Market Mechanisms and Incentives: Applications to Environmental Policy

A Workshop Sponsored by the U.S. Environmental Protection Agency's National Center for Environmental Economics (NCEE) and National Center for Environmental Research (NCER)

Resources for the Future
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Market Mechanisms and Incentives: Applications to Environmental Policy

Resources for the Future
1616 P Street, NW, Washington, DC 20036
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October 17th – 18th, 2006

October 17, 2006: Market Mechanisms in Environmental Policy

8:00 a.m. – 8:45 a.m. **Registration**

8:45 a.m. – 11:45 a.m. **Session I: Brownfields and Land Issues**
Session Moderator: **Robin Jenkins**, EPA, National Center for Environmental Economics

8:45 a.m. – 9:00 a.m. Introductory Remarks: **Sven-Erik Kaiser**, EPA, Office of Brownfields Cleanup and Redevelopment

9:00 a.m. – 9:30 a.m. Environmental Liability and Redevelopment of Old Industrial Land
Hilary Sigman, Rutgers University

9:30 a.m. – 10:00 a.m. Incentives for Brownfield Redevelopment: Model and Simulation
Peter Schwarz and **Alex Hanning**, University of North Carolina at Charlotte

10:00 a.m. – 10:15 a.m. **Break**

10:15 a.m. – 10:45 a.m. Brownfield Redevelopment Under the Threat of Bankruptcy
Joel Corona, EPA, Office of Water, and **Kathleen Segerson**, University of Connecticut

10:45 a.m. – 11:00 a.m. Discussant: **David Simpson**, EPA, National Center for Environmental Economics

11:00 a.m. – 11:15 a.m. Discussant: **Anna Alberini**, University of Maryland

11:15 a.m. – 11:45 a.m. Questions and Discussion

11:45 a.m. – 12:45 p.m. **Lunch**

12:45 p.m. – 2:45 p.m. **Session II: New Designs for Incentive-Based Mechanisms for Controlling Air Pollution**
Session Moderator: **Will Wheeler**, EPA, National Center for Economic Research

12:45 p.m. – 1:15 p.m. Dynamic Adjustment to Incentive-Based Environmental Policy To Improve Efficiency and Performance
Dallas Burtraw, Danny Kahn, and Karen Palmer, Resources for the Future

	1:15 p.m. – 1:45 p.m.	Output-Based Allocation of Emissions Permits for Mitigating Tax and Trade Interactions **Carolyn Fischer**, Resources for the Future
	1:45 p.m. – 2:00 p.m.	Discussant: **Ann Wolverton**, EPA, National Center for Environmental Economics
	2:00 p.m. – 2:15 p.m.	Discussant: **Arik Levinson**, Georgetown University
	2:15 p.m. – 2:45 p.m.	Questions and Discussion
2:45 p.m. – 3:00 p.m.	**Break**	
3:00 p.m. – 5:30 p.m.	**Session III: Mobile Sources** Session Moderator: **Elizabeth Kopits**, EPA, National Center for Environmental Economics	
	3:00 p.m. – 3:30 p.m.	Tradable Fuel Economy Credits: Competition and Oligopoly **Jonathan Rubin**, University of Maine; **Paul Leiby**, Environmental Sciences Division, Oak Ridge National Laboratory; and **David Greene**, Oak Ridge National Laboratory
	3:30 p.m. – 4:00 p.m.	Do Eco-Communication Strategies Reduce Energy Use and Emissions from Light Duty Vehicles? **Mario Teisl**, **Jonathan Rubin**, and **Caroline L. Noblet**, University of Maine
	4:00 p.m. – 4:30 p.m.	Vehicle Choices, Miles Driven, and Pollution Policies **Don Fullerton**, **Ye Feng**, and **Li Gan**, University of Texas at Austin
	4:30 p.m. – 4:45 p.m.	Discussant: **Ed Coe**, EPA, Office of Transportation and Air Quality
	4:45 p.m. – 5:00 p.m.	Discussant: **Winston Harrington**, Resources for the Future
	5:00 p.m. – 5:30 p.m.	Questions and Discussion
5:30 p.m.	**Adjournment**	

October 18, 2006:

8:45 a.m. – 9:15 a.m.	**Registration**	
9:15 a.m. – 12:20 p.m.	**Session IV: Air Issues** Session Moderator: **Elaine Frey**, EPA, National Center for Environmental Economics	
	9:15 a.m. – 9:45 a.m.	Testing for Dynamic Efficiency of the Sulfur Dioxide Allowance Market **Gloria Helfand**, **Michael Moore**, and **Yimin Liu**, University of Michigan
	9:45 a.m. – 10:05 a.m.	When To Pollute, When To Abate: Evidence on Intertemporal Use of Pollution Permits in the Los Angeles NOx Market **Michael Moore** and **Stephen P. Holland**, University of Michigan

10:05 a.m. – 10:20 a.m.	**Break**	
	10:20 a.m. – 10:50 a.m.	A Spatial Analysis of the Consequences of the SO_2 Trading Program **Ron Shadbegian**, University of Massachusetts at Dartmouth; Wayne Gray, Clark University; and Cynthia Morgan, EPA
	10:50 a.m. – 11:20 a.m.	Emissions Trading, Electricity Industry Restructuring, and Investment in Pollution Abatement **Meredith Fowlie**, University of Michigan
	11:20 a.m. – 11:35 a.m.	Discussant: **Sam Napolitano**, EPA, Clean Air Markets Division
	11:35 a.m. – 11:50 a.m.	Discussant: **Nat Keohane**, Yale University
	11:50 a.m. – 12:20 p.m.	Questions and Discussion
12:20 p.m. – 1:30 p.m.	**Lunch**	
1:30 p.m. – 4:35 p.m.	**Session V: Water Issues** Session Moderator: **Cynthia Morgan**, EPA, National Center for Environmental Economics	
	1:30 p.m. – 2:00 p.m.	An Experimental Exploration of Voluntary Mechanisms to Reduce Non-Point Source Water Pollution With a Background Threat of Regulation Jordan Suter, Cornell University, Kathleen Segerson, University of Connecticut, Christian Vossler, University of Tennessee, and Greg Poe, Cornell University
	2:00 p.m. – 2:30 p.m.	Choice Experiments to Assess Farmers' Willingness to Participate in a Water Quality Trading Market **Jeff Peterson**, Washington State University, and Sean Fox, John Leatherman, and Craig Smith, Kansas State University
2:30 p.m. – 2:45 p.m.	**Break**	
	2:45 p.m. – 3:15 p.m.	Incorporating Wetlands in Water Quality Trading Programs: Economic and Ecological Considerations **Hale Thurston** and Matthew Heberling, EPA, National Risk Management Research Laboratory, Cincinnati, Ohio
	3:15 p.m. – 3:35 p.m.	Designing Incentives for Private Maintenance and Restoration of Coastal Wetlands **Richard Kazmierczak** and **Walter Keithly**, Louisiana State University at Baton Rouge
	3:35 p.m. – 3:50 p.m.	Discussant: **Marc Ribaudo**, USDA, Economic Research Service
	3:50 p.m. – 4:05 p.m.	Discussant: **Jim Shortle**, Pennsylvania State University
	4:05 p.m. – 4:35 p.m.	Questions and Discussions
4:35 p.m. – 4:45 p.m.	**Final Remarks**	

4:45 p.m.	**Adjournment**

Testing for Dynamic Efficiency of the Sulfur Dioxide Allowance Market

By

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School of Natural Resources and Environment
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October 27, 2006

Abstract: The sulfur dioxide (SO_2) allowance market is the "grand policy experiment" in environmental regulation. Evidence is mixed on the efficiency of the market. We examine the intertemporal allowance market using monthly data on SO_2 spot market prices from late 1994 through 2003. We test whether the price path follows the Hotelling *r*-percent rule for intertemporal arbitrage. This is a direct test of a competitive market equilibrium and, thus, an indirect test of dynamic efficiency. The Hotelling rule is rejected on balance, which provides limited evidence of inefficiency. We also seek to explain the movement of monthly allowance prices. In an environment of uncertainty, structural breaks in allowance price trends and unexpected changes ("shocks") in markets related to the SO_2 market can affect price movements. We include variables for two endogenous breaks and for shocks in five related markets. These variables substantially improve the goodness of fit. These new insights on the SO_2 allowance market are especially relevant as the market is serving as the template for national and international markets in carbon dioxide emissions.

We are grateful for helpful suggestions and comments from Peter Berck, Dallas Burtraw, Gary R. Hart, Kentaro Kai, Nat Keohane, and Karen Palmer. We thank Junsoo Lee for sharing econometric software used in the research. We also gratefully acknowledge financial support from the National Center for Environment Research, U.S. Environmental Protection Agency (EPA Grant Number R831775).

1 Introduction

The sulfur dioxide (SO_2) allowance market is the "grand policy experiment" in environmental regulation: a large-scale, long-term program to achieve cost-effective regulation of pollution emissions through an economic policy instrument.[1] An "allowance" is a tradable permit under the Clean Air Act's Acid Rain Program. An allowance issued in a particular year authorizes its owner to emit one ton of SO_2 in that year or any subsequent year (under the program's banking provision). Launched in 1994, the market has allocated SO_2 allowances among electricity producers for over a decade. There is widespread agreement about the program's dramatic success (Gayer, Horowitz, and List, 2005), due in part to estimates of compliance cost savings during 1995-99 of $358 million per year (68%) relative to command-and-control regulation (Ellerman et al., 2000). Based on this success, the SO_2 market is serving as the template for CO_2 emission markets under the European Union Emission Trading System (Kruger and Pizer, 2004) and the seven-state Regional Greenhouse Gas Initiative in the northeastern United States (Regional Greenhouse Gas Initiative, 2006).

Yet evidence on the efficiency of the SO_2 market is mixed. Joskow, Schmalensee, and Bailey (1998) conclude that "a relatively efficient private market" had developed by mid-1994 (even prior to the official start of the program), based on evidence that a transparent, single price was clearing the SO_2 market and that intertemporal markets had emerged for allowances of future vintages.[2] Ellerman and Montero (2005) also find evidence of "reasonably efficient banking" of SO_2 allowances over the 1995-2002 period.[3] In contrast, Carlson et al. (2000) find that a large share of potential gains from trade went unrealized in 1995 and 1996, suggesting that a mature market had yet

[1] Stavins (1998) coined the phrase "grand policy experiment." The SO_2 market implements twenty-five years of economic literature that develops the theoretical and policy analysis of tradable permit systems (beginning with Crocker, 1966; Dales, 1968; Montgomery, 1972).
[2] This evidence of market efficiency is also reported in related publications by the same researchers along with additional co-authors; see Ellerman et al. (2000) and Schmalensee et al. (1998).
[3] Ellerman and Montero (2005) develop a theoretical model of efficient banking (storage) of allowances, transform it into a simulation model, and compare simulated banking with actual banking under the program. Their approach to analysis of the intertemporal allowance market differs from ours: they analyze intertemporal quantities, while we analyze intertemporal prices.

to develop. Keohane (2006) finds similar evidence of substantially lower estimated cost savings of \$153 million per year during 1995-99, which is only 17% of his estimated abatement costs under command-and-control regulation. What, then, is the status of the market: are profit opportunities being fully exploited in an efficient market? Or, are firms not maximizing profits, perhaps due to institutional barriers? As the grand policy experiment continues, analysis of market efficiency is critical for ongoing evaluation of the SO_2 market and for design of new pollution markets.

Our research addresses two questions about the intertemporal allowance market. First, what explains the intertemporal movement of monthly prices in the SO_2 spot market from August 1994 through December 2003? Initially falling through 1996, spot prices went through several peaks (above \$200 per ton) and troughs (below \$100 per ton) through 2003.[4] We apply Schennach's (2000) theoretical model of the intertemporal SO_2 allowance market under uncertainty to address this question.[5] Allowances are a storable commodity in the model, so that the risk-free interest rate, an SO_2-specific risk premium, and convenience yield affect SO_2 price movements. As well, according to Schennach, unexpected changes ("shocks") in markets related to the SO_2 market and unanticipated regulations can affect price movements. Our econometric analysis implements this model, including the use of variables for shocks in five markets related to SO_2 (electricity, low-sulfur coal, high-sulfur coal, natural gas, and labor).

Second, is the SO_2 price path consistent with a competitive equilibrium in the intertemporal market? As part of our analysis, we test for equilibrium using the Hotelling rule: whether allowance

[4] Prices climbed dramatically since late 2003 to break the \$1,000 per ton barrier in late 2005. This appears to be caused by the Clean Air Interstate Rule, which was proposed in January 2004 and issued formally in March 2005. The rule will significantly reduce the overall cap on SO_2 emissions beginning in 2010. As in Ellerman and Montero (2005) and Liski and Montero (2005), we do not use data after December 2003 because of the structural adjustment in the market due to this rule.

[5] Schennach's (2000) approach follows the literature on nonrenewable resource markets (Hotelling, 1931), storable commodity pricing under uncertainty (e.g., Pindyck, 1993), and bankable pollution permits (e.g., Kling and Rubin, 1997).

prices follow an *r*-percent trajectory over time (Hotelling, 1931).[6] The question of competitive equilibrium relates directly to the issue of SO_2 market efficiency. Under the *first fundamental theorem of welfare economics*, evidence of competitive equilibrium would imply dynamic efficiency (e.g., Mas-Colell, Whinston, and Green, 1995). In this case, dynamic efficiency involves minimizing present-value cost of compliance with the intertemporal SO_2 regulation. While evidence against a competitive equilibrium would not necessarily rule out efficiency, it does appear to create the possibility of arbitrage profits from intertemporal allowance reallocation.

Here we highlight key results on the two questions. First, our ability to explain SO_2 price movements is greatly improved by two sets of variables: variables for structural breaks in the allowance price path and variables for shocks in SO_2-related markets. We employ an econometric method (Lee and Strazicich, 2003) to identify two endogenous structural breaks in the price path in the late 1990's. These breaks correspond to the time period when convenience yields for allowances of future vintages rose dramatically as a percentage of price. Including the structural breaks and the market shocks substantially improves the goodness of fit and, as well, lowers the standard error of the estimated coefficient on the interest rate variable.

Second, the Hotelling rule is rejected regularly in hypothesis tests on the estimated coefficients for the interest rate variable in several model specifications. We conclude that the allowance market was not in a competitive equilibrium during 1994 to 2003. As the first direct econometric evidence on the SO_2 allowance market, this is an important new insight on performance of the market.

The remainder of the paper is organized as follows. Section 2 presents descriptive evidence on the intertemporal allowance market. Section 3 describes the empirical models for the analysis.

[6] Tests of the Hotelling rule for nonrenewable resources are notoriously difficult to implement because marginal extraction cost is rarely observed with accuracy (Berck, 1995). We circumvent this problem with SO_2 allowances because of their costless extraction and storage, which makes the SO_2 case ideal for testing the rule.

Section 4 describes the data, variables, and econometric methods. Section 5 presents the results, and Section 6 provides closing remarks.

2 Evidence from the Intertemporal Allowance Market

Each year, allowances are distributed free of charge to firms that operate coal-fired power plants in the United States.[7] The birth year of an allowance is defined as its *vintage*, for example, an allowance issued this year is vintage 2006. An allowance can either be used to cover a ton of SO_2 emissions in its birth year or be banked (stored) for future use. The fact that a banked allowance is a perfect substitute for an allowance of a future vintage gives rise to the possibility of an intertemporal market.

Two characteristics of the program then created clear incentives for banking and thereby brought the intertemporal market into reality. First, allowance allocations were substantially higher in 1995 and 1996 than originally planned due to a variety of special provisions (Ellerman et al. 2000). Making compliance unexpectedly easier facilitated banking; the highest levels of annual storage occurred in those years (Table 1). Second, allocations to individual electric generating units decreased substantially in Phase II of the program relative to Phase I. (Phase I covered 1995-99, while Phase II covers 2000 and thereafter. Phase I encompassed only the 263 dirtiest large generating units, and Phase II encompasses almost all coal-fired generating units.) Thus, while the aggregate allocation increased in 2000, the per-unit allocations decreased for the dirtiest units. Electricity producers could be expected to ease this transition by banking allowances from Phase I to use in Phase II. This hypothesis is consistent with the pattern of accumulating unused allowances during Phase I, followed by drawdown of the stock during Phase II (Table 1).

A firm with extra allowances in this program has three choices: it can use the allowances itself (by reducing abatement effort or generating more electricity), it can sell the allowances to

[7] Power plants in Hawaii and Alaska are exempt from the regulation.

another source, or it can bank the allowances. In equilibrium under certainty, the present value of an allowance in any of these three uses should be equivalent; otherwise, profits can be made by reallocating allowances to the higher-valued use. The first two choices lead to equating of marginal costs of abatement across sources. The third option leads to the applicability of the Hotelling rule: a firm will be indifferent between current and future use of an allowance if the present value of allowances is the same in the current and future markets, or (put another way) if the undiscounted price path of allowances provides the same return as the best alternative monetary investment. Under uncertainty, though, this simple dynamic price path becomes more complex.

Schennach's (2000) theoretical model of the intertemporal SO_2 allowance market under uncertainty applies the economics of storable commodities (e.g., Pindyck, 1993). It is useful here to fix several ideas from the model about the SO_2 price path. With active banking and a positive balance in storage (i.e., an interior solution), the equilibrium condition for the price path[8] is

$$E_t p_{t+1} = (1 + r_t^f + r_t) p_t - y_t, \tag{1}$$

where E is the expectations operator, subscripts t and $t+1$ denote time, p_t is SO_2 allowance price, r_t^f is the risk-free interest rate, r_t is the SO_2 asset's risk premium (in the spirit of CAPM), and y_t is convenience yield in dollars per ton. Convenience yield is the service flow to holding a stock of a storable commodity in inventory to protect against complete depletion, or a "stockout" (Pindyck, 1993). Uncertainty must be present in the market to create convenience yield.

The remainder of this section presents descriptive evidence on relationships in the intertemporal allowance market, with a focus on convenience yield. We contrast evidence presented by Ellerman et al. (2000, p. 185-190) on the early years of the market (1994-99) with more recent evidence.

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[8] Schennach (2000) develops the model in continuous time, yet we present the model in discrete time for empirical purposes.

Ellerman et al. examine the intertemporal allowance market from the perspective of the forward market for future vintages of allowances during 1994-99. They assess two characteristics of these markets: the term structure of the market and the convenience yields on future vintages. The term structure of the forward market is measured by the time horizon of future allowance vintages that were selling in this market. In July 1995, the term structure was relatively short: transactions were occurring on vintages of up to +3 years, i.e., vintages that matured in 1996 through 1998. From January 1996 through January 1999, the term structure lengthened substantially, with transactions of vintages that matured in the range of +6 to +8 years. They conclude that the reasonably long term structure of the forward market in the late 1990's reflected a robust, healthy intertemporal market.

Convenience yields on future vintages reflected even stronger descriptive evidence of a relatively efficient intertemporal market. The relationship among convenience yield and the immediate settlement prices on current and future vintages is a particularly simple way to gauge the workings of an intertemporal market. Ellerman et al. (p. 187) derive this relationship as

$$p_t^{v(y)} = p_t^{v(y+t)} + c_t^{v(y+t)},$$

where $p_t^{v(y)}$ is the price of the current-year vintage at time *t*, $p_t^{v(y+t)}$ is the price of a $+t$ years vintage at time *t*, and $c_t^{v(y+t)}$ is the present-value convenience yield on the +t years allowance at time *t*. With both convenience yield and the CAPM risk premium equal to zero, current and future vintages should have the same price at *t*. This is a version of the Hotelling rule for the case of costless extraction and storage. With a positive convenience yield, future vintages trade at a discount to the current vintage. Ellerman et al. report relatively small present-value convenience yields for future vintages in the January 1996 through January 1999 period. For example, +3 vintages traded at a one to two percent discount relative to the current vintage, and +7 vintages traded at a three to four percent discount. Based on this evidence, they conclude that a "robust and efficient" intertemporal allowance market had emerged by early 1996.

The intertemporal allowance market appeared to be operating with textbook-quality efficiency in the late 1990's. The convenience yield on the price of a +7 years vintage allowance for July 1998 is the last datum reported by Ellerman et al.; the +7 vintage traded at a discount of about four percent relative to the current vintage at that time. Four percent is similar to the 5.8 percent discount on the +7 vintage from the annual EPA auction in late March of 1998.

Yet the functioning of the intertemporal market changed dramatically during the 1998-99 period. Table 1 presents publicly available data from the annual EPA auction.[9] Through the March 1998 auction,[10] present-value convenience yields on +7 year allowances were consistently small, with +7 allowances trading at a 4.3 to 5.8 percent discount.[11] In the March 1999 auction, however, the +7 year allowance traded at a 16.5 percent discount relative to the current vintage's price, and the absolute value of the convenience yield was also substantially higher than earlier levels, at $33 per ton. The March 2000 auction yielded an even higher convenience yield in percentage terms: a discount of 56.1 percent relative to the current vintage's price. The discounts remained relatively high thereafter and peaked in the 2005 auction at 62.3 percent.

With convenience yield as an indicator, uncertainty in the allowance market appeared to increase substantially prior to the March 1999 EPA auction and even more prior to the March 2000 auction. The first increase in uncertainty corresponds to the period of the first dramatic increase in SO_2 spot market prices, during which price reached a temporary peak at $197 per ton in July 1998 (Figure 1). The second increase in uncertainty – which occurred quite rapidly – corresponds to a

[9] In late March of each year, EPA sells 2.8 percent of the total number of allowances available that year in an auction. The auction data have the advantage of transparency. Actual transaction prices on forward markets are not publicly available from the private brokerage firms. [[Check accuracy of this statement!!]]

[10] Two future vintages, a +6 year vintage and a +7 year vintage, were sold in the 1995-1997 EPA auctions. Beginning 1998 and continuing thereafter, only a +7 year vintage was sold in the auctions.

[11] Early in the program, researchers criticized the discriminatory price mechanismof the EPA auction for resulting in a lower market-clearing price than would occur in a uniform price auction (Cason, 1993, 1995; Cason and Plott, 1996). Ellerman et al. (2000, p. 171) dismiss this criticism, arguing instead that the private allowance market imposes opportunity-cost bounds that effectively transform the auction into a common-value auction.

period of a rapid decrease in spot prices, from over $210 to under $140 per ton. Thus, the structural changes in convenience yield in the forward market are mirrored by volatility in the spot market.

A relevant fact is that these present-value convenience yields grew large at the same time that the stock of stored allowances was peaking (Table 1). For example, information on the end-of-year stock for 1999 would just become public prior to the March 2000 auction. Moreover, the convenience yields remained large in the first several years of Phase II of the program. Information was available during this period that, although the aggregate stock was declining, its rate of decline was much slower than its rate of growth during Phase I. Thus, convenience yields were increasing despite the evidence of substantial potential liquidity in the allowance market. In effect, the market was putting substantial weight on the possibility that the allowance stock could be depleted within the time frame of a +7 vintage allowance.

The descriptive evidence on the intertemporal allowance market has three implications for our analysis. One, the relative stability of the spot and forward markets during 1996-97 has given way to volatility and relatively large convenience yields. A model of the allowance market under uncertainty – not under certainty – thus appears appropriate. Two, the simple story of expected price movements following the Hotelling rule is insufficient in light of the evidence on convenience yields. The approach thus needs to incorporate convenience yield. Three, structural changes may be an important feature of allowance markets, and thus our methodology needs to allow for their occurrence.

3 Empirical Models

Schennach's (2000) theoretical model of the intertemporal SO_2 allowance market guides our empirical approach. The model describes the planner's problem of minimizing discounted SO_2 abatement costs over an infinite time horizon subject to time-dated allowance allocation, use, and storage. The planner's solution is identical to the competitive market equilibrium based on standard decentralization results. With certainty (perfect foresight), the model predicts that the SO_2 price path would increase smoothly at the rate of interest according to the Hotelling rule. The price path, of course, was quite volatile from 1994 through 2003 (Figure 1), so we reject the certainty model in favor of Schennach's model of the market under uncertainty.

With uncertainty, holding an allowance can generate two returns in addition to the interest rate. One is a risk premium (or discount) to holding allowances as an asset in a diversified portfolio of investments. This type of return has been studied extensively using the capital asset pricing model (CAPM).[12] A second return is convenience yield, which was described earlier. The model incorporates these two arguments.

Uncertainty in the SO_2 market may arise due to market, regulatory, or technological uncertainty (Schennach, 2000).[13] The error term in the regression reflects this new information. Yet we also attempt to capture this new information systematically by constructing variables for shocks in markets related to the SO_2 market.

3.1 Base Model

To develop an estimable form of equation (1), we manipulate the algebra and convert r_t to the empirical specification for CAPM to yield an expression for the expectation at *t* of the allowance price at *t+1*:

$$E_t p_{t+1} - p_t = r_t^f p_t + \frac{s_{am}}{s_{mm}}(r_t^m - r_t^f) p_t - y_t, \tag{2}$$

where r_t^m is the rate of return on the market portfolio of risky assets, s_{am} is the covariance between the rate of return on SO_2 allowances and r_t^m, and s_{mm} is the variance of r_t^m. The variable E_t

[12] Gaudet and Khadr (1991) and Slade and Thille (1997) develop models that integrate the Hotelling and CAPM models. The approach used here is consistent with their models. Slade and Thille also apply the model empirically.

[13] Market uncertainty reflects uncertainty in markets related to the SO_2 market, such as the natural gas market. Regulatory uncertainty reflects uncertain future developments in environmental regulation or regulation of electricity markets. Technological uncertainty reflects uncertain future develops in SO_2 abatement technology or "clean coal" technologies.

represents rational expectations conditional on information available at time *t*. The first term on the right-hand side represents the Hotelling rule for cost-minimizing intertemporal arbitrage in the SO_2 market. The second term on the right-hand side is the risk premium for holding SO_2 allowances as part of a diversified portfolio. The expression $(r_t^m - r_t^f)$ is the excess return on the market portfolio at time *t*. The risk premium for holding allowances is positive when s_{am} is greater than zero, i.e., allowances need to earn a positive premium when the covariance is positive. With risk-averse consumers (investors), an asset return that varies positively with the market portfolio is a liability. The last term on the right-hand side continues as convenience yield.

Because of unexpected shocks to the SO_2 market, the expected value of p_{t+1} is known only with error at time *t*. In other words, the actual price at *t+1* can be written as $p_{t+1} = E_t p_{t+1} + e_{t+1}$.[14] The error term e_{t+1} reflects new information about the SO_2 market that becomes available between *t* and *t+1*. The expected price path is not observable; substituting for $E_t p_{t+1}$ in equation (2) produces an equation with observable arguments:

$$p_{t+1} - p_t = r_t^f p_t + \frac{s_{am}}{s_{mm}}(r_t^m - r_t^f)p_t - y_t + e_{t+1}. \tag{3}$$

To convert to an econometric model, we assume that convenience yield is constant ($y_t = y$) and rewrite the equation as

$$p_{t+1} - p_t = a + b_1 r_t^f p_t + b_2 (r_t^m - r_t^f)p_t + e_{t+1}, \tag{4}$$

where $a = -y$ and $b_2 = s_{am}/s_{mm}$, which is standard practice for CAPM. The restriction $ß_1 = 1$ tests the Hotelling rule, which is the test for a competitive market equilibrium. The sign and significance of b_2 provides information on the CAPM risk premium for SO_2 allowances. Equation (4) is labeled the *Base Model*.

[14] Mankiw and Summers (1984) state the relation between actual and expected interest rates in this form.

Empirically, the intercept term a represents an average for convenience yield over time. We also incorporate two endogenous structural breaks, the first in February 1998 and the second in September 1999. The breaks are intercept shifters, so that the regression results produce information on averages for convenience yield from three phases of the market: (a) Aug. 1994-Jan. 1998, (b) Feb. 1998-Aug. 1999, and (c) Sept. 1999-Dec. 2003.

3.2 Base Model and Market Shocks

An extension of the *Base Model* puts structure on the new information entering the market between *t* and *t+1*. Comparison of equations (2) and (4) shows the difference between the *expected* and *actual* SO_2 price paths in an environment of uncertainty. The expected path in (2) evolves according to the equilibrium returns and service flows earned in the market. With traders lacking perfect foresight as in (4), however, the actual price also changes by another term, e_{t+1}, when new information arrives in the market between *t* and *t+1*. This occurs whenever the resolution of an uncertainty deviates from its expected value.

To capture the role of market uncertainty, we explicitly model new information from unexpected changes in five markets that might affect the SO_2 market.[15] Conceptually, the SO_2 abatement cost function for an electricity producer can be used to identify markets related to the SO_2 market. The arguments of an abatement cost function include: electricity price, low-sulfur coal price, high-sulfur coal price, natural gas price, wage rate, and SO_2 price. The new information from these five markets is derived as forecast errors from time-series models of market prices for low-sulfur coal, high-sulfur coal, natural gas, and labor; and of market quantities for electricity.[16] That is, we forecast monthly prices in each of these markets; compute forecast errors for each market as the

[15] The other general sources of new information – "news" emanating from regulatory and technological uncertainty – are not incorporated into the analysis. As information sources, they are more difficult to model as events that occur at a particular time. Moreover, we conjecture that new information in the five markets incorporates new information from the other sources. For example, new information about a breakthrough in "clean coal" technology should cause an unforeseen change in low- and high-sulfur coal prices.

[16] We use electricity sales instead of prices because prices in electricity markets are still regulated in many places and are not determined only by supply and demand.

difference between actual price and forecast price; and construct five independent variables. The data and time-series models used for this exercise are described further in Section 4.

We develop a second empirical specification using the idea that new information can explain SO_2 price movements. The error term e_{t+1} depends on these five sources of news:

$$e_{t+1} = f(elecusefe_{t+1}, lscprcfe_{t+1}, hscprcfe_{t+1}, ngasprcfe_{t+1}, wagefe_{t+1}) + n_{t+1},$$

where $elecusefe_{t+1}$ is forecast error for electricity sales at $t+1$, $lscprcfe_{t+1}$ is forecast error for low-sulfur coal price at $t+1$, $hscprcfe_{t+1}$ is forecast error for high-sulfur coal price at $t+1$, $ngasprcfe_{t+1}$ is forecast error for natural gas price at $t+1$, $wagefe_{t+1}$ is forecast error for wage rates at $t+1$, and n_{t+1} is the unexplained error term at $t+1$. Substituting this expression for e_{t+1} into equation (4) and converting to an estimable form yields

$$\begin{gathered} p_{t+1} - p_t = a + b_1 r_t^f p_t + b_2 (r_t^m - r_t^f) p_t + b_3 elecusefe_{t+1} + b_4 lscprcfe_{t+1} + \\ b_5 hscprcfe_{t+1} + b_6 ngasprcfe_{t+1} + b_7 wagefe_{t+1} + n_{t+1}. \end{gathered} \tag{5}$$

Equation (5) is labeled the *Base Model and Market Shocks*. Its goal is to explain the volatile nature of SO_2 spot market prices.

4 Data, Variables, and Econometric Methods

In preparation for estimation of equations (4) and (5), variables are constructed using monthly data from August 1994 through December 2003, which totals to 113 observations. The SO_2 spot price (p_t, in dollars per ton) is the monthly Market Price Index from Cantor Environmental Brokerage. Cantor's index series is the most widely cited source of data on SO_2 prices. The U.S. Environmental Protection Agency reports this series in official publications, and it has been used in earlier research (e.g., Joskow, Schmalensee, and Bailey, 1998). The risk-free rate of return (r_t^f, in percentage points at monthly rates) is the 3-month Treasury bill.[17] The rate of return on the market portfolio of risky assets (r_t^m, in percentage points at monthly rates) is the daily average S&P 500 Price Index for a given month. The appendix describes the sources of these data. Table 2 reports summary statistics for the variables used to estimate equation (4), $p_{t+1} - p_t$, $r_t^f p_t$, and $(r_t^m - r_t^f)p_t$.

Equation (5) incorporates the variables for new information on prices in five markets that are related to the SO_2 market through the SO_2 abatement cost function. The markets related to the SO_2 market are: electricity sales, low-sulfur coal price, high-sulfur coal price, natural gas price, and wage in the public utilities and transportation sector. The five variables are forecast errors from monthly predictions of each series. Three steps are followed to produce these variables. First, we estimate a model (an ordinary least squares regression including a time trend and monthly dummies) to forecast each series using monthly data that begins in January 1988 (or January 1990 for electricity sales). These data pre-date the formation of the SO_2 market. Second, we apply the model to forecast the series for every month in our study period (August 1994 through December 2003). The forecasts use data from all months prior to the month at hand to produce the forecast for that month. Thus, for each data series, we generate 112 regressions and 112 predictions spanning September 1994 to December 2003. (We term this procedure the "one-step-ahead" forecast.) Third, we compute the forecast error as the difference between actual value and forecast value for every month of the study. This creates a measure of new information, or a shock, emanating from each of the five markets. Further detail on this method is in the Appendix.

The forecast models are estimated with monthly data. Electricity sales data are from the Energy Information Administration and are measured in megawatt-hours. Low-sulfur coal, high-sulfur coal, and natural gas prices are from the Federal Energy Regulatory Commission and are in cents per million BTUs. Wage rates for public utility and transportation labor are from the Bureau of

[17] The 3-month Treasury bill is the instrument of shortest duration for which monthly data exist for the study period. Monthly data for the 1-month Treasury bill are not available for this period.

Labor Statistics in dollars per hour. The interest rate data, from the Federal Reserve, are monthly data expressed as annual percentages; we convert those annual percentages to monthly percentages. The appendix also describes these data in more detail.

Using these data and the forecast models, five variables are constructed for use in estimating equation (5): $elecusefe_{t+1}$, $lscprcfe_{t+1}$, $hscprcfe_{t+1}$, $ngasprcfe_{t+1}$, and $wagefe_{t+1}$. As a robustness check, we also consider the possibility that new information might not be dispersed immediately and, instead, it affects the SO_2 market with a time lag. This is an empirical conjecture without a formal basis in theory. The implication is that the shock variables at time t ($elecusefe_t$, $lscprcfe_t$, $hscprcfe_t$, $ngasprcfe_t$, and $wagefe_t$) affect the SO_2 price change at time $t+1$ (p_{t+1} - p_t). Table 2 reports the summary statistics for the time $t+1$ version of these variables; the statistics for the time t version are very similar.

