Using Environmental Emissions Permit Prices to Raise Electricity Prices: Evidence from the California Electricity Market[1]

Jonathan T. Kolstad
Wharton School, University of Pennsylvania and NBER

Frank A. Wolak
Department of Economics, Stanford University and NBER

December 1, 2013

Abstract

We study the interaction between the RECLAIM emissions permit market and the statewide electricity market during California's electricity "crisis" in 2000 and 2001. We demonstrate the incentives facing generators with some or all of their generation units located in the RECLAIM market to raise electricity prices by raising permit prices and dispatching higher emissions generation units. Consistent with the model, we find evidence that generation paid statistically significantly higher prices for, held and allowed to remain unused a larger share of permits. We also find generators did not bid as though these higher emission permit prices were actual production costs.

[1] We thank seminar participants at the University of California Engergy Institute POWER Conference and the NBER Summer Institute. Azeem Shaikh provided outstanding research assistance. Paul Joskow and Ed Kahn provided very helpful comments on an earlier draft. Wolak would like to thank the University of California Energy Institute for

1. Introduction

During 2000 and 2001 electricity prices in California's deregulated electricity market reached unprecedented levels and supply shortfalls led to rolling blackouts across the state. The causes of this now infamous "electricity crisis" have been studied in great detail and there is evidence pointing to a variety of mechanisms driving the cost increase. Foremost among them was the exercise of unilateral market power by electricity generators (see e.g. Joskow and Kahn (2002) and Borenstein, Bushnell and Wolak (2002), hereafter BBW). In this paper we develop and test a simple model suggesting an additional contributor to electricity price increases: the interaction of the statewide electricity market with the emissions permit market in the Los Angeles basin. The rising cost of emissions permits in this period and their impact on production cost and prices for electricity generators has been well document (see Joskow and Kahn (2002) and BBW). This paper presents results that suggest generators were not mere victims of rising emissions permit prices. Rather we empirically test a model in which electricity generators with some or all of their units in the catchment area of the Regional Clean Air Incentives Market (RECLAIM) were able to raise permit prices and over-bid relatively costly generation capacity to raise the market clearing price for electricity statewide.

The model of behavior we hypothesize is based on the observation that electricity generators in California produce electricity from a number of generation units statewide while the RECLAIM market only covers a subset of these units – those located in the South Coast Air Quality Management District (SCAQMD) in the Los Angeles basin. Because the these two markets do not overlap, there is an incentive for generators who have some units in the emissions market – who pay for emissions permits – and some outside – whose production cost is unaffected by rising emissions permit costs – to use the units that have to pay for permits to raise the prices paid for electricity for *all* of their units. This incentive holds if all generation units have identical technology (and therefore emissions and permit demand) to produce electricity. If generators have a portfolio of units with varying emissions intensity, the incentive is even greater. Put simply, in situations in which units that must purchase emissions permits clear the market and inframarginal units do not have to pay the same cost for permits – either because they are not covered by the market or because their production technology allows them to produce electricity with lower emissions – higher permit prices increase profits. Not only are price increases profitable, the regulatory framework also made raising the emissions cost of generation for marginal generation units desirable to avoid regulations requiring generator to "cost justify" bids to the statewide electricity market. That is firms that could raise the perceived input cost of their marginal units by raising the price of the requisite emissions permits appeared to be pricing at marginal cost for marginal units even if they were, in fact, able to exercise market power. We test this model of market interaction empirically.

Our empirical inquiry relies on three distinct empirical approaches. We first explore the prices paid in the RECLAIM market across a variety of participants. We identify generators who stood to gain from higher prices for emissions permits through increased electricity prices. We demonstrate that these firms in fact paid higher prices for identical permits in periods in which they were valuable as a tool to raise electricity prices – when supply was such that RECLAIM based units would clear that statewide market. These differences across RECLAIM market actors in prices paid were not, however, apparent prior to electricity market deregulation when generators could not gain from higher permit prices. Variation in prices paid for identical goods (emissions permits) implies some degree of search friction. We demonstrate that the structure of the RECLAIM market – particularly the thin nature of trading and the role of brokers – made large variation in prices in the same period across firms feasible. In addition to evidence on prices paid, we also find that firms who stood to gain from higher emissions permit prices held substantially more unused permits at the end of their vintage; effectively scrapping valuable assets suggesting a preference for reduced supply and increased price.

In our second line of inquiry we model generator behavior in the electricity market. Specifically, we compare estimates for the competitive dispatch (cost minimizing) choices across the available units in a generators portfolio with actual bids made. By consider the decisions of generators with respect to relative intensity of emissions across their units, we are able to estimate whether firms treated emissions permits as a “true” cost of production. We find, to the contrary, that firms overbid relatively intensive emissions plants compared to the behavior we would predict in a competitive environment. Furthermore, this relative overbidding *increased* as the price of emissions permits rose.

Finally, our third line of inquiry builds on the results in Wolak (2003a and 2007). Using a model of expected profit-maximizing bidding behavior in a wholesale market we recover estimates of a generation unit-level variable cost functions. We then regress the true cost of inputs (e.g. fuel and emissions permits) against these estimated variable costs. The coefficients on input fuel costs for each firm are not statistically significantly different from one for all five suppliers, suggesting fuel costs are an actual variable cost of producing electricity. In contrast, the coefficients on emissions costs are jointly statistically significantly less than one for all suppliers with units in the RECLAIM market, suggesting that emissions permit costs were not treated as a variable cost of producing electricity in the same way 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: that costs of emissions permits for oxides of nitrogen (NOx) were a substantial component of the variable cost of producing electricity during the crisis period for units located in the RECLAIM market. 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 produce the upstream emissions. Inefficiencies in the product market can allow firms to influence the production cost of the highest variable cost unit operating through purchase of emissions permits, particularly if the monitoring and design of the emissions market allows purchasers to increase permit prices. As emissions permit markets are used to deal with a widening range of environmental problems this issue is likely to become an increasing concern for policy makers. For example, in Spain's wholesale electricity market Linares et al. (2006) find evidence that the introduction of the European Emissions Trading System (a greenhouse gas emissions permit market) can cause large increases in electricity prices leading to revenue increases for generation firms. This mechanism for electricity price (and profit) increases is consistent with our study if plants requiring CO_2 emission permits to operate are needed to serve demand and the owners of these plants possess unilateral market power in the electricity market.[2]

The remainder of the paper proceeds as follows. In the next section we present a simple model of electricity generator competition in the electricity market incorporating emissions permit prices and regulation of the exercise of market power. In section 3 we describe the important institutional details of the SCAQMD NOx emissions permit market, the California electricity market and regulation and the interaction of the SCAQMD NOx emissions permit market and the electricity market. Section 4 presents our empirical models and results. Section 5 states our key conclusions, avenues for future study and, finally, we provide a brief discussions of other settings in which this type of interaction may be of concern.

2. A Model of Emissions and Energy Market Interaction

[2] The oligopoly model of the Spanish electricity market in Linares et al. (2006) implies that these generation unit owners are able to set market-clearing prices above the variable cost of the highest cost unit producing electricity and that this variable cost reflects input fuel costs and the cost of emissions permits, so that the market-clearing price of electricity paid to all generation units is higher than it would be in the absence of a CO_2 emissions permit market.

In this section we present a simple model of the behavior we study empirically in this paper. Our basic insight stems from the observation that electricity generators have a variety of different plants in a portfolio that they can use to produce energy. If they have a credible means of raising the cost of production for units that determine the market clearing price they will earn additional profits from inframarginal units whose cost is unaffected or less affected by the rise in costs for marginal units. Furthermore, when regulatory scrutiny focuses on pricing in excess of observed marginal cost – the approach employed by the Federal Energy Regulatory Commission (FERC) – this strategy also mitigates regulatory risk associated with exercising unilateral market power. The RECLAIM market created a vehicle for implementing this strategy due to a confluence of enable conditions.

First, geographic variation in a generators portfolio means that units in the RECLAIM market will have substantially higher prices than those outside even if they have identical production functions to convert fuel inputs into electricity – the heat rate of the generator. Second, variation in the rate of emissions across a generators portfolio within the RECLAIM market area means that, for the same price of emissions, some units will have far larger increases in production cost. In both cases, increased emissions cost can raise the cost of marginal units more than inframarginal ones.

2.1 Impact of Emissions Prices on Electricity Pricing and Profits

We begin by demonstrating the impact of changes in emissions costs on market clearing prices for electricity and the associated generator level profit. We simplify the model by considering a duopoly facing a competitive fringe of suppliers.[3] Let the residual demand curve faces by the monopoly equal $D(p, A(t)) = A(t) – p$, where $A(t)$ is positive random variable equal to the level

[3] Our model could be enriched to have more market participants with the ability to exercise unilateral market power and/or more flexible cost functions and residual demand functions. We focus on a simplified model as it demonstrates the key features of firm behavior under regulation that we study empirically while allowing us to solve for a supply function Nash equilibrium in closed-form.

demand at a zero price in period t. Suppose that each of the duopolists has a quadratic cost function equal to $C(q) = cq^2/2$, for $c > 0$. The marginal cost for each firm is equal to $dC(p)/dp = cq$. Suppliers own a portfolio of generation units with different marginal costs, generating a firm specific cost function; a step function, as in Figure 1, with the length of each step equal to the capacity of the generation unit and the height of the step equal to the marginal cost of the generation unit leads.

We incorporate the cost of emissions permits by specifying the marginal cost of a natural gas-fired a generation unit (dollar per megawatt-hour ($/MWh)) i as:

$$MC_i = VOM_i + Heat\_Rate_i * P_{gas} + Emissions\_Rate_i * P_{permit} \quad (1)$$

where VOM_i is the variable operating and maintenance cost in $/MWh, $Heat\_Rate_i$ is the million BTU (MMBTU) per MWh rate at which generation unit i converts fossil fuel heat into MWh, P_{gas} is the price of natural gas in $/MMBTU, $Emissions\_Rate_i$ is the pounds of NO_x emissions produced per MWh of energy produced by unit i, and P_{permit} is the price in $/pound of a NO_x emissions permit.[4] As general rule, generation units with a higher heat rate, meaning that they require more heat to produce one MWh of electrical energy, also have higher NO_x emissions rates, meaning that they emit more pounds of NO_x per MWh electrical energy produced.

Importantly, when higher heat rate plants also emit more NO_x per MWh, if we order the generation units from the lowest to the highest using the marginal cost figure that excludes the cost of NO_x emissions permits, we obtain virtually the same ordering as if we included the NO_x emissions permit costs in the marginal cost. However, the marginal cost curve becomes steeper if P_{permit} increases, because at higher quantities of output from the generation unit owner's portfolio, generation units with higher heat rate and NO_x emissions rates must produce, so that same natural gas and NO_x emissions permit price is multiplied by larger heat rates and emissions rates, respectively. This is demonstrated in Figure 1, which plots the system-wide marginal cost curve

[4] All of the generation units that offer into the California electricity market in the SCAQMD region are natural gas-fired.

with zero RECLAIM permit prices and the system-wide marginal cost curve with positive RECLAIM prices.

