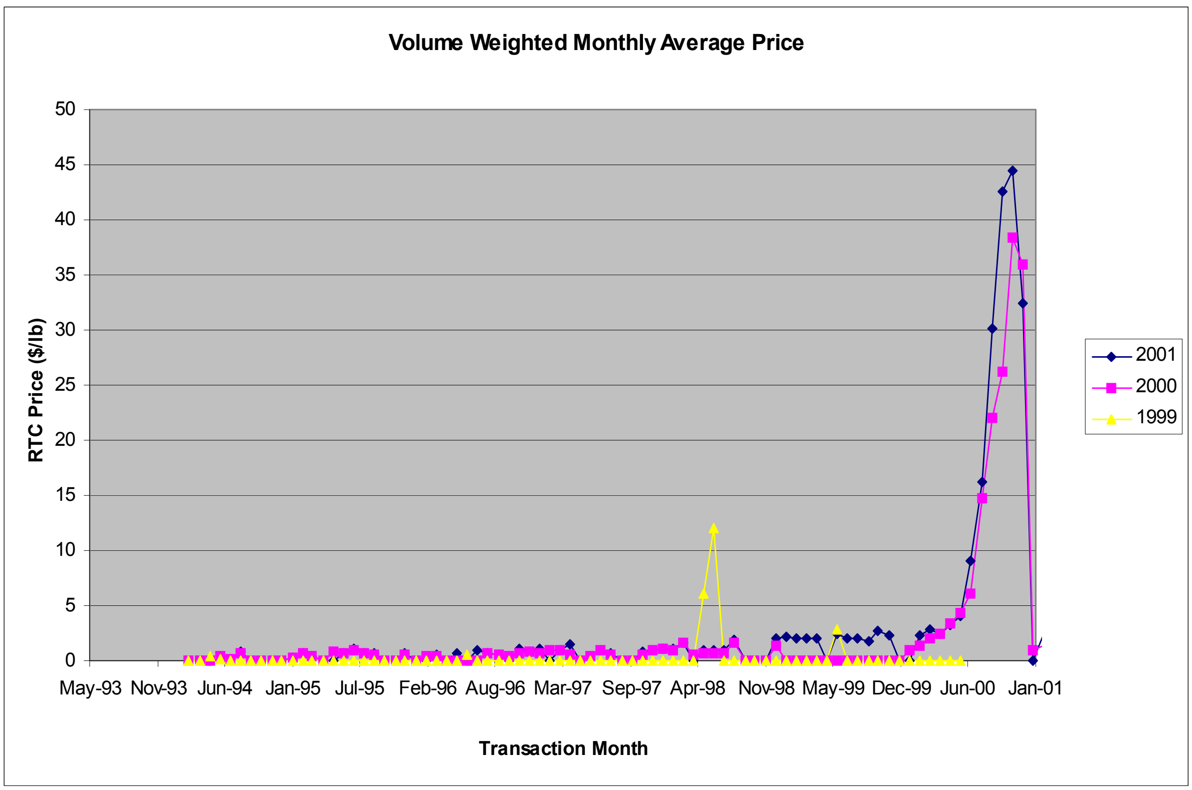

Figure 5: Annual Standard Deviation of Transactions Prices by Vintage

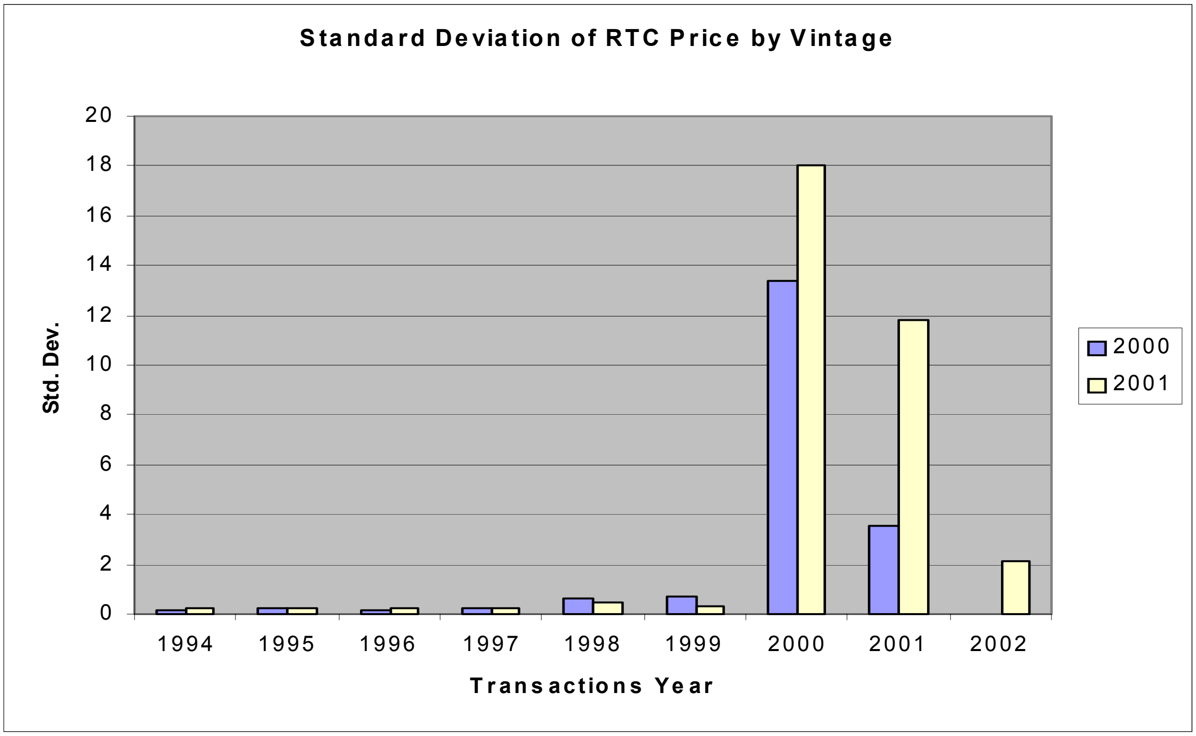