A second robustness check incorporates variables from the Arbitrage Pricing Theory (APT) as potential influences on SO_2 allowance price movements. The APT, as derived in the finance literature, incorporates macroeconomic factors as potential influences on asset price (Cambell, Lo, and MacKinlay, 1997). Following Slade and Thille (1997),[18] variables are developed for the forecast errors of three macroeconomic factors: the Consumer Price Index ($CPIfe_{t+1}$), the interest rate on the 10-year Treasury bond ($10yrbondfe_{t+1}$), and the Industrial Production Index ($IPIfe_{t+1}$). To compute forecast errors, we use the same methods as described above for the market shock variables. The appendix describes the data for the macroeconomic factors, and Table 2 reports the summary statistics for their forecast errors.

Because econometric results may be unreliable if the dependent variable is nonstationary, we first need to test the stationarity of allowance prices and their first difference. One of the possible

[18] Slade and Thille (1997) integrate the Hotelling model of nonrenewable resource markets with the CAPM and APT models from the finance literature. They study shadow price movements in Canadian copper mines.

complications of unit root tests for stationarity is that the presence of structural changes during the time series may make rejection of a unit root more difficult (Perron, 1989). In the time period under study here (August 1994 – December 2003), a number of events occurred that may have created structural changes.[19] As a result, we use a method developed by Lee and Strazicich (2003) that endogenously looks for structural breaks while testing for the existence of a unit root. This method is preferable to including all possible structural shifts in our model, since the latter would require significant assumptions about when the possible shifts first affected the market and would lead to many fewer degrees of freedom. Using this method, we are not able to reject the presence of a unit root for allowance prices, but we are able to reject the presence of a unit root for the first difference of allowance prices.[20] We use the latter as the dependent variable in the regression models.

An advantage of this method, as noted, is that the data themselves suggest the possible timing of structural breaks. Lee and Strazicich include two methods for the test (one with up to two shifts in level, one with up to two shifts in both level and trend), and we conduct the test both for data through 2003 and for data through 2004 (to check for shifts late in the dataset). Based on these results, we develop a candidate list of dates for structural breaks in the model: March 1997, February 1998, September 1999, October 2000, and April 2003. We include these as dummy variables in our estimation of equations (4) and (5). Only the breaks in February 1998 and September 1999 are statistically significant. We drop the others from the model.

One concern with the shock variables is a potential endogeneity problem with the price shocks for low- and high-sulfur coal. This is addressed with a Hausman test for endogeneity bias. We developed several instruments for the two coal price shocks; these include Btu content of low-

[19] These include a change in the president, proposed and actual regulatory changes (e.g., proposed revisions to New Source Review and changes in regulation of particulate matter), legal decisions (including rulings on national ambient air quality standards for ozone), negotiations over international greenhouse gas controls, and disruptions in the California energy market. Indeed, we stop our series at December 2003 because the Clean Air Interstate Rule, proposed in January 2004, may have contributed to sudden major movements in the allowance market.
[20] These results were consistent with the results of an augmented Dickey Fuller test on the two series.

sulfur coal, Btu content of high-sulfur coal, ash content of low-sulfur coal, ash content of high-sulfur coal, a rail cost adjustment factor (RCAF), RCAF squared, and total coal consumption in industry.[21] The appendix describes the data for these variables. We execute the Hausman test following procedures defined in Wooldridge (2002), which allows for generation of Newey-West standard errors. We could not reject the null hypothesis of exogeneity.

We estimate equations (4) and (5) using OLS. To account for the possibility that the error terms (e_{t+1} or n_{t+1}) may be serially correlated and heteroskedastic, we apply the Newey-West procedure to generate robust standard errors.[22]

5 Results

We estimate the *Base Model* of equation (4) with two variations: with and without the endogenous structural breaks. The first break, *break1*, is a dummy variable equal to 1 in February 1998 and 0 thereafter. The second break, *break2*, is a dummy variable equal to 1 in September 1999 and 0 thereafter. Similarly, we estimate the *Base Model and Market Shocks* of equation (5) with and without the structural breaks. The results are reported in Table 3. Section 5.2 reports robustness checks to several additional specifications of the model.

5.1 General Results

One question is: Do allowance prices follow an *r*-percent trajectory over time (the Hotelling rule)? We address this first since the answer is relatively compact. For the Hotelling hypothesis to be maintained, the null hypothesis is that $b_1 = 1$. The estimated coefficients (b_1) for the interest rate variable ($r_t^f p_t$) are negative and of similar magnitude across the four specifications. In the most parsimonious specification (*Base Model* without structural breaks), the null hypothesis cannot be

[21] We thank Nat Keohane for insight into the coal market.
[22] We specify twelve lags in the procedure due to the use of monthly data (Wooldridge, 2003).

rejected (p-value = 0.239 in an F test).[23] However, the estimates of the coefficient become more efficient as more control variables are added to the specification. In the *Base Model* with breaks, the null hypothesis also cannot be rejected (p-value = 0.113 in F test), although this result provides very little evidence in favor of the null hypothesis given the p-value. In contrast, the null hypothesis is rejected in the two specifications of *Base Model and Market Shocks*. Without breaks, the null hypothesis is rejected at the 5% level (p-value = 0.039 in F test). With structural breaks, the null hypothesis is rejected at the 1% level (p-value = 0.000 in F test).

On balance, the statistical evidence rejects the Hotelling rule. The *Base Model* without structural breaks does not reject the Hotelling rule, but neither does it provide much confidence that price is rising with the interest rate. With added controls, the estimated coefficient for $r_t^f p_t$ is significantly different from one and the conclusion becomes clear. By rejecting the Hotelling rule, the SO_2 price path is not consistent with a competitive equilibrium in the intertemporal market.

The second general question is: How do the alternative specifications and the variables perform in explaining allowance price movements? The most parsimonious specification (*Base Model* without breaks) represents the essential theory of a storable commodity under uncertainty.[24] It explains only two percent of the variation in allowance price changes (R^2 = 0.02). After including the structural breaks to account for convenience yield, the regression explains nine percent of the variation. The R^2 increases to 25 percent after incorporating both breaks and price-shock variables in the *Base Model and Market Shocks*. Thus, augmenting the theory-derived variables with empirically motivated variables was a useful effort.

At the same time, substantial variation in allowance price movements remains unexplained. Traders apparently were making decisions with information beyond that captured in our analysis. This reflects the complexity of markets in the real world.

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[23] The results reported in this paragraph are computed using Newey-West standard errors.
[24] This reflects the model of Gaudet and Khadr (1991).

Among individual variables, the estimated coefficient for the interest rate variable ($r_t^f p_t$) is significantly different from zero at the 1% level in the *Base Model and Market Shocks* with the structural breaks. The estimate, -13.20, suggests that a one unit increase in $r_t^f p_t$ results in a $13.20 decrease in the SO_2 allowance price movement $p_{t+1} - p_t$. As noted above, this price decrease violates the Hotelling rule.

As an asset, SO_2 allowances appear not to be earning a risk premium: the coefficient on the CAPM variable ($(r_t^m - r_t^f)p_t$) is insignificant. This is not surprising; as a relatively new market, there is little experience in understanding its relationship to other investment markets, so investors are unlikely to be holding allowances on a widespread basis.

Based on the theoretical model, we interpret the estimated intercept as average convenience yield during August 1994 through January 1998. The intercept is never statistically significant in these regressions, which suggests that convenience yield was zero for the first several years of the market. In the EPA auction results (Table 1), discounted convenience yield on the +7 year vintages ranged between $3 and $7 per ton in these same years. These numbers suggest quite small convenience yields on the current year vintages. Thus, the regression estimates and auction results are generally consistent.

The estimated coefficients on *break1* estimate the change in average convenience yield that occurred in the second phase, February 1998 through August 1999. The coefficients are slightly over 8 and significant. These imply a decrease in average convenience yield during the second phase relative to the first phase (recall that $a = -y$). The regression estimates from the spot market are inconsistent with the auction results, as convenience yield on the +7 year vintage increased markedly between 1998 and 1999. This is a short phase of 19 months, however, so data points from two auctions might not represent an underlying monthly trend.

Finally, the estimated coefficients on *break2* estimate the change in average convenience yield in the third phase, September 1999 to December 2003. In the *Base Model and Market Shocks* with the structural breaks, the estimated coefficient is about -12 and is significantly different from zero at the 1% level. This implies an increase in average convenience yield of $12 per ton during the third phase relative to the second phase. In comparison, convenience yields on the +7 year vintage allowances increased dramatically in the 2000-03 EPA auctions. In qualitative terms, then, the regression and auction results are consistent during the third phase.

Two of the five variables for market shocks are significant—natural gas price and wage. Their signs suggest that these shocks have a positive effect on the magnitude of SO_2 price movements. The positive influence of the natural gas shock makes sense given that natural gas and SO_2 emissions are substitutes: unexpected increases in natural gas prices, for example, would increase demand for allowances and thus cause an increase in allowance price. We did not have strong priors on the variable for wage shocks. Shock variables for low-sulfur coal price, high-sulfur coal price, and electricity use do not individually affect allowance price movements. Tests of the joint hypothesis that the three variables, together, are significant could not reject the null; they also do not exert a collective influence on price movements. More research is required to understand how new information from electricity and coal markets influences the SO_2 allowance market.

5.2 Robustness Checks

We investigate the robustness of the results to a variety of alternative specifications. One question is whether the new information embodied in the shock variables affects the allowance market with a lag. The five variables for forecast error are similar in magnitude and significance in the new specification—at time *t*—as those for forecast error at time *t+1* (Table 4). Information thus is entering the market both with a lag and concurrently, and the same two related markets (natural gas and labor) are affecting the allowance market. [Here, we need to compute the simple correlation between *t* and *t+1* forecast errors to assess whether intertemporal correlation in forecast errors is driving this result.] The estimated coefficients on the interest rate variable ($r_t^f p_t$) and the structural breaks (*break1*, *break2*) are also similar in magnitude and significance between the two specifications of forecast-error variables. In particular, the estimated coefficients on the interest rate variable continue to be negative and significantly different from zero. They also are significantly different from one in the test of the Hotelling rule.

A second robustness check comes through inclusion of three variables for macroeconomic shocks, in accordance with the Arbitrage Pricing Theory and prior research on a nonrenewable resource market (Slade and Thille, 1997). These variables— $CPIfe_{t+1}$, $10yrbondfe_{t+1}$, and $IPIfe_{t+1}$— are included in specifications with the base model and market shocks (Table 5). The macroeconomic-shock variables tend not to influence SO_2 allowance price movements. Two exceptions occur: the estimated coefficients on $CPIfe_{t+1}$ and $IPIfe_{t+1}$ are significantly different from zero ($p<0.10$), each in one specification. [[Note: need a joint test of significance of the macroeconomic variables.]] The estimated coefficients on the remaining variables continue their consistent pattern of sign and significance. For example, the coefficients on the interest rate variable are similar in magnitude to earlier specifications, and they are significantly different from both zero and one ($p<0.01$). The forecast-error variables for natural gas prices and wage rates continue to influence allowance price movements.

[[*Note to Discussant: These are the main robustness checks. We still need to report a few other (minor) checks, but won't get to them in the paper and likely won't report them at the conference.]]*

6 Conclusion

The SO_2 allowance market provides a straightforward test of the Hotelling prediction that, with costless extraction, price of a nonrenewable resource increases at the rate of interest over time. Instead, spot market prices were quite volatile—fluctuating in a band roughly between \$100 and \$200 per ton—through 2003. Experts argue that spot market prices were influenced by a combination of regulatory rulings on air pollution emissions and adjustments in related markets (e.g., Burtraw et al., 2005). Schennach (2000) provides a theoretical examination of the SO_2 allowance market under uncertainty and argues for the Hotelling price path after controlling for these shocks. This paper has implemented Schennach's theoretical model in an empirical analysis of the SO_2 allowance price path.

The major finding relates to a competitive equilibrium in the market. We test for the Hotelling rule as the key element of a competitive equilibrium and find evidence, on balance, against the rule. Instead of prices increasing over time, the preponderance of the evidence suggests a downward trend, after controlling for structural changes and market shocks. This evidence suggests that the market is inefficient, with arbitrage profits remaining to be earned. The finding also could lead to an investigation of market power as a source of imperfect competition in the market. On this topic, however, Liski and Montero (2005) find that the behavior of the four largest firms in the market was consistent with perfect competition during 1995 to 2003.[25] Other possible explanations for this inefficiency include: lack of experience in this market; a strong desire to hold allowances to avoid possibilities of future stock-outs; or the (presumably small) opportunities for profits might be less than the costs of finding those profit opportunities.

[25] Liski and Montero (2005) measure firm size according to allowance allocations. In reaching the conclusion of perfectly competitive behavior, they evaluate the pattern of allowance allocations and SO_2 emissions of the four largest firms from 1995-2003 against predictions of their theoretical model of market power in a storable commodity market.

The main empirical innovation of the research is the use of two statistical methods to construct variables to better explain SO_2 allowance price movements. Using time series models, we developed variables for unexpected shocks in markets related to the allowance market. Based on a method for improving unit root tests, we also incorporated variables for two endogenous structural breaks in allowance price movements. These variables substantially improved goodness of fit for the regression equation.[26] At the same time, substantial variation in allowance price movements remains unexplained. As a market created by a government regulation, regulatory uncertainty may influence the market inordinately. Additional research is needed to further explore the influence of regulatory uncertainty on this market.

The SO_2 cap-and-trade program defines a new paradigm for environmental regulation. Its key features are being replicated by several important programs and proposals in the domain of climate policy and air pollution policy. Our research shows that—despite its obvious successes—important questions remain on the performance of the SO_2 allowance market.

[26] Our finding that the endogenous structural breaks improve goodness of fit is similar to the finding by Lee, List, and Strazicich (2006) that inclusion of such breaks improves forecast accuracy of time trends in nonrenewable resource prices.

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Appendix: Data, Market Shocks, and Endogenous Structural Breaks

This appendix contains more detailed information on (1) the data used here, (2) the method used to develop the market shock variables, and (3) the method for endogenous determination of structural breaks.

The Data

The data collected and used in this analysis include: prices of SO_2 allowances; data used to develop shocks; data to develop the CAPM and APT variables; and instruments for high- and low-sulfur coal prices for two-stage least squares regression. All the data series run through December 2003.

For SO_2 allowances, the data run from the start of the market (August 1994). For variables that we used to develop shocks (electricity sales; prices of high- and low-sulfur coal; prices of natural gas; hourly wages in the utility sector; interest rates for the 3-month Treasury bill, the prime rate and the 10-year Treasury Constant Maturity Rate; the Standard and Poor's (S&P) 500 stock index; Industrial Production Index; and Consumer Price Index), we collected observations starting from January, 1988 (except for electricity sales, where the data prior to January, 1990, were not available). We started the data series for these variables at this date so that we could estimate the time series models (see below) with data prior to the start of the program. There is a balance, in choosing the length of the data series, between having more data and facing an increased likelihood of structural changes in the series. The choice of 1988 as the initial year seemed to fit that balance. Since Alan Greenspan was appointed to be chair of the Federal Reserve System in 1987, this period can be considered to have a relatively stable monetary regime.

Data used in the two-stage least square analysis (the ash content and Btu content in high- and low-sulfur coal; the rail cost adjustment factor; and total coal consumption by industrial sector) run from August 1994 to December 2003.

Prices of SO2 allowances
Prices of the SO_2 allowances come from the Cantor-Fitzgerald Environmental Brokerage, http://www.emissionstrading.com/. They are measured in dollars per allowance, where an allowance is for one ton of SO_2.

Data used to develop shock variables
The profit function for a firm shifts in response to changes in input prices. To model those changes in input prices, we develop estimates of the forecast error between expected and actual input prices for low-sulfur and high sulfur coal, natural gas, and wages. For the electricity market, we use electricity sales instead of electricity prices as the basis for the shock. Many electricity prices are set in regulated markets and, thus, do not reflect underlying demand and supply fundamentals.

Electricity sales--Electricity sales come from the Energy Information Administration of the U.S. Department of Energy, Form EIA-826 Monthly Electric Utility Sales and Revenue Data, which is found at http://www.eia.doe.gov/cneaf/electricity/page/eia826.html. The value is monthly total electric utility sales measured in megawatt-hours.

Wage data--The wage data are average hourly earnings of production workers for the transportation and public utilities sector from the Bureau of Labor Statistics. They are found at http://data.bls.gov/cgi-bin/srgate, using series ID number CEU4422000006 for the Utilities sector.

Interest rate data--The interest rates for 3-month constant maturities Treasury bonds are found at: http://www.federalreserve.gov/releases/h15/ and http://www.federalreserve.gov/releases/h15/data/Monthly/H15_TCMNOM_M3.txt

The prime rate data come from the website of the St. Louis Federal Reserve Bank, at http://research.stlouisfed.org/fred2/series/MPRIME/117 .

The data for the 10-year constant maturities Treasury bonds are found at: http://research.stlouisfed.org/fred2/data/GS10.txt

All three interest rates are presented as annual percentages, with monthly data frequency. To convert each monthly observation to a monthly interest rate, we used the following formula: if r is the monthly interest rate, and i is the annual interest rate, then $i = (1 + r)^{12} - 1$. Rearranging this formula yields

$$r = \exp^{\left(\frac{\ln(1+\frac{i}{100})}{12}\right)} - 1.$$

S&P 500 Index values--Monthly S&P 500 values are from the daily values at this website: `http://www2.standardandpoors.com/spf/xls/index/500_20051224_GALLTOT.xls`
The daily values are averaged for each month.

Industrial Production Index--The data can be found at http://alfred.stlouisfed.org/series/downloaddata?seid=INDPRO&rid=13 . The chosen vintage date was October 1, 2005 (2005-10-01). It provides the index with year 1997 = 100.

Consumer Price Index--The Consumer Price Index for All Urban Consumers is found at: http://data.bls.gov/cgi-bin/surveymost?cu , choosing "U.S. All items, 1982-84=100 - CUUR0000SA0" in the list.

Prices for High- and Low-Sulfur Coal and Natural Gas--Prices of coal and natural gas are from Form 423 Annual Data, issued by the Federal Energy Regulatory Commission (FERC) (http://www.ferc.gov/docs-filing/eforms/form-423/data-annual.asp#skipnavsub), which gives the cost of coal and gas delivered to electric utilities. The price of each kind of coal as well as natural gas is a quantity-weighed average cost measured as cents per million BTU. Data starting in January 2003 were provided directly by Stephen Scott of the Energy Information Administration from the "FERC-423/EIA-423 Survey Information," rather than from EIA website (where they were not yet available). We use spot market prices, not contract prices. For data prior to August, 1994, we use all plants, since price expectations could be expected to arise from all plants. Between August, 1994, and 2000, we use data only from Table A plants (that is, those plants participating in the SO_2 allowance market); after 2000, we use all plants. The list of Table A plants is from http://www.epa.gov/air/caa/caa404.txt.

Low- and high-sulfur coal must be distinguished when constructing price variables. Carlson, et al. (p. 1321) distinguish low- and high-sulfur coal by whether the coal has sulfur content that would produce more or less than 1.2 pounds of SO_2 per million BTU of heat input; we use the same dividing line. Because the FERC form provides sulfur content, not SO_2 content, we convert sulfur to SO_2 content using the following procedure.

Two conversion factors (1.91 for bituminous coal, and 1.76 for sub-bituminous coal) are used here to convert from sulfur (S) to sulfur dioxide (SO_2) (Nathaniel Keohane, personal communication). We use three types of coal (bitumen, bituminous, and sub-bituminous), but exclude anthracite and lignite when separating coal into the low-sulfur and high-sulfur categories since we lack conversion factors for those types. Anthracite is 0.104% of total tons of coal, while lignite is 9.35%.

The following formula computes sulfur dioxide content using delivery-specific, plant-level data from FERC Form 423:

$$\frac{\text{Sulfur content}}{\text{Heat content}} * 10{,}000 * \text{conversion factor appropriate for the coal} = \text{pounds } SO_2/\text{mmBtu}.$$

Coal with over 1.2 pounds SO_2/mmBtu was considered high-sulfur coal, with the rest low-sulfur coal.

Instruments for the prices of high- and low- sulfur coal

Because of concerns about possible endogeneity of high- and low-sulfur coal prices, we sought variables that would contribute to explanation of coal prices but that are unrelated to the other variables in our regressions. We chose seven variables as instruments: ash content and Btu content from both high-sulfur coal and low-sulfur coal; the rail cost adjustment factor (RCAF), which is an index of railroad costs; RCAF squared; and total coal consumption in industry (excluding commercial, transportation, and energy sector consumption).

Btu content and ash content--Information on ash content and Btu content came from the same Form 423 Annual Data used for high- and low-sulfur coal prices. For both Btu content and ash content, these are quantity-weighted averages measured as Btu per pound and percent by weight, respectively.

Rail cost adjustment factor--The rail cost adjustment factor (RCAF) is an index of the costs of rail shipping. RCAF data were provided by the Association of American Railroads (A. Clyde Crimmel, Jr., personal communication). The RCAF data are restated to a 2002 Q4 =100 base.

Total coal consumption in industry--The coal consumption data are from Table 6.2 of the Monthly Energy Review at Energy Information Administration, found at http://tonto.eia.doe.gov/FTPROOT/monthlyhistory.htm . The data are thousands of short tons of coals consumed by the industrial sector. The data were input manually from the "industrial total" column.

Variables for Shocks

We develop shocks for all the prices expected to influence the price of SO_2 allowances through the cost function for abatement: sales of electricity, high- and low-sulfur coal prices, natural gas price, and wages. In addition, we estimate shocks for the variables related to the Arbitrage Pricing Theory: the interest rate on the 10-year constant maturity Treasury bond, the S&P 500 Index, and the Industrial Production Index. The shocks used in the regressions are the differences between true values and predicted values (true values - predicted values). To calculate the shocks, we need predicted values starting from August, 1994, for the relevant data.

Initially, we developed ARIMA models for each variable. The best-fit models tended to be complex, and they produced variables that performed poorly in explaining SO_2 price movements. Since we are trying to estimate how people in the markets would predict price trends, complex formulations seem unrealistic. We instead use, for each variable, a simple linear model of a time trend and monthly dummies. These models produce variables that perform much better in explaining SO_2 price movements.

We use a method (termed "one-step ahead") of using the data to estimate the predicted values. The coefficients for the model were re-estimated every month and used to provide the prediction for the next month. This model reflects an environment with full information. For most of the coefficients for most of the variables, the coefficients of variation for the coefficients were less than one, suggesting that the time series models were indeed fairly stable.

We also experimented with a second and third method of computing predicted values. The one-step-ahead method performed best, yet the other results are reported as robustness checks. In the second method, using what we term the "short" dataset, we used data only from before the beginning of the SO_2 allowance program – from January 1988 (January 1990 for electricity data) to July 1994 – to estimate the model. This method assumes a very naive form of expectations: the model would not be updated at all.

The third method used the "long" dataset – that is, the data from January 1988 (January 1990 for electricity data) through September 2004 to estimate the model. (We collected data through September 2004 for all variables; only after examining the econometric results did we reconsider use of data for 2004. We did not re-calculate the shocks at that point.) The assumption underlying this model is that the time series model is stable for the whole time period. It has the characteristic of using data from after almost all the predictions for those predictions; this could be considered a disadvantage.

Endogenous Determination of Structural Breaks

Lee and Strazicich (2003) describe a method to determine structural breaks endogenously from time series data. We use their GAUSS computer code to conduct a unit root test and to find structural breaks, both for SO_2 allowance prices and for the first difference of SO_2 allowance prices. Their GAUSS codes can be found at http://www.cba.ua.edu/~jlee/gauss/LStwo.txt . Their Model A includes two changes in intercept for the time series; their Model C includes two changes in intercept and two changes in slopes.

We cannot reject the presence of a unit root for SO_2 allowance prices, though we can reject a unit root for the difference of SO_2 allowance prices.

Following Lee and Strazicich's methods, for SO_2 allowance prices, we identify possible breaks in February 1998 and September 1999 from model C; and breaks in March 1998 and October 2000 from model A. For the difference of SO_2 allowance prices, we identify breaks in March 1997 and June 1998 from model C; and February 1998 and August 1998 from model A.

We estimate the regression models with breaks in March 1997, February 1998, September 1999, October 2000, and April 2003. Only the breaks in February 1998 and September 1999 are statistically significant. We therefore drop the other breaks from the model.

Table 1. Descriptive Evidence on the Intertemporal Allowance Market

Year	Allowance Quantities			Market-Clearing Allowance Prices in Annual EPA Auction		
	Annual Allocation (tons)	Annual Use (tons)	End-of-Year Stock (tons)	Current Vintage ($/ton)	+7 Years Vintage ($/ton)	Discount, +7 Price to Current Price (%)
1995	8,744,081	5,298,429	3,445,652	132.00	126.00	4.5
1996	8,296,548	5,433,351	6,298,986	66.05	63.01	4.6
1997	7,147,464	5,474,440	7,961,359	106.75	102.15	4.3
1998	6,969,165	5,298,498	9,630,343	115.01	108.30	5.8
1999	6,990,132	4,944,676	11,673,436	200.55	167.55	16.5
2000	9,966,531	11,201,999	10,372,487	126.00	55.27	56.1
2001	9,553,657	10,633,035	9,297,048	173.57	105.72	39.1
2002	9,542,478	10,193,684	8,648,932	160.50	68.00	57.6
2003	9,541,085	10,595,944	7,598,984	171.80	80.00	53.4
2004	9,541,085	10,259,771	6,873,273	260.00	128.00	50.8
2005	9,539,575	10,222,847	6,173,001	690.00	260.00	62.3

Notes: One allowance gives the right to emit one ton of SO_2. Allowance allocations increased substantially in 2000 at the beginning of the program's Phase II. A 60-day reconciliation period follows the end of the calendar year, so that the end-of-year stock for a given year is determined on March 1 of the following year. The annual EPA auction occurs in late March and includes sales of the current vintage and a future vintage (+7 years) of allowances. Source: U.S. Environmental Protection Agency, 2006a and 2006b.

Table 2. Summary Statistics

Variable	Units	Mean	Standard Deviation
p_t	\$/ton	146.27	38.70
Dependent variable:			
$p_{t+1} - p_t$	\$/ton	0.64	9.83
Base model:			
$r_t^f p_t$	\$/ton	0.49	0.21
$(r_t^m - r_t^f) p_t$	\$/ton	0.47	6.15
Market shocks:			
$elecusefe_{t+1}$	megawatt-hr./month	368,356	7,036,906
$lscprcfe_{t+1}$	¢/million Btu	9.56	15.03
$hscprcfe_{t+1}$	¢/million Btu	5.94	14.42
$ngasprcfe_{t+1}$	¢/million Btu	45.97	105.02
$wagefe_{t+1}$	\$/hour	0.15	0.17
Arbitrage pricing theory:			
$CPIfe_{t+1}$	*unitless*	-1.48	0.88
$10yrbondfe_{t+1}$	percentage points at monthly rates	0.0002	0.0005
$IPIfe_{t+1}$	*unitless*	2.14	4.80

Note: 112 monthly observations, 9.1994 to 12.2003.

Table 3. Explaining SO_2 Allowance Price Movements

	Base Model				Base Model and Market Shocks			
	With Breaks		Without Breaks		With Breaks		Without Breaks	
Variable	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.	Coef.	Std. Err.
constant	3.98	(2.77) [3.84]	3.28	(2.37) [2.81]	3.34	(2.90) [2.18]	1.09	(2.84) [2.60]
Break1	8.17	$(2.85)^{***}$ $[3.36]^{**}$	---	---	8.21	$(2.82)^{***}$ $[3.25]^{**}$	---	---
Break2	-6.89	$(2.90)^{**}$ $[3.96]^{*}$	---	---	-12.05	$(3.31)^{***}$ $[3.41]^{***}$	---	---
$r_t^f p_t$	-10.97	$(4.85)^{**}$ [7.49]	-5.52	(4.46) [5.50]	-13.20	$(4.87)^{***}$ $[4.06]^{***}$	-8.51	$(4.95)^{*}$ $[4.54]^{*}$
$(r_t^m - r_t^f)p_t$	0.05	(0.15) [0.20]	0.09	(0.15) [0.21]	0.05	(0.15) [0.19]	0.15	(0.16) [0.21]
$elecusefe_{t+1}$	---	---	---	---	-3.07e-08	(1.45e-07) [1.38e-07]	6.78e-08	(1.50e-07) [1.60e-07]
$lscprcfe_{t+1}$	---	---	---	---	0.08	(0.08) [0.06]	0.05	(0.08) [0.08]
$hscprcfe_{t+1}$	---	---	---	---	0.01	(0.09) [0.07]	-0.04	(0.09) [0.09]
$ngasprcfe_{t+1}$	---	---	---	---	0.04	$(0.01)^{***}$ $[0.01]^{***}$	0.02	$(0.01)^{**}$ $[0.01]^{***}$
$wagefe_{t+1}$	---	---	---	---	9.45	$(5.84)^{***}$ $[4.30]^{***}$	15.75	$(5.90)^{***}$ $[5.49]^{***}$
R^2	0.09		0.02		0.25		0.15	
N	112		112		112		112	

Notes. The dependent variable is the monthly change in SO_2 allowance prices, $p_{t+1} - p_t$. One, two, or three asterisks indicate significance at the levels $p<0.10$, $p<0.05$ or $p<0.01$, respectively. Conventional standard errors are in parentheses; Newey-West standard errors are in brackets. The variable *break1* is a dummy variable for a structural break beginning February 1998; *break2* is a dummy variable for a structural break beginning September 1999.

Table 4. Robustness Checks; Base Model and Lagged Market Shocks

	Base Model and Lagged Market Shocks			
	With Breaks		Without Breaks	
Variable	Coef.	Std. Err.	Coef.	Std. Err.
constant	5.09	(2.84)*	2.77	(2.75)
		[1.99]**		[2.34]
break1	7.55	(2.85)***	---	---
		[3.44]**		---
break2	-11.26	(3.24)***	---	---
		[3.91]***		---
$r_t^f p_t$	-14.91	(4.81)***	-10.35	(4.84)**
		[4.03]***		[5.07]**
$(r_t^m - r_t^f)p_t$	0.01	(0.15)	0.08	(0.16)
		[0.19]		[0.21]
$elecusefe_t$	-7.81e-08	(1.44e-07)	-2.51e-08	(1.50e-07)
		[1.17e-07]		[1.17e-07]
$lscprcfe_t$	-0.03	(0.08)	-0.06	(0.08)
		[0.07]		[0.08]
$hscprcfe_t$	0.04	(0.09)	-0.01	(0.08)
		[0.07]		[0.09]
$ngasprcfe_t$	0.04	(0.01)***	0.03	(0.009)***
		[0.009]***		[0.008]***
$wagefe_t$	9.79	(5.89)	16.05	(5.88)***
		[7.40]		[6.96]**
R^2	0.27		0.18	
N	112		112	

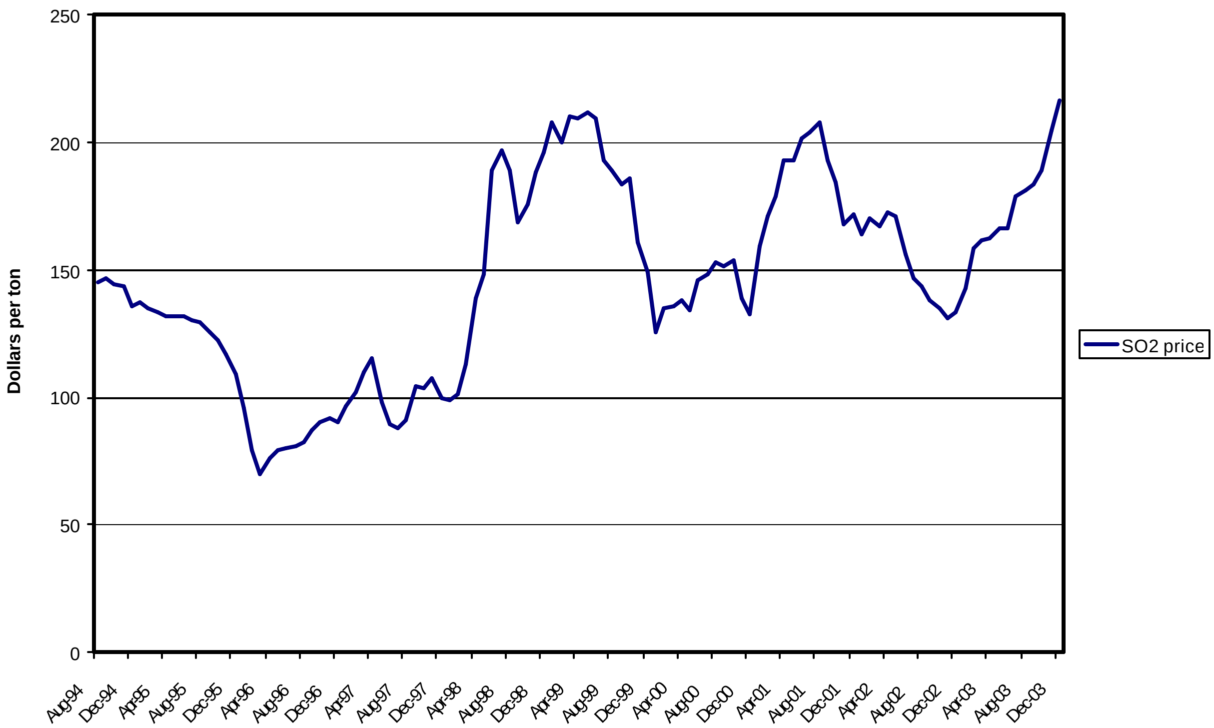
Notes. The dependent variable is the monthly change in SO_2 allowance prices, $p_{t+1} - p_t$. One, two, or three asterisks indicate significance at the levels $p<0.10$, $p<0.05$ or $p<0.01$, respectively. Conventional standard errors are in parentheses; Newey-West standard errors are in brackets.

