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Abstract

The U.S. acid rain program, Title IV of the 1990 Clean Air Act Amendments, is a pioneering experience in environmental regulation by setting a market for electric utility emissions of sulfur dioxide (SO_2) and by including a voluntary compliance provision. Under the Substitution provision, non-affected electric utility units can voluntarily become subject to all compliance requirements of affected units and receive SO_2 tradeable permits (allowances). This paper studies the welfare implications of this voluntary provision and tests the adverse selection hypothesis of voluntary programs. The results indicate that although this provision has had a rather small effect on the overall performance of the SO_2 market, there has been a significant participation, mostly from units with counterfactual emissions (i.e. emissions in the absence of regulation) well below their allowance allocations, which suggests that SO_2 emissions have been higher than otherwise. An *ex post* cost-benefit analysis shows that this adverse selection effect tend to dominate the flexibility effect of permitting shifts in emissions reductions from high-cost affected units to low-cost non-affected units. On the other hand, participation with the Substitution provision confirms that electric utilities are choosing cost-effective strategies to comply with SO_2 limits and that transaction costs have been low.

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Voluntary Compliance with Market-Based Environmental Policy: Evidence from the U.S. Acid Rain Program[1]

I. Introduction

The U.S. acid rain program, Title IV of the 1990 Clean Air Act Amendments, is a pioneering experience in environmental regulation by setting a market for electric utility emissions of sulfur dioxide (SO_2) and by including a voluntary compliance provision.[2] Under the Substitution provision,[3] non-affected electric utility units can voluntarily become subject to all compliance requirements of affected units and receive SO_2 tradeable permits (allowances). By permitting non-affected sources with low control costs to voluntarily opt in, the Substitution provision increases compliance flexibility of affected units and reduces the overall costs of compliance. Due to information asymmetries however, an "opt-in" provision that is attractive to some sources is almost certain to involve the allocation of unneeded allowances (or excess allowances) to at least a few, and those few are more likely to opt in ceteris paribus. In other words, there is an adverse selection effect that may yield to higher emissions.

Since the passage of the Clean Air Act Amendments (CAAA) in November 1990, questions have been raised about the functioning of the SO_2 market and the cost-effectiveness of electric utilities' compliance strategies.[4] Less attention has been paid to the welfare implications of a phase-in design and the possibility for non-affected sources to voluntary opt in and receive SO_2 allowances. We believe that an analysis of a voluntary compliance provision represents a interesting case study of issues of instrument design that

[1] I would like to thank my thesis advisors Denny Ellerman, Paul Joskow and Richard Schmalensee for numerous comments and discussions; Elizabeth M. Bailey, Stuart Siegel, Tom Tietenberg and participants in the EC/OECD/IEA Energy Externalities workshop, MIT Energy Policy workshops, and the EAERE Annual Conference for helpful suggestions; and the EPA's Acid Rain Division Group, specially Joe Kruger and Larry Montgomery, for comments and data. Financial support from the MIT Center for Energy and Environmental Policy Research and Fondecyt-Chile Grant No. 1971291 is gratefully acknowledged. I am solely responsible for remaining errors and omissions.

[2] For the theory and practice of tradeable permits see, for example, Tietenberg (1985) and Hahn and Hester (1989).

[3] Clean Air Act Amendments of 1990 (Public Law 101-549, Sections 404 (b) & (c))

can arise in attempts to implement tradeable permit systems in practice. Particularly if we believe that phase-in or less than fully comprehensive tradeable permit systems are likely to be the rule rather than the exception in future environmental policy. A salient example is provided by current emissions trading proposals in dealing with global warming that call for early carbon dioxide (CO_2) restrictions on OECD countries with substitution possibilities, known as joint implementation provisions, with the rest of the world (see, e.g., Tietenberg and Victor, 1994).

There has been virtually no literature addressing the welfare implications of voluntary programs, in large part because few of such programs have been implemented. In a recent paper, Montero (1997*b*) shows that in designing any phase-in emissions trading program with opt-in provisions, the regulator faces the classical trade-off in the new regulatory economics between production efficiency (compliance costs minimization) and information rent extraction (reduction of unneeded allowances). Furthermore, he indicates that an opt-in design far from optimal may yield no benefits. In a slightly different context, Hartman (1988) and Malm (1996) found strong evidence of adverse selection in voluntary energy conservation programs and concluded that the net benefits of such programs are significantly lower than traditionally believed.[5] Also relevant to this paper is the literature on the effects of both economic regulation (Joskow and Rose, 1989) and environmental regulation (Gollop and Roberts, 1983, and Oates et al., 1989).

In this paper we study the welfare implications of the Substitution provision, the first voluntary program within an emission trading scheme, and test the adverse selection hypothesis based on actual data after the first year of compliance with Title IV—which is 1995. Our results indicate that although the Substitution provision has not had a significant effect on the performance of the SO_2 market, there has been a significant participation, with more than half of the affected electric utilities using this voluntary provision to reduce compliance costs. Unlike previous literature,[6] we find enough evidence

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[4] See Bohi and Burtraw (1992) and Cason (1993 and 1995).

[5] Conversely, Arora and Cason (1996) found no evidence of adverse selection (or free-riding as defined by the authors) in the EPA's 33/50 voluntary program.

[6] See GAO (1994) and Winebrake et al (1995).

that electric utilities are choosing cost-effective strategies to comply with SO_2 limits and that transaction costs associated to this provision have been relatively low.

We find strong evidence of adverse selection. Non-affected units have opted in largely because their actual counterfactual emissions (i.e. emissions in the absence of regulation) were below their historic emissions and hence, their allowance allocations. Others have opted in because they had low marginal control costs, say, below allowance prices. While the latter effect reduces aggregate costs of compliance by shifting emissions reductions from high-cost-affected units to low-cost-non-affected units (the flexibility effect), the former may lead to higher emissions (the adverse selection effect). An ex post cost-benefit analysis suggests that the adverse selection effect tend to dominate. It is important to understand that the adverse selection effect was particularly pronounced in this program by the unanticipated expansion of the market area of low-sulfur coal from Powder River Basin in northeast Wyoming (see Ellerman and Montero, 1996 and forthcoming). Therefore, the motivation in this paper is by no means to ignore the merits of voluntary provisions, but rather call attention for the careful design of programs like this.

The remainder of the paper is organized as follows. Section II provides an overview of Title IV of the CAAA and the SO_2 emissions trading program and the implementation aspects of the Substitution provision. Section III contains a simple model that explains the trade-off between flexibility and adverse selection in a phase-in emissions trading program with voluntary compliance provisions. Section IV presents the data and examines the empirical evidence on voluntary compliance. Section V estimates the effect of the Substitution provision on SO_2 emissions, emission reductions, and the SO_2 market. Section VI examines the importance of different factors in the decision to opt in and discusses possible transaction costs associated to this provision. Section VII estimates the adverse selection effect and carries out an ex post cost-benefit analysis. Concluding remarks are in Section VIII.

II. Voluntary Compliance with Title IV

The design and implementation of the Substitution provision of Title IV have been far from trivial. Large part of EPA's administrative efforts has been spent on this and closely related provisions.[7] To understand its practical implications for electric utilities' compliance strategies, we need to explain the implementation of Title IV and basic elements of the SO_2 trading program and related aspects such as the Reduced Utilization provision and the nitrogen oxides (NO_x) control requirements.