If we assume that the duopolists are restricted to choosing linear supply curves before the value of A(t) is realized, then from Klemperer and Meyer (1989), the symmetric Nash equilibrium supply function for each duopolist is equal to $S(p) = \frac{1}{2}(-1 + \sqrt{1 + \frac{4}{c}})$p. Note that as c, the slope the marginal cost curve, increases the expected profit-maximizing supply function, S(p), and the marginal cost curve become closer together. Since increasing P_{permit} implies a higher value of c, the slope of the marginal cost curve, by purchasing a small number of NO_x emissions permits at a sufficiently high price, the supplier generates a steep offer curv, raising the market clearing electricity price.

The intuition can also be seen graphically in Figure 1. 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 emissions permit 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 1. The second source of increased profits associated with higher RECLAIM prices results 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 1, 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. Thus, even a supplier with all of its units located in the SCAQMD would still want to increase the price of NOx permits provided it has units in its portfolio that have significantly different NOx emissions rates.

2.2 Model of Generator Behavior with Regulatory Oversight

Section 2.1 above demonstrates the basic mechanism by which a generator with a portfolio of generation units can impact market-clearing prices using emissions permits as well as the potential for this to be profitable strategy. In this section we incorporate an additional feature that made this strategy particularly attractive: regulatory scrutiny. Adding the risk of intervention by a regulator (e.g FERC) explains why a generator with the ability to exercise market power would prefer to do so using permit prices to raise the observed cost of a marginal unit rather than merely bidding higher prices and earning profit on that marginal unit as well as inframarginal units. We discuss the details of FERC's regulatory mandate in detail in Section 3.4.

In a regulatory framework where prices are determined to be just and reasonable based on their reflection of underlying cost, the degree of scrutiny (the probability of detection) depends on the difference between the market-clearing price and the marginal cost of the highest cost unit in the supplier's portfolio that produces energy, what we call the supplier's marginal cost. Let p equal market-clearing price and $MC_i(P_{permit})$ equal supplier i's marginal cost where P_{permit} is the price supplier i pays for a NO_x emissions permit. Assume that the expected legal and administrative cost a supplier must pay to defend itself against a Federal Power Act investigation as a function of the market-clearing price and system marginal cost is equal to $g_i((p - MC_i(P_{permit}))^2)$ where a $g_i(t)$ is monotone increasing function of t reflecting supplier i's cost of defending against a Federal Power Act investigation. This function embodies the intuition that the further is the supplier's marginal cost from the market clearing price, the more likely it is that the supplier will have to defend itself against a Federal Power Act investigation.

The following two-stage game embodies the main mechanisms that we investigate empirically. The expected profit function for supplier i=1,2 is equal to:

$$\Pi_i\big(S_i(p), P_{i,permit}\big) = E_A\Big[D\big(p, A(t)\big) - S_j(p)]p - \tfrac{c}{2}[D\big(p, A(t)\big) - S_j(p)]^2 - g_i\big([p - MC_i\big(P_{i,permit}\big)]^2\big) - P_{i,permit}Q_{permit}\Big] \quad (2)$$

where the expectation is taken over the distribution of A(t) and Q_{permit} is quantity of emissions permits purchased, and $S_i(p)$ is the linear supply function of supplier i. The market clearing price for demand realization, $A^*(t)$ is the solution in p to $S_1(p) + S_2(p) = D(p.A^*(t))$. This implies that market-clearing price depends on the realization of A(t), which is why the expectation operator applies to all of the terms in the expression for realized profits.

In the first stage of the game, suppliers choose the prices they pay for emissions permits, $P_{i,permits}$, (i=1,2) anticipating how they will be behave in the second stage of the game, before the value of A(t) is realized. In the second stage of the game the two duopolists chose their expected profit-maximizing linear supply functions, using the cost function that reflects the true cost of producing their output, the value of A(t) is realized and market prices are determined using the supplier's offer curves and the realization of D(p,A(t)).

The supplier's actual marginal cost function reflects a much lower or zero variable cost component for NO_x emissions permits than would be the case if the price of permits was $P_{i,permit}$ chosen the first stage of the game. Let c^{true} equal the true value of c in each firm's cost function. Let $c(P_{i,permit})$ equal the value of c associated with a permit price of $P_{i,permit.}$ Solving the game backwards, each supplier's expected profit-maximizing offer curve is equal to, $S^*(p) = \frac{1}{2}(-1 + \sqrt{1 + \frac{4}{c^{true}}})p$. Substituting these optimal offer curves back into the expected profit function for each supplier yields expressions for the expected profits of each supplier associated with selling in the short-term market and their choice of P_{permit}. Only the second term in (2) depends on the value of $P_{i,permit}$. Firms can lower their expected cost of regulation by raising the price of permits; higher values of $P_{i,permit}$ are the less likely to trigger a Federal Power Act investigation because the value of the supplier's marginal cost function based on $c(P_{i,permit})$ evaluated at the supplier's observed output level will be very close to the market-clearing price. Each firm chooses the price to pay for permits based on their own cost of defending themselves against a Federal Power Act investigation compared to the quantity of permits they must buy (Q_{permit}) at a given price. At the permit price, $P_{i,permit,}$ the supplier's marginal cost implies that the market-clearing price is close to competitive levels and therefore not in violation of the just and reasonable standard of the Federal Power Act.

This model generates a set of clear predictions for the behavior of expected profit-maximizing suppliers with the ability to exercise significant unilateral market power when they are subject to regulatory oversight under the Federal Power Act. First, suppliers that own generation units both within and outside of the SCAQMD region or have significant variation in the NOx requirements across plants will pay significantly higher prices for NO_x emissions permits than other SCAQMD market participants. For these generators a small number of high priced permits generate NO_x costs for market clearing units the resemble high prices without raising the cost of inframarginal units substantially. Second, these suppliers will operate the generation units that require NO_x emissions permits more intensively than is consistent with the prices that they paid for these permits entering the variable cost of these generation units. Third, the expected profit-maximizing offer curves of suppliers with generation units in the SCAQMD region will not reflect higher prices paid for NO_x permits, even though the prices these suppliers pay for other inputs (e.g. natural gas) will be reflected in their offers. Each of these predictions is consistent with the dramatic increase in NO_x emissions permits the SCAQMD during the summer and autumn of 2000 reflecting not a rising cost of emissions but rather generator efforts to disguise the amount of unilateral market power they were able to exercise in the short-term market, reducing the probability they would be subject to a Federal Power Act investigation.

3. Empirical Setting and Enabling Conditions

3.1 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 2 below). SCAQMD is tasked with reducing emissions of criteric pollutants, particularly Nitrogen Oxides (NOx). One component of this effort is the RECLAIM market that began operation in 1994. Any firms in the jurisdiction of the SCAQMD emitting more than 4 tons of NOx and/or SOx annually are included in the market.[5] Initially 390 participants met the criteria for inclusion, though this number fell over time 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). By 2001, the end of our study period, there were 364 market participants.

Each actor in the market receives an annual 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 NOx emissions for that year with the RTCs it holds. This must be done either as of December 31 or June 30 of the year depending on the cycle assignment.[6]

Each firm in RECLAIM receives an allocation of RTCs of different vintages that 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 using actual emissions in one of the years between 1989 and 1992. These annual allocations were then reduced at facility-specific rates in order to meet regulator's desired emissions levels in 2003. Rates of allocation

[5] Certain "essential public services", such as public transit, fire stations and landfills are exempted and remain under command and control regulation of their emissions.
[6] The rationale behind the cycle system was to facilitate the creation of a liquid market for permits and to reduce the potential for large price swings that would occur is fall facilities ended compliance periods simultaneously. Our results, however, suggest that this was not sufficient to create liquidity, at least as measured by convergence in prices across actors.

reduction are based on the reductions that each industry would have had to achieve under the SCAQMD air quality management plan that existed prior to RECLAIM.

The total quantity of RTC allocations was reduced from the 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 allocation of RTCs to all RECLAIM firms was larger than total emissions through 1999. Figure 3, reproduced from Coy et al. (2001), shows the time pattern of annual allocations of RTCs and total annual emissions.

The most dramatic emissions reductions required by SCAQMD were to come from electricity generating facilities and oil refineries. These two industries were allocated 56% of the total initial NOx RTCs. The NOx RTC allocation for power plants was to be reduced by 81% by 2003 relative to their initial allocation and refineries were given an allocation in 2003 that was 67% lower than their initial allotment (Coy et al. 2001). We note, however, that these changes in allocations do reflect the true necessary reductions in these two industries because initial allocation of RTCs were larger than actual emissions at RECLAIMs inception. Coy, et al. (2001) estimate these two industries faced actual reductions in emissions of 67% for power plants and about 48% for refineries by 2003.

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 expects to emit more than their initial allocation in a given year they have three choices. First, they can reduce their emissions by installing the necessary emission reduction technology available. The other options, particularly in the short run, are to purchase RTCs from other actors in the RECLAIM market or to cut output. In theory, the ability to trade RTCs allows all RECLAIM entities to achieve the aggregate emissions level mandated by the SCAQMD at a lower cost than command and control methods. Firms with the lowest marginal cost of pollution reduction have the strongest financial incentives to undertake these investments given the opportunity cost of holding RTCs, which is the price at which they can sell their RTCs to another market participant (see e.g. Fowlie (2010)).

3.2. Market Structure and Competition in California Electricity Market

Section 2 demonstrates that the successful use of RTC permit prices to raise wholesale electricity prices requires a number of initial conditions in the California electricity market. Specifically, the ability to determine market clearing generation units and a difference in the cost between operating those marginal units and inframarginal units with positive emissions permits prices. In this section we describe the California electricity generation market and demonstrate the existence of these conditions.

Without initial conditions that made it unilaterally profitable for suppliers to withhold energy 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 California Independent System Operator (CAISO) control area's electricity needs suppliers required to purchase RTCs to produce electricity would find themselves at a competitive disadvantage relative to other suppliers in the CAISO control area. As a result, their units would have been 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 the SCAQMD and these units would be dispatched only when the demand for electricity is extremely high. In addition to dispatch decisions, suppliers requiring RTCs to produce electricity are at such a cost disadvantage in a workably competitive wholesale electricity market, they would have strong incentives to pay as little as possible for NOx emissions permits. On the other hand, in a market where suppliers have the ability to exercise a substantial amount of unilateral market power and could use higher permit prices to raise cost/bids by marginal units generators have the opposite incentive; generation firms prefer higher RTC prices and disproportionately dispatch high emissions cost plants. This distinction forms that basis of our empirical strategy.

Without initial conditions that made it unilaterally profitable for suppliers to withhold energy 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 California Independent System Operator (CAISO) control area's electricity needs suppliers required to purchase RTCs to produce electricity would find themselves at a competitive disadvantage relative to other suppliers in the CAISO control area. As a result, their units would have been 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 the SCAQMD and these units would be dispatched only when the demand for electricity is extremely high. In addition to dispatch decisions, suppliers requiring RTCs to produce electricity are at such a cost disadvantage in a workably competitive wholesale electricity market, they would have strong incentives to pay as little as possible for NOx emissions permits. On the other hand, in a market where suppliers have the ability to exercise a substantial amount of unilateral market power and could use higher permit prices to raise cost/bids by marginal units generators have the opposite incentive; generation firms prefer higher RTC prices and disproportionately dispatch high emissions cost plants. This distinction forms that basis of our empirical strategy.