Figure 6: Average Transaction Volume by Vintage

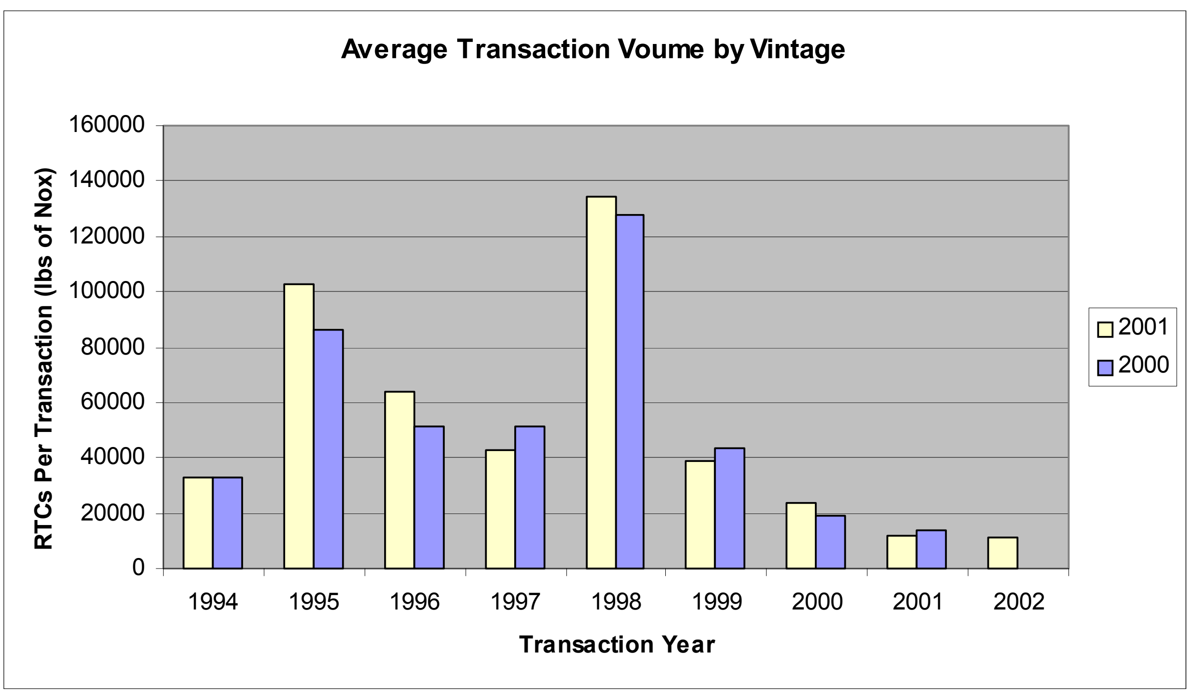

Figure 7: Total Number of Transactions Annually by Vintage