Title IV of the CAAA imposed a reduction of SO_2 emissions from electric utilities, by the use fully tradeable emission permits, called allowances. SO_2 is the primary precursor of acid rain and other acidic deposition, and the SO_2 control measures imposed by Title IV are designed specifically to effect a substantial reduction in those depositions.[8] Allowances convey the right to emit one ton of SO_2 in the year of issuance or any later year and are issued to affected electric generating units[9] based upon a series of formulas heavily dependent on historic fuel use (see Joskow and Schmalensee, forthcoming). Each allowance specifies a particular year, its "vintage", in which it is first available to be used to cover SO_2 emissions. Allowances are fully tradeable, in that allowances of any vintage can be traded to any party (e.g. another utility, broker, individual, etc.) and can be banked for future use, but can not be brought forward for use in an earlier year. At the end of each year, affected sources in the program are required to hold allowances in amounts equal to or greater than the total amount of SO_2 emitted in that year. To control for that, the CAAA requires each affected unit to have continuous emissions monitoring (CEM) equipment on each stack to measure actual SO_2 emissions and to report those emissions to EPA.[10]

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[7] Brian McLean, Director EPA's Acid Rain Program, personal communication, September, 1996.

[8] Discussion of the benefits of SO_2 reduction by Title IV can be found in EPA (1995*b*)

[9] A unit, which is defined as a "fossil-fuel-fired combustion device" in § 402 of the CAAA, corresponds to a single generator and associated boiler. A generating plant can house one or several units, which may be of different sizes, vintages, type or fuel input.

[10] A unit that fails to hold sufficient allowances to cover its emissions is subject to significant financial and legal penalties The penalty for non-compliance is $2000 for each ton of SO_2 emitted that is not covered by an emission allowance designated for that source. In addition, the subsequent year's allocation will be reduced by the tonnage subject to the penalty.

To accomplish the SO_2 emissions reduction intended by Congress, Title IV mandated an aggregate cap on SO_2 of approximately 8.9 million tons by year 2000, approximately half of the 1980 emissions, to be achieved in two phases. Phase I, that covers the period 1995-1999, affects the 263 dirtiest large generating units at 110 power plants whose emissions must be reduced to an average of 2.5 lbs. of SO_2 per million Btu (hereafter #/mmBtu) times their *baseline*, which is the average 1985-87 heat input. Units affected in Phase I were designated by Table A of the legislation; and with few exceptions, Table A included all units of 100 MW of capacity or greater with average emission rates above 2.5 #/mmBtu. Hereafter we refer to these units as *Table A* units. Phase II, which begins in 2000, applies to all fossil fuel plants and further limits emissions to roughly the lesser of 1.2 #/mmBtu or the 1985 emission rate times the baseline.

Title IV includes two provisions under which *Phase II units* – those units that are not mandatorily affected until year 2000 – can voluntarily opt-in into Phase I: the Substitution and Reduced Utilization provisions. For the purpose of this paper we will refer to *Phase I* unit as any unit that is affected in Phase I, which will include all Table A units and any Phase II unit that voluntarily opted in.

Let us first briefly explain the Reduced Utilization provision. Because electric utilities can choose how to dispatch their electricity, the incentive structure created by Phase I may encourage utilities to shift generation and emissions from Phase I to Phase II units. To account for possible shift in emissions through reduced utilization or underutilization of Phase I units,[11] Title IV originally required the submission of a reduced utilization plan for any Phase I unit that is planned to be utilized below its baseline as a method of compliance with the SO_2 emissions limitations. The plan must either (1) designate a Phase II unit, so-called *compensating* unit, to which generation would be shifted, (2) account for the reduced utilization through energy conservation or improved unit efficiency measures, or (3) designate sulfur-free generators (e.g., hydroelectric or nuclear generators). The reduced utilization plan however, is not required if either the underutilized Phase I unit (including any Phase II that opted in) *surrenders allowances* in

[11] A Phase I unit is said to be underutilized if, in any year in Phase I, the total annual utilization of fuel at the unit is less than its baseline.

proportion to the reduced utilization, there is overutilization at other Phase I units in the same dispatch system, or there is a decrease in the dispatch system sales. Thus, the surrender of allowances does not become effective if the total heat input from all Phase I units in the relevant dispatch system is equal or above the total baseline heat input of such units.

On the other hand, Congress established the Substitution provision as a voluntary compliance option to increase compliance flexibility of originally affected units and reduce their overall costs of compliance in Phase I while still achieving the *same* emissions reductions intended originally by Congress under Title IV. The Substitution provision allows the owner or operator of any of the 263 Table A units to reassign units' emissions reduction obligations to a designated non-affected unit, so-called *substitution* unit, under the owner's or operator's control. Upon approval, the substitution unit becomes subject to Phase I requirements with regard to SO_2 and NO_x. There is no restriction to designate substitution units other than having a common operator or owner with a Table A unit.[12] Likewise, there is no restriction to opt in new substitution units or withdraw existing ones in any subsequent year during Phase I.

Allowances are given to substitution units according to fairly complicated rules that were tightened after claims brought by environmental groups trying to prevent allocation of unneeded allowances or *excess allowances* as commonly defined. In an attempt to allocate allowances closer to counterfactual emissions and hence prevent excess allowances, the final rule for allowance allocation is based on the lesser of four emissions rates for the unit in question: (1) 1985 actual SO_2 emissions rate; (2) 1985 allowable SO_2 emissions rate; (3) the greater of 1989 or 1990 actual SO_2 emissions rate; or (4) the most stringent Federal or State allowable SO_2 emissions rate applicable in 1995-99 as of November 15, 1990. The substitution unit's allowance allocation is then calculated by multiplying the lower of the above rates by the baseline, which reflects 1985-87 utilization.[13]

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[12] Phase II units having no common operator or owner with a Table A unit still can opt in under the control-by-contract clause, but allowances are issued equal to 70% or less of the amount under the regular rule.

[13] We note that the original allocation rule only considered (1) and (2).

Some Phase II units may not find it profitable to opt in because they are required to comply earlier than otherwise with the NO_x limits of Title IV, which includes NO_x emission performance standards for coal-fired generating units. Electric utilities are a major contributor to NO_x emissions nationwide, and approximately 85% of electric utility NO_x comes from coal-fired power plants. Title IV specifies a two-part strategy to reduce NO_x emissions from coal-fired plants. The first stage will affect only Phase I units with Group 1 boilers and reduce annual NO_x emissions by 400,000 tons (from 1980 levels) between 1996 and 1999.[14] The second stage, which begins in year 2000, will reduce emissions by 2.0 million tons annually by: (1) maintaining the same standards for Phase I, Group 1 boilers, (2) establishing more stringent standards for Phase II, Group 1 boilers, and (3) establishing new standards for Group 2 boilers.[15]

Title IV includes some provisions that allow Phase II units with Group1 boilers to comply early with the NO_x requirements of Phase I and avoid the more costly standards of Phase II. Like all Table A units, substitutions units that opted in by January 1995 are never subject to revised NO_x emission limitations. This is commonly known as the "NOx grandfathering". Note however, that these units must incur the extra costs associated with early compliance starting in January 1996. The other substitution units that are opting in after January 1995, are not subject to revised NO_x emission limitations until the year 2008 and must start complying with Phase I NO_x limits by January 1997. This latter is the NO_x early election provision, which in fact applies more broadly allowing any Phase II unit to comply early with NO_x limits and cut some of the costs of future compliance without the need to become a substitution unit. Because the NO_x early compliance provision is always a possibility, the "NO_x benefits" of early compliance as substitution units should be thought only in terms of the NO_x grandfathering.[16]

[14] Boilers of coal-fired units can fall in either Group 1 or 2. Group 1 includes tangentially fired boilers and dry bottom wall-fired boilers other than units applying cell burner technology. Group 2 includes wet bottom wall-fired boilers, cyclone boilers, boilers applying cell burner technologies, vertically-fired boilers, arch-fired boilers and any other type of utility boiler (such as fluidized bed or stoker boiler) that is not a Group 1 boiler.

[15] There are five options for compliance with NOx: standard emission limitations, emissions averaging, alternative emission limitations, phase I extensions, and early election. There are some restrictions that apply.

[16] A substitution unit that later on decides to withdraw still remains subject to NO_x control requirements and Phase II benefits.