A number of papers have demonstrated the substantial market power held (and exercised) be generators beginning in May of 2000 and at various periods through the end of the summer of

2001. Both Wolak (2003b) uses the bids submitted by all market participants to CAISO's real-time energy market to quantify changes in the ability to exercise unilateral market power of the five large fossil-fuel generation unit owners in California during the summers of 1998 and 1999 relative to the summer of 2000. BBW estimate the magnitude of system-wide 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. All of these results are consistent with the substantial increase in the ability of each of five large fossil fuel suppliers in California to exercise unilateral market power during the summer 2000 relative to the previous two summers documented in Wolak (2003b).

BBW demonstrate that a major reason for the increase in market power exercised during the summer of 2000 relative to the summers of 1998 and 1999 was the fact that there were many more hours when a considerable fraction of fossil fuel generation capacity in the CAISO control area was needed to meet the state's demand for electricity. For example, during the summers of 1998 and 1999, the amount of energy produced from these units was greater than or equal to 5000 MWh for about half of the hours. In contrast, during the summer of 2000, during approximately half 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. Another factor in the higher prices during the summer of 2000 was substantially higher natural gas prices starting in May of 2000 and continuing until the June 2001. Average natural gas prices in California during the summer and autumn of 2000 were almost twice average prices during that same time period in 1999.

The results in Wolak (2003b) and BBW are consistent with the view that the lower import availability in 2000 relative to 1999 and 1998 resulted in each of the five large fossil fuel suppliers facing significantly less elastic residual demand curves starting in the early summer of 2000. This made it unilaterally profit-maximizing for these suppliers and other suppliers to withhold capacity from the California electricity market in order to raise wholesale prices during the summer of 2000.

3.3 Electricity Production, Incentives and Emissions

During our sample period, more than 50% of the capacity in California was oil or natural gas-fired steam and combustion turbine facilities, with all but a few peaker generation units being natural gas-fired (California Energy Commission, 2001). Roughly 60% of this gas-fired capacity was located in the SCAQMD region and, therefore, included in the RECLAIM market. Furthermore, many of these facilities had very high heat rates, which put them at upper end of the state-wide marginal cost curve based on input fuel costs and variable operating and maintenance costs. As a result, including the price of RECLAIM permits more units inside SCAQMD could be expected to be at the upper end of the statewide marginal cost curve.

Because there is considerable disparity in NOx emissions rates across generation units in RECLAIM, 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 permit prices can alter the least cost dispatch of generation units in California. For example, suppose there are two generation units: a natural gas-fired unit with a NOx emissions rate of 0.10 lbs/MWh and a higher heat rate and a second unit with a NOx emissions rate of 5 lbs/MWh and a lower operating cost excluding emissions. The least cost dispatch, without emissions costs, would have the second plant supply as much electricity as possible with the first plant operating only if there is sufficiently high demand. If, however, the price of RECLAIM permits is high enough then the least cost dispatch could require the higher heat rate unit to be dispatched instead of the lower heat rate unit.

A second important feature of the California market is that for all hours during our sample period, California set market-clearing prices for electricity over geographic areas larger than the area covered by the RECLAIM. For the vast majority of hours there was a single statewide price, but when there was transmission congestion across southern and northern California, separate market prices were set for these two geographic regions, called the 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. Even after the addition of the ZP26 congestion zone, the SP15 congestion zone remained significantly larger and contained more gas-fired generation capacity than the SCAQMD region.

If the area over which prices are set in the electricity market covers a larger geographic area than the SCAQMD, 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 larger SP15 congestion zone that contains SCAQMD. During the sample period, there were a number of merchant power producers in California that owned generation units both in and outside of SCAQMD.

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 emissions 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 likely to be set by the generation unit with the highest combination of NOx emissions costs and fuel costs. Moreover, as noted above, for high enough RTC prices, the unit with highest variable cost is the one with the highest NOx emissions rate.

Regardless of the RTC purchasing strategy of an electricity supplier with some or all of its units located in the 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 an electricity market where firms have the ability and incentive to exercise unilateral market power 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 variable cost disadvantage relative to other generation units. We return to this distinction in our analysis of bidding behavior in sections 4.3 and 4.4 below.

3.4 Regulation of Market Power in Electricity Markets

Different from other infrastructure industries such as telecommunications and airlines, the use of market mechanisms to set prices in the electricity supply industry was not the result of an explicit legislative action. The formation of formal bid-based wholesale markets in the United States was initiated by the Federal Energy Regulatory Commission working with state public utilities commissions (PUCs). Although bid-based electricity markets sell the energy consumed by the majority of the United States population, wholesale electricity prices are still regulated by the Federal Energy Regulatory Commission (FERC) under Section 205 and 206 of the Federal Power Act (FPA) of 1935. These provisions of the FPA require wholesale electricity prices to be "just and reasonable" and if FERC finds that wholesale prices are unjust and unreasonable, then it must order refunds of the payments in excess of just and reasonable price levels. Historically, just and reasonable prices were those that recovered prudently incurred costs plus a reasonable return on capital invested.

These provisions of the FPA complicated the transition to market mechanisms to set wholesale electricity prices. FERC developed the “market-based rate” filing process for jurisdictions with formal wholesale market to address these requirements of the FPA. This administrative process allows suppliers to charge market prices as their filed, FERC-regulated rate under certain conditions. FERC reasons that prices that do not reflect the exercise of unilateral power qualify as just and reasonable, because they are reflective of the cost of production. Specifically, if no supplier has the ability to exercise unilateral market power the market price will equal the marginal cost of the highest cost suppliers operating during that hour. Consequently, if a supplier is able to demonstrate that it has no ability to exercise unilateral market power, that supplier is able to charge a market price as its FERC-regulated wholesale price.

At the start of each formal wholesale market in the United States—the PJM Interconnection, New York Independent System Operator (ISO), the ISO New England, and California ISO—each supplier was required to make a market-based rate filing at FERC demonstrating that it had no ability to exercise unilateral market power in the market for product—energy or ancillary services—that it wished to sell. Before the supplier could sell at a market-determined price, FERC had to certify that the supplier did not have the ability to exercise unilateral market power in the relevant market. In the late 1990s, FERC relied on market structure-based tests where suppliers could not own more than a certain percentage of capacity in what it defined was the relevant market. McGrew (2003) provides description of the market-based rate process in place at the start of the California ISO market in 1998.

Section 206 of the FPA requires that if FERC subsequently determines that market prices do reflect the exercise of unilateral market power and are therefore unjust and reasonable, then it must order refunds from the market participants that were paid these prices of the revenues in excess of just and reasonable levels. The requirement that wholesale prices be just and reasonable and the threat of refunds if prices are unjust and unreasonable creates strong incentives for suppliers with the ability to exercise unilateral market power to attempt to disguise the extent of market power that they exercise.

4. Empirical Models and Results

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 unilateral market power in the California electricity market. We first 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 also show that these same market participants held a larger fraction of the unused RTC permits that could have been used in 2000 and 2001. 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 compared 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 compared to the amount predicted in a workably competitive wholesale electricity market in California during the summer of 2000. Finally, we use the results of Wolak (2003a and 2007) to recover hourly estimates of the marginal cost of producing electricity from each generation unit owned by each of the five large fossil-fuel generation unit owners in the California electricity market. We find that, consistent with fuel costs being an actual expense incurred to produce electricity, a one dollar increases in input fuel costs—the unit's heat rate times the price of natural gas—is associated with a one dollar increase in the estimated marginal cost for that generation unit. Consistent with our argument that NOx emissions permit prices were not treated as input costs in the same manner as input fuel costs, we find that a one dollar increase in NOx emissions permit costs—the generation unit's NOx emissions rate times the NOx emissions permit price—is associated an increase in the estimated marginal cost that is substantially less than one.

4.1. RTC Transaction Prices and Buyer Identity

This section first presents the results of our analysis of the prices for all RTC transactions with positive prices that occurred for permits with vintages from 1997 to 2001. 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, which is fifteen months before it actually began operation. We also excluded all transactions that occurred after June 1, 2001, by which time electricity generators had been fully excluded from the RECLAIM market. This yields a total 1,792 transactions.

We begin by presenting descriptive data on the RECLAIM market and then turn to regressions that formalize the analysis. Figures 3 and 4 present annual mean prices and monthly transaction-volume-weighted-average prices. In both cases we see large increases in 2000 and 2001 suggesting the RECLAIM market behaved in a distinctly different manner prior to 2000 and 2001. The price increase for the 2000 and 2001 vintage RTCs that occurred starting in 2000 is dramatic. 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 (recall that due to cycle assignments the market for cycle 2 2000 permits remained active 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 the SCAQMD, we would expect them to have strong incentives to purchase additional RTC permits beyond their initial allocation at the lowest price possible during 2000. In contrast, wholesale electricity generators may have wanted to raise RTC permit prices to enable them to make higher bids to supply electricity during this same time period. Where this holds, divergent incentives facing RTC permit buyers during 2000 should be observable in an increased variance in transactions prices during this time period. We find precisely this effect.

Figure 6 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 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 because RTCs could be used to raise wholesale electricity prices in California.

In addition, if RTC prices were used to produce higher bids into the wholesale electricity market, firms prefer only to increase prices on a small amount of additional electricity that sets the market-clearing price. If this strategy was being used, we would expect generation owners to purchase the smallest quantities necessary to produce higher bid prices from marginal units rather than buying large quantities of RTCs at inflated prices. Comparing average transaction volume for 2000 and 2001 vintage RTCs, we find a sizeable drop in the transaction size in 2000 and 2001 relative to previous years (Figure 7). Figure 8 also reveals behavior consistent with this strategy. The number of RTC transactions of these two vintages 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 use of smaller and more frequent RTC trades is consistent with the use of RTC prices as a mechanism for increasing the market-wide electricity price, although there are clearly other possible explanations for these observations.[7]

We next turn to a regression-based analysis of RTC permit prices. Our basic identification strategy relies on distinguishing behavior between electricity generators and other

[7] For example, the amount of unused vintage 2000 and 2001 RTCs that individual RECLAIM participants have to sell are much smaller in 2000 than in previous years.

actors before and after the deregulation of the electricity market. To present our regression results, define the following notation:

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

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

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

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

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

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

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

We define generators based on SCAQMD records. The wholesale electricity suppliers with all of their units in the region during our sample period are AES/Williams and Thermo 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.

We estimate the following regression:

$$\ln(p(i)) = \alpha_0 + \sum_{t=1998}^{2001} \delta_j Year(t,i) + \beta_1 Wholesale(i) * AQMD(i) + \beta_2 Wholesale(i) * InOut(i)$$
$$+\beta_3 Wholesale(i) * Out(i) + \beta_4 Wholesale(i) * Utility(i)$$
$$+\gamma_{00} Wholesale(i) * AQMD(i) * Year(00,i) + \gamma_{01} Wholesale(i) * AQMD(i) * Year(01,i) \quad (3)$$
$$+\lambda_{00} Wholesale(i) * InOut(i) * Year(00,i) + \lambda_{01} Wholesale(i) * InOut(i) * Year(01,i)$$
$$+\eta_{00} Utility(i) * Year(00,i) + \eta_{01} Utility(i) * Year(01,i) + \delta_{01} Wholesale(i) * Out(i) * Year(01,i) + \varepsilon_i$$

Results are presented in Table 1. Consistent with our hypothesis, the estimates of γ_{00}, γ_{01}, λ_{00} and λ_{01} are all positive, and all but the estimate of γ_{00} are precisely estimated. Moreover, we find that the joint null hypothesis: $\beta_1 = \beta_2 = \beta_3 = \beta_4 = 0$ cannot be rejected. These two results imply that after controlling for the vintages of permits being purchased in transaction i, 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 not very precisely estimated, 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. Specifically, different participants made purchases at different times and this explains why the average prices they paid are higher for vintage 2000 and 2001 permits. For this reason, we expanded regression to include seven transaction year indicator variables, TransYear(I,t) for t=1995 to 2001. Table 2 reports the results of this regression. Although the transaction year indicator variables for 2000 and 2001 are estimated to be very large and positive, the estimates of γ_{00}, γ_{01}, λ_{00} and λ_{01} remain positive though, in contrast to Table 1, only λ_{00} and λ_{01} are precisely estimated. The joint null hypothesis: $\beta_1 = \beta_2 = \beta_3 = \beta_4 = 0$ still cannot be rejected. The point estimates of η_{00} and η_{01} are positive, but very imprecisely estimated.