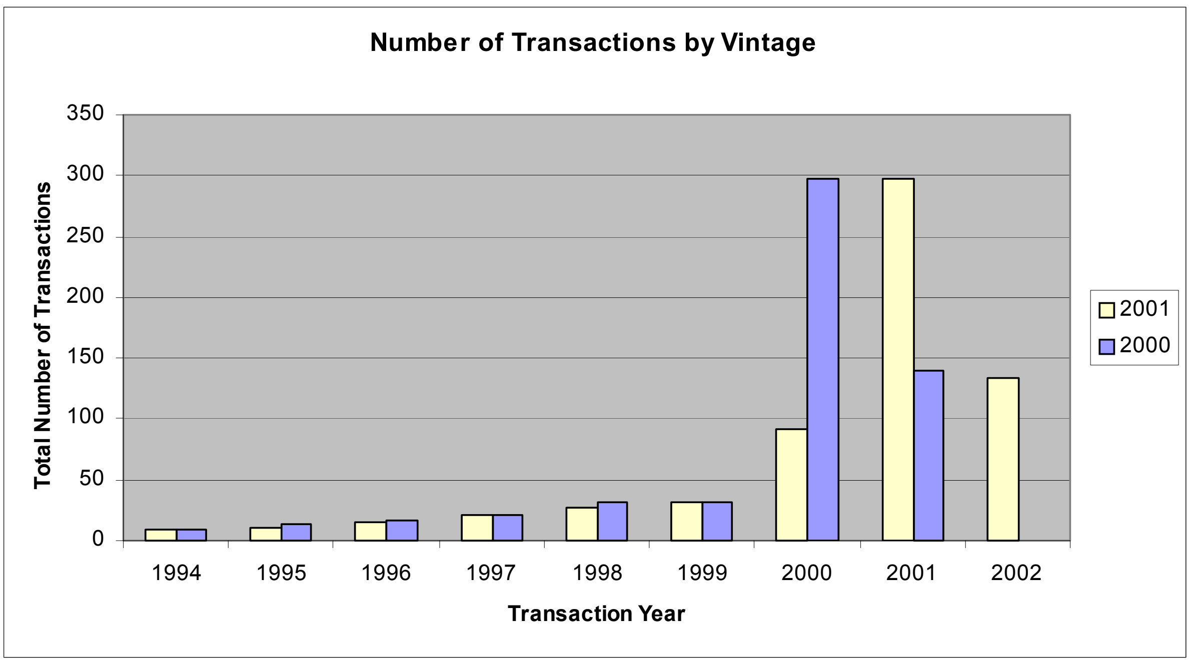

Figure 8: Using NOx Permit Prices to Raise Wholesale Electricity Prices

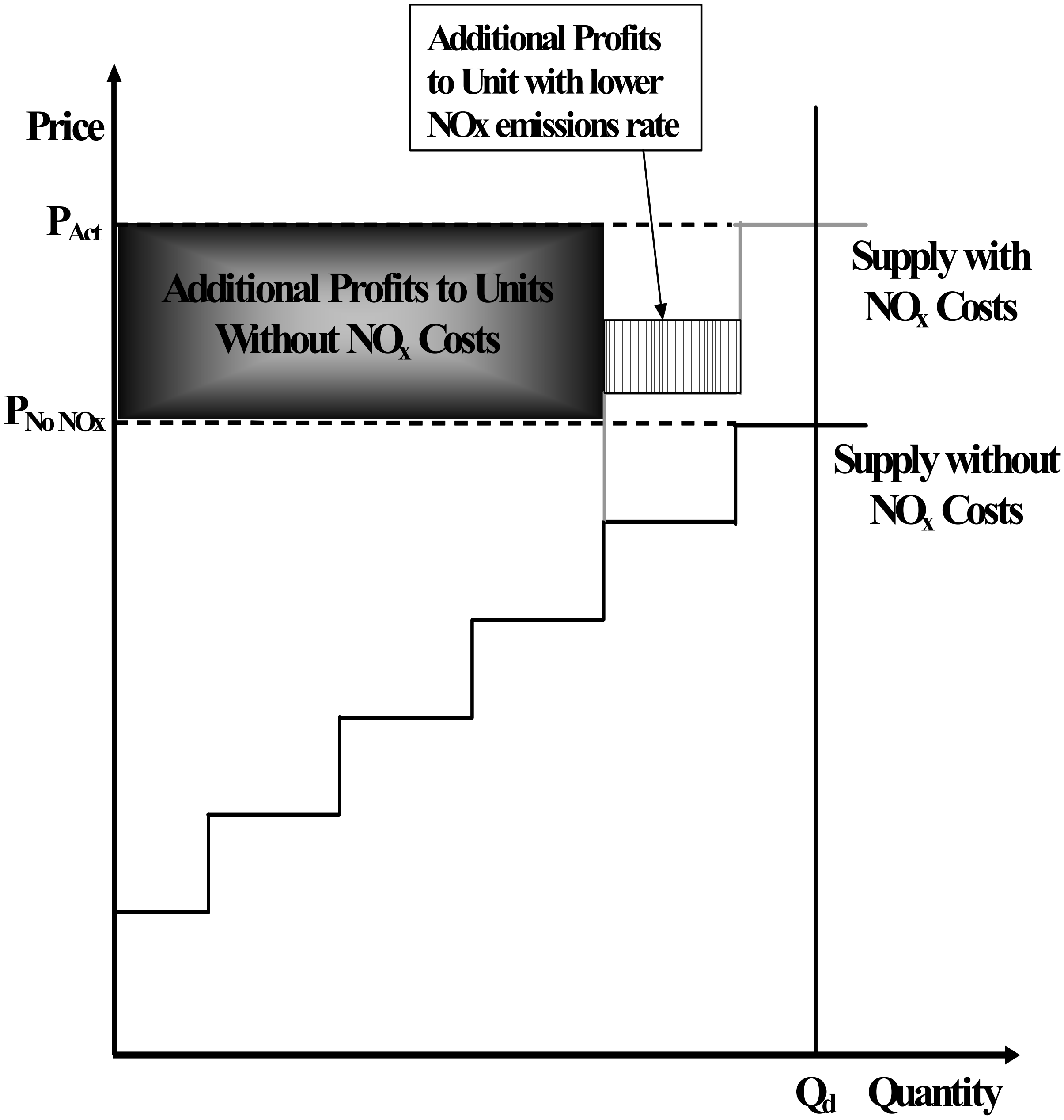