Other small electric utility units and industrial sources of SO_2 that are excluded from the mandatory requirements of Title IV, may elect to enter the SO_2 trading program under the Industrial Sources Opt-in Program and receives allowances approximately equal to their historic emissions (EPA, 1995*a*). Unlike the Substitution provision, it seems that the combined emissions control costs and costs in participating in the Opt-in program has exceeded the revenues from selling allowances for potential sources. Only three industrial plants have found it profitable to opt in, two of which have already obtained approval and received allowances.[17] Although it would be interesting to see whether transaction costs, uncertainty about approval and/or low allowance prices are hindering participation in the Industrial Opt-in program, in this paper we focus exclusively on the empirical evidence on voluntary compliance from the Substitution provision.

III. Flexibility and Adverse Selection in Voluntary Compliance

A. The Asymmetric Information Problem

Like any other regulatory practice, the optimal design of a phase-in emissions trading program with voluntary compliance options is subject to an asymmetric information problem in that the regulator has imperfect information on individual counterfactual emissions and control costs.[18] As explained by Montero (1997*b*), in a world with perfect information and no transaction costs, a regulator would issue allowances to opt-in sources equal to their counterfactual emissions. In practice, however, the environmental regulator cannot anticipate the level of counterfactual emissions. Yet, he(she) must establish an allowance allocation rule in advance that cannot be changed easily even if new information would suggest so. In the Substitution provision, the regulator sets the allowance allocation of opt-in sources equal to their historic emissions (based approximately on 1988 emissions) several years before compliance.

[17] These are Alcoa units in Indiana and DuPont boilers in Tennessee. In total they received 95,882 allowances (*Clean Air Compliance Review*, Nov. 4, 1996).
[18] See Laffont and Tirole (1993) for a complete treatment on regulatory economics.

The asymmetric information or adverse selection problem stands in that those sources eligible to opt in that (for economic reasons) reduced emissions before compliance in 1995 may find it profitable to do so without making any further reduction, since they would receive allowances above their counterfactual emissions. Conversely, some units increasing their emissions above their allowance allocation may not opt in, even if they have low marginal control costs, since reducing emissions just to reach the allowance allocation would be so costly. Aggregate SO_2 emissions may be higher than without the Substitution provision because of the excess allowances; nevertheless, the aggregate cost of compliance would be lower because of both low-control-cost units opting in and excess allowances covering reductions than otherwise would have been made by affected sources.

B. A Model to Illustrate the Trade-off

The implementation of a voluntary provision involves a trade-off between control cost minimization and information rent extraction, or between flexibility and adverse selection (Montero, 1997*b*). For simplicity consider a one-period model. Let q be the aggregate quantity of emissions reductions, $B(q)$ the total social benefits from emissions reduction, $C_{TA}(q)$ the aggregate control costs from affected sources, and $C_{NA}(q)$ the aggregate control costs from non-affected sources. As usual, we assume that $B'(q) > 0$, $B''(q) < 0$, $C'(q) > 0$, $C''(q) > 0$, $B'(0) > C'(0)$, and $B'(q) < C'(q)$ for q sufficiently large (these properties hold for both C_{TA} and C_{NA}).

The model is depicted in figure 1. The horizontal axis indicates the amount q by which total emissions are reduced below their counterfactual level. $B'(q)$ represents the marginal social benefit of emissions reduction as a function of the quantity of emissions q that are controlled. $C'_{TA}(q)$ represents the marginal control cost of emissions reduction from Table A units. Due to imperfect information or political constraints, we let q_{TA} be the emissions reduction target chosen by the authority to be imposed over Table A units. Aggregate control costs without the Substitution provision are given by the area under $C'_{TA}(q)$ from 0 to q_{TA}.

With the inclusion of substitution units that have low marginal control costs (below allowance prices), the new marginal control cost curve shifts downward. Let $C'_{TAS}(q)$ be the aggregate marginal control costs from Table A and substitution units. If counterfactual emissions in the year of compliance are approximately equal to historic emissions and hence to the allowance allocations for all substitution units, the reduction target remains unchanged and aggregate control costs reduce to the area under $C'_{TAS}(q)$ from 0 to q_{TA}, and savings from the voluntary program are given by $A(ABFG)$, where $A(\cdot)$ denotes area. Thus, there is no adverse selection and the flexibility effect dominates.

However, when some substitution units have reduced their counterfactual emissions levels below their historic emissions and in this case below the allowance allocation, the original reduction target q_{TA} reduces to q_{TA} - EA, where EA are the total excess allowances from opt-in sources. EA are used to cover reductions that would have occurred had the voluntary program not been implemented. The adverse selection effect is represented by this shift of the original reduction target to the left. Aggregate control costs are now given by the area under $C'_{TAS}(q)$, from 0 to q_{TA} - EA. While savings from lower cost reductions are given by $A(ABCJ)$, savings from avoided reductions are given by $A(ICFH)$. On the other hand, emissions will be larger than otherwise by an amount equal to EA. The social cost of additional emissions are given by the area under $B'(q)$ from q_{TA} - EA to q_{TA}, which is $A(IDEH)$.

The total savings or net benefits associated with the voluntary program are given by $A(ABCJ)$ - $A(CDEF)$, which can be positive or negative, depending on the slope of the $B'(q)$ and $C'(q)$ curves, how much reduction substitution possibilities between Table A and substitution units are available, and where the original reduction target q_{TA} is situated. As we move the reduction target q_{TA} to the right, marginal costs increase while marginal benefits decrease, and so does the negative effect of excess allowances. Finally, note that with the Substitution provision the equilibrium price drops from p_{TA} to p_{TAS}.

IV. Evidence on Voluntary Compliance

A. The Data

The data used to carry out the empirical analyses pertain to the period 1985-95, being 1995 the first year of compliance with the SO_2 limits of Title IV, and were obtained from different sources. Data on units design and site characteristics are in Pechan (1995), and on emissions and utilization are in Pechan (1995) and EPA's emissions tracking system (ETS). Data on SO_2 control cost and coal contracts were elaborated from Ellerman et al. (1997), the Federal Energy Regulatory Commission (FERC) Form 423, EPRI (1993 and 1995), and EPA (1991). Data on allowance allocations are in Pechan (1995) and in EPA's allowance tracking system (ATS), and on NO_x control cost are in EPA (1991). Additional data sources are explained as we progress.[19]

B. Table A and Substitution units

Participation with the Substitution provision has been quite significant. Phase I affected generating capacity has increased by 47%. Among the 42 operating electric utilities using this voluntary provision, 31 (of a total of 61) are "affected utilities" or utilities with at least one Table A unit.[20] More specific, there are 182 Phase II units that have voluntarily opted in and have become subject to Phase I requirements regarding SO_2 and NO_x. Strictly, seven of these are compensating units that voluntarily became affected under the Reduced Utilization provision. Because the designation as compensating unit is entirely optional, for analytical and practical purposes they can be treated as substitution units, and we will do so in what follows.

In a first attempt to understand voluntary participation, we compare Table A and substitution units. Statistics for selected years are in the first two columns of **table 1**. In

[19] All our data was complemented with a mail survey for Phase I affected utilities (replies covered 37% of affected generating capacity in Phase I) and many telephone interviews with personnel from EPA's Acid Rain Division and electric utilities.

both Table A and substitution units, we observe important emissions reduction between 1988 and 1993, but only in Table A units we observe substantial reductions in the period 1993-95. Since substitution units are, on average, cleaner than Table A units, it is reasonable to expect proportionally less emissions reductions at these units. The difference between allowances and SO_2 emissions in 1995 is nevertheless significant. It is tempting to argue that these 0.48 million allowances, to be used to cover emissions at other Table A units in either 1995 or any subsequent year, are reductions that would have not occurred without the Substitution provision. As we shall see, that is not necessarily the case.