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 RECLAIM 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 degree of precision as those for the InOut suppliers.

These results raise the question of how a functioning market could sustain such deviations in price between different parties. In the years in which it was profitable for generation firms to pay high prices for RTC permits we see a large increase not only in the average price of permits but also in the variance of prices across transaction (Figures 3-7). In addition, the volume traded per transaction dropped significantly (Figure 7). The high variance in transactions prices is inconsistent with a well functioning market where the majority of participants expected permit prices to rise. Instead, these findings are consistent with large search costs in the RECLAIM market. This is, perhaps, surprising given the significant presence of large brokerage firms in the secondary market for RTCs. An alterantive view, however, is that brokers may have functioned in a supporting role to generation firms trying to obtain high priced RTCs in specific periods.

The RECLAIM market included an eclectic set of firms, ranging from very small companies, unlikely to consider their emissions permit allocation as a valuable asset to the business, to large electricity generation firms that require permits for every MWh of electricity sold. In this setting a broker could approach smaller firms and offer a price slightly greater than their reservation value for the RTC asset. The broker could then hold these assets and sell them to generators at very high prices. These smaller players were unlikely to have been fully aware of the value of their RTC holdings and may therefore have been willing to sell at a significantly lower price than at the one at which the broker could subsequently sell the RTC to an electricity producer located in SCAQMD. We test for behavior of this type using our trading data and find evidence that brokers may have increased search costs in the RECLAIM market, particularly in the period of interest. For brevity this discussion is presented in Appendix A.

4.2 Holdings of Unused Emissions Permits

Because holding permits and allowing them to expire unused is likely to impact permit prices, we now analyze the volume of unused RTCs held by different market actors. RECLAIM rules do not allow participants to bank RTCs for use in later compliance periods. Consequently, Cycle 1 2000 vintage permit effectively becomes worthless for offsetting emissions outside of January 1 to December 31, 2000 time period. Firms that stood to gain from high RTC prices could hold RTCs that are valid for a compliance cycle in excess of their actual emissions during that compliance cycle, which would reduce the supply available to market participants and raise permit prices, which would then allow higher electricity prices to be cost-justified based on NOx emissions permit costs. In order to test for the existence of this withholding behavior, we compute a measure of the total RTCs held for each vintage by a firm i (the allocation to the firm net of purchases and sales) and the stock of emissions over that period by firm i. The difference is the unused permits for firm i for period t.[8]

We compute the volume of unused permits by vintage from 1997 to 2000 for each of the three large fossil fuel suppliers with units in SCAQMD, Los Angeles Department of Water and Power (LADWP), energy and permit trading firms registered in the RECLAIM market and a residual category of other small fossil-fuel generation unit owners. We do not include 2001 permits because generators were excluded from the market beginning in February of that year. In addition, we compute holdings and emissions for the entire firm, as opposed to by individual

[8] We are grateful to Stephen Holland for providing the data from Holland and Moore (2007) used to compute these measures.

RECLAIM facility identifiers. This is done to account for the fact that permits allocated to a firm for specific generation units or facilities could easily be re-allocated between different RECLAIM entities in their portfolio. For example, two of the three large fossil-fuel generation unit owners have more than one generation facility the SCAQMD region and therefore many unique facility identification numbers that they can allocate RTCs across. A firm-level, rather than facility-level, unit of analysis accounts for the fact that RTCs held by any of the facility identification numbers owned by that firm could be used to offset emissions at any of the firm's generation units.

We first compute the total unused permits for different types of market actors. The definition of an unused permit is an RTC available to a firm that was not offered to offset one pound of NOx emissions at the end of the compliance period. Table 4 shows the number of unused permits by vintage and generation firm. The three merchant generators vary in the number of unused permits they hold by vintage between 1997 and 2000. We first note the large volume of unused permits held by Generation Firm 1 for the 1999 vintage. For this period the combined permit holdings of entities registered to Generation Firm 1 exceeded actual emissions by almost 450,000 pound of NOx. The compliance cycle structure of RECLAIM means that Cycle 2 1999 vintage permits were available to meet emissions through the end of June of 2000. The enabling conditions for the use of RTCs to raise electricity prices were thus present in the period in which Generator 1 held permits far in excess of emissions. For 1999 vintage permits the incentive to withhold to drive permit prices up is only relevant for Cycle 2 compliance facilities because Cycle 1 facilities had to rationalize emissions with holdings as of December 31, 1999. Decomposing the overall holdings for Generator 1 across plants we find that generation units assigned to Cycle 1 had close to zero left over permits for the 1999 vintage (each power plant had 2 unused RTCs for the 1999 vintage). On the other hand, the single plant owned by Firm 1 assigned to compliance cycle 2 held 413,000 unused RTCs (or 92 percent of the unused permits held by Firm 1).

To determine the extent to which owning a generation unit in the SCAQMD predicts a higher share of unused vintage 1999 and 2000 permits we estimate a model is similar to equation (3) but we replace the dependent variable with the unused permits held by firm i for vintage t as a share of the total unused permits of that vintage in the market. The first specification we estimate is the following:

$$\left(\frac{unused(i,t)}{\sum_{i} unused(i,t)}\right) = \alpha_0 + \sum_{t=1998}^{2000} \delta_j Year(t,i) * Cycle2(i) + \sum_{t=1999}^{2000} \delta_j Year(t,i) + FE(i) \qquad (4)$$
$$+\gamma_{Raise}[Cycle2(i) * Year(99,i) + Year(00,i)] * Raise(i) + \varepsilon_i$$

where *unused(i,t)* is the unused permits held by firm i for vintage t and *FE(i)* is a dummy variable equal to 1 for firm i. The dependent variable is a measure of the share of "available" unused permits of each vintage across the entire RECLAIM market held by a given market actor. Interactions between vintage and the compliance cycle to which firm i is assigned are included to account for differences in market conditions during the firm's year end compliance period. *Raise(i)* is a dummy variable that equals for one for SCAQMD participants that we believe had an incentive to raise wholesale electricity prices. This includes the three large merchant generators with plants in the SCAQMD, plants owned by the LADWP and traders. We define traders to include all firms that had energy or emissions trading specific wing of the company.[9] We include a control for these companies in our regression because they were, potentially, in a position to gain from any electricity price increases that resulted from higher NOx emission permit prices. *Cycle2(i)* is a dummy variable equal to 1 if firm i has any RECLAIM actor in its portfolio whose compliance cycle is 2. The interaction of the availability of a Cycle 2 facility with the dummy for 1999 vintage RTCs captures the potential for withholding 1999 RTCs during the summer of 2000, the time at which Cycle 2 plants were required to meet emissions with RTCs. The coefficient γ_{Raise} is an estimate of the additional share of available unused permits held by

[9] This definition includes some firms that also controlled emissions producing assets in the RECLAIM area. As such some "traders" had real emissions that we include in computing firm level unused RTCs.

participants with both the incentive (the ability to profit from higher prices in the statewide electricity market) and the opportunity (had a Cycle 2 facility for 1999 vintage permits or was active in the market for 2000 vintage permits) to raise RTC prices. A positive and precise estimate for γ_{Raise} is consistent with a greater share of unused permits being held by these actors.

Table (5) below presents parameter estimates for equation (4). We limit our sample to include only firms that had positive emissions in 1998, 1999 and 2000. Thus we are capturing the share of unused emissions among "active" market participants. The coefficient estimate for γ_{Raise} is .025 and is very precisely estimated. The interpretation of this coefficient is that the actors with the incentive and the opportunity to alter RTC prices are predicted to have held a 2.5 percentage point great share of the unused permits in the market in those periods in which price increases were beneficial. Considering these actors held only a very small share of the available unused permits for 1997 to 2000 vintage RTCs, this predicted increase is also economically meaningful. Furthermore, this is evidence that these firms were holding large shares of permits and leaving them unused at the same time that the prices paid for these permits were high and rising.

We also estimate a variant of equation (4) in which we separate those holding unused vintage 1999 permits from those holding vintage 2000 unused permits. Parameter estimates from the alternate specification are presented in Table 6. Consistent with the first specification, the parameter estimates are .028 and .022 for 1999 and 2000 vintage permits respectively. Both are precisely estimated and economically significant.

Our evidence on holdings of unused RTCs seems inconsistent with cost minimization behavior by generation and trading firms in the RECLAIM market. On the other hand, holding large shares of unused permits in high price periods is consistent with the model of using permit prices to raise wholesale electricity prices that we propose. We note, however, that withholding permits is not a necessary condition to raise transactions prices for RTCs in a pay-as bid market for permits. As we discussed earlier, particularly with respect to the role of brokers, without sufficient transparency in the RECLAIM market generation firms could pay high prices for RTCs while other participants pay lower prices.

4.3. 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. Appendix B provides additional detail on computing competitive benchmark output. Critical to our analysis is the assumption in competitive benchmark pricing that suppliers with units located in SCAQMD perceive RTC permit costs as actual production costs. Thus we 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:

$$\begin{aligned} MC_{jd} = {} & \text{(Variable Operating and Maintenance Costs for Unit j)} \\ & + \text{(Heat Rate for Unit j in MWh/MMBTU)*(Price of Input Fuel in day d in \$/MMBTU)} \\ & + \text{(NOx Emissions Rate in lbs of NOx/MWh)*(NOx Emissions Price \$/lb of NOx)} \end{aligned} \tag{5}$$

This expression for marginal cost 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 this analysis 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.[10] 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 our two regressions requires the following additional notation which follows our earlier analysis but is now defined with respect to specific generation units:

$\mathbf{InGen_{hj}}$ = 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 j 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

[10] We note that 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 4 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.

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.

$$
\begin{aligned}
y_{hj} &= \alpha_j + \sum_{J=1999}^{2000} \delta_j Year(J)_h + \sum_{M=2}^{12} \gamma_M Month(M)_h + \sum_{J=1999}^{2000} \eta_j OutGen_{hj} * Year(J)_h \\
&+ \sum_{J=1999}^{2000} \beta_j InGen_{hj} * Year(J)_h + \sum_{J=1999}^{2000} \lambda_j InOutGen_{hj} * Year(J)_h + \varepsilon_{hj}
\end{aligned}
\tag{6}
$$

where α_j is a generation unit fixed effect. Table 7 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 7 suggest fossil fuel units owned by suppliers located 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.

We extend that analysis by considering whether high perceived NOx costs predicted increased deviations in actual hourly unit-level output from those implied by competitive benchmark pricing. If generators prefer high RTC cost units to clear the market we expect relatively increased dispatch of high NOx cost plants relative to competitive predictions. To study this, 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 $/lb for hour h.