Figure 9: Cummulative Distribution of NOx Emission Rates in SCAQMD

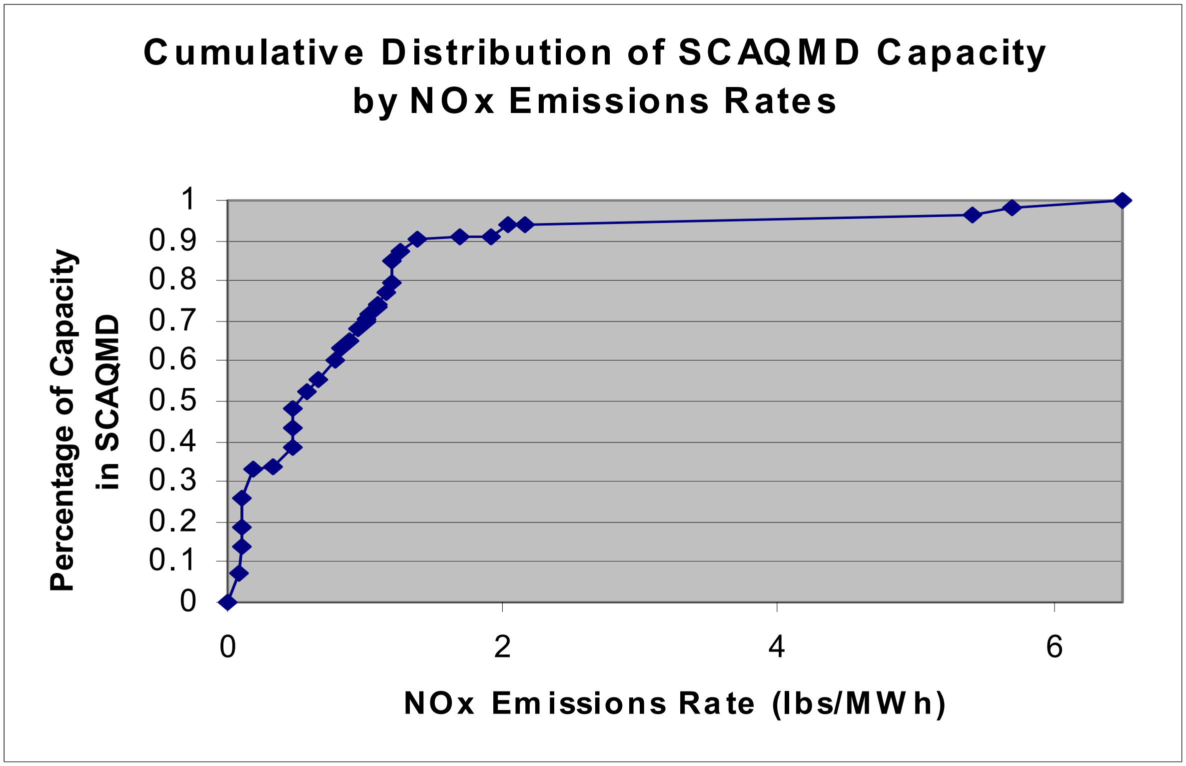