C. Eligible units

Evaluating the effect of the Substitution provision on electric utilities' compliance strategies requires a cross sectional study comparing units that opted in from those that did not. We then need to identify those Phase II units that were eligible to opt in as substitution units, or what we call hereafter *eligible units*. Because the only restriction to opt in a Phase II unit is that of common owner or operator with a Table A unit, we have included in our *eligible units sample* both (1) all units that actually opted in, and (2) all those Phase II units *either* in operating utilities with at least one Table A unit or in holding companies with at least one Table A unit.[21] Phase II units with common operators and/or owners with Table A units are identified according to the utilities and holding companies listed in Pechan (1995), FERC Form 423 and in the US Electric Utility Industry Directory. Our eligible units sample reduces to 620 units.[22]

In the last column of table 1 we include the statistics of relevant variables for the remaining 438 eligible units that did not opt in. By looking at changes on their SO_2 emissions over time, we find the first piece of evidence of adverse selection. Contrary to substitution units, emissions of eligible units that did not opt in have been steadily

[20] The other 11 utilities are either with a holding company with a Table A unit (4), brought in under the control-by-contract clause (6), or have compensating units (1).
[21] In our analysis we do not include any potential substitution unit under the control-by-contract clause because we do not have a good estimate of the corresponding allowance allocation.

increasing. Furthermore, total emissions of eligible units in 1995 are higher than any previous year. It seems that units that are reducing emissions below their allowance allocation before compliance are more likely to opt in, which may ultimately lead to higher emissions. This is one of the main findings of our paper. We explore it further in the next section.

V. SO_2 Emissions and Emissions Reductions

To understand the effect on the SO_2 market and reasons for opting in we have to estimate the extent at which substitution units are reducing emissions or changing utilization as a result of being affected in Phase I. In so doing, we first have to establish what 1995 emissions would have been in the absence of the Substitution provision, or so-called *counterfactual* emissions.

A. Pre-1995 SO_2 Emissions Decline

Table 1 shows that since 1985, SO_2 emissions for both Table A and substitution have been steadily declining instead of increasing as indicated in a recent EPA's forecast (Pechan, 1995). Earlier research (Ellerman and Montero, 1996 and forthcoming) has addressed the reasons for this unanticipated decline and found that the continuing emissions decline was caused primarily by changes in the economics of coal choice, rather than Title IV, that resulted from the remarkable decline in rail rates for low sulfur coal from western coal (mostly Powder River Basin) delivered to higher sulfur coal-fired plants in the Midwest. A secondary reason for the reduction in emissions rates is that a few states have enacted state laws or amended State Implementation Plants (SIPs) under the pre-CAAA to require reductions in SO_2 by 1995 or before.

Low counterfactual emissions at some substitution units can also be explained by a decrease in utilization (heat input). According to the surrender of allowances rule, it can

[22] We eliminate 23 units that were conditional compensating units that under the new rules were not eligible to opt in as compensating units and neither as substitution units because they were originally in a

be profitable to opt in an underutilized Phase II unit if its underutilization is covered by overutilization of other Phase I units in the same dispatch system. Nevertheless, we can observe from table 1, that at the aggregate level underutilization of Phase I units does not seem to be an issue, since 1995 heat input levels are 11% and 4% above the baseline for substitution and Table A units, respectively.[23]

Based on Ellerman and Montero (1996 and forthcoming) and on the fact that only by the second half of 1993 early applications for substitution units would be approved,[24] we assume that none of the reduction observed in substitution units by 1993 can be attributed to early compliance with the Substitution provision. Thus, for the purpose of this paper we use 1993 as the base year against which we test changes in utilization and emissions rates in 1995 due to the Substitution provision. This approach implicitly assumes that all changes (if any) in emission rates and utilization between 1993 and 1995 are caused by the Substitution provision. Although some of these changes cannot be attributable to this provision, we expect them to be rather small, at least at the aggregate level, since 1993 is close enough to the compliance year. Finally, because fuel quantity (utilization) and fuel quality (emissions rate) are different decision variables to the utility operator, to establish 1995 counterfactual emissions we analyze changes in utilization and emissions rates separately rather than change in emissions – which is the product of heat input and emissions rates.

B. Testing for Changes in Utilization

We assume that electric utility operators maximize profits or minimize costs (Gollop and Roberts, 1983), so the optimal level of utilization of a electric utility unit during period t (Q_t) is given by

reduced utilization plan.

[23] In fact, only 3,426 allowances were surrendered because of underutilization according to the Reduced Utilization provision (EPA, 1996). Notwithstanding, Montero (1997*c*) found that on average, substitution units in 1993 were utilized at a lesser extent than other Phase II units.

[24] Application for substitution units was open in February 1993. EPA required at least six month before approving the application.

$$Q_t = Q(p_E, p_L, p_K, p_{NC}, p_C, p_{SP}, p_{SCR}, R, t, c, \varepsilon) \tag{1}$$

where $Q(\cdot)$ is derived by applying Hotelling's lemma to a well-behaved profit function,[25] and is a function of the price of electricity (p_E), the input prices of labor (p_L), capital (p_K), non-coal fuel (p_{NC}), coal (p_C), coal sulfur premium (p_{SP}),[26] the variable cost of running a installed scrubber prior to Title IV (p_{SCR}), the regulatory status under Title IV (R), time (t), units characteristics (c), and a vector of unobserved variables (ε).[27] Regulatory status, R, is included to capture the effects on utilization of a unit that either is a substitution unit or is in a plant with Table A units. Note that the effect of Title IV on coal market prices will be captured by changes in p_{SP} as we explain below.

Differentiating the output or utilization function with respect to time identifies the sources of changes in utilization (unit characteristics are assumed unchanged)

$$\frac{dQ}{dt} = \sum_i v_i \frac{dp_i}{dt} Q + v_R \frac{dR}{dt} Q + v_t Q \tag{2}$$

where

$$v_i \equiv \frac{\partial Q}{\partial p_i}\frac{1}{Q}, v_R \equiv \frac{\partial Q}{\partial R}\frac{1}{Q}, v_t \equiv \frac{\partial Q}{\partial t}\frac{1}{Q}.$$

The first term of the right hand side in (2) represents the effect of changes in input prices. The second term measures changes in operating costs when the units is affected by Title IV as either a substitution unit or because is in a power plant with Table A units. Since relative changes of input prices and operating costs are difficult to compute due to either the presence of long-term contracts, downward trends affecting all prices, or lack of good cost estimates, in this paper we capture changes in relative prices using dummy variables, as we shall see below. The third term measures both changes in aggregate demand and

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[25] $Q(\cdot)$ would be the derivative with respect to p_E.

[26] We decomposed the price of coal between the corresponding to btu content (p_C) and sulfur content (p_{SC}).

[27] R and T are unitary costs for being affected

relative productivity. One would think that existing units are likely to be utilized less than new units ceteris paribus. Finally, v_i, v_R and v_t represent the change in Q per unit of output for a change in the dependent variable.[28]

Estimating the effect of regulatory status, v_R, on utilization requires an econometric model of (2). Assuming that p_E, p_L and p_K remain unchanged in relative terms, our basic specification for the *j*th unit can be written as (subindex *j* has been omitted)

$$\begin{aligned} \mathrm{HT95} = {} & \mathrm{b}_0 + \mathrm{b}_1\mathrm{HT93} + \mathrm{b}_2\mathrm{COAL}\cdot\mathrm{HT93} + \mathrm{b}_3\mathrm{SCRUB}\cdot\mathrm{HT93} + \mathrm{b}_4\mathrm{SUB}\cdot\mathrm{HT93} \\ & + \mathrm{b}_5\mathrm{TAPLT}\cdot\mathrm{HT93} + \mathrm{b}_6\mathrm{HIGHRTE}\cdot\mathrm{HT93} + \mathrm{b}_7\mathrm{RETIRE}\cdot\mathrm{HT93} + \mathrm{e} \end{aligned} \tag{3}$$

where HT95 and HT93 are heat input in 1995 and 93 respectively, COAL is a dummy variable equal to 1 if it is a coal-fired unit, SCRUB is a dummy variable equal to 1 if the unit has a scrubber installed previous to Title IV,[29] TAPLT is a dummy variable equal to 1 if the originally non-affected unit is in a power plant with Table A units, HIGHRTE is a dummy variable equal 1 if its emission rate in 1993 was equal or above 1.2 #/mmBtu,[30] RETIRE is a dummy variable equal to 1 if the unit is said to be retired before 1995 according to Pechan (1995), and e is the error term assumed normally distributed with mean zero.