These results are given in Table 8. 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. 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 9 and are largely consistent with the pooled results that include unit-level fixed effects.

The results in Tables 7-9 suggest that fossil fuel unit owners in the CAISO control area 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.

These results suggest that California fossil fuel unit owners withheld supply from low NOx 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 required 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, for the SP15 congestion zone.

4.4. Generation Unit-Level 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 from June 1 to September 30 for each year from 1998 to 2000. The specific hypothesis we examine is whether or not these firms bid as if their marginal cost of supplying electricity to the CAISO's real-time energy market included RTC emissions permit costs as an actual variable cost similar to input fuel costs.

This is accomplished by applying the procedure described in Wolak (2003a and 2007) for recovering generation unit-level marginal cost functions for facilities that operate in a bid-based short-term wholesale electricity market. We use offers into the CAISO's real-time energy market by the five large fossil fuel suppliers to recover generation unit-level marginal cost functions that are parameterized by input fuel costs and NOx emissions permit costs, where applicable. The bid supply curves into the CAISO's real-time market are submitted at the generation unit-level. These willingness-to-supply curves are step functions with up to ten price steps and quantity increments. Different from the case of Australian National Electricity Market considered in Wolak (2003a and 2007), suppliers can change both their price and quantity offers on an hourly basis.

To construct the first-order conditions for expected profit-maximizing bidding into the CAISO real-time market that will be used to estimate the generation unit-level marginal cost functions for hypothetical Firm A, define the following notation:

$SA_{ijd}(p,\Theta)$ = amount bid by unit j at price p during hour i of day d,

$SA_{id}(p,\Theta) = \sum_{j=1}^{J} SA_{ijd}(p,\Theta)$ = total amount supplied by Firm A at price p during hour i of day d,

where J is the total number of units owned by Firm A and Θ is the vector of bid parameters for Firm A. For the CAISO real-time market, Θ is a Jx24x10x2 dimensional vector because there are

10 price and quantity increments for each generation unit for every hour of the day for each of the J units owned by Firm A.

Because suppliers in the CAISO real-time market are free to change both their price and quantity offers on an hourly basis, if we assume a constant marginal cost of production for each generation unit, the daily variable profit function of Firm A is the sum of 24 hourly variable profit functions. We define further notation:

Q_{id} = real-time demand in hour i of day d,

$SO_{id}(p)$ = amount bid in at price p by all other firms besides Firm A during hour i of day d,

$DR_{id}(p) = Q_{id} - SO_{id}(p)$ = residual demand curve faced by Firm A in hour i of day d at price p,

QS_{jid} = final energy schedule of unit j during hour i of day d,

$QS_{id} = \sum_{j=1}^{J} QS_{ijd}$ = final energy schedule for Firm A during hour i of day d,

C_{jd} = marginal cost of producing output from unit j during day d.

As discussed in BBW, the CAISO is a multi-settlement market meaning that suppliers come into the real-time market with a scheduled output level, for hour i of day d of QS_{id}. The value of $DR_{id}(p)$ is equal to the supplier's total output level.

The realized variable profit function for hour i of day d for Firm A is equal to:

$$\Pi_{id}(\Theta,\varepsilon_i) = (DR_{id}(p_i(\varepsilon_i,\Theta),\varepsilon_i) - QS_i)p_i(\varepsilon_i,\Theta) - \sum_{j=1}^{J} C_{jd}[SA_{ijd}(p_i(\varepsilon_i,\Theta),\Theta)] \qquad (7)$$

where $p_i(\varepsilon_i,\Theta)$ is the solution in p to the following equation $DR_{id}(p,\varepsilon_i) = SA_{id}(p,\Theta)$, which the price where the realized residual demand curve and the bid curve of Firm A intersect. As discussed in Wolak (2003a and 2007), Firm A faces several sources of uncertainty in the realized residual demand curve that it might face when it bids into the real-time market. For hour i, this uncertainty is represented by the random variable ε_{i}.. Following the notation in Wolak (2007), let

p_{ijk} = the bid price for increment k of unit j during hour i for Firm A

q_{ijk} = the bid quantity for increment k of unit j during hour i for Firm A.

In terms of this notation Θ = (p_{ijk}, i=1,2…,24, j=1,…,J, k=1,2,…,10, q_{ijk}, i=1,2…,24, j=1,…,J, k=1,2,…,10). As discussed in Wolak (2007), if the offer price for a bid increment k of unit j for hour i is strictly below the offer cap and above the offer floor, then we know that if the firm maximizes expected profits, the following first-order condition should hold for p_{ijk}:

$$\frac{\partial E_{\varepsilon}[\Pi_{id}(\Theta,\varepsilon)]}{\partial p_{ijk}} = 0\,, \tag{8}$$

Where $E_{\varepsilon}(.)$ denotes the expectation with respect to the distribution of ε. We can follow the same procedure as described in Wolak (2003a and 2007) to construct a differentiable realized variable profit function. Let $\Pi_{id}^{h}(\Theta,\varepsilon)$ denote the differential realized variable profit function parameterized by the smoothing parameter h, as described in Wolak (2003a and 2007). This quantity can be written in terms of the smoothed residual demand curve and smoothed unit-level bid supply curves defined in Wolak (2003a and 2007) as:

$$\Pi_{id}^{h}(\Theta,\varepsilon_i) = (DR_{id}^{h}(p_i(\varepsilon_i,\Theta),\varepsilon_i) - QS_i)\,p_i(\varepsilon_i,\Theta) - \sum_{j=1}^{J} C_{jd}[SA_{ijd}^{h}(p_i(\varepsilon_i,\Theta),\Theta)]\,. \tag{9}$$

The derivative of the smoothed variable profit function with respect to p_{ijk} is equal to:

$$\begin{aligned}\frac{\partial \Pi_{id}^{h}(\Theta,\varepsilon)}{\partial p_{ijk}} &= \{(DR_{id}^{h}(p_i(\varepsilon_i,\Theta),\varepsilon_i) - QS_i) + p_i(\varepsilon_i,\Theta)\frac{dDR_{id}^{h}(p_i(\varepsilon_i,\Theta),\varepsilon_i)}{dp} \\ &\quad -\sum_{j=1}^{J} C_{jd}[\frac{SA_{ijd}^{h}(p_i(\varepsilon_i,\Theta),\Theta)}{dp}]\}\frac{\partial p_i^{h}(\varepsilon_i,\Theta)}{\partial p_{ijk}} - \sum_{j=1}^{J} C_{jd}\frac{SA_{ijd}^{h}(p_i(\varepsilon_i,\Theta),\Theta)}{dp_{ijk}}\,,\end{aligned} \tag{10}$$

where $\frac{\partial p_i^{h}(\varepsilon_i,\Theta)}{\partial p_{ijk}}$ is computed as described in Wolak (2003a and 2007). To estimate the parameters of the marginal cost function for unit j during day d, C_{jd}, we use the derivative of the smoothed variable profit function for Firm A for all price increments that are strictly less than the relevant offer cap and offer floor on the CAISO real-time market for all units during all hours of the day. Specifically we construct the following moment condition for each hour i of the day for Firm A.

$$m_{id}(\beta) = I(uncon_{id})\sum_{j=1}^{J}\sum_{k=1}^{K} I(p_{\max} > p_{ijk} > p_{\min})\frac{\partial \Pi_{id}^{h}(\Theta,\varepsilon)}{\partial p_{ijk}}, \tag{11}$$

where $I(p_{\max} > p_{ijk} > p_{\min})$ is an indicator function for the event that p_{ijk} is strictly above p_{min}, the floor on price bids, and strictly below p_{max}, the cap on price bids, I($uncon_{id}$) is an indicator variable that equals 1 there is a single price of energy for the entire CAISO control area and β is the vector of parameters of the unit-level marginal cost function. We restrict our analysis to uncongested hours, I($uncon_{id}$) = 1, because this simplifies the construction of the first-order conditions for firms with units in multiple congestion zones. This should only reduce the precision of our parameter estimates relative to the case that included all hours in the sample.

We assume the following functional form for C_{jd}, the marginal cost of unit j on day d, in terms of the product of unit j's heat rate and the price of natural gas and unit j's NOx emission rate and the price of RTC permits for units located in the SCAQMD region:

$$\begin{aligned} C_{jd} &= \beta_0 + \sum_{m=1}^{4}\beta_m Firm(m,j) + \sum_{m=5}^{9}\beta_m HR(m,j) * Gas_d * Firm(m,j) \\ &+ \sum_{m=10}^{12}\beta_m NOXR(m,j) * NOXP_d * Firm(m,j) + \eta_{jd} \end{aligned} \tag{12}$$

where the variables are defined as follows:

FIRM(m,j) = indicator variable equal to 1 if j equals m and zero otherwise

HR(m,j) = the heat rate in MMBTU/MWh of unit j owned by firm m

GAS_d = price of natural gas in day d

NOxRATE(m,j) = the NOx emissions of unit j owned by supplier m

$NOxPRICE_d$ = RTC NOx emissions permit price for day d

We use the daily unit-level natural gas price series and the transaction volume-weighted average NOx emissions permit price series used in BBW to compute the GAS_d and $NOxPRICE_d$. Figure 21 plots this NOx emissions price series.

To estimate the elements of β, we construct the following vector of moment restrictions. For each of the five suppliers we stack the values of $m_{id}(\beta)$, i=1,2,…24, for each day d, into a vector. Let $M_d(\beta)$ denote the 120-dimensional vector of moments for all 24 hours of day for each of the 5 large fossil fuel suppliers in the CAISO control area. We estimate β using the smoothed Generalized Method Moments (GMM) procedure described in Wolak (2003a and 2007). 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_m (k=5,..,9) should be 1 and the true values of the β_m (k=10,11,12) should be 1. There are only three suppliers with potentially non-zero coefficients associated with NOx emission costs because only three of the five large fossil-fuel generation unit owners had plants located in the SCAQMD region. They were AES/William, Dynegy, and Reliant. The other two large generation unit owners, Duke and Mirant, only owned units outside of the SCAQMD region.

Table 10 presents the results of estimating equation (11) over our sample period of June 1 to September 30 of 1998, 1999 and 2000.[11] The point estimates of the fuel cost parameters, β_m (k=5,..,9), are not statistically significantly different from 1. Specifically, the size $\alpha = .05$ Wald test of the joint null hypothesis H: β_k=1 for (i=5,...,9) cannot be rejected. Substantially different results are obtained for NOx emission permit costs. The size $\alpha = .05$ Wald test of the joint null

[11] The standard errors are computed as discussed in Wolak (2003a and 2007). The test statistic for the null hypothesis of expected profit-maximizing bidding behavior presented in Wolak (2003a and 2007) is 124.23. This statistic is asymptotically distributed as a χ^2_{N-P} random variable under the null hypothesis, where N = 120 is the number of moment restrictions and P = 13 is the number of parameters estimated, which implies that the null hypothesis of unilateral expected profit-maximizing behavior cannot be rejected.

hypothesis that H: β_m=1 for (i=10,11,12) can be rejected. Moreover, the point estimates of these three parameters are significantly less than one. Because all of the results are qualitatively similar across the β_m (m=5,…,9) and three values of β_m, (m=10,11,12) we only report estimates by the firm number, and not the firm name.[12] The bottom of portion of this table presents the results estimating this model assuming all of the β_m (m=5,…,9) and β_m (m=10,11,12) are equal. These results further confirm our conclusion that fuel costs enter the generation unit-level marginal cost function with a coefficient of 1 and NOx emission costs enter with a coefficient significantly less than one.