Figure 10: Monthly Average Real-Time Prices by Congestion Zone

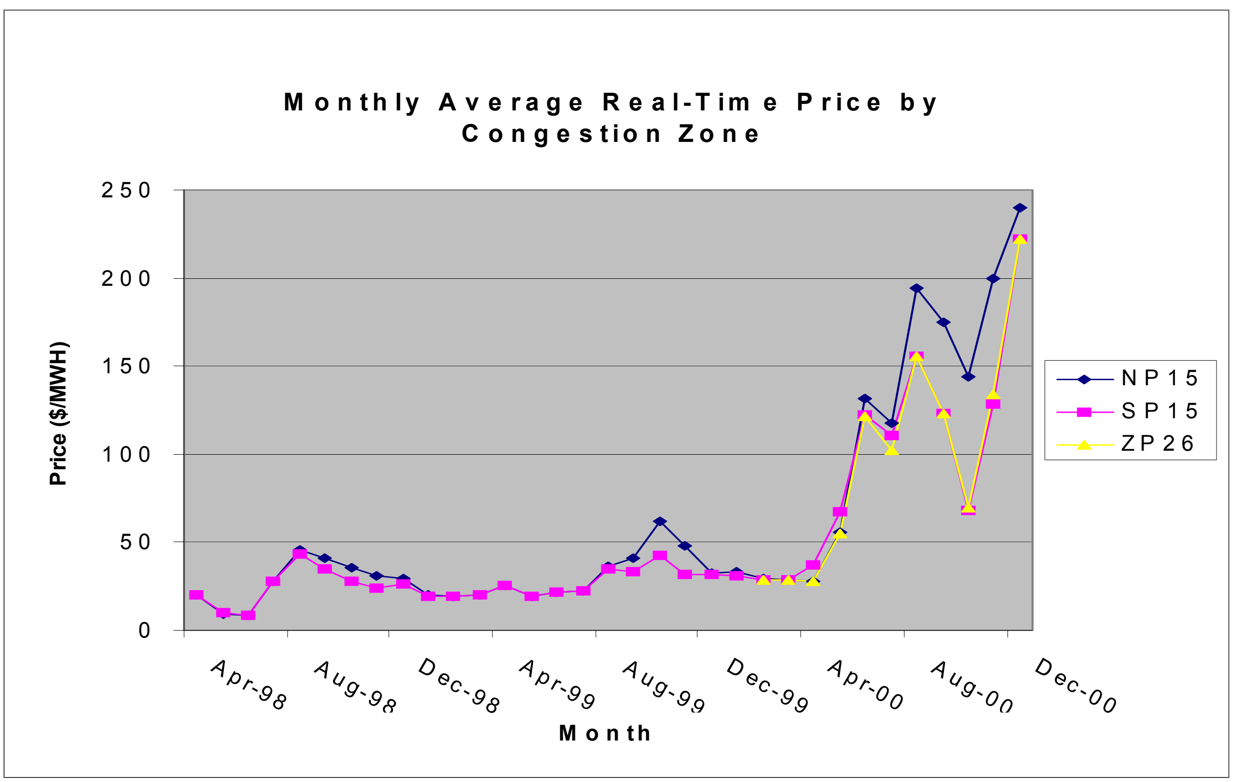

Figure 11: Monthly Average NOx Emission Prices Used in BBW (2002)