Our model in (3) is related to (2) as follows. Coefficient of HT93 measures changes in electricity demand and relative productivity ($b_1 = 1 + v_t$). If between 1993 and 1995 there were no discernible change in unit-specific variables other than a uniform increase in electricity demand across units, all coefficients would be zero except b_1 that would be a bit higher than the unity. We include COAL to capture changes in relative fuel prices between coal-fired units and non-coal fired units (mainly gas and oil fired) ($b_2 = v_C - v_{NC}$). Since coal prices has been decreasing relative to other fuel prices we expect b_2 to be positive. SCRUB is included to see whether operating costs of units with scrubbers have

[28] Think of them as elasticities when prices are normalized to the unity.
[29] These are NSPS scrubbers.
[30] We use 1.2 because units burning coal of 1.2 #/mmBtu did not face sulfur premium.

become relatively lower or higher as a result, for example, of changes in limestone or lime prices ($b_3 = v_{SCR}$). We do not have any prior expectation for b_3.

The effect of regulatory status with Title IV is captured by SUB and TAPLT ($b_4 + b_5 = v_R$). Any relative change in operating cost from becoming a voluntarily affected unit would be reflected in a coefficient b_4 significantly different from zero. Note that in establishing our counterfactual, we assume that any change captured by SUB is the result of becoming a substitution unit. Similarly, if operating costs of a TAPLT unit become relatively lower compared to operating costs of Table A units in the same plant, we should have a positive value for b_5.

Title IV has also effects on the coal market by changing the sulfur premium (p_{SP}) paid by different coal-fired units ($b_6 = v_{SP}$). Before Title IV and because of State regulations, only units burning 1.2 #/mmBtu or lower coal faced $p_{SP} > 0$. Today, with the implementation of Title IV and a nation-wide allowance market, prices for higher sulfur coals also include a sulfur premium.[31] Therefore, units burning higher than 1.2 #/mmBtu sulfur coal have become relatively more expensive to operate than units burning lower sulfur coals. In other words, we expect b_6 to be negative. Finally, we expect the coefficient of RETIRE (b_7) to be negative and close to the unity.

We work with two samples. The "full sample" includes all Phase II and substitution units, while the "eligible sample" includes only eligible units. Ordinary least square (OLS) estimates are in **table 2** for both the full and eligible sample. Since heteroscedasticity does appear to be a problem, based on White and Goldfeld-Quandt tests, we include heteroscedastic-consistent estimates for the standard errors.

Results in the first column of table 3 (Model 1) indicate that, on average, utilization in non-coal fired units has reduced by 11% ($1 - b_1$) between 1993 and 1995. As expected, b_2 is significantly different from zero and positive, which confirms that coal-fired units have increased utilization relative to other unit as a result of lower coal prices. Coefficient b_3 is also significantly different from zero but negative, which suggests an average decrease in utilization of scrubbed units of about 7%.

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[31] In a perfect integrated allowance and coal markets, the price difference between two identical coals but for the sulfur content should be equal to the allowance prices.

Although we found no evidence of changes in utilization due to the Substitution provision (i.e. we could not reject H_0: $b_4 = 0$), our results indicate that Title IV has had a significant effect on units located in Table A plants (b_5) and through the coal market (b_6). To explore the latter result further, we divide HIGHRTE between HIGH12 and HIGH25. These are dummy variables equal 1 for units with emissions rates between 1.2 and 2.5 #/mmBtu and higher than 2.5 #/mmBtu, respectively. Results are in the second column are under Model 2. As expected the stronger effect is observed in units with emissions rate right above 1.2 #/mmBtu. Finally, the effect of RETIRE is as expected.

These results are consistent to different model and sample specifications. Results for the eligible sample are included in the next two columns of table 3 (Models 3 and 4). They entirely follow our previous discussion but for the coefficient of TAPLT (b_5) which now is not significantly different from zero. In Model 5, we extend Model 1 and allow all dummy variables to enter additively. With the exception of RETIRE, results are almost identical to those under Model 1.[32] In summary, we can conclude from our results that although Title IV did affect utilization of Phase II units in 1995, the Substitution provision did not affect utilization of substitution units in that year.

C. Testing for Changes in SO_2 Emission Rates

Let us now test for the reduction in emission rates in 1995 due to the Substitution provision. To capture changes in coal economics and regulatory status that can affect the electric utility operator's coal quality choice (i.e., emissions rates), we follow Ellerman and Montero (1996 and forthcoming) and use a simple linear specification that relates unit-specific emission rates in 1995 to emission rates in 1993 and to unit characteristics. Our equation for the *j*th unit is (we omit sub-index *j*)

$$\begin{aligned} \mathrm{RTE95} = {} & b_0 + b_1\mathrm{RTE93} + b_2\mathrm{SUB}\cdot\mathrm{RTE93} + b_3\mathrm{DPRB}\cdot\mathrm{RTE93} \\ & + b_4\mathrm{DPRB}^2\cdot\mathrm{RTE93} + b_5\mathrm{DPRB}^3\cdot\mathrm{RTE93} + b_6\mathrm{SCRUB}\cdot\mathrm{RTE93} \qquad (4) \\ & + b_7\mathrm{TAPLT}\cdot\mathrm{RTE93} + b_8\mathrm{STATELIM}\cdot\mathrm{RTE93} + b_9\mathrm{RETIRE}\cdot\mathrm{RTE93} + e \end{aligned}$$

where RTE95 and RTE93 are the SO_2 emission rates in 1995 and 1993 respectively, DPRB is distance between the unit and Powder River Basin in northeast Wyoming, STATELIM is a dummy variable equal to one if the unit is subject to SO_2 limits imposed by state laws or regulations other than Title IV, and e is again the error term assumed normally distributed with mean zero.

Our specification allows us also to test for proportional changes associated with designation as a substitution unit. If there were no discernible change in unit-specific emission rates between 1993 and 1995, all coefficients would be zero except for b_1, which would take the value of unity. To test for changes in emission rates due to the Substitution provision we include SUB. We expect then b_2 to be negative. DPRB, $DPRB^2$ and $DPRB^3$ are included to capture changes in emission rates due to lower western coal prices. We expect the three coefficients (b_3, b_4, and b_5) to be jointly significant and negative, positive and negative respectively, which would yield the U-shaped profile obtained by Ellerman and Montero (forthcoming). While we do not have expectations regarding SCRUB, we think that the coefficient of TAPLT should be positive due to intra plant shifts of higher sulfur coal from Table A to non-affected units.[33] Finally, we expect the coefficients of STATELIM (b_7) and RETIRE (b_8) to be negative.

OLS estimates for the full and eligible sample are in table 4. Heteroscedasticity appears to be a problem again, so we include heteroscedastic-consistent estimates for the standard errors. Results for Model 1 are fully consistent with our expectations. We find strong evidence that substitution units are reducing emissions as a result of lower emission rates and that PRB coal continues moving East. While Model 2 still shows that substitution units are reducing emissions after opting in, PRB penetration is less evident, although with the right sign. Probably due to a sample selection bias. In Model 3, we

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[32] An alternative specification model was also used: $\log(HT95)=b_0 + b_1\log(HT93) + b_2COAL + b_3SUB + \ldots + b_7RETIRE + e$. Although not shown here for space limitations, results were practically the same.
[33] Note that a plant for which TAPLT = 1 cannot have any eligible unit.

extend Model 1 and allow all dummy variables to enter additively. With the exception of SCRUB and RETIRE, results are almost identical to those under Model 1.[34]

One might argue that these latter result suffer from an endogeneity problem in that units reducing emissions between 1993 and 1995 for reasons other than Title IV not captured by our model are more likely to be opting in. This is the same as to suggesting a downward emissions trend affecting only a group of units. Since there is no reason to believe that the downward emissions trend takes place only after 1993, we should observe a similar trend sometimes before that. Our same specification (4) allows us to test for changes in emission rates relative to the rate used to calculate individual allowance allocation for substitution units, what is approximately the 1988 rate.