5. Conclusion

Taken together, our results suggest that emissions permit prices were used by electricity suppliers during the last six months of 2000 and early 2001 to enhance their ability to exercise market power in the California electricity market. The evidence presented on the NOx emissions permit purchase prices, unused permit holdings, generation unit operating decisions, and the bidding behavior of suppliers in the CAISO's real-time market are all consistent with the view that the prices of RECLAIM permits were used to justify higher bid prices into California's electricity market. The results in section 4.3 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. The deviations in hourly plant operation behavior relative to the competitive benchmark Section 4.2 suggests that unit owners were successful at raising wholesale electricity prices by bidding high prices from units located in the SCAQMD region during 2000. These units 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

[12] To preserve anonymity, the numbers used for fuel costs do not correspond to the numbers used for NOx emissions permit costs.

electricity relative to what would occur under a competitive benchmark pricing dispatch treating NOx emissions costs as a production cost.

These higher bid prices are also consistent with the greater ability suppliers had to exercise unilateral market power in CAISO real-time market during the last six months of 2000 documented in Wolak (2003b). Furthermore, because market clearing units appeared to be costly to run due to high emissions costs electricity prices appeared to be set at the cost of the marginal plant even if, in fact, these costs reflected behavior in the RECLAIM market and the ability to exercise unilateral market power. In this way, the behavior we observe is not only a strategic mechanism for generators to raise market clearing prices but it also allows them to "cost-justify" bids into the competitive market reducing regulators ability to diagnose market power.

Although our paper focuses on the interaction of the RECLAIM market with the California electricity market in unique period of market turmoil, we believe our results have implications for other emissions permit markets. Perhaps the most relevant application for our findings is the introduction of greenhouse gas (GHG) emissions permit trading to address climate change. Although fossil-fuel generation unit owners produce a fraction of worldwide GHG emissions, they are likely to be early and substantial participants in any GHG emissions permit trading scheme. For example, the European Emissions Trading Scheme Directive established a market for tradable GHG emissions permits. While electricity generators comprise only 20 percent of overall carbon emissions in this market area they represent more than 50 percent of the emissions covered by the market (Linares, et al., 2006). Linares, et. al. (2006) argue high GMG emissions rate generators with the ability to exercise unilateral market power in the wholesale electricity market are likely to more frequently set market wide prices (i.e. maginal units are likely to incorporate GHG permit prices in their bids). For this reason, increases in permit prices are likely to increase electricity prices significantly. This description of the market structure accords with the model of strategic behavior we propose as well as many of the enabling conditions we argue are necessary.

The behavior we document here also underscores the need for transparency in emissions permit markets. This is fundamental to the efficient operation of an emissions permit market but clearly has implications for downstream product markets where firms have the ability to exercise unilateral market power. In particular, the emissions permit market design process should focus on creating conditions for uniformity in permit prices across all types of market actors. One aspect of the RECLAIM market that facilitated the use of RTCs to raise wholesale electricity prices was the paid-as bid nature of transactions. This model allowed suppliers interested in raising RECLAIM transactions prices to do so without impacting the prices paid by other 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. One plausible solution could be periodic trading of RTC permits (with anonymity for buyers and sellers) using a market-clearing price mechanism.

The evidence for strategic use of emissions permits also bears on the debate over the appropriate methodology for allocating emissions rights. A complete answer to this question facing policymakers is beyond the scope of this paper. However, we note that if permits are not only valuable as a right to emit but also potentially as a mechanism to exert unilateral market power in the downstream product market they are even more valuable. Thus, the magnitude of the transfer from consumers to producers when emissions rights are allocated without a price has the potential to be very large. An appropriately designed and administered uniform-price auction has the potential to reduce the ability of market actors to use permits to raise downstream prices if bids in the auction reflect these expected profits.

References

Borenstein, Severin, Bushnell, James, and Wolak, Frank A. (2002) Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market, *American Economic Review*, December, 1367-1405.

California Energy Commission, (2001) “California’s Electricity Market,” April, available from http://www.energy.ca.gov/maps/ELECTRICITY_MARKET.PDF.

Coy, Carol, Mueller, Pang, Luong, Danny, Tsai, Susan, Nguyen, Don and Chen, Fortune (2001), “SCAQMD White Paper on the Stabilization of NOx RTC Prices.” South Coast Air Quality Management District. Diamond Bar, CA.

Fowlie, Merredith. (2010) “Emissions Trading, Electricity Industry Restructuring and Investment in Pollution Control.” *American Economic Review*, June, 100(3), 837-869.

Holland, Stephen and Moore, Michael (2007) “When to Pollute and When to Abate? Evidence on Intertemporal Permit Use in the Los Angeles NOx Market.” UCEI Center for the Study of Energy Markets, WP 178.

Joskow, Paul and Kahn, Ed. (2002) “A Quantitative Analysis of Pricing Behavior In California's Wholesale Electricity Market During Summer 2000: The Final Word,” *The Energy Journal*, December.

Klemperer, Paul and Meyer. (1989). Margaret, “Supply Function Equilibria in Oligopoly Under Uncertainty,” *Econometrica*, Nov, 57(6), 1243-1277.

Klier, Thomas, Mattoon, Rick and Praeger, Michael. (1996). A Mixed Bag Assessment of Market Performance and Firm Trading Behavior in the NOx RECLAIM Program. *Chicago Federal Reserve Working Paper*. WP-1996-12. August.

Linares, Pedro, Javier Santos, Francisco, Ventosa, Mariano and Lapiedra, Luis. (2006) “Impacts of the European Emissions Trading Scheme Directive and Permit Assignment Methods on the Spanish Electricity Sector,” *The Energy Journal*, 27(1), 79-98.

Wolak, Frank A. (2003a) “Identification and Estimation of Cost Functions Using Observed Bid Data: An Application to Electricity, *Advances in Econometrics: Theory and Applications, Eighth World Congress, Volume II*, Mathias Dewatripont, Lars Peter Hansen, and Stephen J. Turnovsky (editors), Cambridge University Press, 133-169.

Wolak, Frank A. (2003b) “Measuring Unilateral Market Power in Wholesale Electricity Markets: The California Market 1998 to 2000" *American Economic Review*, May, 425-430.

Wolak, Frank A. (2007) “Quantifying the Supply-Side Benefits from Forward Contracting in Wholesale Electricity Markets, *Journal of Applied Econometrics*, volume 22, 1179-1209.

Appendix A

Evidence for brokers role in search costs can be seen by analyzing the average spread between purchase and sale price for RTCs where a broker facilitated the transaction. Using the RECLAIM trade data we compute the difference between price paid for RTCs by brokers and the sale price to generators with units inside and outside the RECLAIM market, generators with units only inside, and to all other participants in the market. Table 3 presents the average difference for these groups by year. For 2000 and 2001 vintage RTCs, brokers appear to be taking significant losses on trading with non-generation firms.[13] On the other hand trades made with generation unit owner with facilities inside and outside of the RECLAIM region were profitable for both 2000 and 2001 vintage permits. Trades of 2001 vintage permits were also profitable when the buyer was a wholesale electricity supplier with generation units only inside the SCAQMD area. This is consistent with the results presented in 4.1 in which estimates of γ_{01}, λ_{00} and λ_{01} are greater than 0 and precisely estimated, but γ_{00} is not. For every vintage of permit and buyer type whose behavior is consistent with strategic use of RTC permits, brokers appear to have made very large spreads, whereas for all other transactions they actually lost money on average, at least on the basis of transactions prices.

Taking a closer look at one of the largest brokers in the RECLAIM market provides an example of how brokers might have found facilitating generator behavior to raise transactions prices for NOx permits a profitable enterprise. This broker made a significant number of trades in the RECLAIM market and had been active in the market since its inception. It traded on behalf of generation firms (both InOut and AQMD type firms) throughout their operation in the RECLAIM market, before and during the "California Electricity Crisis" period. However, the broker dramatically increased work with generators in periods in which it was profitable to pay very high

[13] Brokers were also paid a transaction fee, typically a percentage of the total transaction cost. This would have allowed them to recoup the cost of these trading losses. This analysis was done using RECLAIM transaction data. Thus we do not have data on the terms of the fees or the amount that brokers may have made.

prices for RTCs. Specifically, 1998 and 1999 vintage RTCs sales to InOut generators were only 2.44% and 7.91% of the firm's total sales in the RECLAIM market. For 2000 and 2001 permits, however, sales to InOut generators jumped dramatically to 29.55% and 12.37% of sales for those respective vintages. This change is not unexpected, viewed in light of the profitability of trading with generators, but it does underscore the potential gains brokers would have made by finding low priced permits on the "illiquid" or smaller side of the RECLAIM market and selling to generators in high willingness to pay periods. The broker's trades with generators with units solely inside the SCAQMD also increased for 2000 and 2001 vintage permits. In fact, for 2000 vintage permit sales 44% of their sales revenues was with generation unit owners with units both inside and outside of SCAQMD or only inside SCAQMD.

Appendix B

BBW provides additional detail on computing the competitive benchmark pricing. In this appendix we provides some additional detail as it relates to our estimates.

To account for the fact that the vector of hourly unit-level outputs from all fossil fuel generation units in California is a realization from the joint distribution of unit-level availabilities for all 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 their 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 generation unit-level availabilities. As BBW note, 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 variable cost of all units in the CAISO control area. This issue is particularly important for the present analysis.

For each hour from June 1, 1998 to December 31, 2000, we compute the average unit-level output for each fossil-fuel generation unit in the California ISO control area from each competitive benchmark price realizations for each of the 100 draws from the joint distribution of unit-level availabilities. The following notation is used:

$\mathbf{OUT\_ACT_{hj}}$ = 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 7 of BBW, the actual California market price is set by the intersection of the import supply curve with the aggregate willingness to 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 within-control-area bidder (a higher willingness to supply output at the same price) will replace expensive imports. 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. The net result of the assumed price-taking offer behavior of California suppliers under the BBW competitive benchmark pricing simulation is a larger average supply from these fossil-fuel units than the amount actually supplied by these units. That is why the average value y_{hj} is negative.