Table 5. Robustness Checks; Base Model, Market Shocks, and Arbitrage Pricing Theory

	Base Model, Market Shocks, and Arbitrage Pricing Theory Variables			
	With Breaks		Without Breaks	
Variable	Coef.	Std. Err.	Coef.	Std. Err.
constant	9.79	(4.63)**	1.32	(4.28)
		[4.49]**		[4.06]
break1	14.66	(4.21)***	---	---
		[4.83]***		---
break2	-16.74	(4.62)***	---	---
		[5.00]***		---
$r_t^f p_t$	-22.47	(7.16)***	-14.43	(6.61)**
		[7.90]***		[5.60]**
$(r_t^m - r_t^f)p_t$	0.08	(0.15)	0.07	(0.16)
		[0.19]		[0.20]
$elecusefe_{t+1}$	-3.03e-08	(1.45e-07)	1.13e-08	(1.53e-07)
		[1.42e-07]		[1.43e-07]
$lscprcfe_{t+1}$	0.07	(0.08)	0.07	(0.08)
		[0.06]		[0.07]
$hscprcfe_{t+1}$	0.007	(0.09)	0.02	(0.09)
		[0.08]		[0.09]
$ngasprcfe_{t+1}$	0.03	(0.01)**	0.03	(0.01)***
		[0.01]***		[0.01]***
$wagefe_{t+1}$	7.73	(5.94)	12.67	(6.13)**
		[4.75]		[5.03]**
$CPIfe_{t+1}$	2.95	(1.87)	-0.87	(1.59)
		[1.57]*		[1.41]
$10yrbondfe_{t+1}$	2777	(2671)	-1988	(2491)
		[2786]		[3004]
$IPIfe_{t+1}$	0.35	(0.42)	0.57	(0.37)
		[0.45]		[0.33]*
R^2	0.29		0.18	
N	112		112	

Notes. The dependent variable is the monthly change in SO_2 allowance prices, $p_{t+1} - p_t$. One, two, or three asterisks indicate significance at the levels $p<0.10$, $p<0.05$ or $p<0.01$, respectively. Conventional standard errors are in parentheses; Newey-West standard errors are in brackets.

Figure 1. SO2 Spot Market Prices, Aug 1994 - Dec 2003



When to Pollute, When to Abate? Evidence on Intertemporal Permit Use in the Los Angeles NO_x Market

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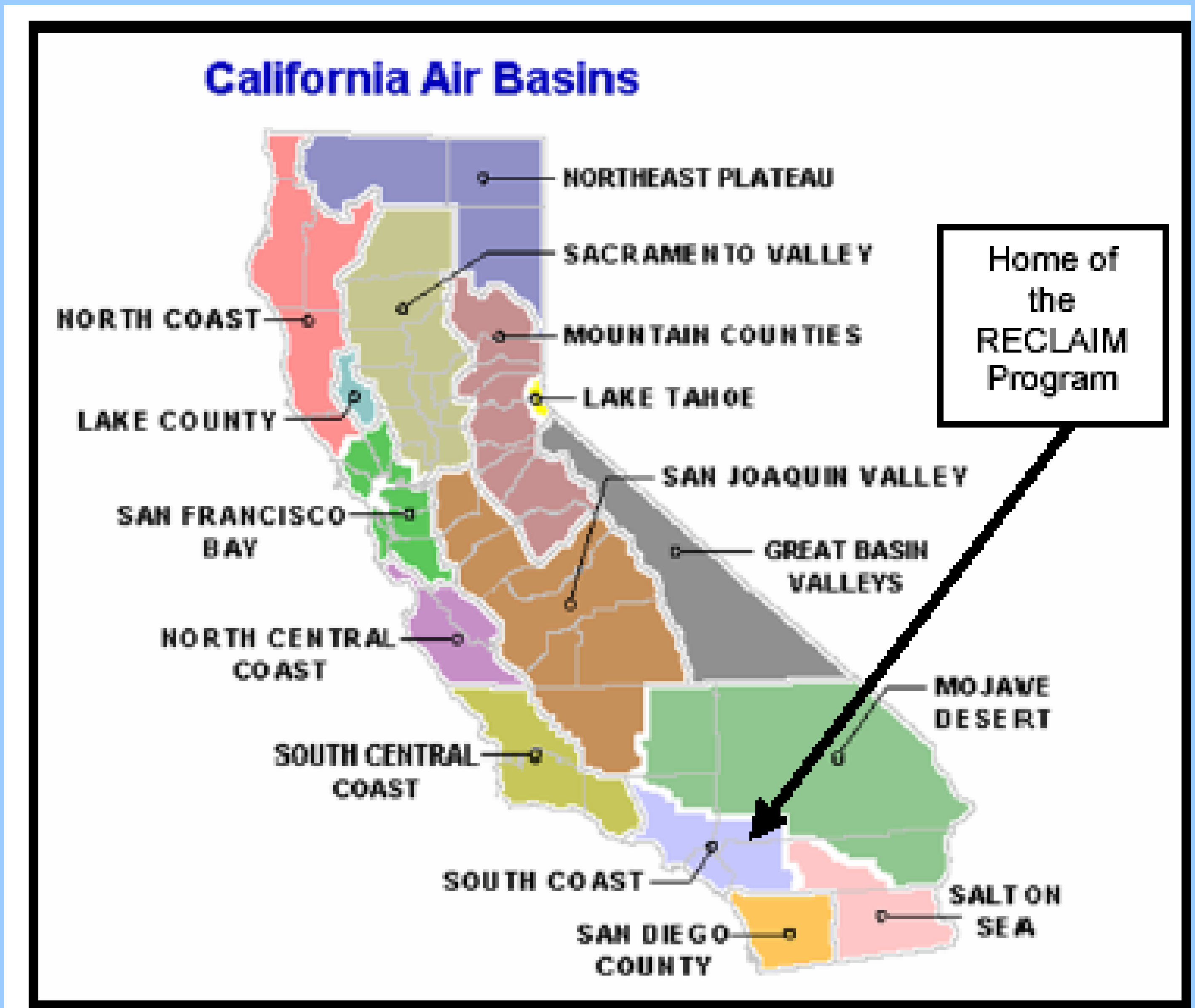
Motivation for Study

- Tradable permit programs
  - Numerous programs; many proposed
  - Politically feasible; cost effective
- Market design issues
  - Bankable??
    - Short cycle: less intertemporal trading
    - Long cycle: potential hotspots or non-attainment
- RECLAIM overlapping permit cycles
  - Equilibrium properties: cost effective?
  - Empirical analysis: consistent w/ equilibrium?

The RECLAIM Program

- RECLAIM: Regional Clean Air Incentives Market
- Implemented January 1994
- Goal: Compliance with National Ambient Air Quality Standards (NAAQS) by 2003
- NO_x and SO_2 caps declining annually
  - 75% decrease in NO_x cap, 1994-2003
- Stationary sources
- Heterogeneous industries (“facilities”)
  - Electricity generators, petroleum refineries, cement factories, many others
- Four counties in the Los Angeles smog airshed

South Coast Air Quality Management District (SCAQMD)

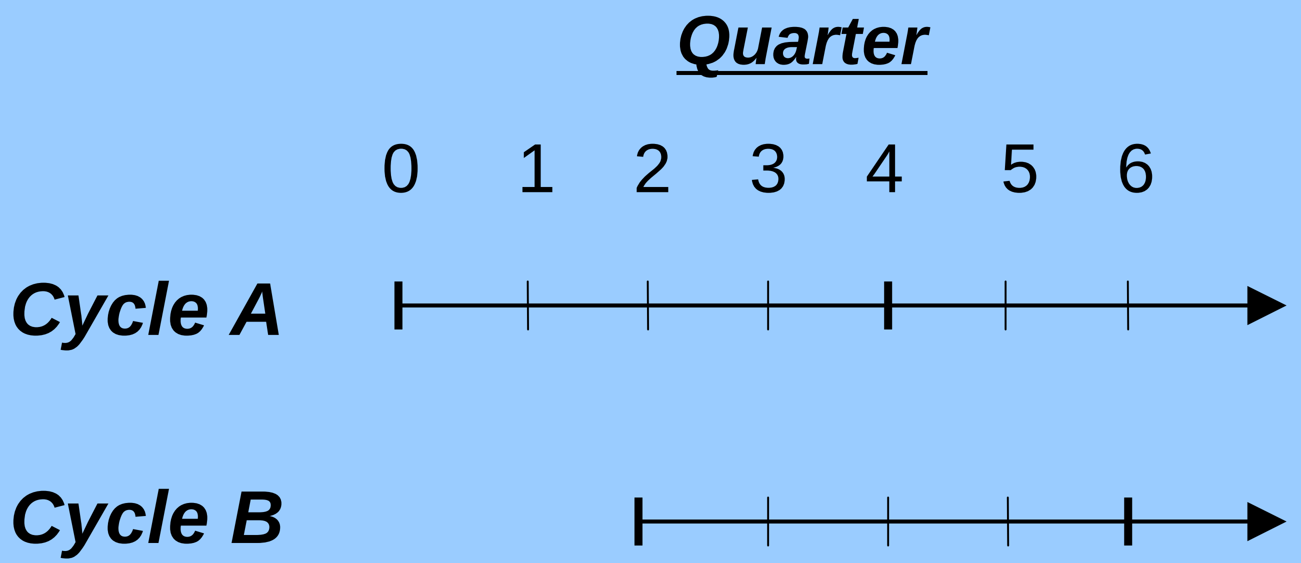


The RECLAIM Market

- RECLAIM trading credit, or RTC
  - 1 pound of emissions
- Tradable, but not bankable
- Annual compliance

- Overlapping compliance cycles
  - Cycle A: January-December compliance year
  - Cycle B: July-June compliance year
- Facilities are assigned to a cycle
- Permits are tradable between cycles
  - Cycle A facility can buy and use a Cycle B permit

Overlapping Compliance Cycles



-- Emissions reported quarterly --

-- Annual compliance --

Modeling the RECLAIM Market

- Dynamic model
  - Time as quarters (quarterly reporting of emissions)
- Supply side
  - Semi-annual permit caps
  - E_t = supply of permits that expire in quarter t
  - $E_t > 0$ if t is even; $E_t = 0$ if t is odd
- Demand side
  - Firm objective function: minimize the discounted sum of abatement costs and permit costs

- Demand side (continued)

$$\min_{d_t^A d_t^B} \sum_{t=1}^{\infty} \delta^t c_t(a_t) + \delta^{t+i} p_{t+i}^{t+i} d_t^A + \delta^{t+i} p_{t+i}^{t+i+j} d_t^B$$

where

a_t = abatement

$c(a_t)$ = abatement cost function

d_t^A = demand for cycle A permits

d_t^B = demand for cycle B permits

p_{t+i}^{t+i} = price of cycle A permits at compliance time

p_{t+i}^{t+i+j} = price of cycle B permits at compliance time

δ = discount factor

$a_t = \varepsilon_t - d_t^A - d_t^B$, with ε_t = counterfactual emissions

- Demand side (continued)
  - Demand correspondences for permits of each cycle for each quarter
  - Defined for firms in compliance cycle A and for firms in compliance cycle B
  - Aggregate demand sums the individual demands

- Equilibrium
  - Intertemporal arbitrage: $p_t^\tau = p_0^\tau \delta^{-t} = p_0^\tau (1+r)^t$
  - Equilibrium condition:

$$\delta^t c_t'(a_t) = \delta^{t+i} \min\{p_{t+i}^{t+i}, p_{t+i}^{t+i+j}\} = \min\{p_0^{t+i}, p_0^{t+i+j}\}$$

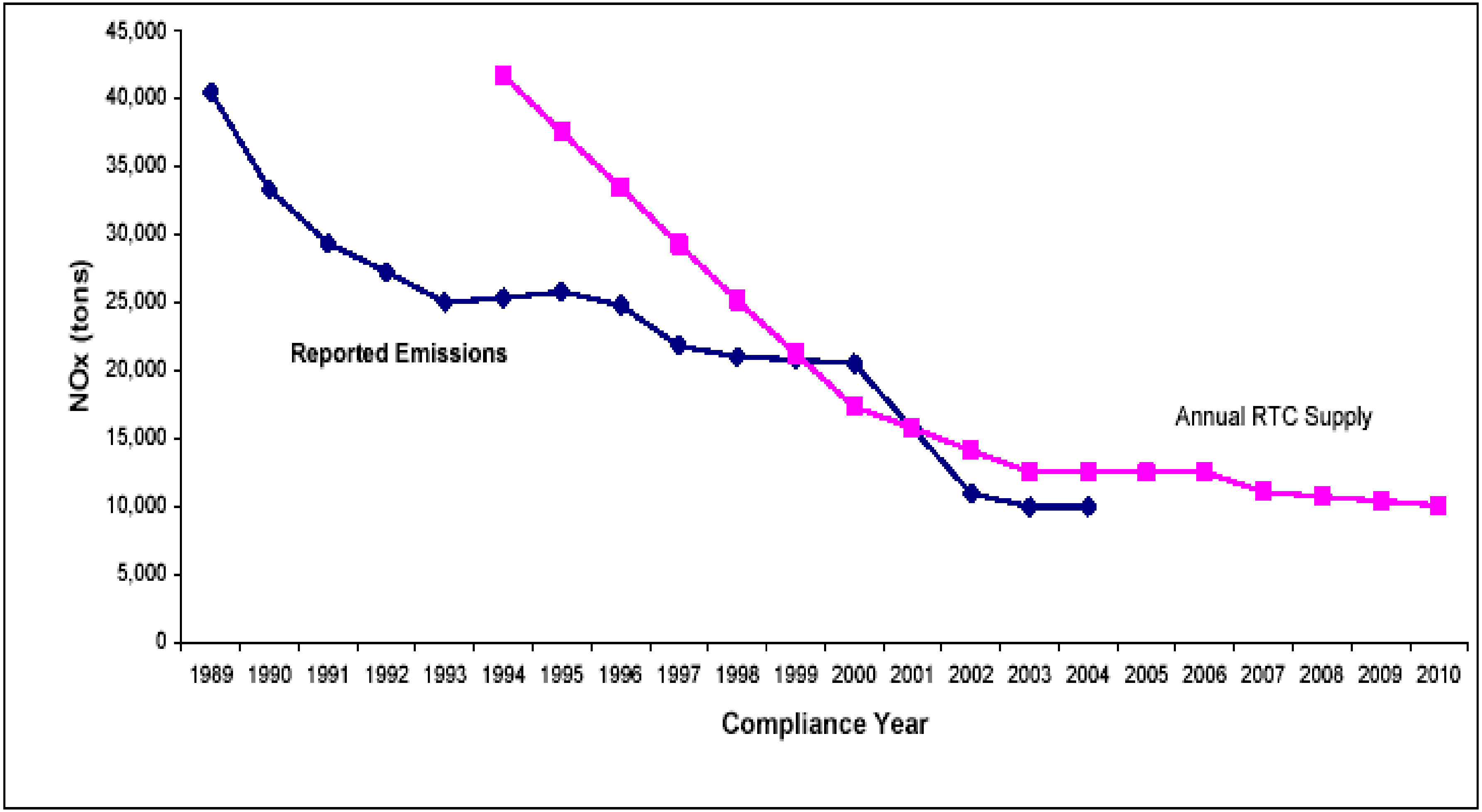
Main Theoretical Results

- A competitive equilibrium exists
  - It is cost effective
  - It is not necessarily dynamically efficient
- The equilibrium is invariant to:
  - Reassigning a firm from Cycle A or Cycle B to the other cycle
  - Reallocating the initial endowment of permits
- Emissions are higher in quarter *t-1* than in quarter *t* (where *t* is a compliance quarter)
  - Qualifying conditions: positive prices and controlling for abatement costs

Data and Variables

- Panel data on emissions
  - Facility-level (cycles A and B)
  - Quarterly, 1994-2003
  - NO_x and SO_2
  - > 400 facilities and > 12,000 observations (NO_x)
- Control variables
  - Fixed effects
  - SIC codes
  - Annual endowment of permits
  - Producer prices
  - Actual and average temperatures
  - Zone (coastal or not)

Two Phases:
Nonbinding and Binding Caps



Proposition: *Emissions are higher in quarter t-1 than in quarter t (where quarter t is a compliance quarter)*.

- Difference-in-differences estimator:

$$e_{it} = \alpha + \beta_1 CmplncQtr + \beta_2 Scrcty + \beta_3 CmplncQtr * Scrcty + \nu_i + \varepsilon_{it}$$

where

e_{it} = NO_x emissions by facility *i* in quarter *t*

CmplncQtr = dummy variable for last quarter in cycle

Scrcty = dummy variable for scarcity phase

ν_i = facility fixed effects

ε_{it} = error term

$$e_{it} = \alpha + \beta_1 CmplncQtr + \beta_2 Scrcty + \beta_3 CmplncQtr * Scrcty + \nu_i + \varepsilon_{it}$$

β_1 = Average difference in quarterly emissions between quarters *t-1* and *t* in pre-scarcity phase

β_2 = Average change in quarter *t-1* emissions after entering scarcity phase

β_3 = Average difference between quarter *t* and quarter *t-1* changes in emissions after entering scarcity phase

>> Hypothesis: $\beta_3 < 0$

Delayed Abatement

Difference in Differences
Dependent variable: quarterly NOx emissions

	Spec. 1	Spec. 2	Spec. 3
Coeff	1686	1504	5162*
Std Err	1798	1789	1854
CmplncQtr	Yes	Yes	Yes
Scrcty	Yes	N.A.	Yes
Year Dummies	No	Yes	No
Facility F.E.	Yes	Yes	Yes
N	14,089	14,089	11,687
Facilities	530	530	528

Note: Model predicts negative coefficient.

Proposition: *Assignment of a firm to Cycle A or Cycle B does not affect quarterly emissions*.

DID Estimator:

$$e_{it} = \alpha + \beta_1 LateQtr + \beta_2 Scrcty + \beta_3 LateQtr * Scrcty + \nu_i + \varepsilon_{it}$$

where

e_{it} = NO_x emissions by facility *i* in quarter *t*

LateQtr = d.v. for last two quarters of compliance year

Scrcty = d.v. for scarcity phase

ν_i = facility fixed effects

ε_{it} = error term

>> <u>Hypothesis</u>: $\beta_3 = 0$

Predictive Power of Cycles

Difference in Differences

Dependent variable: quarterly NOx emissions

	Spec. 1	Spec. 2	Spec. 3
Coeff	-1555	-2686	-2684
Std Err	2088	2095	1823
LateQtr	Yes	Yes	Yes
Scarcity	Yes	N.A.	Yes
Year Dummies	No	Yes	No
Facility F.E.	Yes	Yes	Yes
N	12,014	12,014	10,125
Facilities	403	403	403

Note: Model predicts zero coefficient.

Summary

- Market design issues moving to forefront
- RECLAIM's overlapping cycles feature
  - Limited intertemporal trading
  - Cost effective
  - Reasonable for some pollutants and certain regulatory contexts
- Tests of theoretical propositions underway

Preliminary Draft
Do Not Quote
Comments Welcome
Last updated on 10/3/06

A Spatial Analysis of the Consequences of the SO2 Trading Program

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Abstract

Title IV of the 1990 Clean Air Act Amendments (CAAA) set a cap on the SO_2 emissions of the dirtiest coal-fired electric utilities at 9 million tons per year (roughly 50% below their 1980 levels, to be fully implemented in 2010). At the same time, Title IV significantly changed the manner in which coal-fired utilities were regulated from command-and-control emission standards to a system of tradable allowances. In this paper we examine the level of the health benefits and abatement costs associated with the air quality improvements mandated under Title IV and compare them with the level of health benefits and abatement costs that might have occurred from a comparable reduction in emissions using a command-and-control system. Using data for 148 coal-fired utilities during the first year of Title IV (1995), we find as expected that the benefits of reduced SO_2 emissions under Title IV greatly exceeded the costs: we estimate benefits of nearly \$56 billion and costs of only \$558 million. We then compare the health benefits and abatement costs under allowance trading versus a hypothetical command-and-control system requiring the same overall level of emission reductions. We find that the allowance trading system led to sizable savings (16.8%) in abatement costs, but that allowance buyers tended to have emissions with higher marginal benefits (damages) than sellers, more than offsetting the savings in abatement costs. This result suggests a possible role for spatially-based 'exchange rates' in allowance trading. We explore the possibility of spatially-based allowance systems, such as trading regions, but find that considerable heterogeneity in marginal benefits within regions limits the potential gains from such systems.

I. Introduction

During the late 1980's, prior to the passage of Title IV of the 1990 Clean Air Act Amendments (CAAA), there had been a spirited debate involving Congress, the Environmental Protection Agency (EPA), and academics, about the importance of reducing sulfur dioxide (SO_2) emissions due to the problem of acid rain. Acid rain occurs when SO_2, released as a gas from coal when it is burned at high temperatures, reacts with water in the atmosphere to form sulfurous acid and sulfuric acid and then returns to earth in the form of raindrops and dry particles. Some of the acid rain caused by SO_2 emissions from coal-fired utilities in the upper Midwest falls in Canada. Thus, in addition to domestic pressure to reduce SO_2 emissions, Canada was also putting political pressure on the U.S. to decrease its SO_2 emissions. Soon after the passage of the CAAA the U.S. and Canada formally agreed to control transboundary acid rain by signing the Canada-United States Air Quality Agreement.

The ecological damage from acid rain, while important, is relatively minor when compared to decreases in premature mortality from SO_2 reduction. For example, Burtraw et al (1997) estimate the expected environmental benefits from recreational activities, residential visibility, and morbidity from the Acid Rain Program to be only \$13 per capita in 1990. On the other hand, in 2002 the EPA estimated that, by 2010, human health benefits from the Acid Rain Program will be approximately \$50 billion annually (due to many fewer cases of premature mortality, fewer hospital admissions and fewer emergency room visits). These human health benefits mainly arise from lower ambient levels of secondary particles (PM_{10} and $PM_{2.5}$) – which have been linked in numerous studies to premature mortality – which form when SO_2 combines with ammonia in the atmosphere.

Most of the SO_2 emissions in the United States come from coal fired electric utilities. Title IV of the 1990 CAAA establishes an annual emissions cap of 9 million tons of SO_2

emissions from all fossil-fuel fired electric utilities over 25 megawatts, to be fully implemented by 2010. This annual cap requires the affected electric utilities to reduce their total SO_2 emissions by 10 million tons below their 1980 levels. Title IV also significantly changed the manner in which coal-fired utilities were regulated from command-and-control emission standards to a more flexible, cost-efficient system of allowance trading. The more flexible allowance trading approach made the considerable SO_2 reductions politically feasible and is generally thought to have led to large cost savings relative to the previous command-and-control approach. For example, Keohane (2003) estimated that the allowance trading system resulted in annual cost savings between \$150 million and \$270 million relative to a uniform emissions-rate standard. Furthermore, the tremendous flexibility of the allowance trading program provides the market with the proper incentives to produce an efficient allocation of SO_2 reductions, if SO_2 emissions have the same marginal benefit everywhere across the United States. However, our estimates of the health benefits resulting from SO_2 reductions indicate substantial heterogeneity across plants in the marginal benefit per ton of SO_2 reduced. Therefore, since Title IV allows one-to-one allowance trading, we should not expect the resulting allocation of emission reductions to maximize the net benefits from SO_2 reductions.

In this paper we extend the work of Shadbegian, Gray, and Morgan (2006) by examining two different scenarios of SO_2 reductions leading to significant air quality improvements. In one scenario, we measure these improvements relative to the level of emissions under the former command-and-control regime, which allowed a greater level of emissions. In another scenario, we measure the improvements relative to a counterfactual distribution of emissions based on requiring emissions reductions similar in magnitude to those actually achieved under Title IV, but imposed on plants through a reduction in the allowable emissions rate for all plants, without the possibility of trading.

The overwhelming majority of the dollar-valued benefits from air quality improvements come from the impact of airborne fine particulate matter ($PM_{2.5}$ and PM_{10}) on premature mortality. In 1997 the EPA estimated that \$20 trillion dollars of the estimated \$22.2 trillion dollars worth of benefits derived from the Clean Air Act of 1970 (between 1970 and 1990) resulted from reductions in particulate-related premature mortality. In this paper, we use a spatially-detailed air pollution receptor model (the Source-Receptor Matrix) to model the impact that SO_2 emissions have on $PM_{2.5}$ concentration levels in each county in the United States during 1995, the first year of Title IV. We then use information from the epidemiology literature on the correlation between exposure to $PM_{2.5}$ and mortality to translate the reductions in secondary $PM_{2.5}$ concentrations in each county in the U.S. into the dollar benefits from reductions in premature mortality.

Are the substantial air quality improvements due to lower SO_2 emissions costless? The answer could be yes if increases in efficiency resulting from the new allowance trading system (e.g. more flexibility in complying with regulations, less uncertainty about future regulatory requirements) more than offset the extra abatement costs on a plant-by-plant basis. However, a more likely outcome is that some plants will still face higher abatement costs, which will be passed along to their customers. Furthermore, if some plants buy SO_2 allowances to increase their emissions (or at least not to lower them by as much as they otherwise would have), the population impacted by the worsening air quality (or at least the relatively less clean air) will be 'paying' some of the costs of the greater air quality improvements near other plants that reduced their emissions in order to sell SO_2 allowances. In addition to comparing the costs and benefits that arise from lower SO_2 emissions under Title IV, we simulate the impact of requiring a comparable reduction in overall SO_2 emissions under the old command-and-control regime, assuming that a uniform emission standard is in place at all plants.

Using data for the 148 dirtiest coal-fired utilities we find, as expected, that the aggregate benefits in 1995 from lower SO_2 emissions under Title IV greatly exceed their costs: we estimate benefits of $56 billion (a bit larger than EPA's estimates of total benefits of $50 billion by 2010) and costs of only $558 million. Therefore, the net benefits from the SO_2 reduction are roughly $55 billion or $100 in benefits for every $1 in abatement costs. Comparing the consequences of requiring similar overall emissions reductions using command-and-control regulation, we find that trading results in significantly lower costs ($94 million or 16.8% lower). However, shifts in the spatial distribution of emissions tend to lower aggregate benefits from SO_2 reductions, since allowance buyers have emissions with higher marginal benefits (damage) than allowance sellers. This result suggests the possibility of limiting trades between plants, either by defining trading zones that would allow only trades between plants in the same zone, or by developing some sort of 'exchange rate' for allowance trades, based on the relative marginal benefits of the two plants involved. We explore the possibility of trading zones, but find that considerable heterogeneity in marginal benefits within regions limits the potential gains from such systems.

The rest of the paper is organized as follows. In section II we present background information on Title IV of the CAAA of 1990. Section III contains a brief survey of the literature on studies examining various aspects of the Title IV trading program. Section IV describes the methodology we use to estimate both the health benefits and the costs of SO_2 abatement under Title IV and Section V describes our sample of plants. In Section VI we discuss our findings and we end with some concluding remarks in Section VII.

II. Title IV: Background Information

Title IV of the 1990 CAAA significantly changed the manner in which coal-fired utilities were regulated in the U.S. Before Title IV utilities were regulated by command-and-control emission standards, where utilities were required to meet individual emission standards set by regulators. Title IV established a more flexible, cost-efficient cap-and-trade program that set a cap on total SO_2 emissions, allocated allowances among generating units equal to that cap, and allowed plants to freely trade these allowances among their own units, to sell them to other plants, or to bank them for future use.[1] The only requirement imposed on a plant under the allowance trading program is that, at the end of the year, it must have one allowance for each ton of SO_2 emitted that year. Thus, the allowance trading program created by Title IV provides more flexibility to comply with any given emission standard, because utilities which have high marginal abatement cost may purchase SO_2 allowances from utilities which have lower marginal abatement costs.

The overall goal of Title IV was to decrease total SO_2 emissions to roughly 9 million tons by 2010, approximately half of the 1980 level. The reduction was to be accomplished in two

[1] The only time a plant is denied the right to buy allowances is when that plant is located in a county which is in violation of the National Ambient Air Quality Standard (NAAQS) for SO_2, which is set at a level to prevent local adverse health outcomes. However, this has not proved to be a major hindrance in the SO_2 allowance market since the Title IV cap requires a considerably larger reduction of aggregate SO_2 emissions than what is required to meet the NAAQS for SO_2.

phases. Phase I, which occurred from 1995-1999 targeted the dirtiest 110 power plants with 263 generating units. These generating units, referred to as the Table A units, were required to lower their aggregate emissions to 7.2 million tons per year in 1995, 6.9 million tons in 1996, and then 5.8 million tons from 1997-1999. In 1990, together the Table A units emitted 8.7 million tons of SO_2, but they only emitted 4.5 million tons in 1995 (nearly 50% less). During Phase I the initial number of allowances a generating unit was allocated was determined by multiplying its average 1985-1987 heat input by an average emission rate of 2.5 lbs of SO_2 per million BTUs of heat input.[2] Each SO_2 allowance gave a generating unit the right to emit one ton of SO_2, and at the end of the year the generating unit could only emit an amount of SO_2 equal to the number of allowances it held.[3]

Phase II, which began in 2000, expanded the cap-and-trade program to include any fossil-fueled fired generating units with an output capacity of 25 megawatts or greater.[4] In addition to including most of the smaller and cleaner units, Phase II also required the Table A units to make further reductions in their SO_2 emissions – reducing their aggregate SO_2 emissions by an additional 3.4 million tons, down to 2.4 million tons by 2010. During Phase II basic annual allowance allocations to each generating unit are based on an average emission rate of 1.2 lbs of SO_2 per million BTUs of heat input, a much more stringent standard than the emission rate of 2.5 lbs during Phase I.

Two additional provisions of Title IV – ‘substitution’ and ‘compensation’ – allow other generating units not required to make reductions during Phase I to voluntarily come under Title IV along with the Table A units. The substitution provision allows Table A units to contract for emission reductions at non-Table A units instead, thereby reducing the cost of SO_2 reduction. On the other hand, the compensation provision prevents Table A units from meeting their emission reductions by simply reducing generation. In other words, if a Table A unit significantly reduces its generation below its baseline levels then it must bring one or more non-Table A units under Phase I regulation to compensate. The increased generation at the non-Table A units must offset the reduction at the Table A unit.

The total number of allowances available to participating units in 1995 was 8.7 million. The initial allocation of allowances issued to the Table A units was approximately 5.55 million. The number each unit received was based on their historical coal use and emission rates. The ‘compensating’ and ‘substitution’ units were granted a total of 1.33 allowances. Additional allowances were also issued through allowance auctions (175,000 in 1995) and through other bonus provisions in the CAAA including: Phase I Extension Allowances; Early Reduction Credits; Small Diesel Allowances; and Conservation Allowances. A total of 1.35 million Phase I Extension Allowances were allocated to Phase I units that either reduce their emissions by 90% or transferred their reductions to other units that reduce their emissions by 90%. Approximately 314,000 Early Reduction Credits were allocated to units that voluntarily reduced their emissions between 1990 and 1995. Slightly more than 50,000 allowances were issued as conservation and small diesel allowances. Small diesel allowances were given to small diesel refineries in 1995 that manufactured and desulfurized diesel fuel in 1994, while conservation allowances were earned by plants that undertake efficiency and renewable energy measures.

[2] Note allowances are allocated to individual generating units and not to plants.
[3] Generating units face a fine of $2000 for each ton of SO_2 emitted for which they do not have an allowance.
[4] Some of these smaller generating units (111) joined Phase I, under the “substitution” and “compensation” provisions of the CAAA, and are included in this analysis.

During 1995 SO_2 emissions from Phase I generating units dropped significantly.[5] Phase I plants emitted only 4.9 million tons of SO_2, 4.6 million tons less than they emitted in 1990 – 3.2 million tons less than was required by Title IV. However, large decreases in SO_2 emissions were observed just after the passage of Title IV, even before the trading system was in place and plants were required to make large reductions. There have been several explanations offered to help explain the pre-1995 reductions. First, plants may have acted strategically by complying early with Title IV. Early compliance would allow utilities to pass on to consumers the additional higher cost of low-sulfur coal and/or the cost of installing scrubbers. Second, certain states revised their State Implementation Plans requiring electric utilities to lower their SO_2 emissions prior to 1995. However, the most probable explanation is that the deregulation of railroads made it much less expensive to ship low-sulfur coal from the Powder River Basin to Midwest, the geographic region which experienced the greatest SO_2 reductions between 1985 and 1993 (Ellerman and Montero, 1998).

Finally, the SO_2 cap-and-trade program builds in even more flexibility by letting allowances that are not used in one year to be 'banked' and used in any later year. In other words, a plant can lower its emissions below their annual allowance allocation, thereby not exhausting their allotment of allowance and 'deposit' the extra allowances in an 'emissions bank.' These 'banked' allowances are perfect substitutes for future year allowances, and may be used or sold. Phase I plants 'banked' many allowances from 1995-1999 most likely to smooth the transition the more stringent limits imposed under Phase II starting in 2000. In particular, plants banked more than 11.5 million allowances during Phase I (1995-1999). Plants then used 1.2 million of these banked allowances in 2000, the first year of Phase II, followed by 1.08 million allowances in 2001 and another 650,000 million allowances in 2002. This systematic drawing down of the allowance bank suggests that the over compliance during Phase I was intentional (rather than being an unexpected result of lower than expected prices for low-sulfur coal).