To test for changes in emissions rates between 1993 and 1988 we regress RTE93 on RTE88. If there were no discernible change in unit-specific emission rates between 1993 and 1988 for substitution units, the coefficients of SUB would be not significantly different from zero. Results for the same two samples are the last two columns of in table 4 (Models 4 and 5). We do not find evidence supporting the argument for a downward trend affecting only some units in either sample. Therefore, we conclude that some substitution units are opting in because they have low control costs and hence they are making reductions that would have not taken place otherwise.

D. Counterfactual Emissions and Emissions Reductions

In calculating our counterfactual, we use actual 1995 heat input levels as the heat input level that would have prevailed in the absence of the Substitution provision, and predict the emission rate in 1995 from specification (4) for SUB = 0. Using the coefficient results of the first column of table 4, for a 95 percent confidence level we have that 1995 emissions reductions from substitution units can be anywhere between 74 and 378 thousand tons of SO_2, with an expected value of 226. Consequently, counterfactual aggregate emissions can be expected to be about 1079. Excess allowances, the difference

[34] An alternative specification model was also used: $\log(RTE95)=b_0 + b_1\log(RTE93) + b_2SUB + b_3DPRB + \ldots + b_8RETIRE + e$. Although not shown here for space limitations, results were the same.

between 1995 allowances and counterfactual emissions, are expected to be about 250 thousand allowances.[35] Because of excess allowances, SO_2 emissions in 1995 and in the future will be higher than otherwise. This is the adverse selection effect. In section 6 we come back to this issue about whether the costs associated to adverse selection effect outweigh the benefits of the flexibility provided by voluntary compliance.

E. Effect on the SO_2 Market

From our model in figure 1, we can observe that if an opt-in provision has no effect on allowances prices it does not have effect at all in the market. In our case, both emissions reductions and excess allowances whether they were anticipated or not can have an downward effect on prices. After the first year of compliance, however, the effect of the Substitution provision on the SO_2 market appear rather modest. First, emissions reductions from substitution units represent less than 6 percent of the total 3.9 million tons reduction observed in 1995 (Ellerman et al, 1997). Second, in the likely event that excess allowances were not anticipated, they represent a small fraction of the almost 1.7 million ton of unanticipated reduction from Table A units by 1993 (Ellerman and Montero, forthcoming). Furthermore, excess allowances represent about 7 percent of the total of 3.4 million allowances banked at the end of 1995 (Ellerman et al., 1997). This preliminary analysis suggests that the Substitution provision can explain only a small fraction of the lower than expected allowance prices.

VI. The Decision to Opt in

We have identified three reasons for opting in, namely excess allowances, low control costs, and the NO_x grandfathering. In this section we use discrete choice econometric models to (1) disentangle the relative importance of these three factors in the decision to opt in, and (2) to see whether these and other "economic" variables can

[35] Similar numbers were obtain using coefficients from the eligible sample: 1101, 247, and 228 thousand tons/allowances for the counterfactual emissions, emissions reductions, and excess allowances

successfully explain electric utilities behavior regarding the Substitution provision. The latter is simply an attempt to estimate transaction costs associated to this provision.[36]

A. Model Specification

The dependent variable we model, SUB, is the utility operator's decision to voluntarily opt in an eligible unit. We do not observe the net benefits of opting it in, only whether the decision is made or not. Therefore, our observation is

$$\begin{aligned} &SUB = 1 \qquad \text{if } SUB^* > 0 \\ &SUB = 0 \qquad \text{if } SUB^* \leq 0 \end{aligned}$$

where SUB^* is an index function that can be written as

$$SUB^* = a_0 + \sum a_k x_k + u \tag{6}$$

where x_k are the k unit's characteristics that affect the decision to opt in and u is the error term that we assume has a standard logistic distribution with mean zero. Our model will predict an eligible unit as substitution unit if the index function $a_0 + \sum a_k x_k$ is greater than zero or if $\Lambda(SUB^*) > 0.5$, where $\Lambda(\cdot)$ is the logistic cumulative distribution function.

The k variables in the index function are chosen to capture the benefits and costs of opting in an eligible Phase II unit into Phase I. Let us start with the benefits. First, to capture the benefits of having counterfactual emissions below historic levels and hence below the allowance allocation, we create EXALLOW that is the difference between allowance allocation and counterfactual emissions normalized by unit's size (capacity). Counterfactual emissions, which are the predicted emissions in the absence of the

respectively.

[36] For a description of transaction costs in emissions trading programs see Stavins (1995) and Montero (1997).

Substitution provision, are obtained from the analysis in Section V.[37] The allowance allocation for each unit is obtained in two forms. For actual substitution units we use the 1995 allowance allocation. For eligible units that did not opt in, we calculate the allowances based on the allocation rule described earlier.

However, according to the special provisions for monitoring emissions from common emissions stacks, a Phase II unit with a common stack with a Phase I unit (including substitution units) has to be designated as a substitution unit, unless an additional continuous monitoring system were to be installed. In fact, all 12 Phase II units with common stacks with Table A units were opted in as substitution units. On the other hand, we observe some cases in which not all eligible units under the same "common stack" were opted in. To cope with this issue, we include an additional variable, COMSTACK, that for units with single stacks takes the value of zero. For eligible units with common stacks we define COMSTACK as the difference between the aggregate of EXALLOW at the common stack level and divided by the number of units under that common stack and normalized by unit's size. For instance, a unit for which EXALLOW is negative can be still opted in if COMSTACK is sufficiently positive such that the costs of additional monitoring are higher than the allowance costs associated with the negative EXALLOW. Needless to say, we expect the coefficient in COMSTACK to be positive.

Second, to capture the benefits of having low SO_2 control costs can be more complicated since we do not have good costs estimate for oil- and gas-fired units. We follow two approaches. As a first approximation we use RTE93 and DPRB simultaneously. We would expect the higher the emission rate the lower the compliance costs since both the probability of finding nearby suppliers of lower sulfur coals is higher and control technology options are larger.[38] Thus, the coefficient of RTE93 is expected to be positive. We also believe that the closer to Powder River Basin (or any other Western coals) the lower the cost of compliance (Ellerman and Montero, forthcoming). Note that by including RTE93 and DPRB simultaneously, we control for those nearby units that

[37] Here we use estimates from Model 1 of table 3.
[38] Since gas is more expensive than coal, this rough approximation would also work for units with combined cycle turbines.

already switched to western coal and have consequently low emission rates. It would be too costly for them to continue reducing emissions.

In a second approach, we include a (marginal) cost variable of coal switching and cleaning, MGCOST, for a subset of coal-fired units based on EPA's (1991) average control cost estimates.[39] For either approach, we also include a variable that controls for coal contract constraints at the plant level. Based on data from the FERC Form 423, we create CONTRACT, which is equal to the ratio between the amount of coal delivered under contract and the total amount delivered in 1995, or in 1993 if it is lower.[40] We expect its coefficient to be negative. Finally, we include SCRUB as a proxy for control costs in what we believe units with new source performance standards (NSPS) scrubbers can have lower variable cost of further control.