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: Average Difference Between Broker Purchase Price and Sale Price for RTCs

RTC Vintage	1997	1998	1999	2000	2001
Non Generation Buyer	-$0.02	-$0.12	-$0.21	-$12.77	-$5.52
Inout Generator Buyer		-$0.15	$0.05	$2.05	$14.54
AQMD Generator Buyer			$0.23	-$4.95	$11.87

Table 4: Number of Unused RTCs by Market Participant Type

	Generator 1	Generator 2	Generator 3	LADWP	Other Generators	Traders
1997	14,665		N/A	702,465	20,924	311,213
1998	283,408	10,004	80,228	750	13,558	93,270
1999	448,354	0	0	14,817	5,096	62,327
2000	472	3,490	0	9,623	908	98,396

Table 5: Share of Unused RTCs Given Buyer Characteristics and Transactions Date

Dependent Variable = Share of Market Wide Unused RTC NOx Emissions Permits		
Variable	Parameter Estimate	Standard Error
Cycle2*Year98	-0.004	0.002
Cycle2*Year99	0.001	0.003
Cycle2*Year00	-0.004	0.002
Year99	-0.008	0.002
Year00	-0.002	0.002
[Cycle2*Year99+Year00]*Raise	0.025	0.007
Number of Observations = 1,634		R2 = 0.48

Table 6: Share of Unused RTCs Given Buyer Characteristics and Transactions Date Separating Cycle 2 1999 and 2000

Dependent Variable = Share of Market Wide Unused RTC NOx Emissions Permits		
Variable	Parameter Estimate	Standard Error
Cycle2*Year98	-0.004	0.002
Cycle2*Year99	0.001	0.003
Cycle2*Year00	-0.004	0.002
Year99	-0.008	0.002
Year00	-0.001	0.001
Cycle2*Year99*Raise	0.028	0.009
Year00*Raise	0.022	0.008
Number of Observations = 1,634		R2 = 0.48

Table 7: 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	0.46
InOutGen*Year99	35.032	0.593
InOutGen*Year00	66.69	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 8: 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	33.12	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 9: 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 4 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 4 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 4 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 5 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 4 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 5 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 regressions include monthly dummy variables.

Table 10: Unit-Level Marginal Cost Functions Given Fuel Costs and NOx Emissions Rate Costs

Generation Unit Level Marginal Cost Function for Unit j in Hour i (Derived from Assumption of Expected Profit-Maximizing Bidding Behavior)		
Variable	Parameter Estimate	Standard Error
Intercept	4.290	0.922
Firm2	1.493	0.204
Firm3	0.502	0.203
Firm4	-0.332	0.189
Firm5	-0.123.	0.232
Gas*HR1	0.944	0.062
Gas*HR2	0.871	0.076
Gas*HR3	0.935	0.042
Gas*HR4	1.012	0.049
Gas*HR5	0.893	0.084
NOxPrice*NOxRate1	0.347	0.113
NOxPrice*NOxRate2	0.319	0.115
NOxPrice*NOxRate3	0.292	0.132
Estimation Constraining All Gas*HR and NOxPrice*NOxRate Coefficients To Be Equal		
Intercept	4.106	0.198
Firm2	1.323	0.232
Firm3	0.631	0.198
Firm4	-0.408	0.212
Firm5	-0.082	0.282
Gas	0.972	0.041
NOxPrice*NOxRate	0.344	0.083

Figure 1: Using NOx Permit Prices to Raise Wholes Electricity Prices

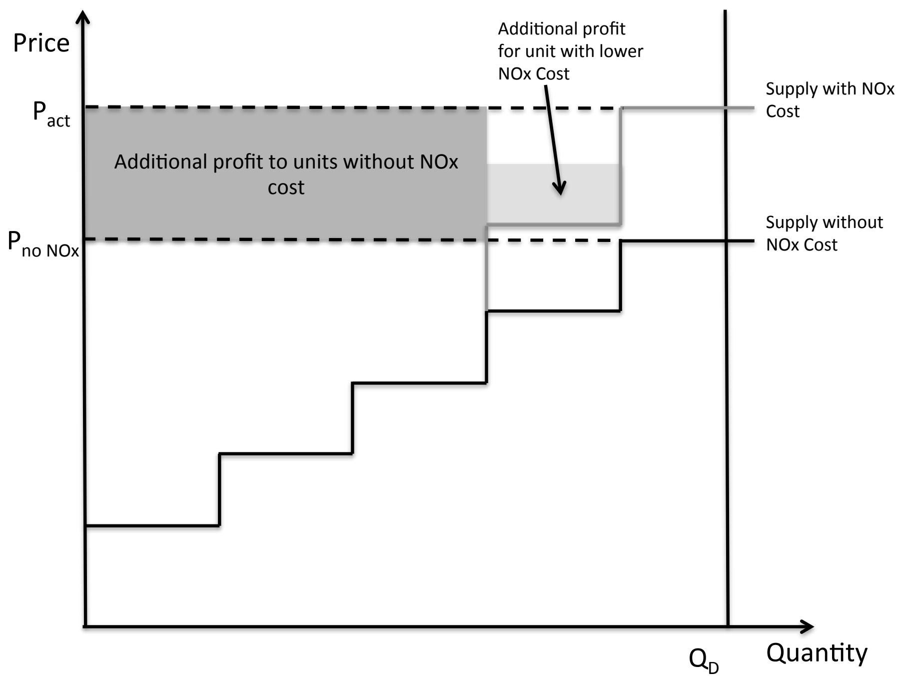

Figure 2: Map or SCQAQMD Coverage Area

Source: South Coast Air Quality Management District (http://www.aqmd.gov/map/mapaqmd1.pdf)