III. SO_2 Trading Program: Literature Review

Prior to the introduction of emissions trading, Gollop and Roberts (1985) showed that a cost-effective allocation of pollution abatement arising from allowance trading among electrical utilities could produce an almost 50% reduction in abatement costs, suggesting potentially huge savings from emissions trading. In the years since the advent of Title IV, many papers, including Burtraw et al (1997), Joskow et al (1998), Schmalensee et al (1998), Carlson et al (2000), Popp (2000), Keohane (2002,2003), Ellerman (2003), and Shadbegian and Morgan (2003), have examined many different aspects of the actual SO_2 allowance trading program including its cost savings, environmental effectiveness, spatial patterns of abatement, pollution control innovations, and the efficiency of the banking of allowances. The likely success of any pollution allowance-trading program depends critically on the efficiency of the allowance trading market. Joskow et al (1998) evaluate the efficiency of the SO_2 allowance market by comparing the price of allowances auctioned by EPA between 1993 and 1997 with private market allowance price indices. If the SO_2 allowance market is efficient then EPA auction prices and private market prices will be equal. Joskow et al find that by the end of 1994 EPA auction prices and private

[5] Recall our analysis is done at the plant level, but regulation of the electric utilities takes place at the generating level. Phase I plants include the 110 plants (with 263 generating units) that were regulated under Phase I plus the 38 plants (111 generating units) that opted into Phase I.

market prices for SO_2 allowances were virtually identical implying that the private market for tradable allowances was relatively efficient. Furthermore, Schmalensee et al (1998) also conclude that the private market for tradable allowances was relatively efficient by noting the tremendous growth in the number of market trades from 1995 to 1997: 1.6 million, 4.9 million, and 5.1 million allowances were traded, respectively.

Keohane (2003) concludes that Title IV's allowance trading system resulted in annual cost savings between \$150 million and \$270 million relative to a command-and-control uniform emissions-rate standard. On the other hand, Carlson et al. (2000) find that the sizeable decrease in pollution abatement costs during the beginning of Title IV relative to the initial estimates was due more to the technological progress that lowered the cost to switch to low sulfur coal and the reduction in the price of low sulfur coal rather than the ability to trade allowances per se. Shadbegian and Morgan (2003) examine the impact of the stringency of SO_2 regulations on the productivity of electric utilities before and after the implementation of Title IV. They estimate that a 10% increase in regulatory stringency lowered productivity by 0.66% prior to Title IV, while during Title IV that same increase in regulatory stringency had no significant impact on productivity. The productivity gain is equivalent to 31 million more kilowatts (kwh) of electricity – equivalent to \$1.5 million cost savings, evaluated at \$0.05/kwh.

Ellerman (2003), among other issues, examines whether or not the more than 11 million allowances 'banked' during Phase I was optimal. He concludes that, given a reasonable set of assumptions concerning both the discount rate and the expected growth of SO_2 emissions during the banking period, the level of banking that took place during Phase I was consistent with rational, cost-minimizing behavior on the part of the electric utilities.

Beyond the direct cost-savings that arise from the use of market-based mechanisms to protect the environment, economists have argued for their use because of the potential gains from induced technological change. Popp (2003) and Keohane (2002) have both provided empirical evidence that Title IV led to induced technological change. Popp shows that prior to the passage of the 1990 CAAA, regulation which mandated the use of scrubbers with a 90% removal efficiency rate in many new plants, created incentives which led to innovations that decreased the cost of operating scrubbers, yet did little to increase the ability of scrubbers to abate pollution. However, Popp provides evidence that since Title IV there has been technological innovations that have improved the removal efficiency of scrubbers. Keohane examines the choice of electric utilities' to install a scrubber or switch to low sulfur coal under command-and-control versus a more flexible system of allowance trading. He provides evidence that fossil-fuel fired electric utilities that were subject to Title IV were, for a given increase in the cost of switching to low sulfur coal, more likely to install a scrubber.

One potential reason why an allowance trading system may not maximize net benefits from emission reductions is that emissions from different sources may have different impacts on human health (or other benefits). Baumol and Oates (1988, Chapter 12) argue that differences in health impacts across different emission sources can lead to a suboptimal outcome when high marginal damage sources buy allowances from low marginal damage sources on a one-for-one basis. Tietenberg (1995) reviews the literature on the spatial effects associated with tradable allowances, arguing that the first-best option – potentially each source paying a different price for an allowance – significantly complicates the trading process, so a range of second-best options have been proposed. One second best option that has been proposed in the literature is to minimize the distortion which may arise from heterogeneous marginal damages across sources by dividing the control area into different zones. The zones should be defined such that emission sources are similar enough within a zone to allow unrestricted trading. On the other hand, trading will be permitted between zones only at a predefined trading ratio (‘exchange rate’) that is based on the relative marginal damages. Creating a system of trading zones is appealing since it should increase the level of net benefits relative to a completely unrestricted trading system. However, as Atkinson and Tietenburg (1982) point out, a system of trading zones has three undesirable effects: 1) it increases compliance costs by reducing the number of cost minimizing trades; 2) it makes the final allocation of air quality improvements more reliant on the initial allocation of allowances, since that allocation determines the overall level of emissions in each zone; and 3) it decreases the number of market participants which increases the likelihood of noncompetitive behavior. Furthermore, a system of trading zones places more burden on the regulator since the regulator would need to know the marginal damage function of all sources to set the optimal trading ratios (‘exchange rates’).

IV. The Benefits and Costs of Cleaner Air

A. Benefits from Cleaner Air

We estimate the human health benefits from SO_2 reductions (SO2BEN) from a given emission source by the change in mortality risk from exposure to ambient particulate concentrations caused by those SO_2 emissions. These human health benefits are calculated using a simplified linear damage function, based on estimated parameters from the literature:

SO2BEN = SO2DIFF*AIR_QUAL_TC * HEALTH_CHG * POP * VSL.

AIR_QUAL_TC is the transfer coefficient – the change in air quality (ambient particulate matter – $PM_{2.5}$) per ton change in SO_2 emissions (SO2DIFF). HEALTH_CHG is the change in mortality risk to the impacted population corresponding to the changes in air quality. POP is the size of the impacted population, and VSL (value of statistical life) is the dollar value associated with reducing premature mortality.

We calculate air quality changes at any given location using the Source-Receptor (S-R) Matrix Model, as described in Latimer (1996) and Abt (2000). The S-R Matrix model was initially calculated using the Climatological Regional Dispersion Model (CRDM). The model includes data on air pollution emissions from 5,905 separate sources in the U.S., along with additional sources from Mexico and Canada.[6] The S-R Matrix relates emissions of each particular pollutant from each source to the resulting ambient concentrations of each pollutant in every county in the U.S. More specifically, the S-R Matrix provides the necessary transfer coefficients to calculate the county-by-county changes in annual average pollutant concentrations for a one unit change of emissions for a particular pollutant from each source. The S-R Matrix transfer coefficients are a complicated function of numerous factors including wet and dry deposition of gases and particles, chemical conversion of SO_2 and nitrogen oxide (NO_X) into secondary particulates, effective stack height, and several atmospheric variables (including wind

[6] Emissions sources in the U.S. include ground-level sources, county-level sources and individual sources. Emissions from ground-level sources are estimated for each of the 3,080 contiguous counties (excludes Alaska and Hawaii, whereas elevated sources are grouped according to effective stack height. Point sources with an effective stack height taller than 500 meters are modeled as individual sources of emissions. All emission sources in the same county with an effective stack height less than 250 meters are aggregated into a single county-level source – the same is done for emission sources with an effective stack height between 250 meters and 500 meters. Ground-level emission sources are also aggregated to the county level. The S-R matrix models 5,905 U.S. emission sources.

speed and direction, stability, and mixing heights). We use the AIR_QUAL_TC to measure the impact of SO_2 emissions on ambient concentration of $PM_{2.5}$ in each county.

Our study concentrates on the human health benefits from lower ambient concentrations of secondary particulates ($PM_{2.5}$) that result from reductions in SO_2 emissions. We use the results from the American Cancer Society (ACS) study, the most complete analysis of long-term mortality effects from air pollution to date (Pope et al., 2002) to measure HEALTH_CHG. Pope et al. find that a 10 $\mu g/m^3$ increase in $PM_{2.5}$ concentrations leads to an approximate 4% (95% confidence interval: 2%, 6%) higher mortality rate in the exposed population. We assume that the secondary particulates formed from SO_2 have the same impact on premature mortality (Pope et al. found similar numbers for sulfate particles in their study).[7] We estimate the exposed population, POP, based on county-level data from the 1990 Census of Population, which provides the number of people living in each county (and thus the number of exposed people by the average ambient pollution concentrations in that county).

Finally, we use a recent EPA (1997) benefit-cost analysis that estimated the value of a statistical life (VSL) to put a dollar value of premature mortality. The EPA study combined contingent valuation and wage-risk studies to provide a central VSL estimate of $5.4 million (in 1995 dollars) per life saved. Note that our study assumes constant values for the VSL and HEALTH_CHG terms for the entire population. In other words, each exposed person is assigned the same average dollar harm from exposures to fine particulates and the same level of sensitivity to fine particulates.[8] Note also that the very large estimates we find for the benefits of lowering SO_2 emissions are a combination of these two factors: one will get smaller benefits by assuming either smaller health effects or a lower VSL.

B. Costs of Cleaner Air

There are three basic options (or combinations of options) available to plants to comply with Title IV: install a scrubber, switch to lower sulfur coal, or buy allowances. We measure the cost of abating a ton of SO_2 emissions in two ways. Our first estimate of the cost of complying with Title IV (COST1) is based on the actual method each plant chose to use, given the option of purchasing allowances. From Ellerman et al (1997) we have an estimate of the average cost of SO_2 abatement for each of the 374 units (plant-boiler observations) regulated by Title IV during Phase I – this consists of the 263 units mandated to reduce their SO_2 emissions by Title IV plus the 111 units which 'opted' into Phase I. According to Ellerman et al (1997) the average cost of 'switching' and 'scrubbing' in 1995 was $153 and $265 per ton respectively, whereas the average price of an allowance was $128.50.[9] Our second estimate of the cost of complying with Title IV (COST2) is based on Keohane (2003), which models each unit's abatement costs based on its decision to install a scrubber or not. The decision to install a scrubber is first evaluated given the Title IV allowance trading program and then given a traditional command-and-control regime (a no trading scenario) designed to produce the equivalent aggregate SO_2 emission reductions realized under the 1990 CAAA. Keohane estimates the emissions and SO_2 abatement costs at each of the plants assuming both an emissions trading regime and a command-and-

[7] Chay and Greenstone (2003a, 2003b) analyze the impact of the exposure of fine particulate matter on infant mortality, and find similar results to the ACS study, measured in terms of increased mortality rates.

[8] Our data would readily allow our calculations to vary both in terms of sensitivity and valuation for different subpopulations – if one could generate a consensus on how to quantify such differences, a politically charged issue that we avoid here.

[9] We would like to thank Denny Ellerman for providing us with this data.

control regime, and the difference in costs between the two regimes gives us our second measure of SO_2 abatement costs. [10]

Who pays these extra abatement costs? One possible answer is “nobody”, if efficiency improvements resulting from the new allowance trading system (e.g. more flexible production switching, less uncertainty about regulatory requirements) outweighed the additional abatement costs on a plant-by-plant basis. However, a more likely scenario is that plants facing higher costs of pollution abatement will pass along these costs to their customers. We assume that all of the extra costs are passed through to the utility’s customers, and that all customers live in the same state where the utility is located.[11] We use data from the 1990 Census of Population to allocate each plant’s extra abatement costs equally to all people living within that state.

V. Sample Coverage

Phase I of Title IV regulated the emissions of 263 generating units (the Table A generating units) owned by 110 plants. An additional 38 substitution and compensation plants (111 generating units) opted into Phase I, bringing the final total to 374 generating units. Our sample consists of all 148 plants and their 374 generating units. The geographic distribution of these plants – heavily concentrated in the Midwest - is shown in Figure 1.

In Table 1 we present information on SO_2 emissions and the allocation of SO_2 allowances obtained from the EPA’s Allowance Tracking System (ATS).[12] The 148 plants in our sample emitted a total of 9.5 million tons of SO_2 during 1990, the year Title IV was passed. By 1995, our 148 plants had reduced their SO_2 emissions by 4.6 million tons from their 1990 levels, cutting them almost in half, although Title IV had only required them to reduce emissions by 15%, to 8.1 million tons.

VI. Distribution of Benefit and Costs

In Table 2 we present two scenarios of health benefits and abatement costs. In Scenario 1 we calculate the benefits and costs associated with the actual 1995 SO_2 emissions reductions (costs are based on Ellerman et al (1997)): counterfactual SO_2 emissions minus actual emissions. The counterfactual emissions in 1995 are those we would have observed in the absence of the CAAA of 1990, based on calculations presented in Ellerman et al (1997). In Scenario 2 we take the actual reduction in SO_2 emissions as given, and compare the costs and benefits associated with achieving that aggregate reduction using two different policy regimes, allowance trading and command-and-control (reducing the allowable emissions rate uniformly across plants), based on calculations from Keohane (2003). A visual comparison of the benefits from reducing SO_2 emissions under the two scenarios can be seen in Figures 2 and 3. Not surprisingly, given the concentration of the plants in the Midwest and the pattern of airflow from west to east, the benefits that result from the large reductions in emissions in Scenario 1 are highly concentrated geographically. Scenario 2 involves a reallocation of emissions reductions across plants, so we see both losers and winners in Figure 3.

[10] We would like to thank Nat Keohane for providing us with this data.
[11] If we had data on cross-state electricity sales, we could adjust our cost calculations to reflect this.
[12] We would like to thank Denny Ellerman for providing us with this data.

As expected, the aggregate benefits in 1995 resulting from reductions in SO_2 emissions from the 1995 counterfactual levels far outweigh their costs: we estimate benefits of nearly $56 billion and costs of only $558 million. An alternative assumption on abatement costs is that the actual cost of a ton of abatement is equal to the allowance price ($128.5 in 1995), which results in total abatement costs of only $496 million. In either case these increased abatement costs are dwarfed by the increased benefits from the SO_2 reduction, which are roughly 100 times as large.

Scenario 2 shows that allowance trading results in a sizable reduction in abatement costs ($94 million or 16.8%), relative to achieving the same aggregate emissions by a hypothetical command-and-control system. These cost savings are outweighed, however, by the changes on the benefits side. Plants with decreased emissions under allowance trading are more likely to be low-benefit plants, while plants with higher emissions under allowance trading are more likely to be high-benefit plants. In other words, we find that plants which buy allowances (to emit more SO2) are more likely to be high-benefit plants, while plants that sell allowances (and thereby emit less SO2) are more likely to be middle- or low-benefit. This is reflected in the average benefits at buying and selling plants: the buying plants have a mean benefit of $17,519 while the selling plants have a mean benefit of $14,777. These differences are not huge, but it is still the case that the plants which are buying (selling) allowances are those plants which yield the highest (lowest) benefits from abating a ton of SO_2. This result drives the negative impact of the trades on overall benefits observed in Table 2, and suggests that the allowance trading system might benefit from a spatially-based ‘exchange rate’ based on differences in the impacts of emissions across these plants.

Tables 3A, 3B, and 3C explore in more detail the differences across plants in marginal benefits generated from reductions in SO_2 emissions. Table 3A shows the distribution of the benefits per ton of reduction across our 148 plants. The variation in these numbers across plants is based on a variety of factors, including effective stack height and meteorological conditions, though the principal determinant is the population density downwind. There are a few outliers at the top and bottom of the distribution, but most plants fall between $9,600 and $19,500 per ton in marginal benefits. The plants towards the top of the distribution tend to be in places like Pennsylvania, while plants in Alabama, Florida, Georgia, and Mississippi tend to be near the bottom, although there is some within state variation as well.

Table 3B examines the hypothetical results from Scenario 2 in more detail, comparing plants which had higher emissions under the allowance trading scenario to plants which had higher emissions under the command-and-control scenario. Table 3C contains a similar comparison, but this time we analyze the actual emission decisions of plants, seeing whether the plants are buying or selling allowances in 1995. The two tables give similar results – plants with low marginal benefits tend to be sellers of allowances, while plants with high marginal benefits tend to be buyers of allowances.

What causes these differences across plants in marginal benefits? The largest factor is the location of the plant, but stack height is also important. Table 4 illustrates that there are large differences in marginal benefits across EPA regions. In particular, EPA regions 3 and 5 tend to have more plants with higher marginal benefits, while there are more plants with lower marginal benefits in EPA regions 4 and 7. Table 4 also shows that the very highest marginal benefit plants all have relatively low stacks (under 250 feet in effective stack height). When this is coupled with being located near a metropolitan area, the emissions from the plant can have a relatively strong local effect. Most of the plants in our sample have considerably higher stacks, and such plants tend to have small or moderate marginal benefits. Also note that plants with higher benefits tend to have higher abatement costs. This helps explain the finding that allowance trading has tended to move emissions from low-benefit to high-benefit plants – plants with higher costs are more likely to buy allowances, and the current trading system provides them with no incentive to consider the extent to which their own emissions are likely to be especially harmful. An examination of the data for individual plants shows that large, newer plants with tall stacks with relatively low benefits tend to be doing much of the additional abating required under allowance trading.[13]

We now turn to an examination of the possibilities of spatially-based limits on trading between plants, in order to reduce the number of trades which increase emissions at high-benefit plants and reduce emissions at low-benefit plants. Since marginal benefits are connected to downwind population, which is expected to differ by plant location, one possible solution is to define a set of trading regions and to require that trades occur only between plants in the same region. If plants in the same region have the same marginal benefits, this will rule out problematic trades. Our data does not identify individual trades, but presents aggregate purchases (or sales) for each plant.[14] We can simulate the effect of trading regions by requiring the buying and selling of allowances to balance within each region, and seeing how this affects the aggregate benefits of reducing emissions, assuming that the changes in allowance trading lead to comparable changes in plant-level emissions.

Table 5A shows the distribution of buying and selling within each EPA region, while Table 5B shows the distribution for each state; each table also presents the national totals. As expected, the national-level data show that emissions from the buyers tend to have higher marginal benefits than emissions from the sellers (roughly 10% higher – benefits per ton of \$16,500 vs. \$15,000). We see considerable heterogeneity in the trading behavior and marginal benefits across states within the same region. Most states have some plants buying allowances and some plants selling them, and there is often a considerable difference in marginal benefits between buyers and sellers. We see that some regions have relatively consistent behavior across plants in different states (e.g. region 3 with allowance buying and region 7 with allowance selling in nearly all states of the region), but that others show more heterogeneity across states (e.g. region 4 with allowance selling by plants in Georgia and allowance buying by plants in Kentucky and Tennessee). The key element for the success of a trading zone approach is the distribution of the marginal benefits. The evidence that there is substantial within-region heterogeneity in marginal benefits indicates that trades between high- and low-benefit plants would continue, leading to possible problems for aggregate welfare.

Table 6 shows the results from two simulations of the impact of changing the allowance trading process by imposing trading zones. The first simulation splits the set of plants into groups based on EPA regions. The second creates two 'super-regions', one including regions 4 and 7 (the Southern and Midwestern regions) and the other including the rest of the sample (the Northeast regions).[15] In both cases we force balanced trading within each region. We first

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[13] We have also examined the correlations among these variables (available from authors), but this did not add much additional information to the results presented here.

[14] We have recently received the necessary data to identify individual trades – the buying plant, the selling plant, their location, and the total number of allowances traded. This will allow us to do more detailed simulations.

[15] We considered simulating the effects of state-level trading zones, but this ran into the problem that some states have no buyers (or no sellers) of allowances – so there is no natural way to force those states into equilibrium. Creating 22 separate trading zones also raises concerns with implementation in terms of the market power that it would generate for individual facilities within the smaller states.

calculate the excess demand (or supply) for allowances within the region. If there is excess demand, we eliminate it by increasing sales and decreasing purchases of allowances within the region, in proportion to the size of the plants buying and selling allowances within that region (and similarly for excess supply). To the extent that this reduces purchases (or increases sales) by high-benefit plants, it will increase social welfare.

The results show some benefits from trading zones, but they are not very large. The baseline data indicates 867,000 allowances being traded across plants, for which the discrepancy in marginal benefits between buyers and sellers amounts to a shortfall in benefits of $1.055 billion. Imposing the 2-region trading zone model would result in excess demand (supply) of about 25,000 allowances in each region, which reduces the shortfall in benefits by $113 million, or about 11% of the original shortfall. A 6-region trading zone model takes advantage of the greater variation in excess demand and supply across those regions, reducing the shortfall in benefits by $143 million, or about 14% of the original shortfall. While the absolute change in the shortfall from these trading zones might seem large in absolute terms, it would still leave 80-90% of the shortfall in place, and at the cost of considerably complicating the trading process (and possibly losing the political impetus that led to passing the enabling legislation). As noted earlier, the substantial within-region heterogeneity in marginal benefits is limiting the benefits from trading zones.

An alternative approach would be to assign each plant an 'exchange rate' proportional to its marginal benefits, and require that plants buy sufficient allowances to cover their emissions, after accounting for the exchange rate. This would tend to force high-benefit plants to abate their pollution (rather than buying many extra allowances to compensate for the high benefits). Our initial attempts to model an individual plant's actual decision about buying and selling allowances have not been very successful (not predicting very well the actual buy/sell decision), so we are not presenting those results here. We can note that the variation in marginal benefits across plants is somewhat larger than the variation in our measure of abatement costs, so the plants' final decisions about buying and selling allowances under an 'exchange rate' system are likely to be driven primarily by differences in marginal benefits, rather than costs.

VII. Concluding Remarks

In this paper we analyze plant-level information on fossil fuel fired electric utilities to examine the distribution of costs and health benefits associated with the air quality improvement achieved by Title IV of the 1990 CAAA and compare it to the distribution under a command-and-control regime. In addition to comparing the costs and health benefits that arise from reductions in SO_2 emissions under Title IV, we use data on abatement costs to simulate the impact of requiring a comparable reduction in SO_2 emissions under the old command-and-control regime, by assuming uniform emission standards at all plants. We examine the distribution of benefits and costs both in terms of the regions being affected and the socio-economic composition of the affected population.

Our results for Scenario 1 suggest that, as expected, the aggregate health benefits in 1995 caused by reductions in SO_2 emissions under Title IV greatly exceeded their costs. We estimate benefits of $56 billion and costs of only $558 million leading to $55 billion dollars of net benefits from the SO_2 reductions.

Our results for Scenario 2 compare the results from allowance trading under Title IV versus a hypothetical command-and-control system with uniform emission standards that would achieve the same overall reduction. We find that allowance trading saves a substantial fraction of the abatement costs, but the geographic shift in SO_2 emissions induced by allowance trading goes in the other direction, generating a reduction in the abatement benefits. To understand the importance of shifts in emissions across plants for Scenario 2, we examine the distribution of the marginal benefits of reducing emissions across our 148 plants. The differences are not huge: the median benefit per ton is about $15,000 and 80% of plants fall between $10,000 and $20,000. However, when we consider which plants are buying or selling allowances, we find that plants that buy allowances tend to be high-benefit and plants that sell allowances tend to be middle or low-benefit.

This helps explain the negative net benefits from allowance trading we find for Scenario 2, and raises the question of whether a spatially-based approach to trading would improve the results. We find that alternative trading zone models (with 2 and 6 trading zones) result in only modest reductions in the overall performance of the model (reducing the shortfall in benefits by about 11-14%). This arises from the considerable heterogeneity of marginal benefits across plants within the same region. Given the necessary increase in complexity for the trading system, the modest improvements may not be sufficient justification for making a change. Next steps in the evolution of this research will involve incorporating more detailed measures of abatement costs and data on actual individual allowance trades to generate a plant-level (or unit-level) model of the tradeoff between abatement costs and allowance purchases, allowing us to model the impact of marginal benefit-based exchange rates on the overall performance of the allowance trading system.

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Table 1 – Phase I Plants

	Phase I Plants*
SO_2 Emissions in 1990 (tons)	9,468,183
SO_2 Emissions in 1995 (tons)	4,902,778
Allowances in 1995	8,076,472
Boilers	374
Plants	148

* = Includes the 110 Table A plants plus the 38 "Substitution and Compensation" plants

Table 2 – Benefits and Costs

	Scenario 1	**Scenario 2**
Benefits	$55.94 billion	-$1,255 million
Costs	$0.56 billion	-$94 million
Net Benefits	$55.38 billion	-$1,161 million

Table 3A – Distribution of Benefits per Ton Reduction Across Plants

Distribution	Benefits/Ton
Maximum	$35,868
90%	$19,662
75%	$17,477
50%	$15,414
25%	$12,575
10%	$9,601
Minimum	$3,763

Table 3B – Distribution of Benefits per Ton Reduction (Scenario 2 Outcomes)
Command-and-Control vs. Allowance Trading

	Low Benefits (<$12,500)	Middle Benefits ($12,500-$17,500)	High Benefits (>$17,500)
Higher Emissions under Allowance Trading	**9**	**34**	**20**
Lower Emissions under Allowance Trading	**20**	**32**	**5**

Table 3C – Distribution of Benefits per Ton Reduction
Actual Trading Outcomes - Buying and Selling

	Low Benefits (<$12,500)	Middle Benefits ($12,500-$17,500)	High Benefits (>$17,500)
Allowance Buyers	**12**	**36**	**15**
Allowance Sellers	**19**	**28**	**9**

Table 4 – Determinants of Benefits per Ton Reduction

	Low Benefits (<$12,500)	Middle Benefits ($12,500-$17,500)	High Benefits (>$17,500)
Region			
1 (MA,NH)	**1**	**0**	**1**
2 (NJ,NY)	**2**	**3**	**1**
3 (MD,PA,WV)	**0**	**13**	**10**
4 (AL,FL,GA,KY,MS,TN)	**22**	**11**	**1**
5 (IL,IN,MI,MN,OH,WI)	**4**	**43**	**13**
7 (IA,KS,MO)	**12**	**7**	**1**
Stack Height			
Low	**2**	**12**	**14**
Medium	**17**	**24**	**13**
High	**22**	**41**	**3**
Abatement Costs			
Low	**20**	**33**	**7**
Medium	**15**	**22**	**10**
High	**6**	**22**	**13**

Table 5A – Distribution of Buying and Selling Across EPA Regions

Region	Total	Buy	Sell	Total Buy	Total Sell	Net Buy	MB-Buy	MB-Sell
1	2	1	1	4612	-1848	2764	$18,155	$9,510
2	6	2	2	7791	-48537	-40746	$17,593	$10,366
3	23	14	7	199284	-156723	42561	$18,229	$20,962
4	34	16	10	277268	-225112	52156	$12,545	$11,332
5	63	27	26	371025	-350174	20851	$17,584	$17,330
7	20	3	10	6915	-84499	-77584	$18,441	$9,814
	148	63	56	866893	-866893	0	$16,498	$14,982

Table 5B – Distribution of Buying and Selling Across States

Region	State	Total	Buy	Sell	Total Buy	Total Sell	Net Buy	MB-Buy	MB-Sell
1	MA	1	0	1	0	-1848	-1848	-	$9,510
1	NH	1	1	0	4612	0	4612	$18,155	-
2	NJ	1	1	0	1161	0	1161	$19,507	-
2	NY	5	1	2	6629	-48537	-41908	$15,679	$10,366
3	MD	4	3	1	21347	-1837	19510	$18,517	$28,203
3	PA	12	7	3	86575	-27997	58578	$18,978	$19,057
3	WV	7	4	3	91362	-126889	-35527	$16,703	$20,453
4	AL	3	1	1	6743	-19045	-12302	$11,826	$9,324
4	FL	3	2	0	11668	0	11668	$8,283	-
4	GA	10	2	5	1728	-124781	-123053	$10,198	$10,928
4	KY	12	7	2	141832	-11484	130348	$15,196	$15,518
4	MS	2	1	1	9515	-431	9084	$5,588	$5,749
4	TN	4	3	1	105783	-69371	36412	$13,324	$12,575
5	IL	12	5	5	87372	-48005	39367	$14,848	$15,998
5	IN	15	11	4	147839	-26129	121710	$15,754	$18,249
5	MI	2	1	1	812	-16234	-15422	$30,354	$16,393
5	MN	2	0	1	0	-15	-15	-	$15,371
5	OH	22	9	8	134523	-180352	-45829	$20,195	$19,436
5	WI	10	1	7	478	-79439	-78961	$15,128	$15,762
7	IA	6	1	3	1543	-1725	-182	$4,322	$12,061
7	KS	2	0	1	0	-3636	-3636	-	$3,931
7	MO	12	2	6	5372	-79138	-73766	$25,500	$9,671
	TO	148	63	56	866893	-866893	0	$16,498	$14,982

Table 6 – Shortfalls in Benefits from Allowance Trading
Impacts of Trading Zones

Excess demand/supply	Shortfall in Benefits	$ Improvement over Baseline	% Improvement over Baseline
Baseline model (no zones)			
0	-$1055 M	$0	0%
2-region model (region 4+7, 1+2+3+5)			
(25429, -25429)	-$942 M	$113 M	10.7%
6-region model (regions 1,2,3,4,5,7)			
(2764, -40746, 42561, 52156, 20851, -77584)	-$912 M	$143 M	13.6%

Figure 1
Distribution of Plants in Database
(148 Plants; scale=1995 SO_2 emissions in tons)

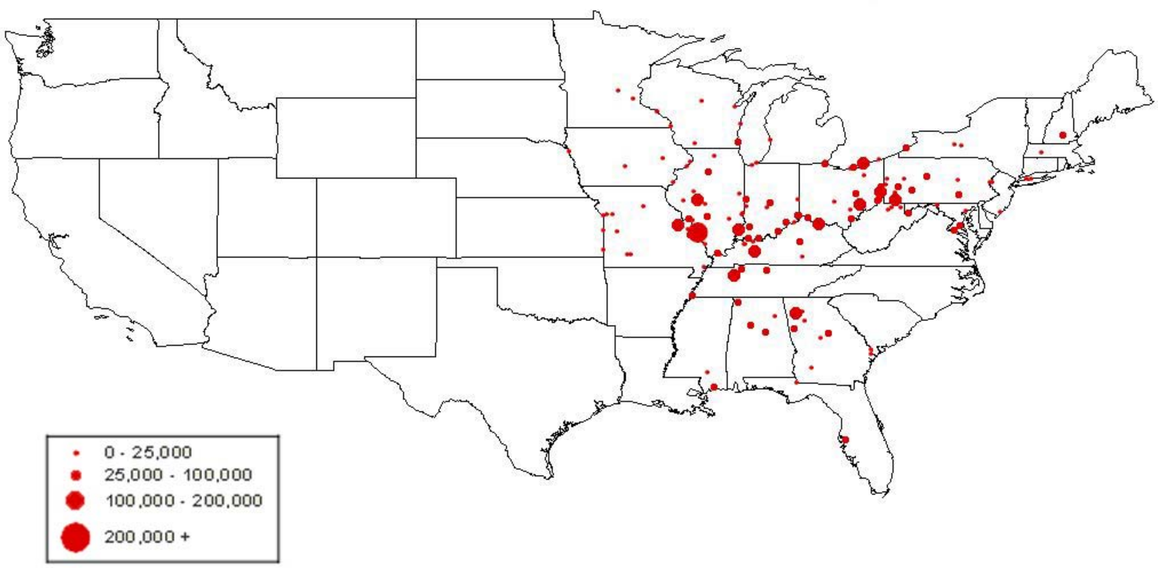


Figure 2
Geographic Distribution of Benefits
Scenario 1

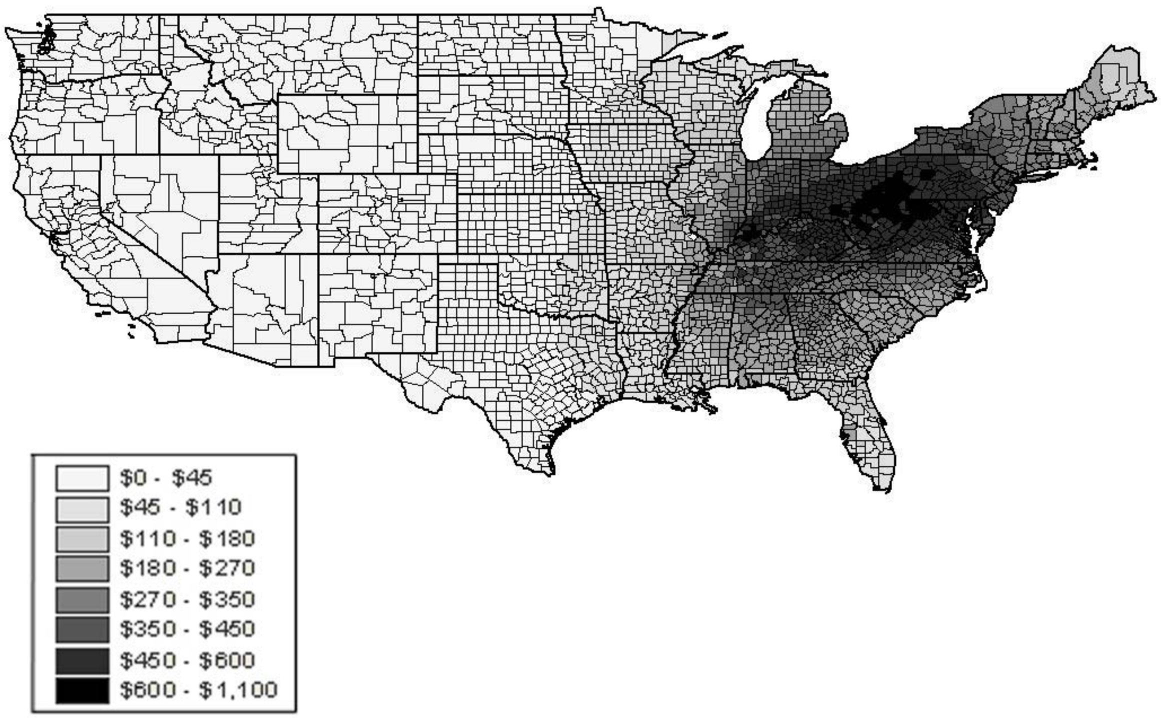
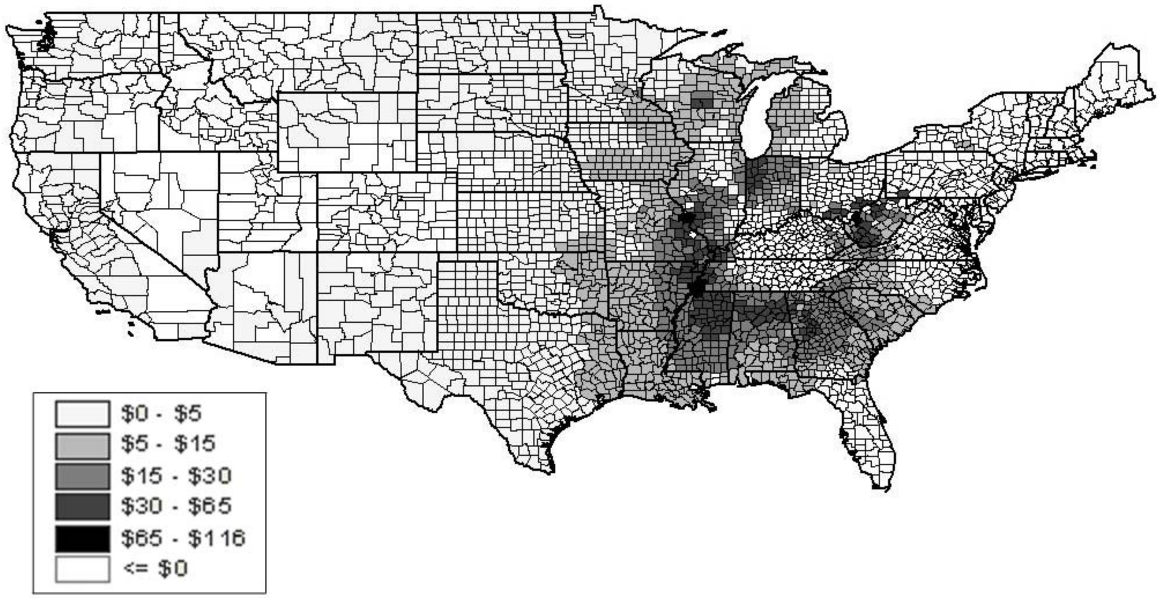
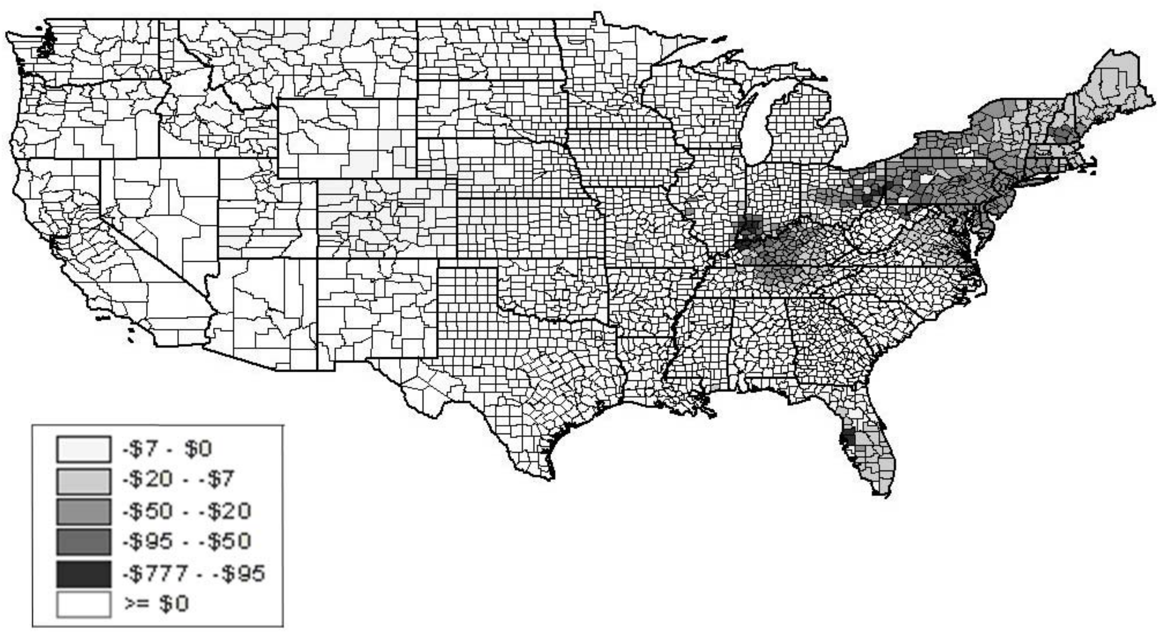


Figure 3
Geographic Distribution of Benefits
Scenario 2

Net Winners



Net Losers



Emissions Trading, Electricity Industry Restructuring, and Investment in Pollution Abatement*

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Abstract

Policy makers are increasingly relying on emissions trading programs to address environmental problems caused by air pollution. If polluting firms in an emissions trading program face different economic regulations and investment incentives in their respective industries, emissions markets may fail to minimize the total cost of achieving pollution reductions. This paper analyzes an emissions trading program that was introduced to reduce smog-causing pollution from large stationary sources (primarily electricity generators). Using variation in state-level electricity industry restructuring activity, I identify the effect of economic regulation on pollution permit market outcomes. There are two important findings. First, plants in states that have restructured electricity markets were less likely to adopt more capital intensive compliance options. Second, this economic regulation effect, together with a failure of the permit market to account for spatial variation in marginal damages from pollution, have had substantial negative health impacts.