Third, to capture the benefits and costs associated to the NO_x grandfathering we must first account for the fact that only coal-fired units with Group 1 boilers are affected by NO_x requirements in Phase I. In addition, we must keep in mind that eligible units can always make use of the NO_x early compliance provision without opting in as substitution units. Therefore, the "NO_x net benefits" of early compliance as substitution units should be thought only in terms of the NO_x grandfathering.[41] To capture the NO_x costs of early compliance with Phase I limits we include NOXPH1 that is the difference between the 1993 NO_x emission rate (NOXRTE93) and the Phase I required rate (PH1RATE) multiplied by a Group 1 dummy variable (GROUP1). Note that if PH1RATE > NOXRTE93 we make NOXPH1 = 0. For the benefits we include GROUP1 as a first approximation. For the units in which we have control costs data from EPA (1991) we include marginal cost of compliance with NO_x requirements in Phase II for Group 1 boilers (MCNOXG1). In addition, in order to test whether the NO_x grandfathering becomes important only if marginal costs are very high, we create a dummy variable, MCNOXHG, that is equal to 1 if marginal control costs are above the average

[39] For fuel switching, average and marginal costs are very close if not the same.
[40] Thus we control for both: contract expirations in 1995 and new contracts signed in 1995.
[41] The importance of the NO_x grandfathering is reflected by the fact that among the 124 substitution units with Group 1 boilers, 104 are subject to the NO_x grandfathering. The other 20 units filed application to opt in after January 1995.

MCNOXG1of 711 \$/ton of NO_x. We expect the coefficients related to GROUP1, MCNOXG1 and MCNOXHG to be all positive. [42]

There are some other costs associated with bringing a Phase II unit into Phase I. First, there will be a constraint in generation beyond the baseline. If emissions rates are unchanged from the "allowance allocation rate", additional allowances would be required to cover the extra emissions. Thus, we would expect that ceteris paribus a plant with a large number of Table A units should be less likely to include new units in Phase I. We include in our specification GNCNPLT that stands for generation constraint at the plant level. It is calculated as the ratio between total "Table A affected" capacity at the plant and the total capacity at the plant. We expect the coefficient of GNCNPLT to be negative.[43] Second, some electric utility staff have commented that uncertainty about the actual utilization level can be an important factor in the decision to opt in a Phase II unit. If the level of utilization by the end of the year turns out to be larger than the projected utilization at the time the unit was opted in, the operator must acquire additional allowances to cover for the extra emissions. If the operator however, decides to withdraw the unit from the Substitution program, he (she) must incur the apparently non-negligible administrative costs of excluding the allowance costs from the rate base during that year. Therefore we expect that the larger the uncertainty about future utilization the less likely the unit would be opted in. Since uncertainty has been found higher in peak units, which are relatively small compare to base load units (Montero, 1997*a*), we use the inverse of installed capacity as a proxy for uncertainty level (UNCERT). Its coefficient is expected to be negative.

Finally, we expect that transaction costs or additional costs of using the Substitution provision not captured by our explanatory variables should be reflected in the constant term, a_0. We expect this term to be negative. Conversely, a positive constant term would suggest additional benefits not captured by our variables.

[42] Although not correlated, in some cases a high NOXPH1 may also mean a high MCNOXHG, so NOXPH1 would not be picking up the cost of earlier compliance with Phase 1.

B. Econometric Results

Because we do not have complete data for all observations, we work with two samples. The first sample includes all eligible units (eligible sample). The second sample reduces to 316 coal-fired units, for which we have EPA's (1991) data on SO_2 control costs and on NO_x control costs for all Group1 boilers of the sample (reduced sample). Summary statistics are in **table 4**.

The maximum likelihood (ML) logit estimates for the two samples are in **table 5**. The effect of each independent variable on the probability of observing a unit opting in is presented in the form of odds ratios in the column next to the logit estimates. An odds ratio greater than one indicates that the odds of a unit being opted in increase when the independent variable increases.[44] Results show that almost all relevant coefficients are significantly different from zero and with the expected signs. Furthermore, they are quite consistent to alternative samples and model specifications.

Coefficients for EXALLOW and COMSTACK are positive and significantly different from zero at the 99% level, and odds ratios are greater than the unity in all cases. In the second column of Model 1 for example, the odds ratio indicate that for a unit that experiences an increase of 1 in EXALLOW, the odds of that unit being opted in increase by 5.1%. Alternatively, if the odds of the event of opting that unit is 1 (i.e. probability of opting in equal to 50%), an increase in EXALLOW of one standard deviation (34.8) increases the probability of opting in to 85 percent.

Coefficients controlling for SO_2 marginal control cost (RTE93, DPRB, MGCOST, SCRUB and CONTRACT) are less consistent but still significant in most cases. In Model 1, all coefficients have the expected signs and very significant but CONTRACT, which is only significantly different from zero at the 90% level. In Model 2 however, coefficients were either not significant and sometimes with the wrong sing. In fact, MGCOST turned out be a poor proxy for actual marginal costs, mainly because coal markets are in

[43] One can argue that if a plant is 100% "Table A affected" no unit can be brought in, and *gencnplt* would be obviously very significant and negative. In our sample however, there are no such cases simply because those plants do not have eligible units.
[44] The relation is: odds of the event occurring = probability event occurs / (1 - probability event occurs)

continuous change, which can make earlier estimates unreliable. In Models 3 and 4 we retained RTE93 and DPRB obtaining better results. Although not significant, CONTRACT and DPRB have the right sign.

The benefits of the NO_x grandfathering are found very significant and particularly well explained by either MCNOXG1 or MCNOXHG, as shown in Models 2, 3 and 4. For instance, if we analyze the increase in the odds of a unit with a Group1 boiler that happens to have a high NO_x marginal cost, we find the probability of opting-in increases from, say, 50% to 84%. This result is largely consistent with observations of actual substitution units with very negative EXALLOW but subject to the NO_x grandfathering. Because, in order to benefit from the NO_x grandfathering it is only required one year of compliance with Phase I, say, 1995, all these units are very likely to withdraw in 1996. On the other hand, the costs of early compliance with NO_x seem to be either relatively unimportant compared to the NO_x grandfathering benefits or not well captured by NOXPH1. Only in Model 1 its coefficient is with the expected sign, although not significant.

Results concerning generation constraints (GENCNPLT) and uncertainty about utilization (UNCERT) are almost always significant and with the right sign for the different specifications and samples. Finally, based on results for the intercept we find transaction costs or additional costs of using the Substitution provision not captured by our explanatory variables to be, on average, not significant. We only obtain a constant term significantly different from zero in Model 2, which seems to have specification problems since control costs are not capture at all.

The goodness of fit of our logit model can be evaluated as how many units are successfully predicted. The predicted value for SUB takes the value of 1 (i.e. predicted as a substitution unit) if $P(SUB^* > 0) = \Lambda(SUBHAT) > 0.5$ and zero otherwise. As shown in table 5, the correctly classified rate varies around 80% for the different models. In looking at the misspredicted observations, we find that most of the substitution units wrongly predicted as non-substitution units are due to the NOx grandfathering not totally captured by our variables. On the other hand, among the eligible units wrongly predicted as substitution units, we find some evidence of transaction costs affecting a few units not taking advantage of their apparently cost savings opportunities.

In spite of the misspredictions, based on the above results we can conclude that the behavior of electric utilities regarding the Substitution provision can be well explained using "economic" variables and hence transaction costs appear to be relatively low. An important implication from this observation may be that there is no reason to believe that transaction costs associated to the overall SO_2 emissions trading program can be that large. This is entirely consistent with the large trading activity reported by Joskow et al. (1996).

C. Competing Reasons for Opting in

In order to estimate the importance of the different factors affecting the decision to opt-in, we first test null hypothesis for (i) excess allowances, (ii) low control costs, and (iii) NOx grandfathering, separately. The χ^2 statistics, included at the end of **table 5**, indicate that the three hypotheses are rejected at the 99% significance level in most cases but (iii) for Model 1 and (ii) for Model 2. The fact that χ^2 statistics are much higher for (i) does not permit us to conclude that having excess allowances is the most important factor in explaining the large participation observed.