Figure 3: RTC Supply and Reported Emissions

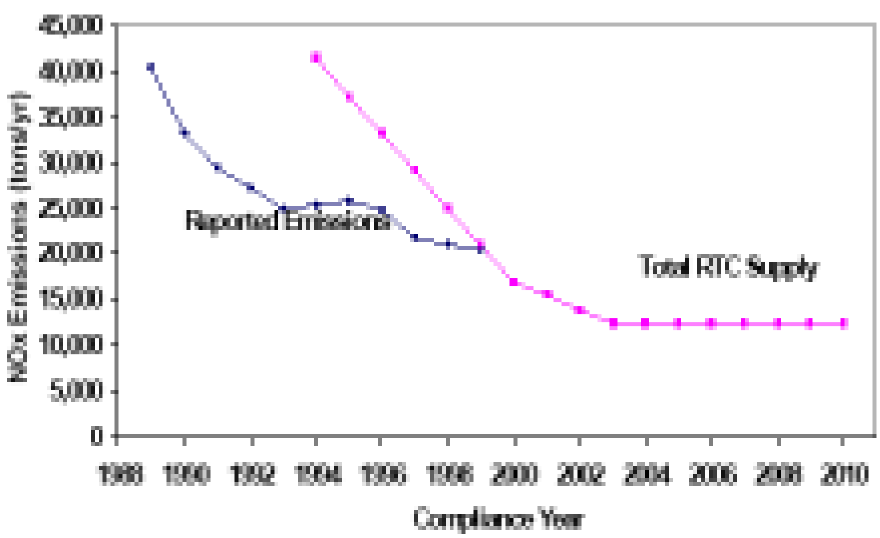

Figure 4: Mean RTC Price for 2000 and 2001 Vintage Permits

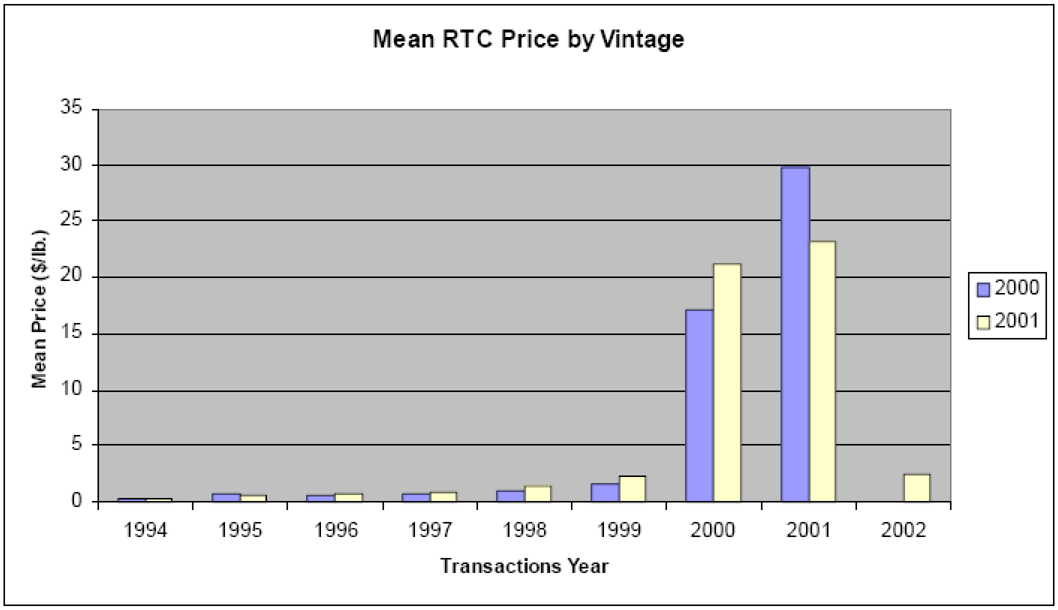

Figure 5: Transaction Volume Weighted Average RTC Prices

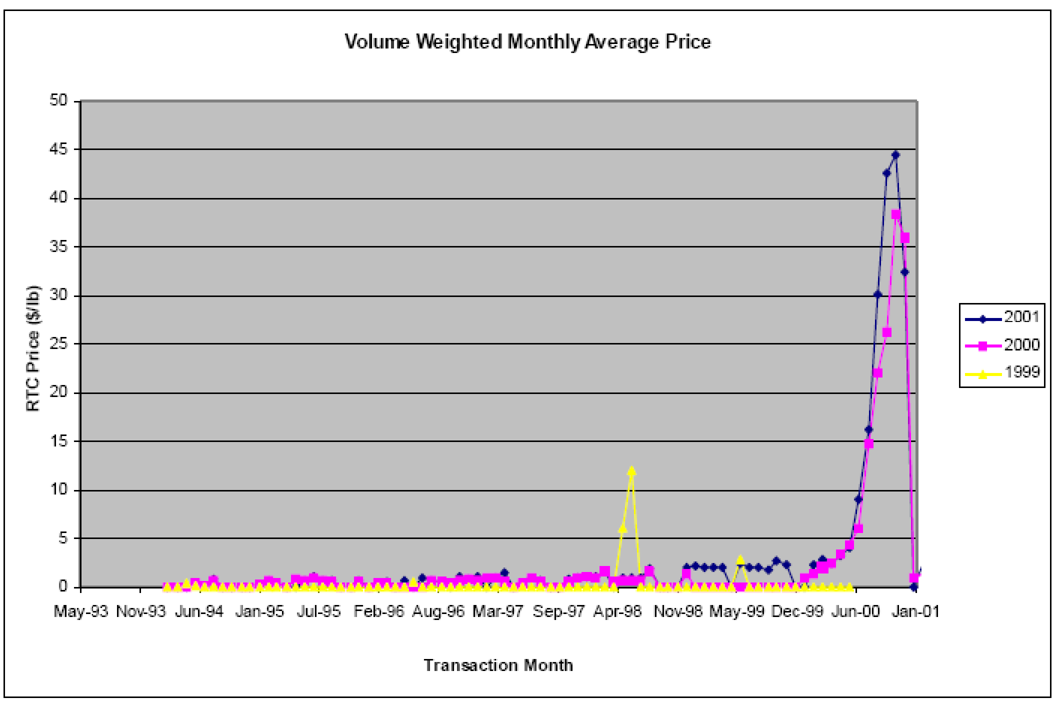

Figure 6: Standard Deviation of RTC Transaction Prices by Year

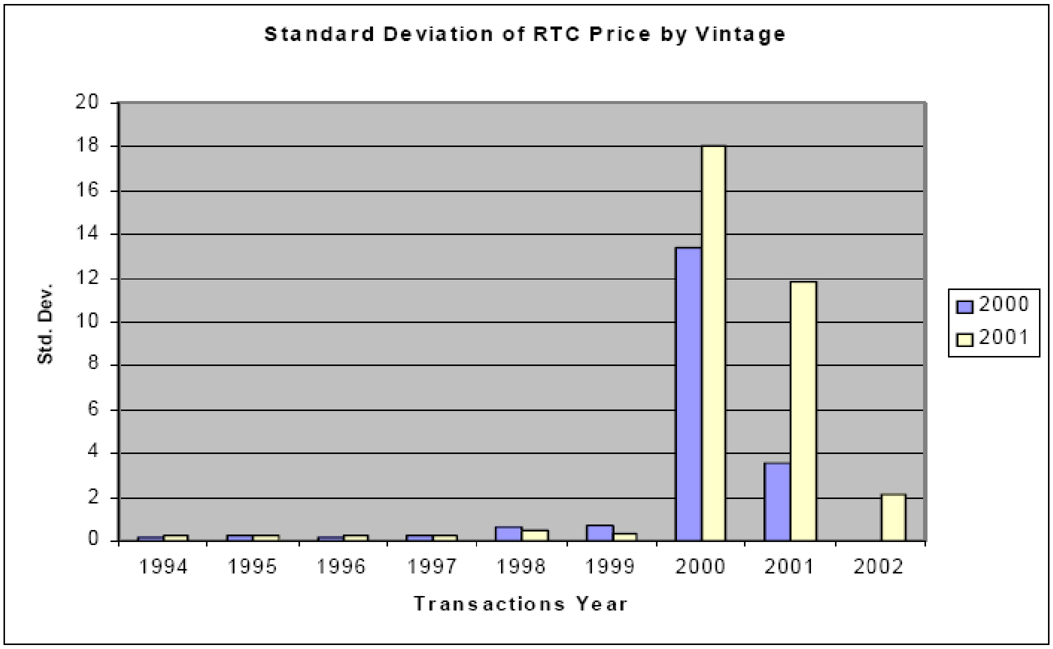

Figure 7: Average Transaction Volume by Year

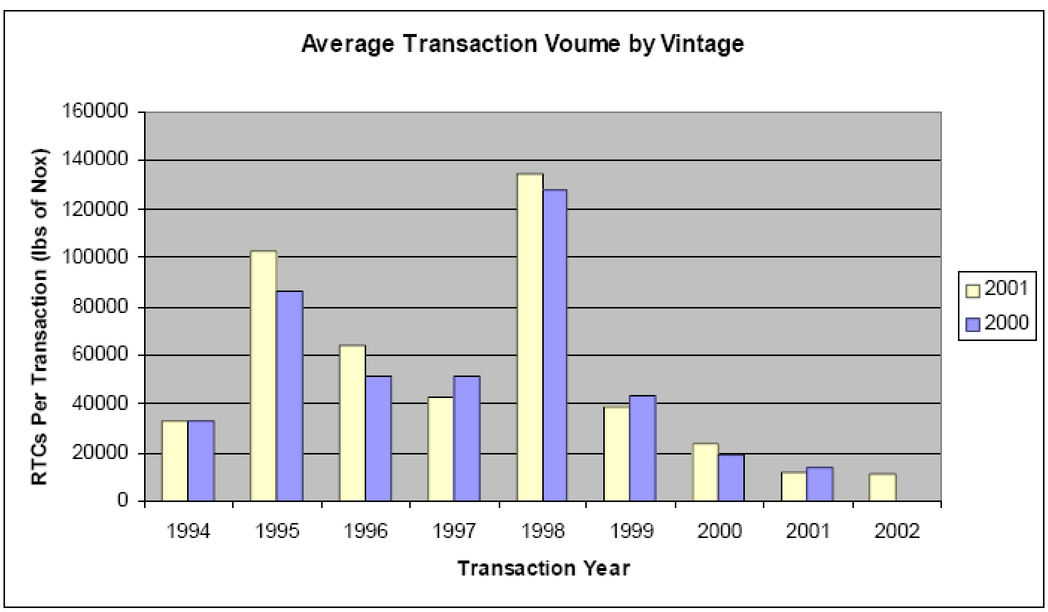

Figure 8: Total Annual RTC Transaction Volume

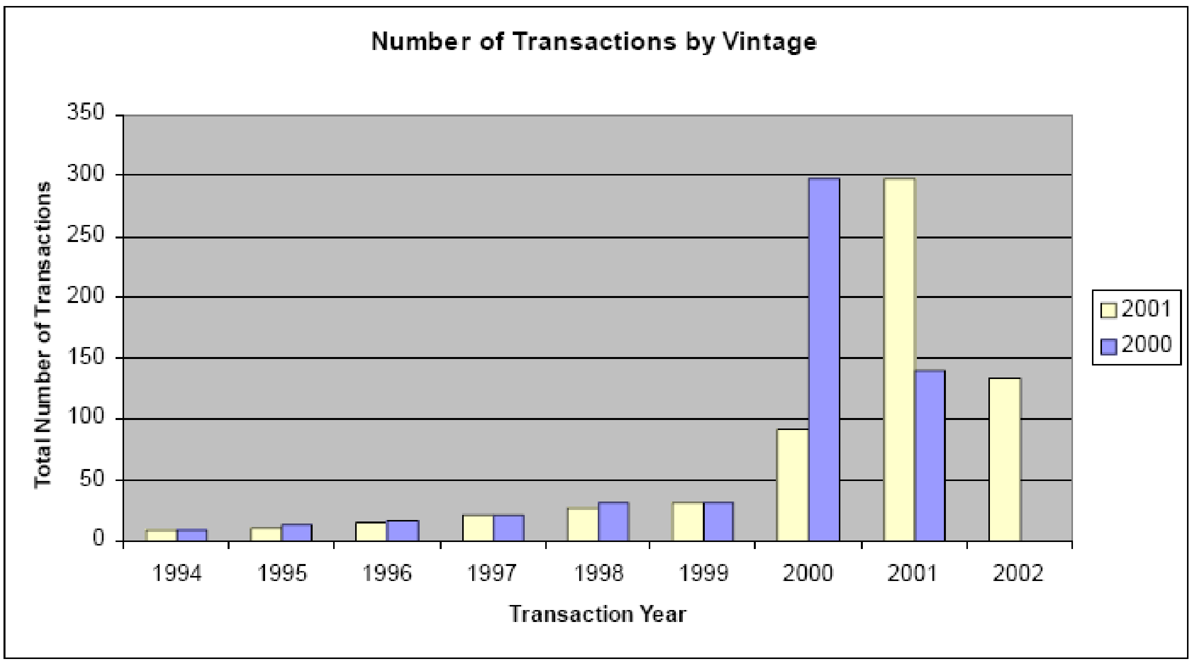

Figure 9: Cummulative Distribution of NOx Emission Rates in SCAQMD

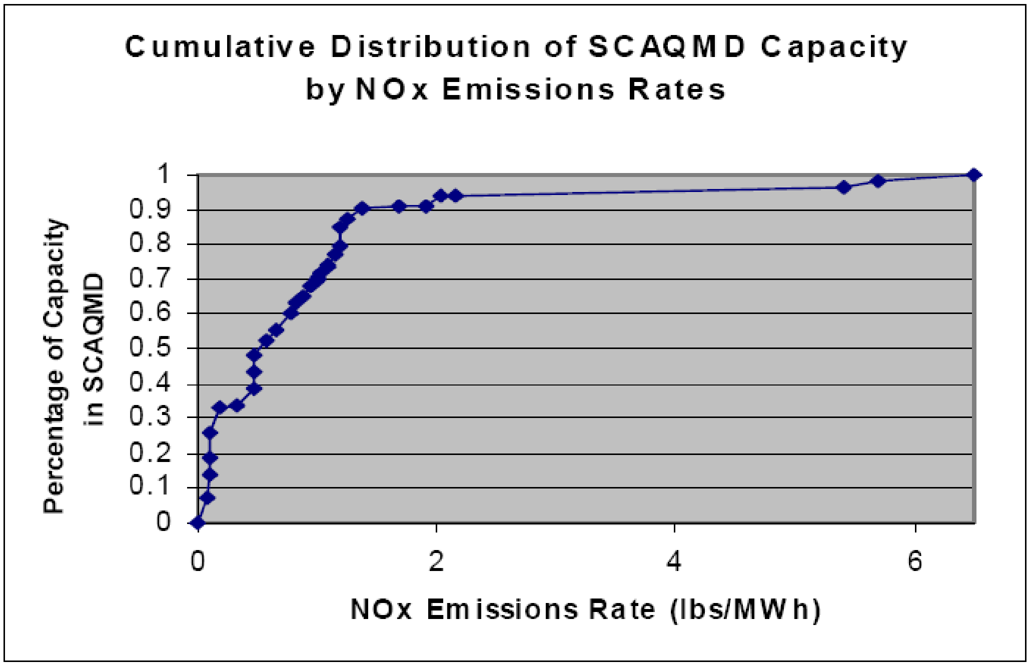

Figure 10: Monthly Average Real-Time Prices by Congestion Zone

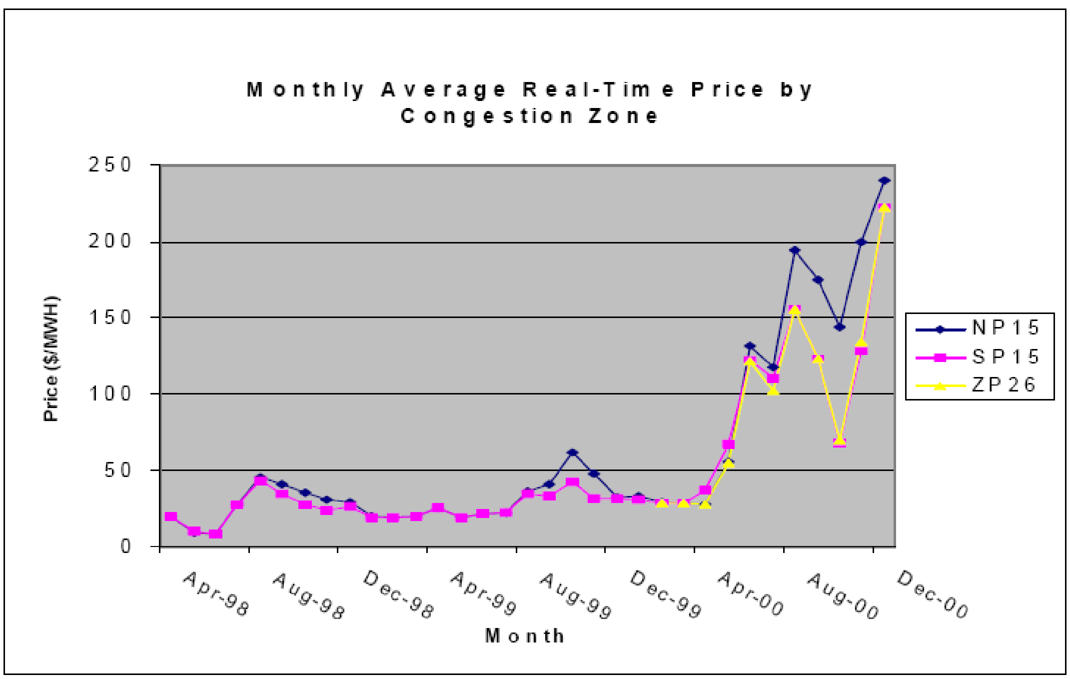

Figure 11: Monthly Average NOx Emission Prices Used in BBW (2002)