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When the U.S. federal government first began regulating major sources of air pollution in the 1960s, the conventional approach to meeting air quality standards involved establishing maximum emissions rates or technology-based standards for regulated stationary sources. At that point, the idea of establishing a cap on total permitted emissions, distributing tradeable pollution permits to regulated sources, and letting a market coordinate pollution reduction among regulated firms was just beginning to take hold among a small group of economists (Coase, 1960; Crocker, 1966; Dales, 1968; Baumol and Oates, 1971). Over the past few decades, the environmental regulatory landscape has changed dramatically. The "cap and trade" approach to regulating point sources of pollution is now the centerpiece of industrial air pollution regulation in the United States.

Economists have long pointed out that an efficient pollution permit market minimizes the total social cost of meeting an exogenously determined cap on emissions. In the first-best permit market equilibrium, each firm chooses a level of pollution abatement such that the marginal cost of reducing pollution is set equal to the social marginal benefit from emissions reduction at the firm. However, there are two important assumptions underlying economic arguments for the efficiency of permit markets that are unlikely to be satisfied by many existing and proposed cap and trade (CAT) programs.[1] The first pertains to the objectives of the firms regulated under CAT programs; the second to the terms of permit trading. This paper assesses the consequences of violating these two assumptions in practice using a unique data set from a major U.S. Nitrogen Oxide (NOx) emissions trading program (the NOx Budget Trading Program). I find that inter-state variation in economic regulation, together with the failure of the permit market to account for spatial variation in marginal damages from pollution, have distorted investment in pollution controls away from the first-best, thereby reducing the efficiency of pollution permit market outcomes.

In a formal proof of the existence of a cost effective permit market equilibrium, it is typical to assume that all firms have the same objective function (Montgomery, 1972). Although firms are assumed to differ in terms of the price they receive for their products, costs of production, and costs of reducing emissions (indeed, it is this heterogeneity that gives rise to gains from permit

[1] Several assumptions are required to demonstrate the efficiency of cap and trade programs. These include: zero transaction costs, perfectly competitive permit markets, perfect enforcement and compliance, perfectly competitive product markets and profit maximizing (or cost minimizing) behavior. In a multiple-receptor, non-uniformly mixed pollutant case, economists further assume an "exposure" or damage based permit system.

trading), it is assumed that all firms are essentially solving the same cost minimization problem when deciding how to comply with CAT regulation.

In fact, firms in the same pollution permit market may approach the choice of how to comply with a CAT program very differently. The vast majority of the emissions regulated under CAT programs come from electricity generators.[2] The recent wave of electricity industry restructuring in the United States has resulted in significant inter-state variation in electricity industry economic regulation. Thus, in addition to having different production and abatement costs, generators in the same CAT program face different economic regulation and investment incentives depending on the nature of their electricity market.

The first question addressed by this paper: have differences in electricity market regulation affected how coal plant managers chose to comply with a multi-state NOx emissions trading program?[3] I develop and estimate a random-coefficients logit (RCL) model of the firm's compliance choice that controls for unit-level variation in compliance costs and allows for correlation across choices made by the same decision maker. I find that plants in restructured electricity markets were less likely to choose more capital intensive compliance options as compared to similar plants operating in regulated electricity markets. More capital intensive compliance options are associated with significantly greater emissions reductions.

These findings have implications for both technical and allocative efficiency. With respect to the former, these results imply that it is not always the plants with the lowest NOx control costs that have invested in pollution control equipment. Observed compliance decisions are compared to those predicted by a deterministic model which minimizes the total technology hardware and operating costs required to comply with the cap. Results suggest that too much investment has occurred in regulated versus restructured electricity markets, as compared to the relative levels of investment predicted by the deterministic model. Unfortunately, because of relatively poor air quality in states with restructured electricity markets, these are precisely the states where

[2] All of the emissions regulated under the Acid Rain Program and over 90% of the emissions regulated under the NOx SIP Call come from electricity generators. The cap and trade program laid out in the proposed Mercury Rule applies exclusively to the electricity sector.

[3] The paper focuses exclusively on the compliance decisions of coal-fired electricity generators. 85 percent of the point source NOx emissions regulated under the program comes from coal plants.

pollution control equipment could deliver the greatest health benefits.

These results are particularly troubling because pollution permit markets, as they are currently designed, fail to reflect considerable spatial variation in marginal benefits from pollution reductions. Currently, all major cap and trade programs are "emissions-based": a permit can be used to offset a unit of pollution, regardless of where in the program region the unit is emitted. Designing a program in this way presumes that the health and environmental damages resulting from the permitted emissions are independent of where in the regulated region the emissions occur. A growing body of scientific evidence indicates that this is not the case for NOx, which is classified as a "non-uniformly mixed" pollutant because damages from increased NOx emissions depend on the location of the source (Lin et al., 2002; Mauzerall et al., 2005).

This leads to the second key assumption underlying the efficiency of permit market equilibria that is often violated in practice. Economists have traditionally assumed that CAT programs regulating non-uniformly mixed pollutants will be "exposure-based" (i.e., permits will be defined in terms of units of damages) rather than emissions-based (Montgomery, 1972; Tietenberg, 1974). In the second part of the paper, I evaluate the consequences of violating this assumption in a case where inter-state variation in electricity market regulation has the potential to exacerbate the allocative inefficiency associated with emissions-based trading. The estimates of the RCL compliance choice model are used to assess whether an exposure-based market design would have significantly affected the spatial distribution of NOx emissions permitted under the NOx Budget Trading Program (NBP). I derive parameters of conditional distributions specific to each decision maker (i.e. plant manager or parent company). Drawing from these conditional distributions, I predict the compliance choices that these agents most likely would have made had the NOx emissions market been designed to reflect spatial heterogeneity in marginal damages from pollution.

I find that the decision to adopt an emissions-based program (versus a damage-based permit market designed to achieve the same total emissions) has substantially increased daily NOx emissions in areas where air quality problems are most severe. Epidemiological studies consistently find a statistically significant association between NOx related air quality problems and increased mortality and morbidity (WHO, 2003). Simulation results suggest that exposure-based permit trading would have moved as much as 300 tons of NOx per day out of high damage areas and into low damage areas where the pollution does less damage.[4] Recent epidemiological research suggests that a spatial shift in NOx emissions of this magnitude could reduce premature deaths from ozone exposure by hundreds each year (Mauzerall et al. 2005).

These findings are relevant to three related areas of the literature. First, a number of authors have addressed the broad question: how effective are existing U.S. cap and trade programs? Most have focused exclusively on the Acid Rain Program (ARP) that was established in 1990.[5] This is, to my knowledge, the first paper to evaluate the performance of the NBP, which is second only to the ARP in terms of size and scope.

Second, strands of both the industrial organization and environmental economics literatures have considered the effects of economic regulation and industry structure on firms' investment decisions.[6] Previous empirical work that considers how economic regulation in electricity markets has affected firms' CAT compliance choices has focused predominantly on the Acid Rain Program.[7] Because the Acid Rain Program started before restructuring began, these papers use more subtle variations in cost recovery rules and coal protection measures to identify an effect of electricity market regulation on compliance choices. Results have been mixed.[8] I revisit this question post-restructuring, now that there is significantly more interstate variation in electricity industry regulation and investment incentives, and thus increased potential for variation in economic regulation to undermine the efficiency of the permit market.

Finally, there is a growing literature that considers non-uniformly mixed pollution permit

[4] This daily shift in NOx emissions would only occur during "ozone season" (May-September) when the the NOx SIP Call is in effect. Firms do not need to purchase permits to offset uncontrolled emissions occuring outside ozone season because NOx related air quality problems are less severe during the cooler months of the year.

[5] Papers analyzing the operation and performance of the Acid Rain Program include: Joskow et al.(1998), Keohane (2005), Shadbegian et al. (2006), Schmalansee et al.(1998), and Stavins (1998).

[6] There is a large literature that extends, corrects and tests the "Averch and Johnson effect" (1962). Empirical results have been mixed. In the environmental economics literature, several papers have illustrated how, in theory, economic regulation can undermine the ability of a pollution permit market to operate efficiently (see Bohi and Burtraw, 1992; Carlson et al., 1998; Coggins and Smith, 1993; Fullerton et al., 1997).

[7] Mansur (2004) is an exception. He considers how market concentration in restructured electricity markets affects firms' short run compliance decisions under market-based NOx regulation.

[8] Bailey (1998) tests whether permit market participation (measured at the state level) is affected by how favorable an electricity market regulator has been to shareholder interests. She finds very limited evidence. Keohane (2005) finds no discernable effect of economic regulation on the decision to install a scrubber. Conversely, Arimura (2002) and Sotkiewicz (2003) do find evidence that economic regulations affected ARP compliance decisions.

trading.[9] Previously, deterministic models of the compliance decision that assume strict cost minimization on behalf of all firms have been used to assess ex ante the merits of imposing spatial constraints on NOx permit trading.[10] The analysis presented here allows for a more realistic ex post evaluation of alternative, exposure-based permit market designs. Unlike previous studies, I find that the adoption of exposure-based NOx permit trading would have delivered significant health benefits. This result is particularly relevant to the debate that is currently taking place over the design of future emissions trading programs.[11]

The next two sections describe the emissions trading program, electricity market regulation, and restructuring in the United States. Section 3 describes the data and presents summary statistics. Section 4 introduces a model of the firm's compliance decision. Estimation results are presented in Section 5. In Section 6, I use the model to simulate compliance decisions under exposure-based trading. Section 7 concludes.

1. The NOx Budget Program

The NOx Budget Program (NBP) is an emissions trading program that limits emissions of NOx from large stationary sources in nineteen Eastern states. These NOx emissions contribute to the formation of ozone.[12] High ambient ozone concentrations have been linked to increased mortality, increased hospitalization for respiratory ailments, irreversible reductions in lung capacity, and ecological damages.

The NBP was primarily designed to help Northeastern states come into attainment with

[9] Analytical papers that consider imposing spatial constraints on trading and related alternative market designs include Duggan and Roberts (2002), Hahn (1990), and Krupnick et al. (1983). Shadbegian et al.(2006) use data from the first year of the ARP to assess the benefits from limiting permit trading to within pre-determined zones. They conclude that considerable heterogeneity in marginal benefits within regions would limit the potential gains from such a system.

[10] Farrell et al. (1999) consider imposing geographic constraints on NOx permit trading in the Northeast and conclude that the benefits do not justify the costs. Krupnick et al.(2000) argue that there is no clear benefit to spatially differentiated NOx trading. Finally, the EPA considered imposing restrictions on interregional trading during the planning stages of the NBP. The Integrated Planning Model (IPM), a deterministic model that does not reflect interstate variation in electricity market regulation, and which assumes plant managers select compliance options to minimize costs, was used to simulate outcomes under different policy designs. Results suggested that benefits from exposure based trading would be negligible (EPA, 1998c).

[11] In March of 2005, the EPA issued two new, large scale emissions trading programs, both of which regulate non-uniformly mixed pollutants and are emissions-based. One of these programs, the Mercury Rule, has been particularly controversial because the proposed market fails to reflect spatial variation in damages from pollution.

[12] NOx reacts with carbon monoxide and volatile organic compounds (such as hydrocarbons and methane) in the presence of sunlight to form ozone in the lower atmosphere.

the Federal ozone standards. During high ozone episodes, significant portions of the Northeast and parts of the Midwest can fail to attain the Federal standard (OTAG, 1997). Surface ozone concentrations are a function of both in situ ozone production and pollutant transport; both are significantly affected by prevailing meteorological conditions. Several states that were in attainment with Federal ozone standards were included in the NBP because their NOx emissions contribute to the non-attainment problems of downwind states. Although some states contribute significantly more than others to the ozone non-attainment problem, the NBP applies uniform stringency across all 19 states.

The NBP mandated a dramatic reduction in average NOx emissions rates.[13] In the period between when the rule was upheld by the US Court of Appeals (March 2000) and the deadline for full compliance (May 2004), firms had to make costly decisions about how to comply with this new regulation.[14] To comply, firms can do one or more of the following: purchase permits to offset emissions exceeding their allocation from other firms, install one of several types of NOx control technology, or reduce production at dirtier plants during ozone season.[15]

Two factors that are likely to significantly influence a manager's choice of compliance strategy are the up-front capital costs K and anticipated variable compliance costs v (i.e. compliance costs incurred per unit of electricity produced). The capital costs, variable operating costs, and emissions reduction efficiencies associated with different compliance alternatives vary significantly, both across NOx control technologies and across generating units with different technical characteristics.

Figure 1 is a graphical illustration of the compliance choice set corresponding to one particular unit in the sample. Each of the eight points plotted in fixed cost ($/kW) variable cost (cents/kWh) space corresponds to a different compliance "strategy". With the exception of the "no retrofit"

[13] Pre-retrofit emissions rates at affected coal plants were, on average, three and a half times higher than the emissions rate on which the aggregate cap was based (0.15 lbs NOx/mmbtu).

[14] Coal plants in 9 Northeastern states had to achieve compliance by May 2003. Plants in the Southeastern states had to comply by May 31 2004.

[15] The specific control technologies available to a given unit vary across coal-fired units of different vintages and boiler types. Compliance options that incorporate Selective Catalytic Reduction (SCR) technology can reduce emissions by up to ninety percent. NOx emissions rates can be reduced by thirty-five percent through the adoption of Selective Non-Catalytic Reduction Technology (SNCR). Pre-combustion control technologies such as low NOx burners (LNB) or combustion modifications (CM) can reduce emissions by fifteen to fifty percent, depending on a boiler's technical specifications and operating characteristics.

option (i.e. the firm will rely entirely on the permit market to comply with the program), all of the compliance strategies involve retrofitting the unit with a NOx control technology or combination of technologies.[16] Variable costs v include the costs of operating the control technology plus the costs of purchasing permits to offset uncontrolled emissions.[17] The broken line represents a quadratic frontier or envelope function $K(v)$ fit to the points in this choice set that minimize K given v. Points to the right of the fronteir are not cost minimizing.

Choice sets, variable costs, capital costs and emissions reductions associated with a given strategy vary significantly across units with different operating characteristics. For all units, however, the most capital intensive compliance options (i.e., those incorporating selective catalytic reduction technology) are associated with significantly greater emissions reductions.

2. Electricity Industry Restructuring and the Compliance Decision

Until the mid-1990s, over ninety percent of electricity in the United States was generated by vertically integrated investor-owned utilities (IOUs), most of whom were operating as local monopolies regulated by state public utility commissions (PUCs) (Fabrizio et al., 2006). The remainder was supplied by government entities or cooperatives. Traditionally, the most widely used form of regulation has been "rate of return" regulation; rates are set by regulators so as to allow the utility to recover prudently incurred operating costs and earn a "fair" rate of return on its rate base (i.e. the value of assets less depreciation).

Averch and Johnson (1962) illustrate how, under certain conditions, a firm subject to rate of return regulation will find it profitable to employ more capital relative to variable inputs (including labor and fuel) than is consistent with cost minimization. A significant share of the regulation literature has since been devoted to elaborating upon and testing this result.[18] Partly in response

[16]In generating this figure, I implicitly assume that this unit will comply perfectly with the program and that the unit will not achieve compliance by reducing production. Because all units are equipped with continuous emissions monitoring equipment, it is reasonable to assume full compliance. Compliance among coal-fired units was 100 percent in 2004 (EPA, 2005). The assumption that production levels at these coal-fired units will not be significantly affected by this environmental regulation also finds empirical support. This assumption is discussed in detail in Section 6.3.

[17]Using detailed unit-level data, estimates of capital costs and variable compliance costs can are generated for each unit, for each NOx control technology. These calculations assume a permit cost of \$2.25/lb NOx; the average futures permit price (per lb NOx) in the years leading up to the NBP. Permits started trading in early 2001 in anticipation of the NBP. A discussion of how these cost estimates are generated is included in Section 4.

[18]Joskow(1974) provides an excellent survey of the earlier Averch and Johnson(AJ) literature. Attempts to

to the debate over the AJ capital bias, "incentive" or "performance based" regulation became increasingly common throughout the 1970s, 1980s and early 1990s.[19]

Proponents of electricity industry restructuring have argued that replacing rate hearings and fuel adjustment clauses with the discipline of a competitive market would increase efficiency and reduce electricity prices. In the 1990s, all fifty states held hearings to assess the benefits of restructuring. Ownership structure and operating incentives have dramatically changed in the nineteen states that have passed restructuring legislation. Utilities in these states have been required or encouraged to divest the majority of their thermal generation assets to unregulated entities. Generators submit bids (prices and quantities) that they are willing to produce in a given hour; Independent System Operators (ISOs) combine these bids and intersect the aggregate supply curve with demand in order to determine the wholesale market clearing price.

2.1. Environmental Compliance Choices in Regulated Electricity Markets

In regulated electricity markets, the environmental compliance decisions of regulated firms were likely influenced by PUC regulations governing capital and variable cost recovery. In each of the seven states in the NBP that have not enacted electricity industry restructuring, firms have successfully sought rate base adjustments in order to recover costs of capital required to invest in NOx control equipment, and to allow shareholders to earn a return on equity.[20] Firms have also won approval for various kinds of rate adjustment clauses or rate freezes which allow them to recover costs associated with purchasing NOx permits, operating pollution control equipment, and pre-approved construction work in progress.[21]

2.2. Environmental Compliance Choices in Restructured Markets

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empirically test the AJ effect using data from the US electricity industry have met with mixed results. Courville (1974), Spann (1974) and Hayashi and Trapani (1976) find support for the hypothesis, whereas Boyes (1976) does not.

[19] "Performance based regulation" is a broadly defined concept that refers to any regulatory mechanism that links profits to desired performance objectives (such as improved operating efficiency, improved environmental performance or cost minimizing procurement). Ratemaking under PBR is typically a two-step process. First, a rate base is established to allow the utility to earn a fair rate of return on prudently incurred and projected costs. Second, the utility is given financial incentives to reduce operating costs and increase production efficiency.

[20] In a recent survey, regulators report allowing up to three additional points on the return of shareholder equity for investment in pollution reduction equipment at coal plants, in addition to what would otherwise be earned on prudent investments (NARUC 2004).

[21] For details on PUC rulings in these case, see: Charleston Gazette, 2004; Electricity Daily, 2003; Megawatt Daily, 2003; NARUC, 2004; Platts Utility and Environment Report 1999, 2000a, 2000b, 2001a, 2001b, 2002a, 2002c, 2002d, 2002f; PR Newswire, 2002; Southeast Power Report, 2000.

In the absence of a regulator willing to guarantee cost recovery, the consequences of making large capital investments in pollution control equipment were highly uncertain in restructured electricity markets. The introduction of the NBP increased wholesale prices in restructured electricity markets through its effect on the variable (per kWh) compliance costs of the price-setting or "marginal" generating units. Because coal-fired units typically have low operating costs relative to other units supplying the market, they are typically inframarginal.[22] The generating units that most often set the wholesale electricity price (gas and oil plants) tend to have significantly lower environmental compliance costs as compared to coal. Managers of coal units in restructured electricity markets likely anticipated that the NBP-induced increases in average wholesale electricity prices would not fully reflect their relatively high environmental compliance costs. As one industry analyst has observed "coal plants will still be dispatched, but their (profit) margins will be less."[23]

When there is uncertainty about electricity market conditions, compliance strategies that rely to a significant extent on purchasing permits (versus making large, irreversible capital investments) have option value. If a manager chooses to rely on the permit market for compliance, she has more control over the environmental compliance costs she will incur going forward.[24] This option value did not exist in regulated electricity markets in which firms are guaranteed to recover compliance costs.

Finally, higher costs of capital made securing financing for a large capital investment in NOx control technology relatively more costly for firms in restructured electricity markets (Business Wire 2003; Platts Utility Environment Report, 2002e). Credit rating changes in the energy sector were overwhelmingly negative over the time period in which plant managers were having to make their compliance decision.[25] This negative trend has affected generators operating in restructured industries disproportionately.

[22] A unit will generally operate when its marginal costs of production are less than or equal to the last unit dispatched to serve the load. Because coal-fired units typically have low operating costs relative to other units, they are normally operated to serve the minimum load of a system. They run continuously and produce electricity at an essentially constant rate. Increases in variable environmental compliance costs at these "base load" plants will not significantly affect the wholesale electricity price or the plants' capacity factors.

[23] "High Coal Costs Put the Squeeze On Power Plants."Matthew Dalton; *The Wall Street Journal*; June 29, 2005.

[24] For example, in hours when electricity prices are too low to allow variable compliance costs to be recovered, the firm can choose not to operate.

[25] Downgrades outnumbered upgrades 65 to 20 in 2000; that ratio was up to 182 to 15 in 2002. In 2003, 18 percent of firms were non-investment grade (Senate Committee on Energy and Natural Resources, 2003).

2.3 Generating A Testable Hypothesis

The hypothesis that the type of electricity market in which a coal plant is operating will significantly affect the choice of how to comply with the NBP follows directly from the preceding discussion of industry regulation and investment incentives. A more formal economic model of the relationship between economic regulation and environmental compliance is included in Appendix A. The assumptions underlying the model (namely that plant managers choose compliance strategies to minimize costs) may be too restrictive for this particular application.[26] The model is presented as a possible but not necessary motivation for the empirical analysis that follows.

2.4. Identifying an Effect of Economic Regulation on the Compliance Decision

Ideally, in the interest of empirically testing for a relationship between economic regulation and the environmental compliance decision, coal units would be randomly assigned to either a restructured or a regulated electricity market. This would guarantee that the type of electricity market in which a coal plant is operating was pre-determined and completely exogenous to firms' environmental compliance decisions. Although this controlled experiment did not occur, three factors make it possible to causally relate differences in economic regulation to differences in compliance choices.

First, the timing of the NBP and electricity industry restructuring was such that a state's restructuring status was completely pre-determined. All 19 states that were ultimately included in the NBP held hearings to consider restructuring their respective electricity industries between 1994 and 1998. By 1999, restructuring bills had been passed in 12 of these states and D.C. By 2000, the remaining 7 states had all officially resolved not to move forward with electricity restructuring (EIA).[27] Consequently, when the courts upheld the NBP and the terms of environmental compliance were finally established, plant managers knew what type of electricity market they would be operating in.

Second, the factors that determined a state's restructuring decision are independent of the

[26] In the case of regulated plants, it is most common to assume that managers maximize profits subject to regulatory constraints (Averch and Johnson, 1962; Bohi and Burtraw, 1992). However, several alternative management objectives have been suggested, including maximizing returns on investment, maximizing output, maximizing revenues and maximizing reliability of supply (Bailey and Malone, 1970).

[27] Of the 19 states that are affected by the NOx SIP Call, 12 have restructured their electricity industries: CT, DE, IL, MA, MD, MI, NJ, NY, OH, PA, RI and VA. The remaining 7 chose not to go forward with restructuring: AL, IN, KY, NC, SC, TN, WV.

factors that determine compliance costs at coal-fired generating units. Most states that decided against restructuring did so because electricity rates were relatively low to begin with (Bushnell and Wolfram, 2005; Van Doren and Taylor 2004).[28] Other authors have argued that the availability of profitable nearby export markets also increased the probability that a state would pass restructuring legislation (Ando and Palmer,1998). Finally, the California electricity crisis was enough to dissuade any states who had yet to pass restructuring legislation as to whether restructuring would deliver a net gain (politically or otherwise). Momentum behind restructuring fell flat after the California electricity crisis in 2000.

Third, there is significant overlap in the distribution of the variables that determine compliance costs. Coal plants serving restructured markets are extremely similar to those serving regulated markets. Empirical analysis presented in the following section demonstrates these similarities.

III. A First Look at the Data

3.1. Data description

The data set includes the 702 coal-fired generating units that are regulated under the NBP. Of these, 322 are classified as "regulated" for the purpose of this analysis.[29] The results presented here are generated using data from 632 units.[30]

I do not directly observe the variable compliance costs and fixed capital costs or the post-retrofit emissions rates that plant managers anticipated when making their decisions. I can, however, generate unit-specific engineering estimates of these variables using detailed unit-level and plant-level data. In the late 1990s, to help generators prepare to comply with market-based NOx regulations, the Electric Power Research Institute[31] developed software to generate cost

[28] Low rates were a consequence of having access to cheap hydro and coal generation, limited investment in nuclear power, or fewer long-term fixed price contracts with independent power producers that had been encouraged under the 1978 Public Utility Regulatory Policy Act.

[29] Regulated plants include those subject to PUC regulation in states that have chosen not to restructure their electricity industries, and any state or municipally owned and operated facilities in restructured markets.

[30] Compliance costs for the remaining 70 coal fired units cannot be generated due to data limitations. These units appear on states' lists of coal-fired units in the NOx SIP Call, but appear only sporadically in EPA, EIA and Platts databases. These units appear to be significantly smaller and younger on average. The mean capacity is 22 MW compared to the sample average capacity of 252 MW (only 22 of the excluded units reporting). The mean age is 14 years, compared to a sample average of 36 years (only 4 of the excluded units reporting).

[31] The Electric Power Research Institute (EPRI) is an organization that was created and is funded by public and private electric utilities to conduct electricity industry relevant R&D.

estimates for all major NOx control options available to coal-fired boilers, conditional on unit and plant level characteristics. The software has been used not only by plant managers, but also by regulators to evaluate proposed compliance costs for the utilities they regulate (Himes, 2004; Musatti, 2004; Srivastava, 2004). I use this software to estimate capital and variable compliance costs at the unit level (EPRI, 1999b).

Cost estimation requires detailed data on over 80 unit and plant level operating characteristics (such as boiler dimensions, pre-retrofit emissions rates, plant operating costs, etc.). Together with these data inputs, the software can be used to first identify which NOx control technologies are compatible with which boilers, and then to generate boiler-specific variable costs and fixed cost estimates for each viable compliance option. Post-retrofit emissions rates are estimated using the EPRI software, together with EPA's Integrated Planning Model (US EPA 2003). Appendix B describes these data in detail.

3.2. Summary Statistics

Figures 2a and 2b summarize the observed compliance choices for units in restructured and regulated electricity markets in terms of MW of installed capacity (87,828 MW in regulated markets and 88,370 MW in restructured markets). More specifically, the figures summarizes the NOx control technology retrofits reported by these plants between 2000 and 2004. A significantly larger proportion of the coal capacity in unrestructured markets has been retrofit with SCR (the control option that is the most capital intensive and delivers the most significant emissions reductions). Conversely, in restructured markets, a greater proportion of capacity has either not been retrofitted, or has been retrofitted with controls that can achieve only moderate emissions reductions (such as combustion modifications or SNCR). These data are consistent with, but not proof of, the hypothesis introduced in the previous section.

There are several reasons why we might observe differences in compliance strategy choices across electricity market types. One appealing explanation is that this permit market is efficiently coordinating investment in pollution controls such that the plants with the lowest control costs are installing control equipment, and that SCR costs happen to be relatively high in restructured markets. Put differently, it is possible that these differences can be explained by differences in unit-specific compliance costs. Another possible explanation has to do with variation in choice sets. Because units in restructured markets have historically been subject to more stringent environmental regulations prior to the NBP, differences in adoption patterns could be attributable to the fact that generators in restructured markets were more likely to have carried out retrofits prior to 2000.

Table 1 presents summary statistics for unit-level operating characteristics that significantly determine choice sets and compliance costs: nameplate capacity, plant vintage, pre-retrofit emissions rates, pre-retrofit heat rates and pre-retrofit summer capacity factor. Overall, these two groups of coal generators look extremely similar.[32] These results indicate that the unit characteristics that help determine compliance costs are distributed similarly within the two sub-populations of coal fired units.

These two groups of units are also very similar in terms of the NOx controls installed at the time the NBP was promulgated. Over 80% of capacity in both populations had some type of low NOx burners installed; 5% of capacity in restructured markets and 7% of capacity in regulated markets had adopted some form of emissions reducing combustion modifications. No SCR retrofits had taken place in regulated markets as of 2000. Only two units had installed SCR in restructured markets.[33]

Although fifteen different compliance strategies are observed in the data; the most alternatives available to any one unit is ten.[34] With the obvious exception of the "no retrofit" option, all of the observed compliance strategies chosen by plant managers involve some combination of eight different NOx control technologies.Table 2 characterizes the choice sets which vary across units depending on unit operating characteristics and pre-existing NOx controls. The size and content of choice sets do not significantly differ across market types.

Table 3 presents summary statistics for compliance costs (estimated at the unit level) for

[32] The one dimension in which these two groups do differ somewhat is the pre-retrofit emissions rate which is lower on average among units in restructured markets. This is to be expected; because of persistent air quality problems in the Northeast, these plants have historically been subject to more stringent pollution regulation.

[33] These two units are excluded from the analysis as there was no longer a compliance choice to make.

[34] These strategies are: (1) combustion modification, (2)combustion modification combined with low NOx burners, (3) (4) (5) (6) four different types of low NOx burner technologies, (7)low NOx burners combined with SCR, (8) overfire air, (9) overfire air combined with low NOx burners, (10) SCR, (11) SNCR, (12) SCR with overfire air, (13) SNCR with overfire air, (14) low NOx burners, SCR and overfire air, (15) no retrofits.

the most commonly adopted technologies. There are no significant differences in average costs across the two electricity market types.[35] Taken together, these descriptive statistics suggest that variation in compliance costs and choice sets is insufficient to explain the substantial differences in observed compliance choices across market regimes.

4. An Empirical Model of the Compliance Choice

In this section, I develop an empirical model of a plant manager's choice between mutually exclusive approaches to complying with this emissions trading program. The purpose of specifying the model is twofold. First, it provides a framework to test whether economic regulation has affected the environmental compliance choice. Second, the model provides a means to evaluate how these plant managers would have responded to a permit market designed to reflect spatial variation in marginal damages from pollution.

This analysis focuses exclusively on the compliance choices that were made in the years leading up to the compliance deadline (2000-2004).[36] Because it is difficult to identify the precise point in this four year period at which this decision was made, these compliance choices are modeled as static decisions.[37]

The manager of unit n faces a choice among J_n compliance strategy alternatives (indexed by $j,\ j = 1...J_n$). Plant managers are assumed to choose the compliance strategy that minimizes the unobserved latent variable C_{nj}. The deterministic component of C_{nj} is a weighted sum of expected annual compliance costs v_{nj}, the expected capital costs K_{nj} associated with initial retrofit and

[35] Average costs are slightly higher for units in more regulated electricity markets. This is likely due to the fact that plants with higher pre-retrofit emissions rates tend to have higher retrofit costs.

[36] Past research has cautioned against trying to identify differences in the underlying propensity to adopt a new technology using choices observed over a short time period. Particularly in the case of a "lumpy", capital intensive technology, the pattern of technology diffusion across firms can be driven by differences in opportunities to adopt (Rose and Joskow, 1984). Fortunately, the NOx SIP Call eliminates temporal variation in technology adoption opportunity by design; every coal plant manager was forced to make a decision of how to comply with the program during the four years between when terms of compliance were officially established and when full compliance was required of all plants.

[37] Because of labor shortages and a limited number of tower-cranes needed to complete SCR retrofits, many plants reported delays of several years between when they made their compliance decision and when the pollution control retrofit was completed (Cichanowicz, 2004; Midwest Construction, 2005). Consequently, reported retrofit dates are a very noisy measure of when the compliance decision was actually made. There is arguably a dynamic component to the compliance strategy choice that is ignored by this specification. Plants could postpone the decision to invest in pollution controls until after the NOx SIP Call program had taken effect. However, because more pollution control equipment was installed than is needed to comply with SIP Call, the decisions analyzed here will determine regional emissions patterns to a significant extent for the foreseeable future (Natural Gas Week, 2004).

technology installation, and a constant term α_j that varies across technology types :

$$(1) \qquad \begin{aligned} C_{nj} &= \alpha_j + \beta_n^v v_{nj} + \beta_n^K K_{nj} + \beta_n^{KA} K_{nj} \cdot Age_{nj} + \varepsilon_{nj}, \\ where \quad v_{nj} &= (V_{nj} + \tau m_{nj}) Q_n \end{aligned}$$

An interaction term between capital costs and demeaned plant age is included in the model. Older plants can be expected to weigh capital costs more heavily as they have less time to recover these costs. The variable cost (per kWh) of operating the control technology is V_{nj}. The variable costs associated with offsetting emissions with permits is equal to the permit price τ multiplied by the post-retrofit emissions rate m_{nj}.[38] Expected average annual compliance costs are obtained by multiplying estimated per kWh variable costs by expected seasonal production Q_n.

Expected seasonal electricity production at a unit (Q_n) is assumed to be independent of the compliance strategy being evaluated. Anecdotal evidence suggests that managers used past summer production levels to estimate future production, regardless of the compliance choice being evaluated (EPRI, 1999a). I adopt this approach and use the historical average of a unit's past summer production levels ($\bar{Q}_n$) to proxy for expected ozone season production. Empirical support for this assumption is presented in section 6.3.

It is likely that the compliance choice characteristics that are relevant to the compliance decision are not limited to observable cost characteristics. Technology constants α_j capture unobserved, intrinsic technology preferences or biases such as widely held perceptions regarding the reliability of a particular type of NOx control technology. A stochastic component ε_{nj} is included in the model to capture the idiosyncratic effect of unobserved factors.

This reduced form model has just enough structure to capture the differences in responsiveness to capital costs and variable costs across units, and across electricity market types more generally. It is straightforward to map the parameters in this model to the parameters in the economic model specified in Appendix A. This allows for a more structured interpretation of the estimated

[38] The unit-specific, compliance strategy-specific estimates of K_{ni} and V_{ni} are generated using the EPRI cost estimation software described in section 4.1. Emissions rates (which also vary across units and control technologies) are estimated using the software and accompanying documentation and EPA's IPM model (US EPA 1998d), in addition to other sources in the technical literature which are discussed in the data appendix.

coefficients; the cost coefficients can be viewed as functions of a plant's cost of capital, cost recovery parameters, and the scale parameter of the extreme value distribution. However, it is not clear that cost minimization is the most accurate way to characterize the objective functions of all plant managers. This model is sufficiently general to accommodate a variety of possible objectives.

A. The Conditional Logit Model

I first estimate a conditional logit (CL) model of the compliance decision. Conditional on observed unit characteristics, coefficients are not permitted to vary across units. The ε_{nj} are assumed to be iid extreme value and independent of the covariates in the model.[39]

Let y_n be a scalar indicating the observed compliance choice, $y_n \in \{1, ...J_n\}$.. The closed form expression for the probability (conditional on the vector of coefficients β and the matrix of covariates X_n) that the n^{th} unit will choose compliance strategy i is:

$$P(y_n = i|X_n, \beta) = \frac{e^{-\beta' X_{ni}}}{\sum_{j=1}^{J_n} e^{-\beta' X_{nj}}}. \tag{2}$$

This conditional choice probability is derived in Appendix C.

B. The Random Coefficient Logit Model

The CL model, however elegant, is not the best choice for this application. First, this model does not account for random variation in tastes or response parameters; conditional on observed plant characteristics, the coefficients in the model are not allowed to vary across choice situations. There are likely to be factors affecting how plant managers weigh compliance costs in their decision-making that we do not observe. Examples include variation in plant's costs of capital, managerial attitudes towards risk, contractual arrangements, and subtle variations in PUC cost recovery rules. To the extent that variation in unobserved determinants of the compliance choice is significant, errors will be correlated and CL coefficient estimates will be biased.

[39] This stochastic term is subtracted from (versus added to) the deterministic component of costs in order to simplify the derivation of choice probabilities implied by this model (see Appendix 3). These choice probabilities are very similar to the standard logit choice probabilities derived under assumptions of random utility maximization (McFadden, 1973).

The second limitation has to do with the panel structure of data used to estimate the model. While I only observe one compliance choice for each coal-fired boiler or "unit", an electricity generating facility or "plant" can consist of several physically independent generating units, each comprising of a boiler (or boilers) and a generator. Some plants only have one boiler, but there can be as many as ten boilers at a given plant. The 632 boilers in the sample represent 221 power plants owned by 86 different companies or public agencies. It seems reasonable to assume that the same plant manager made compliance decisions for all boilers at a given plant. It is also possible that compliance decisions could be correlated across facilities owned by the same parent company. The CL model cannot accommodate this correlation across choice situations associated with the same decision maker.

The random-coefficient logit (RCL) model, a generalization of the CL model, does a better job of accommodating unobserved response heterogeneity and relaxes the troublesome iid error structure assumption. This specification allows one or more of the model parameters to vary randomly across decision makers. I assume that the variable cost coefficient (β^v) and the capital cost coefficient (β^K) are distributed in the population according to a bivariate normal distribution, thereby accommodating any unobserved heterogeneity in responses to changes in compliance costs.

I maintain the assumption that the unobserved stochastic term ε_{nj} is iid extreme value and independent of β and X_{nj}. To accommodate the panel nature of the data, the (unobserved) β vectors are allowed to vary across managers according to the density $f(\beta|b, \Omega)$, but are assumed to be constant over the choices made by a manager.[40] Thus, the coefficient vector for each manager (indexed by m) can be expressed as the sum of the vector of coefficient means b and a manager-specific vector of deviations η_m. Because the η_m are assumed to be equal across choices made by the same manager (at the same plant), the unobserved component of anticipated costs is correlated within a plant. This does not imply that the errors corresponding to all choices faced by a single manager are perfectly correlated; the extreme value error term still enters independently for each choice.

[40] Alternatively, beta vectors could be held constant across all units, and across all plants owned by the same parent company. Interviews with industry representatives indicate that it is sometimes the case that environmental compliance decisions are made or influenced by the parent company (Whiteman, 2005). A model where cost coefficients are allowed to vary across parent companies, but not across plants, is also estimated.

Conditional on β_m, the probability that a manager of a plant comprised of T_m units makes the observed Y_m compliance choices is:

(3) $$P(Y_m = \boldsymbol{i} | X_m, \beta_m) = \prod_{t=1}^{T_m} \frac{e^{-\beta'_m X_{mit}}}{\sum_{j=1}^{J_{mt}} e^{-\beta'_m X_{mjt}}},$$

where $\boldsymbol{i}$ is a $T_m * 1$ dimensional vector denoting the set of observed choices made by manager m. Here, the n subscript denoting the unit has been replaced by a unique mt pair. Unconditional choice probabilities $P(Y_m = \boldsymbol{i})$ are derived by the integrating conditional choice probabilities over the assumed bivariate normal distribution of the unobserved random parameters.

The unknown vector of coefficient means b and covariance matrix Ω describe the distribution of the β_m in the population.[41] Parameter estimates are those that maximize the following log likelihood function:

(4) $$LL(b, \Omega) = \sum_{m=1}^{M} \ln \int_{-\infty}^{\infty} \prod_{t=1}^{T_m} \frac{e^{-\beta'_m X_{mit}}}{\sum_{j=1}^{J_{mt}} e^{-\beta'_m X_{mjt}}} f(\beta | b, \Omega) d\beta.$$

Unconditional probabilities are approximated numerically using simulation methods. The RCL estimates are those that maximize the simulated likelihood function. For each decision maker, 1000 two-dimensional vectors of independent standard normal random variables are drawn. To simulate a random draw from the bivariate normal density $f(\beta | b, \Omega)$, each vector of standard normals is multiplied by the cholesky factor L of the covariance matrix and the resulting product is added to the vector b. To increase the accuracy of the simulation, pseudo-random Halton draws are used (Bhat 1998; Train, 2001).[42] The value of the integrand [3] is calculated for each decision

[41] The model is parameterized in terms of the Cholesky factor L of the covariance matrix Ω, so as to allow the two random cost coefficients to be correlated. Because the covariance matrix is positive definite, it can be expressed as the product of the lower triangular matrix L and its transpose.

[42] Researchers have found that using Halton draws (versus random draws) provide more uniform coverage over the domain of the integration spaceand results in more accurate computation of probabilities for a given number of draws. Bhat(2003) finds that 125 Halton draws produces more accurate estimates than 2000 random draws.

maker, for each draw. The results are averaged across draws. The maxlik algorithm in Gauss is used to find estimates of the parameters in b and L that maximize the simulated likelihood of the observed compliance choices.[43] To estimate standard errors, the robust asymptotic covariance matrix estimator is used (Mc Fadden and Train, 2000).

C. Manager Specific Parameters

The RCL estimates of b and Ω provide information about how the capital and variable cost coefficients are distributed in the population, but tell us nothing about where one manager lies in the distribution relative to other managers. Recent work demonstrates how simulated maximum likelihood estimates of random-coefficient, discrete choice models can be combined with information about observed choices in order to make inferences about where in the population distribution a particular agent most likely lies (Allenby and Rossi, 1999; Revelt and Train, 2000; Train, 2003).[44]

Following Train (2003), let the density describing the distribution of β in the population of managers be denoted $g(\beta|b,\Omega)$. The probability of observing the m^{th} manager making the choice he does when faced with the compliance decision described by the matrix of covariates X_m is given by [4]. This probability is conditional on information we cannot observe (β_m). The marginal probability of observing this outcome is $P(Y_m|X_m,b,\Omega) = P(Y_m = \boldsymbol{i}|X_m,\beta)g(\beta|b,\Omega)$. Let $h(\beta|\boldsymbol{i},X_m,b,\Omega)$ denote the distribution of β_m in the sub-population of plant managers who, when faced with the compliance choice set described by X_m, would choose the series of strategies denoted $\boldsymbol{i}$. Applying Bayes rule, this manager specific, conditional density of β_m can be expressed:

$$h(\beta|\boldsymbol{i},X_m,b,\Omega) = \frac{P(Y_m = \boldsymbol{i}|X_{m,}\beta)g(\beta|b,\Omega)}{P(Y_m = \boldsymbol{i}|X_m,b,\Omega)}. \tag{5}$$

These conditional distributions are implied by the simulated maximum likelihood estimates of the population distribution parameters and the choices we observe. To illustrate this more

[43] Gauss code is based on that developed by Train, Revelt and Ruud (1999).

[44] Alternatively, a finite mixture logit (FML) model could have been estimated in order to obtain information about where in the larger population distribution a particular type of manager lies.However, a demonstrated limitation of these models is that they often cannot adequately capture all of the heterogeneity in the data (Allenby and Rossi, 1999; Rossi et al. 1996).

explicitly, [5] can be reformulated as:

$$h(\beta|\boldsymbol{i}, X_m, b, \Omega) = \frac{\prod_{t=1}^{T_m} \frac{e^{-\beta'_m X_{mit}}}{\sum_{j=1}^{J_{mt}} e^{-\beta'_m X_{mjt}}} g(\beta|b,\Omega)}{\int_{-\infty}^{\infty} \prod_{t=1}^{T_m} \frac{e^{-\beta'_m X_{mit}}}{\sum_{j=1}^{J_{mt}} e^{-\beta'_m X_{mjt}}} g(\beta|b,\Omega) d\beta}. \quad (6)$$

These conditional distributions can be used to derive conditional expectations of functions of β. For example, the expected probability that alternative i will be chosen by the m^{th} manager in a counterfactual choice situation denoted $T+1$ can be expressed as:

$$E[P(y_{m,T+1} = i|Y_m, X_m, b, \Omega)] = \frac{\int_{-\infty}^{\infty} \prod_{t=1}^{T_m+1} \frac{e^{-\beta'_m X_{mit}}}{\sum_{j=1}^{J_{mt}} e^{-\beta'_m X_{mjt}}} g(\beta|b,\Omega)}{\int_{-\infty}^{\infty} \prod_{t=1}^{T_m} \frac{e^{-\beta'_m X_{mit}}}{\sum_{j=1}^{J_{mt}} e^{-\beta'_m X_{mjt}}} g(\beta|b,\Omega) d\beta}, \quad (7)$$

A simulated approximation to this expectation is obtained by first drawing from the estimated population distribution $g(\beta|b, \Omega)$ and then simulating conditional values of the counterfactual choice probability for each draw.[45]

5. Estimation

Tests of the hypothesis introduced in Section 3 can be formulated as a test of whether the random parameter estimates differ significantly across electricity market types. There are two possible approaches to comparing coefficient estimates across groups. First, a single model that includes interactions between the coefficients of interest and a dummy variable indicating group membership can be estimated using pooled data. A second approach involves estimating the model separately for each group.

[45] This approach involves integrating over the estimated distribution of the random coefficients in the population; this formulation accounts for sampling and simulation error in estimates of b and Ω. Integrals are simulated in the same way as for the unconditional RCL choice probabilities.

The first approach implicitly assumes that the variance of the disturbance term is equal across groups (Allison, 1999). Because the extreme value error term is likely capturing different unobserved variables in the restructured and regulated cases, this assumption is unlikely to be met.[46] Consequently, the results from estimating a single model using pooled data are underemphasized.

The advantage of the second approach is that coefficient estimates and standard errors are consistent within each group. In order to identify the logit model, all coefficients have been scaled by the scale parameter of the extreme value distribution. When the model is estimated separately using data from restructured and regulated markets, direct comparisons of coefficients across the two groups are confounded by this identification assumption. Within a model, however, tests of the significance of a given coefficient are valid; the ratio of the coefficient and the variance of the unobserved stochastic term will only be zero if the coefficient is zero. Consequently, such comparisons can be informative if the pattern of coefficient significance varies across groups.

5.1. Conditional logit model results

The first two columns of Table 4 report estimates for the more restrictive CL specification in which coefficient values are not permitted to vary across plant managers. In both the restructured and regulated cases, a nested likelihood ratio test of this specification against a benchmark specification that includes only technology specific constants indicates that including variable and capital cost variables significantly improves the fit of the model.[47]

All of the technology type constants are negative and significant at the 1 percent level, regardless of whether the CL model is estimated using data from regulated or restructured markets.[48] One interpretation of this result is that, relative to the baseline option of no control technology

[46] Monte Carlo experiments have illustrated that the most likely outcome of estimating a single equation with interaction terms when the residual variances differ across groups is that the slope coefficients will be found not to differ even if they actually do, but it is also possible to find an effect when no effect exists (Hoetker, 2003).

[47] The fit of the nested (or more restrictive) model can be evaluated using a chi-square statistic. This test statistic is calculated by taking twice the absolute difference in the log likelihoods for the two models. If significant, (degrees of freedom are equal to the difference in the number of parameters between the two models), the nested model should be rejected (Bhat, 1998). The test statistics reported in the last row of Table 3 are larger than the χ^2 statistic with 3 degrees of freedom and a p-value of 0.001.

[48] I include only three technology fixed effects for the three major categories of NOx controls: Post-combustions pollution control technologies (SNCR and SCR), Combustion Modifications (CM) and Low NOx Burner (LNB) technologies. Although cost estimates and emissions reduction estimates were generated for sub-classes of these categories (for example, there are four different types of low NOx burners in the data), including a more complete set of technology fixed effects did not improve the fit of the model.

retrofit, managers were biased against retrofits in general (controlling for costs).

The coefficient on variable compliance costs is statistically significant at the 1 percent level and has the expected negative sign in both the regulated and restructured electricity market cases. These results indicate that expected variable compliance costs are an important factor affecting the plant's compliance choice. When the model is estimated using data from restructured electricity markets, the coefficient on capital costs is statistically significant and has the expected negative sign. An increase in the capital cost of a compliance option decreases the probability that the option will be chosen by a plant in a restructured electricity market. However, when the model is estimated using data from regulated electricity markets, the coefficient estimate is positive and is not statistically significantly different from zero, suggesting that capital costs might not be a significant factor in the compliance decisions at regulated plants.[49]

5.2. Random Coefficient Logit Results

Results from estimating the RCL model are presented in the third and fourth columns of Table 4. Estimated standard deviations of the two random coefficients are statistically significant. The results of a nested likelihood ratio test imply that, in both the restructured and regulated cases, allowing for response heterogeneity significantly improves the fit of the model. These results suggest that cost coefficients vary significantly across managers in regulated and restructured markets.[50]

When the model is estimated using data from restructured markets, the means of both the capital and variable compliance cost coefficients are negative and significant at the 1 percent level. The estimated standard deviations are also large in absolute value and statistically significant, indicating that there is unobserved variation in responsiveness to changes in compliance costs.[51]

[49] A single model was estimated using pooled data. Interactions between cost variables and a dummy variable indicating a restructured electricity market are included in this model. Whereas the coefficient on the uninteracted capital cost variable is not statistically significant, the estimated coefficient on the interaction between capital costs and the restructured market indicator is statistically significant and has the expected negative sign. These results are consistent with the results in Table 4.

[50] These RCL estimates are robust to various optimization routines and variation in the number of pseudo-random draws used in the simulations.

[51] There are several possible explanations for this variation, including variation in costs of capital and variation in managers' risk aversion. In an effort to attribute some of this variation to observable plant characteristics (such as plant size and whether or not the plant had been divested), other interactions were also tested, but none improved the fit of the model.

The negative and significant coefficient values on the capital cost/age interaction term indicates that older plants weighed capital costs more negatively in their compliance decision, presumably due to shorter investment time horizons.

Different results are obtained when the model is estimated using data from regulated markets. The point estimate for the capital cost coefficient is substantially smaller than the point estimate obtained using data from restructured markets, and is not statistically significant at the 1 percent or 5 percent level. The standard deviation of this coefficient is significant, suggesting that there is unobserved heterogeneity in how responsive managers are to variation in capital costs. The capital cost/age interaction term is significant and has the expected negative sign. Among older regulated plants, the capital cost coefficient is statistically significant, possibly because regulators are unlikely to approve a major capital investment in pollution control equipment if the plant is very old and expected to retire soon. The variable cost coefficient is also statistically significant and negative when the model is estimated using data from regulated electricity markets.

The RCL estimates of the moments of the distribution of β in the population are combined with the observed choices in order to derive the parameters of manager specific conditional distributions. The population parameter estimates $\hat{b}$ and $\hat{\Omega}$ are substituted into [6] and the first and second moments of these conditional distributions are calculated (using the same matrix of Halton draws that were used to estimate [5]). Table 5 presents the summary statistics for the estimated moments of these 221 manager-specific distributions. If the model is correctly specified, the average of the means of the manager specific conditional distributions (the $\bar{\beta}_m s$) should be very close to the estimated population means. These results offer no evidence to suggest that the normality assumptions are inappropriate. The standard deviations of the conditional means are significantly larger than zero, suggesting that variation in the conditional means captures a significant portion of the total estimated variation (Revelt and Train, 2000).

The elasticities implied by the model estimates provide a more intuitive characterization of the responsiveness of compliance decisions to changes in compliance costs. Table 6 presents average elasticities with respect to both own capital costs and own average ozone season variable compliance costs for the most commonly observed compliance choices. Elasticities for each choice situation are calculated using point estimates of the means of the corresponding manager-specific conditional distributions. These summary statistics indicate that choice probabilities in restructured markets are, on average, more sensitive to changes in compliance costs in general, and capital costs in particular. We should be most interested in how changes in costs affect the probability of adopting the cleanest and most capital intensive technology: SCR. The model predicts that a one percent increase in the capital cost of an SCR retrofit, holding all else equal, will result in an average decrease of 5.7 percent in the probability that SCR will be chosen among units in restructured electricity market. This average decrease is 1.3 percent in regulated markets. The corresponding variable cost elasticities are 1.8 and 1.3, respectively. The standard deviations of these elasticity estimates are reported in parentheses.

One way to get around the scaling problem that confounds direct comparisons of these coefficients across groups is to compare ratios of coefficient estimates. The ratio $\beta^K : \beta^v$ can be interpreted, under certain assumptions, as an estimate of the discount rate (see Appendix A). The point estimates of this ratio is 44% and 16% in restructured and regulated markets, respectively. This ratio can also be estimated at the unit level using manager-specific coefficient estimates. When the ratio $(\beta_m^K + \beta_m^{KA} \cdot A_{nt}) : \beta^v$ is estimated for each unit, two distributions of ratio estimates are generated. The mean and standard deviation of these distributions are 33.7% ($\sigma = 120\%$) and 7.7% ($\sigma = 24.2\%$).in restructured and regulated markets, respectively.[52]

These results suggest that, on average, managers in regulated electricity markets were willing to tolerate higher up-front costs in order to lower their variable compliance costs, as compared to managers in restructured electricity markets. Making formal statistical inferences about the difference between these two ratio estimates requires standard error estimates. Unfortunately, more standard approaches to estimating the variance of a function of random variables (such

[52] Researchers have in the past made simplifying but restrictive assumptions in order to circumvent problems associated with estimating the parameters of the distribution of a ratio of random parameters. One common approach involves assuming that the coefficient in the denominator is fixed (Hensher et al, 2004; Layton and Brown, 2000). Sonnier et al. (2005) show that constraining the coefficient in the denominator to be fixed in order to get a ratio that is normally distributed results in an overestimate of the variance of the ratio, even when the true variance is small. Other reseachers have reparameterized the RCL model so as to identify the ratio directly. Rather than set the scale parameter to one, one of the coefficients in the model is restricted to equal one (Train and Weeks, 2004; Sonnier et al. 2005). This approach is inappropriate for this application, where the capital cost and variable cost coefficients are likely to differ across models.

as using the delta method or a bootstrap) are inappropriate here.[53] Standard deviations of the manager-specific, technology-specific elasticity estimates are reported.

5.3. Further Robustness Tests

Company versus plant manager specific coefficients

Many of the facilities analyzed here are owned by a common parent company. If the environmental compliance decision was made at the company (versus manager) level, a specification that allows for correlation in choices made across facilities owned by the same parent company would be more appropriate. An RCL model that restricts the cost coefficients to be equal across units owned by the same parent company was also estimated.

Table 7 reports the estimation results. Patterns of coefficient significance are robust to specification choice. Whereas the null hypothesis that the capital cost coefficient equals zero can easily be rejected in the restructured market case, it cannot be rejected in the regulated market case. Similar to the results generated under less restrictive assumptions of manager-specific coefficients, estimating the parameters of company-specific distributions lend support to the assumption of a bivariate normal distribution for the random parameters. The point estimates of the average ratio $\beta_p^K : \beta_p^v$, (where p denotes parent company) are 0.30 and 0.10 in restructured and regulated markets, respectively.[54]

Alternative specifications

Section 3 offered several reasons why plant managers (or owners) in regulated markets might be more likely to adopt more capital intensive compliance options, including an Averch and Johnson effect, lower costs of capital, and less uncertainty about capital cost recovery. In the interest of trying to tease apart the relative importance of these factors, several alternate specifications were tried. For example, in restructured electricity markets, cost variables were interacted with a

[53] The delta method is often used to estimate the standard error of ratio statistics, based on a first order Taylor series expansion of the ratio centered at the mean of b. The delta method cannot be used here because the variance of $\beta^K : \beta^v$ is not well-defined. The same problem arises if a bootstrap is used to estimate the standard errors of these ratios. The support of the estimated distribution of β^v for both restructured and regulated electricity markets overlaps zero. With enough samples, the bootstrap eventually generates estimates of β^v that are arbitrarily close to zero, implying infinitely large estimates of the ratio.

[54] Ideally, a formal statistical test would be carried out to determine which of these two specifications is most consistent with the data. Classical inference based on log-likelihood ratio statistics is invalid because these are non-nested models. A formal test of these non-nested hypotheses is beyond the scope of this paper (see Vuong, 1989).

dummy indicating that the plant had been divested. Divested (or recently purchased) plants would have high debt:equity ratios and higher costs of capital. In the regulated model, cost variables were interacted with dummy variables indicating whether the unit was a government owned or investor owned plant. None of these interaction terms significantly improved the fit of the model.

Testing the exogeneity of Q_n

A final test pertains to how plant managers formed their expectations about future production. I have assumed that production expectations are independent of the compliance alternative being evaluated. The average of a unit's past summer production levels in the years preceding the compliance decision $\bar{Q}_n$ is used to proxy for expected ozone season production. Because coal generation tends to serve load on an around-the-clock basis, the capacity factors of most coal plants are unlikely to be significantly affected by a compliance-related change in variable operating costs.[23] However, if $\bar{Q}_n$ consistently under (or over) estimates what managers actually expected, the variable operating cost measures will be biased.

It is impossible to know whether all plant managers used $\bar{Q}_n$ to approximate Q_n in their decision making.[55] However, unit level production data from the first ozone season can be used to assess how well $\bar{Q}_n$ predicts the electricity production we do observe.[56] The following equation is estimated:

$$Q^*_{n,04} = \theta_0 \bar{Q}_n + \theta_j \sum_{j=1}^{J_n} D_{jn} \cdot \bar{Q}_n + u_n, \tag{8}$$

where $Q_{n,04}$ is the observed production at unit n during the 2004 ozone season, D_{jn} is an indicator for whether unit n adopted pollution control technology j, and u_n is a random error term. A robust covariance matrix estimator that accounts for within plant correlation in the error terms is used.[57] If unit-level production was significantly affected by firms' compliance decisions, one or more of the θ_j will be statistically significant. A positive (negative) θ_j indicates that, on average, firms choosing compliance strategy j increased (decreased) their production relative to those units

[55] Anecdotal evidence indicates that managers used past summer production levels to estimate future production, regardless of the compliance choice being evaluated (EPRI, 1999a).

[56] The first ozone season in which all coal-fired units had to comply was 2004.

[57] There are several reasons why the error terms might be correlated across units in the same facility. For example, an facility-wide outtage would affect the production of all units at a plant.

who chose to rely entirely on the permit market for compliance.

Results are reported in Table 8. The coefficient on $\bar{Q}_n$ is 1.03 when the model is estimated using data from the regulated markets and very precisely estimated, whereas none of the interaction terms are significant. This implies that unit level production, on average, increased slightly in regulated markets once the NBP took effect, but was not significantly affected by the compliance strategy chosen. When the model is estimated using data from restructured markets, the coefficient on $\bar{Q}_n$ is 1, also with a small standard error. Only the SCR interaction term is positive and significant at the five percent level. This is an interesting, but not surprising result. In restructured markets, units installing SCR slightly increased their ozone season production on average, where as production levels at all other plants were generally unchanged.

These results are supportive of the model assumptions in regulated markets. If managers correctly anticipated how compliance decisions would affect future production, they used past ozone season production as a proxy for future production in their evaluation of all compliance options. In restructured markets, managers who correctly anticipated that adopting SCR (and possibly SNCR) could result in increased production (by a quantity denoted by ΔQ_n) would have changed their production expectations accordingly. This would increase annual compliance costs associated with SCR by $\Delta v_{n\ SCR} = (V_{n\ SCR} + \tau \cdot m_{n\ SCR})\Delta Q_n$.[58] Per kWh compliance costs are relatively low for SCR (see Figure 1), so $\Delta v_{n\ SCR}$ should be small. Because it is hard to know whether managers correctly anticipated this increase, and because the increase is likely to be small, the same assumptions regarding expected production are maintained for all units, for all compliance strategies.

5.4. Summary of Estimation Results

Because of the identification assumptions underlying the logit model and the difficulties associated with estimating the variance of a ratio of two random variables, there is no completely satisfying

[58] In fact, this increase in per kWh compliance costs would potentially be offset by increased revenues. Under the assumption that expected production is independent of the compliance choice, revenues from the sale of electricity do not vary across compliance alternatives and therefore drop out of the discrete choice model. If expected production is higher conditional on adopting SCR, revenues will increase by an amount equal to $\sum_{t_{n\ SCR}=1}^{T_{nSCR}} q_{nt_{nSCR}} P_{nt_{nSCR}}$, where t_{nSCR} indexes the additional hours in which the n^{th} unit would operate if it installed SCR, and P_{nt} is the electricity price the n^{th} unit expects to receive in hour t.

way to formally demonstrate that the relative magnitude of the means of the two cost coefficient distributions differs across electricity market types. However, the empirical evidence strongly suggests that the negative coefficient on capital costs is substantially larger in absolute value when the model is estimated using data from restructured electricity markets. Whereas we can easily reject the null hypothesis that the capital cost coefficient is greater than or equal to zero in the restructured market case, we fail to reject this hypothesis when the model is estimated using data from regulated electricity markets. When the ratio of the variable and capital cost coefficient estimates are compared (hereby eliminating the scale parameter that confounds direct comparisons of coefficients across market types), we find further support for the hypothesis that plants in restructured electricity markets weigh capital costs more heavily in their compliance decisions.

6. Implications of the Results

6.1. Implications for technical efficiency

Estimation results suggest that it is not always the plants with the lowest abatement costs that install pollution control technologies. To assess the magnitude of technical inefficiency, engineering cost estimates associated with observed compliance choices are compared with a stylized, compliance cost minimizing counterfactual.

A deterministic model that simulates efficient pollution permit market clearing is specified. The model is used to identify the set of compliance strategies that minimizes the sum of estimated hardware and operating costs subject to an exogenously set cap. The cap is set equal to the (undiscounted) emissions reductions associated with observed compliance choices. The model assumes that each unit chooses the compliance option that minimizes the present value of discounted compliance costs. To determine the relevant investment time horizon, I assume all units retire at 65 years. I use the financial parameters typically assumed by federal and state regulatory agencies when analyzing industry pollution regulation (i.e. IPM model assumptions) to discount future costs (EPA, 2003).

Table 9 reports some results from this exercise. The estimated net present value (NPV) of discounted compliance costs associated with observed choices is \$9.3 B, whereas the estimated NPV of discounted costs associated with the set of choices that deliver the same emissions reductions at minimum cost is \$6.7 B. The deterministic model predicts that investment in pollution control will be divided approximately equally across electricity market regimes.[59] Under cost minimization, however, 61% of investment occurs in regulated markets.

Note that the costs associated with observed choices exceed cost minimizing levels in both market regimes. The deterministic model is overly simplistic in assuming that all firms use the same discount rates, costs of capital, etc. when making their compliance decisions. In restructured markets in particular, this was certainly not the case.[60] What this exercise does illustrate, however, is that restructured markets as a whole were much closer to the stylized, cost-minimizing level of investment, as compared to regulated producers.

6.2. Implications for Permit Market Design

Ozone non-attainment problems are significantly more severe in states that have restructured electricity markets, largely because of differences in levels of industrial activity, population densities, and meteorological conditions. Consequently, the health benefits from reducing NOx pollution are significantly greater in these states.

Consider the health effects of choosing to install selective catalytic reduction (SCR) technology (the most capital intensive NOx control option) at a unit in a regulated electricity market versus a unit in a restructured electricity market. An average unit in the sample emitted 15 tons of NOx per day in 1999; retrofitting a *single unit* with SCR technology results in daily NOx reductions of 12 tons on average. A recent study finds that shifting 11 tons of NOx emissions per day from a relatively "low damage" location (North Carolina, a state that has not restructured its electricity market) to a "high damage" area (Maryland, a state that restructured its electricity industry) over a ten day period results in the loss of approximately one human life (Mauzerall et al., 2005).[61] If there were two technically identical plants located in Maryland and North Carolina, respectively, we would much rather see the investment in SCR occur at the plant in Maryland. However, results

[59] This is not surprising; recall that units are divided, and technology costs are distributed, very similarly across market regimes (see Tables 1 and 2).

[60] For example, firms that had recently divested generation assets could finance investments in pollution control equipment relatively more easily than firms who had recently purchased a divested plant.

[61] Recent epidemiological studies indicate that health impacts increase linearly with increasing ozone concentrations (US EPA, 2003; Steib et al., 2003, as cited in Mauzerall et al., 2005).

presented in the previous section indicate that if these two plants faced the same choice set, it is more likely that the investment would occur in North Carolina.

Like all major CAT programs in the United States, the NBP is emissions-based. The regulatory constraint is defined in terms of pounds of pollution; a permit is worth a pound of emissions, regardless of where the pound is emitted. Because the permit market fails to reflect spatial variation in benefits from reducing NOx emissions, there will likely be insufficient incentives for efficient levels of investment in the regions where investment in pollution controls will deliver the greatest benefits. Because air quality problems are more severe in states that have restructured their electricity markets, the allocative inefficiencies associated with emissions-based trading of a non-uniformly mixed pollutant are exacerbated by the economic regulation effects discussed in the previous section.[62]

Whereas environmental regulators have no control over electricity market regulation, they do have control over how pollution permit markets are designed. An alternative approach to designing permit markets involves setting a cap on total damages and establishing trading ratios that determine the terms of interregional permit trading.[63] To set up such a system, the marginal damages resulting from increased NOx emissions in different regions of the regulated area must be estimated. The trading ratio R corresponding to a particular region is set equal to the estimated damages for that region divided by the damages in a designated numeraire region. These regions can be as small as the available data on marginal damages allows. In the extreme case, ratios would be set at the facility level. Under emissions-based trading, $R_n = 1 \; \forall \; n$. The introduction of trading ratios that reflect spatial variation in marginal damages increases the marginal cost of polluting in areas where pollution does the most damage, thereby increasing the incentives to install pollution

[62] It is worth noting that it need not have happened this way. If marginal damages from pollution were lower in states with restructured electricity industries, the two effects would work in opposing directions.

[63] It should be emphasized that policy makers did think about incorporating trading ratios into the design of the NBP. The EPA received over 50 responses when, during the planning stages of the NOx SIP Call, it solicited comments on whether the program should impose restrictions on interregional trading in order to reflect the significant differential effects of NOx emissions across states(FR 63(90): 25902). Most commentors supported unrestricted trading and expressed concerns that "discounts or other adjustments or restrictions would unnecessarily complicate the trading program, and therefore reduce its effectiveness" (FR 63(207): 57460). A deterministic simulation exercise similar to the one discussed in the previous section was carried out. Cost-minimization was assumed and interstate variation in electricity market regulation was not represented. Simulation results indicated that imposing spatial constraints on trading would not result in significant shifts in the location of emissions. Consequently, the program was designed so that emissions are traded on a one-for-one basis.

controls in relatively high damage areas. The effect of trading ratios on compliance decisions, and thus patterns of emissions, will depend on how responsive firms' compliance choices are to changes in variable compliance costs. If the bias of managers against capital intensive compliance options is sufficiently strong in high damage areas, it could be that the use of trading ratios would not have affected compliance choices.

In the interest of assessing how the use of NOx trading ratios would affect compliance decisions, we want to compare observed compliance choices with the choices that would have been made under exposure based trading. The econometric model can be used to simulate these counterfactual compliance decisions. Drawing from the manager-specific distributions of cost coefficients implied by the RCL estimates, I simulate the compliance choices that these managers most likely would have made had the NOx emissions market been designed to reflect spatial heterogeneity in marginal damages from pollution. Unlike previous studies,[64] I will find that the decision to adopt an emissions-based versus an exposure-based permit market has significantly affected the spatial distribution of permitted emissions.

6.3. Simulating Exposure-Based Trading

Defining trading ratios

Several assumptions had to be made in setting up the simulation of exposure-based NOx permit trading. The first set of assumptions pertain to how trading ratios are defined. Although there was discussion of imposing spatial constraints on permit trading during the planning stages of the NBP, a complete proposal of appropriate jurisdictional boundaries or trading ratios was never established. However, there are two papers in the literature which estimate marginal damages from incremental increases in NOx emissions in the Eastern United States that provide estimates of marginal damages that can be used to construct blunt estimates of trading ratios (Krupnick

[64] Farrell et al. (1999) consider imposing geographic constraints on NOx permit trading in the Northeast and conclude that the benefits do not justify the costs. Krupnick et al. (2000) argue that there is no clear benefit to spatially differentiated NOx trading. Finally, the EPA used the IPM model to simulate exposure based trading under the NBP (1998c). Results suggested estimated benefits did not justify the added complexity.

et al., 1998; Mauzerall et al., 2005).[65,66] Based on these papers, I consider two exposure-based trading scenarios. In both cases, one permit is required to offset a pound of pollution in low damage areas. In "high damage" areas, 1.5 and 5 permits are required per pound in the first and second scenarios, respectively.

Ideally, trading ratios would incorporate all available information on how marginal damages from NOx pollution vary across counties, municipalities, or even facilities. I was unable to obtain marginal damage estimates at this level of detail. “Low damage” states are defined to be those that are either completely or marginally in attainment with the federal one hour and eight hour ozone standards (according to the US EPA’s “Green Book”). “High damage” states are those that include counties classified as moderate, severe or serious under the one hour and eight hour standards (EPA Green Book). Under exposure-based trading, I assume that a permit is required to offset a pound of NOx in low damage areas; 1.5 permits (or 5 permits in the second scenario) are required in high damage areas.

Defining the baseline

A second set of assumptions have to do with establishing a baseline or benchmark against which to compare simulated emissions under exposure-based trading. Under emissions-based trading, the number of permits distributed equals the total cap on emissions. Assuming perfect compliance, the regulator has complete control over the total amount of pollution that is emitted. Under a trading ratio system, the regulator cannot directly cap emissions. The number of permits distributed equals the permitted damages. The total quantity of permitted emissions will depend on which firms use permits, and which firms invest in pollution reduction. If more permits are used in low

[65] Krupnick et al.(1998) generate trading ratios for a subset of the states affected by the NOx SIP Call. The authors use an urban airshed model to link regional changes in NOx emissions in different regions to regional, population weighted changes in ozone concentrations. They use emissions and meteorological data from three typical five day ozone episodes in 1990 to estimate trading ratios. The authors note that 1990 was a "good" ozone year; their estimates of typical changes in ozone concentrations attributable to sources are conservative. Averaged across typical episodes, ratios range from 1 in low damage areas to 1.5 in high damage areas.

[66] Mauzerall et al (2005) use a comprehensive air quality model (CAMx) to quantify the variable impacts that a fixed quantity of NOx emitted from individual point sources can have on downwind ozone concentrations and resulting population weighted health damages. Simulations were carried out using data from a 10 day period in 1995 (July 7-17). Considering fatality effects only (i.e. ignoring morbidity) and using “off the shelf” estimates of the value of a statistical life, the estimated damage per ton of NOx emissions ranges from 1995 $10,700 to $52,800 depending on ambient temperature and location. This suggests that the appropriate trading ratios in high damage areas could be as large as 5:1. Ratios that take morbidity and environmental damages into account would be even larger.

(high) damage areas, the total amount of pollution will be greater (smaller) for a given cap.

To facilitate a comparison between emissions-based and exposure-based permit market designs, I assume that the cap is defined in terms of emissions in both cases. Put differently, I simulate compliance choices and emissions under exposure-based and emissions-based permit markets that are designed to deliver the same total quantity of seasonal emissions (in terms of pounds of NOx). The emissions predicted by the model conditional on the predicted compliance choices are used as the basis for comparing alternative exposure-based trading outcomes. The emissions-based benchmark outcomes are simulated in the same way that emissions under counterfactual, exposure-based trading are simulated. Appendix D includes a discussion of how this benchmark outcome compares to emissions observed in the first year of permit trading.

D. Simulation

Two sets of simulations are carried out: one which assumes decisions are made by plant managers, and the other which assumes decisions are made at the firm level. The econometric model is used to predict emissions under emissions-based and exposure-based permit trading as follows:

1. The permit price τ is initially set equal to the price that prevailed during the years in which firms were making their compliance decision ($2.25/lb).
2. A vector of coefficients b^r is drawn from the distribution of the random coefficients in the population; r denotes the repetition ($r = 1...1000$).
3. For each unit, expected choice probabilities as defined in [7] are approximated for all compliance available choices. These are conditional on the price τ, b^r, the character and outcomes of observed choices of the corresponding manager (or firm), and the assumed trading ratio R_m.
4. Unit level compliance choices for all choice situations faced by each manager (firm) are predicted. Each unit is assumed to choose the compliance strategy with the highest estimated probability.
5. Seasonal emissions (measured in lbs of NOx) corresponding to the predicted choices are calculated and summed across units.

6. If the total quantity of emissions equals the assumed cap, τ is the equilibrium price and the simulation stops. Equilibrium emissions in high damage areas and low damage areas are calculated.

7. If the total quantity of emissions exceeds (is less than) the cap, τ is increased (decreased) by \$0.01. Steps 3-6 are repeated.[67]

This procedure is repeated 1000 times under the baseline case (emissions-based trading), the conservative exposure-based trading case where $R = 1.5$ in high damage areas, and the less conservative exposure-based trading case where $R = 5$ in high damage areas. Distributions of predicted equilibrium emissions are generated for each scenario. Summary statistics are reported in tables 8 and 9.

If we assume that compliance decisions are made at the facility level (i.e. cost coefficients are allowed to vary across facilities owned by the same parent company) the model predicts an average reduction of 129 tons per day (6 percent) in emissions in the high damage states under the first case ($R = 1.5$), and an average reduction of 457 tons per day (22 percent) in high damage states under the second case ($R = 5$). If we assume that parent companies make compliance decisions, simulation exercises predict reductions of similar magnitude (7 percent and 23 percent, respectively).

These results suggest that the health damages that have resulted (and that will continue for the foreseeable future) from the decision to adopt an emissions-based permit design are non-negligible. Allowing for the fact that the model does over-predict actual emissions (See Appendix D), a 6 to 23 percent decrease in observed emissions in high damage areas translates to moving 92-360 tons of NOx emissions *per day* out of high damage areas into low damage areas, depending on the chosen trading ratios.

VII. Conclusion

This paper provides evidence that generators in restructured electricity markets were less likely to install capital intensive pollution control technology as compared to very similar plants in

[67] If this iterative procedure arrives at a point where adding or subtracting a cent delivers aggregate emissions on either side of the cap, the price that delivers the quantity of emissions just below the cap is chosen to be the equilibrium price. Equilibrium emissions are calculated and the simulation stops.

regulated electricity markets. This result is robust to a variety of specifications.

The relationship between economic regulation in the electricity market and pollution control technology adoption decisions affects permit market efficiency in two ways. First, because the plants with the lowest pollution control costs are not always the ones installing pollution controls, the permit market may fail to minimize the total economic cost of meeting the exogenously determined emissions cap. Whereas a deterministic model that assumes cost minimization and assumes away interstate variation in electricity market regulation predicts that investment in pollution control equipment will be approximately equal in restructured and regulated markets, estimated costs conditional on observed choices suggest that over 60% of investment occurred in regulated markets.

Second, because air quality problems are more severe in states that have restructured their electricity markets, inefficiencies associated with emissions-based trading of a non-uniformly mixed pollutant are exacerbated. In theory, exposure-based permit trading could reduce the efficiency costs of the negative capital bias in restructured electricity markets. The econometric model is used to predict how technology adoption, and thus emissions, would have been different under an exposure-based trading program designed to meet the same total emissions cap. The model predicts that 6-27 percent of permitted emissions (or 92-413 tons of NOx per day, based on observed emissions in 2004) would have been moved out of high damage areas and into low damage areas under a generally defined exposure-based program, relative to an emissions-based program. Recent epidemiological research suggests that a spatial shift in emissions of this magnitude could reduce premature deaths from ozone exposure by hundreds each year. There would also be additional benefits, including reduced morbidity and reduced environmental damages. While this analysis is somewhat limited in how accurately it can measure the precise number of tons of NOx that would move out of high damage areas and into low damage areas under exposure-based trading, the inefficiency of emissions-based permit trading is clear.

The Mercury Rule and the Clean Air Interstate Rule, both finalized in 2005, are scheduled to take effect in 2010. Both will affect electricity generators in both restructured and regulated electricity markets. Both propose to use an emissions-based permit trading program to regulate non-uniformly mixed pollutants. The findings presented here caution against designing permit markets that fail to reflect spatial variation in marginal damages from pollution, particularly when variation in economic regulation across electricity markets is already reducing the probability that pollution controls will be installed in the areas where they deliver the greatest social benefits.

Appendix A: A Model of Compliance Cost Minimization

For all units in the sample, $K_n'(v) < 0$; $K_n''(v) \geq 0$. For ease of exposition, the compliance decision is represented as a choice of a point on the continuous, convex cost frontier $K_n(v)$.

The Compliance Decision in Restructured Markets

Three ISOs operate centralized power markets in the region regulated by the NBP.[68] All three operate as uniform price auctions wherein the price is set by the marginal bidder. The manager's compliance choice of v_n can affect the unit's position in the dispatch order (relative to other units supplying the market). If the unit is never the marginal (price setting) unit, an increase in v_n will have no effect on the wholesale electricity price.

Let $\bar{P}_n$ represent the average wholesale electricty price paid to unit m. Let ψ_n represent the fraction of variable compliance costs that is not translated into increases in $\bar{P}_n$:

$$1 - \frac{\partial \bar{P}_n}{\partial v_n} = \psi_n. \tag{A1}$$

The compliance choices of plants in this sample will rarely affect the average electricity price $\bar{P}_n$ that the firm receives in the wholesale market because coal-fired generating units are typically infra-marginal. For a unit that is never marginal, $\psi_n = 1$.

The levelized annual compliance cost that the manager of the *nth* plant expects to incur if she chooses choose compliance strategy j is:

$$\begin{aligned} LAC_{nj} &= \psi_n v_{nj} Q_n + l_n K_{nj}, \\ l_n &= \frac{r_n(1+r_n)^{T_n}}{(1+r_n)^{T_n} - 1} \end{aligned}$$

The installation cost K_{ni} is multiplied by the levelized annual cost factor l_n. This yields the annual capital ammortiziation over a period T_{ni} . The annuity interest rate r_n is a weighted average of the cost of debt and the opportunity cost of equity (i.e. the firm's cost of capital).

I assume that the manager chooses v_{ni} to minimize levelized annual compliance costs subject

[68] These are the New York ISO, the New England ISO and the "PJM" (Pennsylvania Jersey Maryland) ISO.

to the constraint that the chosen compliance strategy must lie on the least-cost compliance frontier $K_n(v_{ni})$:

$$\text{(A2)} \qquad \min_{v} \; LAC_n = \psi_n v q_n + l_n K_n(v),$$

Minimization of the above constrained optimization problem implies:

$$\text{(A3)} \qquad K_n'(v) = -\frac{\psi_n Q_n}{l_n}$$

The manager will want to choose the point on the compliance cost frontier such that the (negative) slope is equal to the ratio of the cost of an incremental change in variable compliance costs and the cost of an incremental change in fixed compliance costs. [69]

The ratio of the capital cost and variable cost can be interpreted as approximately equal to the firm's discount rate r_n scaled by $\psi_n$when the firm's investment is infintely long:

$$\begin{aligned} LAC_n &= \psi_n v_{nj} + l_n K_{nj}, \\ \frac{dK_n}{dv_{nj}} &= \psi_n \frac{(1+r_n)^{T_n} - 1}{r_n (1+r_n)^{T_n}} \\ \lim_{T_n \to \infty} \frac{dK_{nj}}{dV} &= \psi_n r_n. \end{aligned}$$

For a plant that is always inframarginal and that has an infinitely long investment horizon, the ratio of the variable cost and capital cost coefficient is equal to the firm's discount rate r_n.

Compliance Choices in Unrestructured Markets

I assume that managers at regulated utilities comply with environmental regulations while minimizing compliance costs borne by shareholders (or taxpayers in the case of government owned facilities). Following the example of Fullerton et al.(1997), I define parameters that describe how

[69] This implies that an increase in the cost of capital will, ceteris paribus, be associated with a less capital intensive compliance choice. Similarly, a decrease in ψ_n would lead to a less capital intensive compliance choice.This assumes that restructured markets are closely monitored, so that sellers need to justify bids with operating costs.

compliance costs are shared between ratepayers and shareholders.[70] Let θ_n^V represent the portion of variable compliance costs born by the utility and its shareholders versus the ratepayers. Similarly, let θ_n^K be the portion of capital investments in NOx control technology that the utility cannot pass through to ratepayers.

I assume that the manager chooses v_{ni} to minimize levelized annual compliance costs subject to the constraint that the chosen compliance strategy must lie on the least-cost compliance frontier $K_n(v_{ni})$:

$$\text{(A4)} \qquad \min_v LAC_n = \theta_n^v v Q_n + \theta_n^K l_n K_n(v).$$

Minimization of the above constrained optimization problem implies :

$$\text{(A5)} \qquad K_n'(v) = -\frac{\theta_n^v Q_n}{\theta_n^K l_n}$$

The ratio of the capital cost and variable cost can be interpreted as approximately equal to r_n scaled by the ratio of the cost recovery parameters:

$$\begin{aligned} LAC^{REG} &= \theta^V V + \theta^K lK, \\ \frac{dK}{dV} &= \frac{\theta_n^V}{\theta_n^K l} = \frac{\theta_n^V}{\theta_n^K} \frac{(1+r_n)^{T_n} - 1}{r_n(1+r_n)^{T_n}} \\ \lim_{T\to\infty} \frac{dK}{dV} &= \frac{\theta_n^V}{\theta_n^K} \cdot r_n \end{aligned}$$

If variable and capital costs are treated symmetrically by regulators, this will be r_n. Otherwise, when cost recovery rules favor capital intensive compliance options, the ratio of these model coefficients will overestimate r_n.

Consider two units that face the same compliance cost frontier $K(v)$ and operate at the same production levels but operate in different electricity market environments. Let U denote the firm operating in an unrestructured electricity market and R denote the firm operating in a restructured

[70] There is some evidence that the fixed and variable components of compliance cost have been treated asymmetrically by regulators, so I define different cost recovery parameters for different compliance cost components.

electricity market. If firm R chooses to locate on a steeper portion of $K(v)$, it must be that:

$$\frac{\theta_n^v}{\theta_n^K}\frac{1}{l_R} > \psi_n \frac{1}{l_U}.$$

There are at least three reasons why we might expect this inequality will hold:

1. $\frac{\theta_n^v}{\theta_n^K} > \psi_n$: Rates of return authorized by regulators provide stronger investment incentives in regulated markets as compared to restructured markets.

2. $\frac{1}{l_R} > \frac{1}{l_U}$.: Regulated utilities have higher credit ratings and lower costs of capital on average.

3. *Differences in the option value of waiting*: Managers in regulated markets are assured of cost recovery; there is no uncertainty and thus no option value. To the extent that managers in restructured markets account for real option value when evaluating option alternatives, [A3] will overestimate the slope at the optimal point..

Appendix B: Data Description

Data needed to identify coal units regulated by the NBP

1. U.S. EPA's Clean Air Markets: Program provides a comprehensive list of all the units affected by the NBP (includes the facility name, facility and unit identification numbers, location and contact information).
2. U.S. EPA National Electric Energy System (NEEDS).

Unit-level compliance strategy choices

1. EPA Electronic Data Reporting for the Acid Rain Program/subpart H.
2. Energy Information Administration (EIA).
3. Institute for Clean Air Companies.
4. MJ Bradley & Associates.

Data required to estimate control costs at the unit level

1. U.S. EPA National Electric Energy System (NEEDS).
2. EPA Electronic Data Reporting for the Acid Rain Program/subpart H.
3. U.S. EPA Emissions and Generation Integrated Database (EGRID).
4. Energy Information Administration (EIA) Form 767.
5. Energy Information Administration (EIA) Form 860
6. Platts BaseCase:
7. Raftelis Financial Consultants Water and Wastewater Rate Survey.
8. Bureau of Labor Statistics: Regional estimates of boilermaker and construction wages.
9. Personal Correspondence: Representatives from the major coal-fired boiler manufacturers (Alstom Engineering, Babcock Power, Foster Wheeler, Riley Power Inc.) provided valuable information about the technical specifications of the boilers in the sample De-NOx Technologies LLC provided data on reagent and reagent transportation costs. Other technical assistance was provided by Cichanowicz Consulting Engineers LLP.

Permit Price/Transaction Data

1. Evolution Markets LLC

Estimates of anticipated post-retrofit NOx emissions rates (conditional on boiler characteristics) constructed using the following sources:

1. Biewald, B., J. Cavicchi, T. Woolf and D. Allen. 2000. “Use of Selective Catalytic Reduction for control of NOx Emissions from Power Plants in the U.S.” *Synapse Energy Economics Inc.*

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13. US Environmental Protection Agency. 1998. Regulatory Impact Analysis for the NBP, FIP and Section 128 Petitions, Office of Air Quality Planning and Standards, Office of Atmospheric Programs, Washington D.C.

14. US Environmental Protection Agency. 1998. Analyzing Electric Power Generation under the CAAA. Office of Air and Radiation. Washington D.C.

Appendix C: Deriving the Conditional Logit Choice Probabilities Implied by Cost Minimization

It is straightforward to show that for additive, iid extreme value (Type I) errors, the assumption of cost minimization does not yield the standard CL choice probabilities due to the asymmetry of the assumed distribution. In the standard Random Utility Maximization (RUM) logit model, the assumption of an additive extreme value error term is motivated by a desire for simple closed-form expressions for choice probabilities. Here I show that, in the context of cost minimization, assuming that the extreme value term is subtracted from (versus added to) the deterministic component implies equally convenient expression for choice probabilities. This closely follows the derivation of the standard RUM choice probabilities in Train(2003).

The unit (denoted n) chooses from among J_n compliance alternatives. The cost that the unit associates with each alternative is comprised of a deterministic component and a stochastic component:

$$C_{ni} = \beta_m X_{ni} - \varepsilon_{ni},$$

where ε_{ni} is assumed to be independently, identically distributed type I extreme value. To derive the choice probabilities, I assume that the unit chooses the compliance option that minimizes anticipated compliance costs.(For ease of notation, the n subscript on the coefficient vector β is dropped). Let P_{ni} be the probability that unit n chooses alternative i :

$$\begin{aligned} P_{ni} &= \text{Prob } (\beta' X_{ni} - \varepsilon_{ni} < \beta' X_{nj} - \varepsilon_{nj} \quad \forall\ j \neq i) \\ &= \text{Prob } (\varepsilon_{nj} < \beta' X_{nj} - \beta' X_{ni} + \varepsilon_{ni} \quad \forall\ j \neq i) \end{aligned}$$

The expression for the conditional choice probability :

$$\begin{aligned} P_{ni}|\varepsilon_{ni} &= \prod_{j \neq i} F(\beta' X_{nj} - \beta' X_{ni} + \varepsilon_{ni}) \\ &= \prod_{j \neq i} \exp(-\exp(-(\beta' X_{nj} - \beta' X_{ni} + \varepsilon_{ni}))) \end{aligned}$$

Unconditional choice probabilities are obtained by integrating over the distribution of ε_n :

$$\begin{aligned} P_{ni} &= \int_{\varepsilon=-\infty}^{\infty} \prod_{j \neq i} \exp(-\exp(-(\beta' X_{nj} - \beta' X_{ni} + \varepsilon_{ni}))f(\varepsilon_n)\ d\varepsilon_n \\ &= \int_{s=-\infty}^{\infty} \prod_{j \neq i} \exp(-\exp(-(\beta' X_{nj} - \beta' X_{ni} + s))\exp(-s)\exp(-\exp(-s))\ ds \end{aligned}$$

Note that $\exp(-\exp(-(\beta' X_{nj} - \beta' X_{nj} + s))) = \exp(-\exp(-s))$. Making this substitution:

$$
\begin{aligned}
P_{ni} &= \int\limits_{s=-\infty}^{\infty} \prod_j \exp(-\exp(-(\beta' X_{nj} - \beta' X_{ni} + s))\exp(-s)ds \\
&= \int\limits_{s=-\infty}^{\infty} \exp - \sum_j \exp(-(\beta' X_{nj} - \beta' X_{ni} + s))\exp(-s)ds \\
&= \int\limits_{s=-\infty}^{\infty} \exp(-\exp(-s)) \sum_j \exp(-(\beta' X_{nj} - \beta' X_{ni}))\exp(-s)ds
\end{aligned}
$$

We define a variable t such that $t = \exp(-s) \Rightarrow dt = -\exp(-s)ds$. Making this substitution:

$$
P_{ni} = \int\limits_{s=0}^{\infty} \exp(-t \sum_j \exp(-(\beta' X_{nj} - \beta' X_{ni}))dt
$$

Evaluating this integral, we are left with:

$$
P_{ni} = \frac{1}{\sum\limits_j \frac{\exp(\beta' X_{ni})}{\exp(\beta' X_{nj})}}
$$

An alternative way of expressing this conditional choice probability:

$$
P_{ni} = \frac{\frac{1}{\exp(\beta' X_{ni})}}{\sum\limits_j (\frac{1}{\exp(\beta' X_{nj})})} = \frac{\exp(-\beta' X_{ni})}{\sum\limits_j \exp(-\beta' X_{nj})}
$$

Appendix D: Comparing predicted and observed emissions

Significant discrepancies exist between observed emissions during the first ozone season and emissions predicted by the model under emissions-based permit trading. Table A1 compares observed emissions from the first ozone season of the NBP (2004) to the emissions predicted by the model (I use manager-specific cost coefficients here).

Table A1: Observed and Predicted Average NOx Emissions (tons per day) by Market Type

	Observed (2004 season)	Predicted | Observed Choices	Predicted | Predicted Choices
			(BASELINE)
Restructured markets	1662	2272	2349
NOx emissions (tons/day)			(64)
Regulated markets	1592	2022	1999
NOx emissions (tons/day)			(64)
Total	3254	4294	4348
NOx emissions (tons/day)			(6)
% Emissions in	51%*	53%	54%
restructured markets			(0.5%)

Notes: Standard deviations are in parentheses.

The second and third columns report predicted emissions conditional on observed choices and conditioned on simulated choices, respectively. Although the model is quite accurate in predicting compliance choices, it does a poor job of predicting emissions. Predicted emissions (based on predicted compliance choices) are 34% higher than observed emissions overall and over 40% higher in states with restructured electricity markets.

A closer look at the data reveals three reasons for these discrepancies. First, the model assumes that emissions rates (measured in lbs NOx/mmbtu) for those units that choose not install any pollution controls will equal the unit's average, historic ozone season emissions rate (i.e. 1999-2002). In fact, emissions rates at units that chose to rely entirely on the permit market for compliance fall by an average of 21% in the first ozone season, relative to past summers. This relationship does not differ significantly across electricity market types.[71] Emissions rates at these plants were likely reduced by changing boiler conditions so as to reduce NOx formation during combustion.

Second, the unit-specific, technology-specific, post-retrofit NOx removal rates assumed by the model also appear to have been conservative. These are the same estimates that were made available to plant managers while they were making their compliance decisions. Among units that adopted some pollution control technology other than SCR, observed post-retrofit NOx emissions rates are, on average, 27% below predicted post-retrofit NOx rates. Among units adopting SCR,

[71] The average decrease in NOx rates is 22% (with a standard deviation of 26%) in regulated markets and 19% in restructured markets (with a standard deviation of 21%).

observed post-retrofit emissions rates are, on average, 41% below predicted rates in restructured electricity markets and 28% below predicted rates in regulated markets. The reason for the difference across electricity market types is that several plants installing SCR reportedly were unable to complete their SCR retrofits in time for the first ozone season; most of these are in regulated electricity markets. Consequently, observed NOx rates in the summer of 2004 greatly exceeded the predicted NOx rates at these plants. The emissions rates at these plants, and the proportion of permitted NOx emissions in states with regulated electricity markets, should decline in future ozone seasons as SCR retrofits are completed.

Finally, assumptions about unit-level heat rates (measured in mmbtu/kWh) also underestimate ex post observed unit-level performance. The model assumes that future unit-level heat rates will equal those observed in previous summers. On average, units performed more efficiently in the summer of 2004 than in past ozone seasons. When observed heat rates are regressed on predicted heat rates and NOx control technology dummies, the coefficient on predicted heat rates is 0.91 with a standard error of 0.01. None of the technology dummies are statistically significant. Results do not change when regression equations are estimated separately for regulated and restructured markets.

Because observed emissions are significantly lower than the emissions predicted by the model, comparing emissions predicted under counterfactual exposure-based policy simulations with observed emissions would be uninformative and misleading. Instead, baseline emissions (i.e., the emissions associated with the observed, emissions-based permit trading program) are simulated in the same way that emissions under counterfactual, exposure-based trading are simulated.

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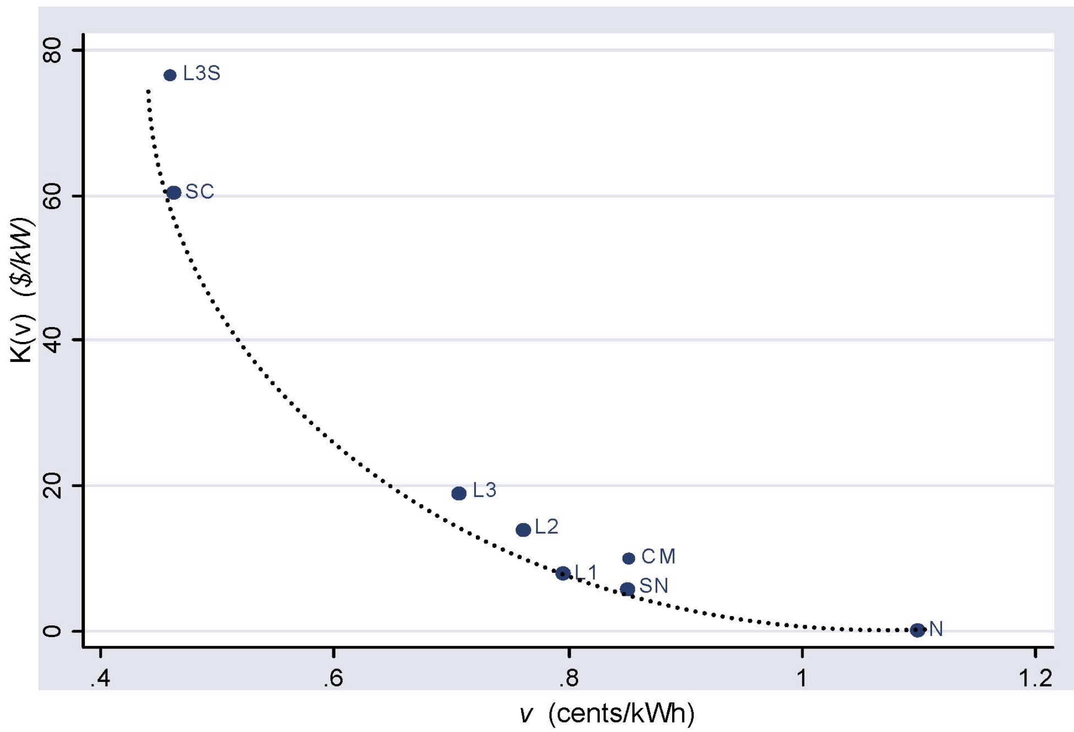


Figure 1: Estimated NOx Control Costs for a 512 MW T-Fired Boiler

Strategy code	Technology	lbs NOx/mmBtu
N	No Retrofit	0.42
SN	Selective Non-Catalytic Reduction (SNCR)	0.34
CM	Combustion Modification	0.33
L1	Low NOx Burners with overfire air option 1	0.31
L2	Low NOx Burners with overfire air option 2	0.28
L3	Low NOx Burners with overfire air options 1&2	0.26
SC	Selective Catalytic Reduction (SCR)	0.13
L3S	L3 + SCR	0.11

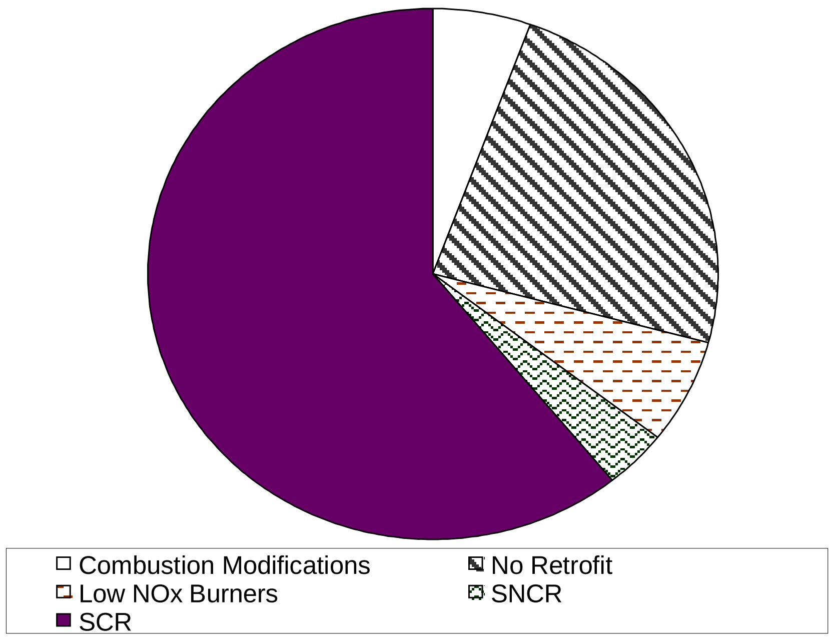


Figure 2a: Compliance Choices of Units in Regulated Markets

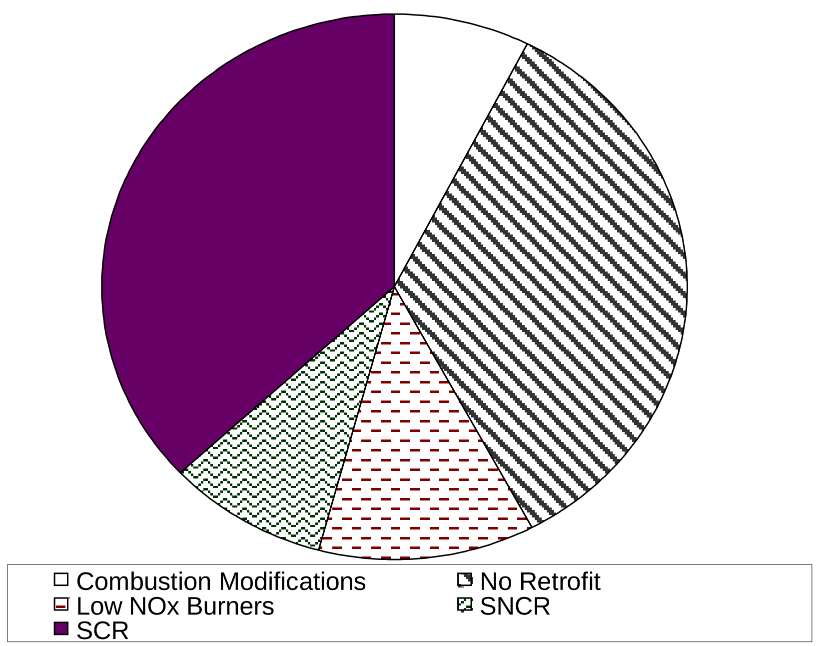


Figure 2b: Compliance Choices of Units in Restructured Markets

Table 1: Summary Statistics by Electricity Market Type

Variable	Restructured	Regulated
# Units	310	322
# Facilities	113	108
Capacity (MW)	275	268
	(243)	(258)
Pre-retrofit NOx emissions (lbs/mmBtu)	0.50	0.54
	(0.21)	(0.22)
Pre-retrofit summer capacity factor (%)	64	67
	(16)	(13)
Pre-retrofit heat rate (kWh/btu)	11,376	11,509
	(2153)	(1685)
Unit Age (years)	37	36
	(11)	(11)

Notes: Standard deviations in parentheses. Summary statistics generated using the data from the 632 units used to estimate the model.

Table 2: Choice Set Summary Statistics by Electricity Market Type

Variable	Restructured	Regulated
# Choices	6.8	6.6
	(1.8)	(1.7)
Combustion Modification	75%	72%
LNB +OFA	36%	32%
SNCR	92%	90%
SCR	100%	100%

Table 3: Compliance Cost Summary Statistics for Commonly Selected Control Technologies

Technology	Capital Cost ($/kW)		Per kWh operating costs (cents/kWh)	
	Restructured	Regulated	Restructured	Regulated
Combustion Modification	12.61	12.21	0.94	1.06
	(4.87)	(4.24)	(0.38)	(0.39)
Low NOx Burners w/ OFA	29.72	31.16	0.64	0.64
	(13.83)	(20.55)	(0.20)	(0.16)
SNCR	16.60	19.16	0.97	1.03
	(14.41)	(21.88)	(0.41)	(0.38)
SCR	70.36	72.90	0.52	0.54
	(21.02)	(25.52)	(0.31)	(0.19)

Notes: Standard deviations are in parentheses.

Table 4. Conditional and Random Parameters Logit Results

	Conditional Logit Model		RCL Model	
	Restructured	Regulated	Restructured	Regulated
	Technology Type Constants			
α_{POST}	-1.89**	-2.63**	-1.35*	-3.39**
	(0.34)	(0.38)	(0.52)	(0.59)
α_{CM}	-1.81**	-2.20**	-1.87**	-2.48**
	(0.26)	(0.28)	(0.30)	(0.32)
α_{LNB}	-1.86**	-2.15**	-1.55**	-2.49**
	(0.33)	(0.29)	(0.37)	(0.31)
	Cost Variables			
Annual compliance costs (V) ($100,000)	-0.30**	-0.31*	-1.21**	-1.00**
	(0.09)	(0.15)	(0.26)	(0.21)
Capital cost (K) ($100,000)	-0.06**	0.02	-0.53**	-0.16
	(0.02)	(0.06)	(0.12)	(0.10)
K*Age	-0.003	-0.002	-0.22**	-0.11*
	(0.002)	(0.003)	(0.06)	(0.05)
Cholesky 1	–		-1.42**	-0.51**
(σ_V)	–		(0.30)	(0.16)
Cholesky 2	–		0.30**	0.14**
(σ_K)			(0.08)	(0.05)
Cholesky 3	–		0.04	0.04
(off diagonal)			(0.11)	(0.07)
# units	310	322	310	322
# facilities	113	108	113	108
Log-likelihood	-431.2	-387.1	-359.4	-326.3
LR Test	compare to technology constants		compare to logit	
	103.94**	211.71**	143.66**	121.64**

Notes: Robust standard errors are in parentheses. *Indicates significance at 5%. **Indicates significance at 1%.

Table 5: Expected Means and Standard Deviations of Manager Specific Coefficient Distributions

Coefficient	Restructured		Regulated	
	Population parameter estimate	Average of conditional parameter estimates	Population parameter estimate	Average of conditional parameter estimates
Annual operating cost (V)	-1.21**	-1.13	-1.00**	-1.00
($100,000)		(1.00)		(0.33)
Capital cost (K)	-0.53**	-0.54	-0.16	-0.16
($100,000)		(0.19)		(0.10)
Elements of the Cholesky factor L of Ω				
Cholesky 1	-1.42**	-0.94	0.51**	0.40
(σ_V)		(0.30)		(0.07)
Cholesky 2	0.30**	0.23	0.14**	0.11
(σ_K)		(0.04)		(0.02)
Cholesky 3	0.04	0.07	0.04	0.002
(off diagonal)		(0.04)		(0.01)
# plants		113		108

Notes: Standard deviations are in parentheses. *Indicates significance at 5%. **Indicates significance at 1%.

Table 6: Average Own Capital Cost and Own Annual Compliance Cost Elasticities for Commonly Selected Technologies

Technology	Own capital cost elasticities		Own annual cost elasticities	
	RESTRUCTURED	REGULATED	RESTRUCTURED	REGULATED
Combustion Modification	-1.03	-0.25	-4.63	-4.40
	(0.81)	(0.33)	(7.37)	(5.02)
Low NOx Burners with overfire air	-1.25	-0.49	-3.75	-2.18
	(1.40)	(0.32)	(4.01)	(1.34)
No retrofit	–	–	-10.02	-8.19
			(18.16)	(13.50)
SCR	-5.74	-1.33	-1.75	-1.34
	(4.02)	(1.15)	(3.23)	(1.64)
SNCR	-1.07	-0.27	-7.56	-6.96
	(0.65)	(0.38)	(14.09)	(8.98)

Notes: These elasticities are calculated using the point estimates of the means of the conditional coefficient distributions. Standard deviations are in parentheses

Table 7: Alternative RPL Specification Results

	Restructured	Regulated
Annual compliance costs (V) ($100,000)	-0.65**	-0.711**
	(0.15)	(0.16)
Capital cost (K) ($100,000)	-0.21**	-0.06
	(0.08)	(0.05)
K*Age	-0.05	-0.07*
	(0.03)	(0.03)
Cholesky 1 (σ_V)	0.52**	0.27**
	(0.20)	(0.06)
Cholesky 2 (σ_K)	0.21**	0.07*
	(0.08)	(0.03)
Cholesky 3 (off diagonal)	0.10	0.04
	(0.06)	(0.03)
# units	310	322
# facilities	50	45
Log-likelihood	-395.59	-351.01

Notes: Robust standard errors are in parentheses. *Indicates significance at 5%. **Indicates significance at 1%.

Table 8: Testing the Independence of Ozone Season Production and Compliance Strategy Choice

	Restructured	Regulated
Past ozone season	1.00**	1.03**
production	(0.04)	(0.01)
(average kWh)		
Past production x	-0.12	-0.04
Combustion modification	(0.07)	(0.04)
Past production x	0.04	-0.04
low NOx burners	(0.07)	(0.05)
Past production x	0.09*	-0.00
SCR	(0.05)	(0.03)
Past production x	0.08	0.02
SNCR	(0.05)	(0.02)
Observations	310	322
R-squared	0.97	0.97

Notes: Dependent variable is observed unit level production in June-September 2003. Standard errors robust to within plant correlation are in parentheses.*Indicates significance at 5%. **Indicates significance at 1%.

Table 9: Comparing Observed Choices to a Cost-Minimizing Counterfactual

	Restructured	Regulated	Total
Estimated costs|	3.65	5.62	9.27
Observed choices	(39%)	(61%)	
($ Billion)			
Estimated costs|	3.28	3.30	6.58
Cost minimizing choices	(50%)	(50%)	
($ Billion)			

Table 10: Exposure-Based Trading Simulation Results: Facility-level decision making

	BASELINE CASE	Trading Ratio Case I (1:1.5)	Trading Ratio Case II (1:5)
High damage area	2053	1924	1596
NOx emissions (tons/day)	(55)	(78)	(146)
Low damage area	2295	2423	2750
NOx emissions (tons/day)	(55)	(78)	(146)
Total	4347	4347	4346
NOx emissions (tons/day)	(6)	(7)	(8)
% Emissions in	47%	44%	37%
High Damage Area	(1)	(1)	(3)

Notes: Standard deviations are in parentheses.

Table 11: Exposure-Based Trading Simulation Results : Company-level decision making

	BASELINE CASE	Trading Ratio Case I (1:1.5)	Trading Ratio Case II (1:5)
High damage area	2078	1930	1596
NOx emissions (tons/day)	(107)	(137)	(146)
Low damage area	2270	2418	2750
NOx emissions (tons/day)	(108)	(136)	(146)
Total	4348	4348	4346
NOx emissions (tons/day)	(10)	(7)	(8)
% Emissions in	48%	44%	37%
High Damage Area	(5)	(3)	(3)

Notes: Standard deviations are in parentheses.

Air Papers of October 18th Session
Comments by Sam Napolitano
Director, Clean Air Markets Division, U.S. Environmental Protection Agency

General

- EPA's air programs have enormous respect for the contributions that environmental and other economists have made to the Agency's efforts to better design programs. We appreciate the authors (of the air papers at this workshop) efforts to carry forward the invaluable work that economists have done over the last 35 years.
- The authors evaluate the Acid Rain Program (ARP) and the NO_x Budget Trading Program (NBP) using self-designed metrics of success. They largely ignore the reasons that Congress established for the programs. However, EPA has to set up programs under existing authorities in response to what Congress, States, and the public want done.
- The authors do not consider evidence on how well these programs have done and negatively focus on the programs not meeting objectives that the authors believe are appropriate. Reading these papers, you do not see that these programs are well designed and are highly successful at doing what they are intended to do, and more. The attached presentation that was given at the workshop on October 18th outlines air trading results and sources for program evaluations. It also provides other background information important for the authors to consider.

Shadbegian, Gray, and Morgan

- Authors briefly recognize Congress's aim for the ARP was to address an environmental issue (acid rain damage) and then focus on health benefits and costs to estimate net benefits (which Congress never intended and recent case law suggests is not allowed).
- The paper covers major aspects of the ARP -- trading vs command and control (CC) and trading ratios vs. simple trading, yet the analysis rests on an outdated air quality modeling tool (EPA has had four other better models in play since the 1996 Source-Receptor model used here was developed). Additionally, there is a very general explanation of the health and cost data and other important assumptions that leave the reader at a loss to determine if the analysis is credible. This concern is amplified when key results, such as those in Table 2, are hard to follow, presented in an inconsistent way (i.e. billions vs. millions of some year $), and appear to be partially wrong.
- The authors select ARP Phase I, which has limited value in determining overall program effectiveness and a comparative framework for CC versus trading that is different than that used when Congress made the original choice in 1990. Phase I was meant to move the trading program smoothly into place addressing the plants with the greatest sulfur dioxide emissions, but was not geared to be the final regulatory solution for these units and the rest of the power sector. Notably, Phase I was marked by limited cross-industry trading and worked through companies making internal changes to their fleets of electric generation units akin to some types of CC. Looking at ARP Phase II (coverage of entire power industry under a tighter emissions cap, where we have 6 years of experience, a lot more actual trading, and an enormous amount of emissions data available for analysis) would have provided a much better assessment. Also, it is arguable that the authors' chose the wrong comparative framework. The one stakeholders considered in 1990 when the ARP was set up would have compared allowance trading at a fixed allowance allocation level to CC achieving that level of reduction, not the level of over control reached due to the incentives provided uniquely by trading's "banking" provision. In that case, trading produces far greater net benefits than CC.
- Given the apparent simple analytics used in conjunction with the uncertainty that generally exists in this type of analysis, a very plausible conclusion is that the two approaches get roughly the same amount of benefits, but trading is cheaper than CC when the authors find that the benefits of trading and CC are within 2 percent of each other and that the trading program is close to 20 percent cheaper.

- Authors should consider framing the problem an additional way, considering that for the same cost, your analysis suggests that trading is likely to get a lot more benefits. Even at the high end of the costs per ton avoided, using scrubbers, the $94 million saved by the trading program appears to be able to provide an extra $94 million/$265 per ton = 355,000 tons of reductions. At an average value of about $15,000 per ton, those reductions would be worth over $5 billion, leaving an equal-cost trading program with several billion dollars more net benefits than CC.
- Surprised that once the authors found that the ARP Phase I had a benefit-cost ratio of about 100 to 1 they didn't point out that the overall public welfare (net benefits) could be substantially increased through regulation beyond Title IV. This analysis shows that further SO_2 controls, like EPA those provided in the Clean Air Interstate Rule (CAIR), are clearly warranted.
- Recommend replacing reference of total ARP benefits with the recently peer-reviewed article by Lauraine G. Chestnut and David Mills, *A fresh look at the benefits and costs of the US acid rain program,* Journal of Environmental Management, September 2005. It estimates the annual benefits of the ARP in 2010 at $122 billion (2000 $).

Fowlie

- The author does not recognize that the NO_x Budget Trading Program (NBP) was designed to lower ozone transport from upwind to downwind states to compliment state/local government actions to attain the 1-hour and 8-hour ozone standards. The NBP was meant to be part of a suite of federal regional measures and state/local government actions that collectively provide cost-effective control. The success of the NBP should be determined by its contribution to cost-effective ozone standard attainment, the goal that it had. Fowlie selects instead a cost-benefit framework; which the last 10 years of case law has shown Congress did not intend EPA to use.
- One of the author's two major points is that in designing the NBP, EPA did not properly factor in the differences that will occur in pollution control choices by companies that have electric generation prices that either are, or are not, regulated. She posits that due to the Averch-Johnson (A-J) effect where there is price regulation; there is a market distortion that tilts companies to use more capital intensive controls over what occurs without price regulation. Despite this contention, the author never proves that price-regulated firms chose capital-intensive controls to a greater extent than would be expected on the basis of cost-effectiveness, nor than any observed effects can be attributed to the A-J effect. In our recent examination of what occurred in states with and without price control, we found that our cost-minimization model reasonably predicts what actually has occurred under the NBP. EPA found that the more likely reasons for more capital-intensive pollution controls in price-regulated states are that there were more large units with high NO_x rates operating at higher capacity factors and facing lower construction costs as well as other factors that Fowlie did not focus on. Notably, at the time the NBP was set up EPA gave extensive consideration to the implications of the electric restructuring underway and the IPM model that EPA used was also used by FERC when it considered ways to improve restructuring due to its suitability for the task.
- There were other things going on in the last decade that further draw into question the A-J effect having a role in compliance decisions. For instance, compliance with Phase I ARP during 1995-1999 saw little, if any, of the major Southern utility power stations (where there was price regulation), select the addition of capital intensive scrubbers (they largely switched to lower sulfur coals), whereas Ellerman in 1997 reported that about half of all Phase I compliance resulted from scrubber installation.[1]
- Even if the author's point about the A-J effect was reasonable, it appears that the problem would have been created from the failure of an initiative that was supposed to provide restructuring of the power industry throughout the US, not due to poor design of the NBP per se. In 1996–1998 when EPA developed the NBP program, the Administration's position and that of many leading economists was that restructuring was occurring nationwide and the question was whether the federal government should accelerate its pace (the Clinton Administration sent Congress several bills to do

[1] Ellerman, A Denny et al, *Emissions Trading under the U.S. Acid Rain Program – Evaluation of Compliance Costs and Allowance Market Performance*, MIT CEEPR, October 1997.

so.) Notably, the market distortion that results from only partial industry restructuring after the collapse of California's system in 2000 should have been further exacerbated by the price caps many states placed on electric generation markets that are just now starting to expire. Luckily, this price control action was very substantially counterbalanced by the large economic rents received by low-cost coal-fired units, because market prices were often set by gas-fired units at the margin that were much more expensive to operate. Past analysis has shown us that even with the addition of capital-intensive pollution controls, the rents for coal-fired generation remain large so that "competition" should not lead to inordinate pressure on companies to cut capital costs. Additionally, some states actually put NBP pollution control investment in stranded asset estimates to be recovered by utilities as restructuring was phased in as an additional hedge on potential company losses of profitability. An issue that appears to have delayed, but not necessarily stopped, some cost-effective controls was the financial problems several companies had in the Northeast due to overbuilding capacity and post-Enron concerns that arose for merchant plant operators that were tarred with the brush of questionable financing. These critical aspects of restructuring are not recognized by the author while the more ephemeral A-J effect is.

- The author's second major point is that EPA should have used exposure-based trading. In a purely theoretical sense, her point is well-taken. However, some practical reflection on how to make it work shows it's likely to be problematic. Done right, there would be different trading ratios for NO_x for all the 2,600 participants in the emissions trading system that would be constantly changing as other emitters increased and decreased their emissions of NO_x and other pollutants such as VOCs that interact with NO_x to create ozone. Additionally, NO_x reduction has even greater benefits from lowering fine particle formation that should be weighed and this action also must be considered in conjunction with SO_2 emissions, if again the aim is to maximize net benefits of a program. Furthermore, one could argue that such a system should cover all sources and not just those from the power sector, if it is to truly provide the most benefits for the cheapest cost. In that case, we would have millions of sources to consider and the system would be unworkable.
- In addition, a system like this would heavily favor protection of large urban centers over rural areas. How could we explain this inequitable level of protection to Congress and the public outside of urban centers?
- There are reduced forms of exposure-based trading that could be laid out as more practical. Those companies adversely affected by these forms of trading are likely to make their application very challenging. There would be a lot of thorny technical issues such as what weather conditions should be used to develop the trading ratios (bad vs. good vs. average ozone-related years) and time period of the year (10 ozone episode used in the Mauzerall article that the author relied on vs. summer ozone season vs. annual control). In looking at this in the past, EPA has questioned whether it could be definitely assured that there would far greater benefits from such an approach that warranted the added complexity, administrative cost, potential loss of the virtual 100 percent compliance with the existing trading approaches, and added litigation burden and risk of losing litigation that would delay program implementation (and public health protection) that would occur. Notably, EPA considered simple versions of such approaches when it designed the NBP. The Agency constructed high and low NOx reduction regions that were self-contained trading regions to provide more reductions where they were most needed. Reasonable control options cost more, but did not substantially improve air quality. EPA also considered how to lower emissions from power plants contributing most to future ozone nonattainment by using trading ratios to affect such an approach. This was a lot like the simple example that Fowlie uses in her paper, but was based on much more sophisticated and detailed air quality modeling work and economic analysis.[2] EPA designed a targeted emissions reductions (TER) approach that factored in the spatial effects of ozone formation (e.g., a ton of reduction in MD was more helpful than a ton of reduction in NC to lower ozone formation in New

[2] Analysis managed by Dr. Gary Dorris was provided in a Stratus Consulting report to EPA entitled *Development and Evaluation of a Targeted Emission Reduction Scenario for NOx Point Sources in the Eastern United States: An Application of the Regional Economic Model for Air Quality (REMAQ),* November 24, 1999. This study was the outgrowth of a Phd thesis of Dr. Dorris for the same advisor for a PhD thesis that Meredith Fowlie has for this work.

York City) in an effort to provide the same air quality improvement as the simple NBP trading approach at a lower cost. The resulting approach was two-tenths of a percent cheaper than the program that EPA put in place to address the current 8-hour ozone standard without factoring in the potentially serious increases in transaction and administrative costs. There was little to show for the added complexity that would have to be introduced through trading ratios.

Hefland, Moore and Liu

- Congress authorized "banking" of allowances to increase the flexibility and cost-effectiveness of the ARP. The focus was not on finely tuned economic efficiency through temporal trading.
- EPA has seen banking as an invaluable tool in allowing the regulated community to adjust easily to changes in the economy and electric demand, leading to the power sector initially over controlling emissions and providing very large early program benefits (see first paper), and providing a glide path in the longer term for industry movement to comply with the increasingly tighter controls under the emissions caps that we first set up for SO_2 under the ARP and more recently in CAIR.
- Given that the ARP has a very active market – lots of players and a large volume of trading for today's and future allowances – and we are finding the program to be a lot less expensive with allowances prices that were much lower than expected until quite recently – and broad acceptance -- it appears to be working. Authors need to make a clearer case of about why their "theoretical findings" should mean something to those of us running the program and how we might fix "the problem."
- Note, we have found that having several pollutants in trading programs leads our linear program model (IPM) to different results from the expected "Hotelling effect" for any one pollutant. Things get a bit more complicated, as actions taken at the margin have cobenefits in addressing SO_2, NO_x, and Hg emissions.
- I recommend that the authors talk to some of the very sophisticated consultants following the market, such as ICF Resources, PEAR, Evolution Markets, NAT Source, brokers and large company trading departments – they may have much more important street wisdom to offer for why the current and futures markets behave as they do – something a 1,000 regression analyses will never reveal.
- If you are not considering how CAIR, Clean Air Mercury Rule, and the Clean Air Visibility Rule as well as New Source Review settlements that often lead to arcane allowance surrender schemes and how companies are considering the future strong possibility of mandatory carbon controls (which will at least alter, perhaps even collapse the SO_2 market), it does not appear you will ever get a handle on why this market is behaving as it does.

****

Environmental economists have made vast contributions to environmental protection over time – we have the successful air emission trading programs and advanced quantitative benefits analysis that routinely shape our major regulations. Considering further the constructive contributions that you could make in the air pollution area, I ask that you to consider working on:

- Determining in very tangible terms (like $) the benefits of protecting the environment, protecting or restoring ecological balance. Our lack of ability in this area is leading to less consideration of environmental benefits in crafting regulations.
- Where to go next on trading, identifying other sectors where we can make it work that will provide the public benefits.

Thank you for the opportunity to discuss these papers.

Discussion

Helfand et al., “Testing for Dynamic Efficiency of the Sulfur Dioxide Market”

Fowlie, “Emissions Trading, Electricity Industry Restructuring, and Investment in Pollution Abatement”

Shadbegian et al., “A Spatial Analysis of the Consequences of the SO2 Trading Program”

Nathaniel Keohane
Yale School of Management

EPA Market Mechanisms and Incentives Conference
October 18, 2006

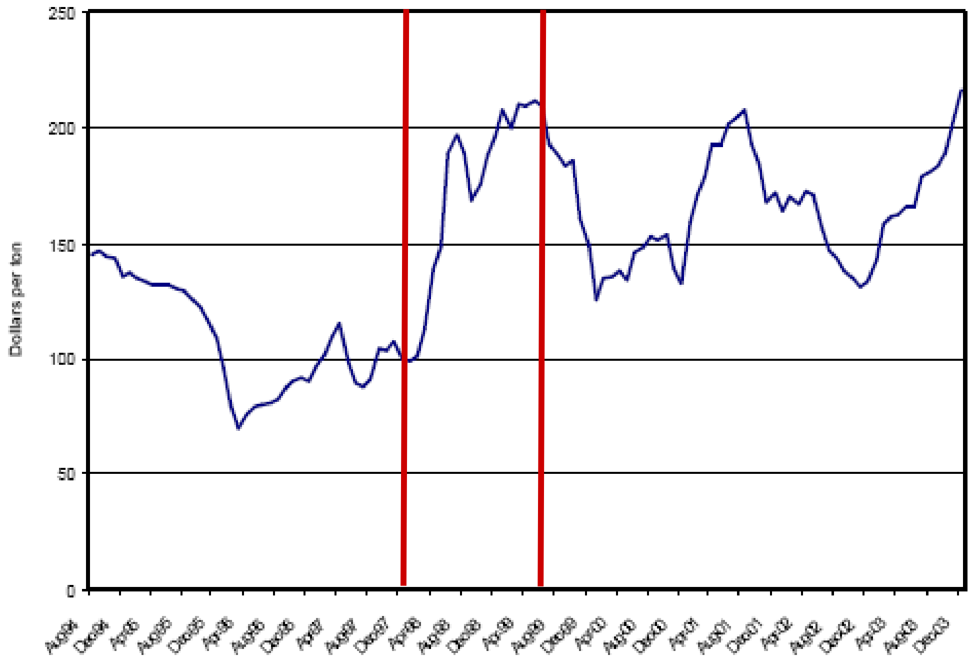
Helfand, Moore, and Liu: Overview

- Econometric analysis of SO2 allowance price movements, 1994-2003
- Two key questions:
  1. Did allowance prices follow basic Hotelling prediction?

     (No)

  2. Does information from prices in related markets (e.g., low-sulfur coal) help to explain SO2 allowance prices?

     (Yes, for wages and natural gas; no, for coal prices; still much to be explained)



Helfand, Moore, and Liu: Comments

This is an interesting (and policy-relevant) question; they bring a promising econometric method to bear; and they have a solid base of results to explore.

Three comments:

- Can more be done with the raw data?
- What do the results tell us?
- Endogeneity concerns

Helfand, Moore, and Liu: Comments

1. Can more be done with the raw data?

    - In a case like this, should be much to learn from graphical presentation of data
    - Show allowance stock (liquidity), forward market (convenience yield), etc. data in graphs
    - Summary statistics!
    - Could also show prices in other markets (natural gas, etc) alongside SO2 allowance prices

Helfand, Moore, and Liu: Comments

2. What do the results tell us?

Peculiar findings need to be explained:

- Very large and significant negative coeff on time-t price (Hotelling term)

	With Breaks	
variable	Coef.	Std. Err.
constant	3.34	(2.90)
		[2.18]***
break1	8.21	(2.82)**
		[3.25]***
break2	-12.05	(3.31)***
		[3.41]***
$r_t^f p_t$	-13.20	(4.87)***
		[4.06]***
$(r_t^m - r_t^f)p_t$	0.05	(0.15)
		[0.19]
$elecusefe_{t+1}$	-3.07e-08	(1.45e-07)
		[1.38e-07]
$lscprcfe_{t+1}$	0.08	(0.08)
		[0.06]
$hscprcfe_{t+1}$	0.01	(0.09)
		[0.07]***
$ngasprcfe_{t+1}$	0.04	(0.01)***
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$wagefe_{t+1}$	9.45	(5.84)***
		[4.30]***
R^2	0.25	

Helfand, Moore, and Liu: Comments

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- Why is wage such a strong predictor?

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Helfand, Moore, and Liu: Comments

3. Endogeneity concerns

- Econometric model:

$$p_{t+1} - p_t = \alpha + \beta_1 r_t^f p_t + \beta_2 (r_t^m - r_t^f) p_t + \varepsilon_{t+1}$$

$$\varepsilon_{t+1} = f(elecprcfe_{t+1}, lscprcfe_{t+1}, hscprcfe_{t+1}, ngasprcfe_{t+1}, wagefe_{t+1}) + v_{t+1}$$

- There seem to be clear endogeneity concerns here. Indeed, the main premise is that the forecast errors are related.
- Might be useful instead to think of a system of equations with a single error structure, and estimate accordingly.
- This appears to be one of the “robustness checks,” but seems to me to be central to identification.
- (Note: Would be nice to have more transparency in how price forecasting is done. Show results in appendix, specify eqns., etc.)

Fowlie: Overview

Two basic findings.

1. Power plants in states with restructured electricity markets were less likely to adopt capital-intensive compliance strategies in the lead-up to the NOx emissions trading program.

- Sophisticated econometric model of power plant compliance decisions is then used to simulate what would have happened under a counterfactual "exposure-based" trading system
  - NOx program effectively assumes "uniform mixing", but we know that in reality, source location matters
  - A key advantage of the policy simulation is the detailed estimation of manager-specific preferences about costs

2. Exposure-based trading would have reduced emissions in high-damage areas by 6 to 22% depending on trading ratio; implies significant effects on mortality.

Fowlie: Comments

Overall, a terrific paper: frames an interesting problem, knows the data well, applies sophisticated econometric methods with care

One major comment on paper's conclusions

Fowlie: Comments

Efficiency implications for investment decisions

- Main result motivated as violating the usual assumption that all firms in the emissions market solve the same cost minimization problem
- Fowlie estimates total costs under hypothetical cost-minimizing behavior; finds that actual costs were 43% higher
- Might be useful to sort out two related issues:
  - Underlying objective function differs across firms
  - Regulation (vs. restructuring) affects investment decisions

Fowlie: Comments

Efficiency implications for investment decisions, cont'd

Are investment decisions more or less efficient in restructured markets vs. regulated markets?

- Three reasons expect more investment in regulated markets:
  - AJ effect under conventional regulation (→ overinvestment in regulated markets)
  - option value due to irreversibility and uncertainty over cost recovery in restructured states (→ less investment)
  - greater capital constraints in restructured states (→ less investment)
- But none of these says which regime is "wrong"
- Countervailing evidence in paper:
  - Firms in regulated markets ignored capital cost in their decisions
  - On other hand, approximated discount rates appear to be more reasonable in regulated markets (16% vs. 44%)

Shadbegian, Gray, and Morgan: Overview

Compares costs and benefits of Title IV SO_2 trading program to two counterfactual scenarios:

1. Pre-existing regulation (weak state-level CAC regulations)
2. Uniform emissions standard to achieve observed emissions reduction

Use plant-level cost estimates along with fine-grained SR matrix to estimate benefits.

Main findings:

1. Overall net benefits were large, with benefits 100x larger than costs (benefits of $56 billion, costs of $560 million)
2. However, estimated net benefits of trading vs. CAC are <u>negative</u>; while costs were lower, benefits were also lower because plants with relatively high marginal damages emitted relatively more

Shadbegian, Gray, and Morgan: Comments

Tackles a crucial question, namely the net benefits of trading under the 1990 CAAA, and employs exactly the right benefits and (one hopes) cost data.

Two comments:

- Look more closely at substitution/compensation program?
- Simulation of trading under counterfactual policies

Shadbegian, Gray, and Morgan: Comments

1. Look more closely at substitution/compensation program?

   - Montero (1998) demonstrated the adverse selection problem inherent in voluntary "opt-in" programs
   - Those plants tended to be ones with low abatement costs.
   - Were they also plants with low marginal damages?
   - In other words, what were the net benefits from substitution and compensation?

Shadbegian, Gray, and Morgan: Comments

2. Simulation of trading under counterfactual trading-zone policies

- Why limit trading zones to geographically contiguous areas?

- In simulation with trading zones, market clears by scaling down allowance purchases among plants in proportion to their size
  - To the extent that abatement costs are positively correlated with marginal benefits, proportional scaling will overstate the reductions in damages achieved by trading zones
  - Seems like it would be preferable to take into account plant-level costs. (They may already have tried something like this.)

Overview

Two themes run through these papers:

1. Efficiency of real-world allowance markets

2. Emissions trading with spatial variation in marginal benefits

1. Efficiency of real-world allowance markets

Conclusions: SO2 market does not appear to have operated with full efficiency, over time or across plants.

- **HML**: Time series data on allowance prices does not support efficient markets hypothesis.
- **Fowlie**: Power plants did not make cost-effective investments under cap-and-trade program.

1. Efficiency of real-world allowance markets

Conclusions: SO_2 market does not appear to have operated with full efficiency, over time or across plants.

Would be useful to draw connections to previous literature

- Work by Burtraw and Ellerman & Montero on why allowance prices were so low in Phase I
    - One reason: “Too much scrubbing”
    - Connects to both of the papers above

1. Efficiency of real-world allowance markets

Conclusions: SO2 market does not appear to have operated with full efficiency, over time or across plants.

Would be useful to draw connections to previous literature

This is also an area where anecdotal evidence from talking with folks in industry might help shed light

- A friend at Cinergy reports that his analysts thought that SO2 allowances were way underpriced at ~$200 in early 1990s
- Are there factors that industry analysts focus on that are being missed in these analyses?

1. Efficiency of real-world allowance markets

Conclusions: SO2 market does not appear to have operated with full efficiency, over time or across plants.

Would be useful to draw connections to previous literature

This is also an area where anecdotal evidence from talking with folks in industry might help shed light

And as always, we must ask: What is the relevant counterfactual?

- "Warts and all" analysis, not textbook idealization
- Especially relevant for Fowlie's analysis, since the source of variation there is in the regulation of the electricity industry, not the form of environmental policy

2. Spatial variation in marginal benefits

Conclusions: In both the NOx and SO2 markets, spatial variation in benefits matters. Emissions-based trading reduces welfare.

- **Fowlie**: Compares simulated emissions distributions under the single NOx market vs. simple exposure-based trading.
- **SGM**: Estimate welfare consequences of a single SO2 market, compared with a command-and-control counterfactual

2. Spatial variation in marginal benefits

Conclusions: In both the NOx and SO2 markets, spatial variation in benefits matters. Emissions-based trading reduces welfare.

What is the magnitude of the effect?

At first reading, Fowlie and SGM have very different takes on effectiveness of simple trading rules

- Fowlie: Simple geographic trading rules make a big difference
- SGM: Simple geographic trading rules don't make much difference

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What is the magnitude of the effect?

At first reading, Fowlie and SGM have very different takes on effectiveness of simple trading rules

- Fowlie: Simple geographic trading rules make a big difference
- SGM: Simple geographic trading rules don't make much difference

In fact, the difference is smaller than it might appear

- Fowlie: 6-22% difference in emissions in high-damage areas
- SGM: 10-14% decrease in damages (increase in benefits)

2. Spatial variation in marginal benefits

Conclusions: In both the NOx and SO2 markets, spatial variation in benefits matters. Emissions-based trading reduces welfare.

What is the magnitude of the effect?

What are the alternatives?

- Trading ratios or transfer prices based on relative impacts
- SGM have the information needed to do this in principle
- Indeed, with the SR matrix in hand it is much harder to do the efficiency analysis than to design an efficient policy instrument
  - The latter does not require information on plant-level costs
- Here we bump up against the science
  - Atmospheric chemists complain about even the PM10 SR matrix
  - Modeling ozone precursors such as NOx appears very hard