Following Arora and Cason (1996), we develop a more intuitive approach to interpret parameter estimates. Based on Model 4, Table 7 shows the relative importance of the different factors on the probability of opting in an eligible unit. Each row changes one or more explanatory variable(s) by one standard deviation and indicates the increase in the opting probability. The first row indicates shows that when all variables are at their sample mean values, Model 4 predicts a probability of opting-in of 32 percent, which is between the participation rate in the reduced sample (114/316 = 0.36) and the overall participation rate (182/620 = 0.29). The second row indicates that if all other unit's characteristics remain at their sample mean values but excess allowance EXALLOW increases to one standard deviation above its sample mean, the predicted opting-in probability increases from 32 to 84 percent. Among the single variables, COMSTACK has the largest impact, increasing the opting-in probability to 87 percent, as shown in row 3.

Rows 4, 8 and 9 indicate that having counterfactual emissions below the allowance allocation appears to be the most influential factor in explaining the large participation with the Substitution provision.[45] Control costs considerations, on the other hand, also appear quite important. This is entirely consistent with the emission reductions estimates of Section V. Finally, while the NOx grandfathering may seem less important on average, it is worth indicating that for some units it was the single most important factor in the decision to opt-in.

VII. An Ex-post Cost-Benefit Analysis

Our analysis here is restricted exclusively to the implementation of the Substitution provision. We take all the other provisions of Title IV as given. In addition, we do not include any administrative costs borne by EPA as part of implementing and running this provision, although we know they are not negligible.

A. Conceptual Issues

To calculate the *ex-post* net benefits we use the model develop in Section III, which we need to correct for banking.[46] When banking allowances is introduced, the cost-benefit calculation complicates somehow. While all control costs from substitution units accrue today, part of benefits from shifts in reductions and benefits and social costs from excess allowances accrue in the future. This future can be any time between 1995 and the time the bank of allowances runs out.

From an intertemporal arbitrage condition in a perfectly functioning market, we know that in the absence of the Substitution provision, the net present value of the cost of reducing one additional ton of SO_2 in the future and before the bank runs out would be equal to the allowance price that would have been observed in 1995 had the Substitution

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[45] The same conclusion is obtained from other three Models.

[46] Think of figure 1 as the first year of compliance, where q_{TA} would have been the observed reduction from Table A units in the absence of the Substitution provision.

provision not been implemented (equivalent to p_{TA} in figure 1).[47] With the Substitution provision, we have that both emissions reductions and excess allowances from substitution units imply an equivalent amount of less reduction to be made, sometimes now and before the bank runs out, by the group of originally affected units.[48] Furthermore, the new equilibrium price would be lower (equivalent to p_{TAS} in figure 1). The benefits of the avoided more costly reductions would be equal to product of excess allowance and reduction from substitution units times an average price, $\overline{p}$, that lies between p_{TAS} and p_{TA}. Because if $\overline{p} > p_{TA}$, it would be optimal for Table A units to reduce a bit more. On the other hand, if $\overline{p} < p_{TAS}$, it would be optimal for substitution units to reduce a bit less.

The costs of producing excess allowances and reductions from substitution units, which are zero and positive respectively, are also borne today. The social costs associated to additional SO_2 emissions from excess allowances are borne at the time those excess allowances are used to "replace" SO_2 reductions that would have taken place otherwise. This occur gradually between now and before the bank runs out.

B. Numerical Results

In doing the cost-benefit calculation, we proceed as follows. First, the use the results of Section V to account for the 1995 reduction and excess allowances, which are expected to be 226 thousand tons and 250 thousand allowances respectively. Second, based on Ellerman et al. (1997), and EPRI (1993 and 1995), we use an average marginal control cost of substitution units of 55 dollars per SO_2 ton removed (hereafter \$/ton). The control cost savings associated to the 1995 reduction by substitution units can be calculated as the difference between the avoided costs and the marginal costs of substitution units times the SO_2 reduction. Provided that average avoided marginal cost $\overline{p}$ will be somewhere between p_{TA} and p_{STA} in figure 1, and that the Substitution provision is relatively small part of the SO_2 market, $\overline{p}$ cannot be much higher than the 1995 average

[47] Because of banking and stricter Phase II limits, allowance prices should increase at some discount rate that discounted to the present are equal to actual prices. When bank runs out this is not longer true.

allowance price of \$129.[49] If we take the latter number, the savings are equal to 16.7 ($74 \cdot 0.226$) million dollars. In terms of figure 1, this would be area *A*(*ABCJ*).

Third, we calculate the benefits and social costs of excess allowances separately. Benefits, the result of avoided control costs, will be approximately equal to present value of allowances price times the number of excess allowances, which is 32.3 ($129 \cdot 0.250$) million dollars. In figure 1, this would be area A(*ICFH*). On the other hand, social costs which will take place when electric utilities decide to use the excess allowances to cover emissions reductions, will be approximately equal to present value of the marginal benefits of SO_2 reduction times the excess allowances. Estimates of (annual) marginal benefits of SO_2 reductions are clearly above actual allowance prices and vary from 314 to 2326 \$/ton.[50] One might also argue that the marginal benefit of an extra SO_2 ton removed should not be too different from the expected allowance price at the time the reduction target was decided (about \$300). In figure 4, this cost would be *A*(*IDEH*).

Finally, we can perform several net benefits calculations under different assumptions. For example, if we assume that allowances will be used in year 2000, for a marginal benefit of \$300 and discount rate of 8%, the latter figures would indicate that the *ex-post* net benefits of the substitution program are negative, about 2 million dollars ($16.7 + 32.3 - 300 \cdot 0.250 \cdot 1.08^{-5}$).[51] If EPA marginal benefit figure is used, the negative net benefits can account for several hundred million dollars, regardless when the excess allowances are used. Although we think that EPA SO_2 marginal benefits figures are relatively high, we do not have good reasons to believe that marginal benefits are much lower than expected allowance prices at the time the CAAA was signed into law.

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[48] Besides Table A units, it can possibly include some Phase II units, which become affected after year 2000.

[49] From Clean Air Compliance Review (several issues). One can reasonably argue that avoided costs may be even higher than $\bar{p}$, because the observed price of allowances at the time of investment compliance commitments was higher than \$129.

[50] Values are in 1994 dollars. The 314 figure Cifuentes and Lave's (1993) low estimate and the 2326 figure is EPA's (1995). These estimates only consider human health benefits from SO_2 reduction. Because they are based on linear damage response functions, the marginal benefits curve tend to be flat in the relevant ranges.

[51] Note that the numbers are highly sensitive to the counterfactual and the coefficient of SUB in equation (4). In fact, a 95% confidence interval for net benefits goes from -25 to 21 million dollars.

From a methodological point of view is worth explaining that an *ex post* analysis may not say much about whether implementing the program is efficient from *ex ante* perspective (i.e. positive expected net benefits). Setting apart legislative and administrative cost of running the program, failing to anticipated PRB coal intrusion in Midwestern coal markets accounts for large part of the unexpected negative net benefits.

VIII. Conclusions and Policy Implications

We have studied the Substitution provision of the SO_2 emissions trading program not only because it constitutes the first voluntary compliance program within a emissions trading scheme but also because we believe that an analysis of a program such as this represents a interesting case study of issues of instrument design that can arise in attempts to implement future tradeable permit schemes. We carried out empirical analyses based on actual data after the first year of compliance with Title IV – which is 1995 – in order to assess the practical and welfare implications of the this provision.

Our first result indicates that the Substitution provision has had a rather small effect on the overall performance of the SO_2 emissions trading program and on SO_2 emissions reductions. Nevertheless there has been a significant participation, with more than half of the "affected" electric utilities using this voluntary compliance option to reduce compliance costs. This observation provides further evidence to the notion that, in general, electric utilities are choosing cost-effective strategies to comply with SO_2 limits. Consistent with that is our finding that transaction costs associated to Substitution provision have been relatively low.

In another result, we show that non-affected units have opted in, largely because their actual counterfactual emissions (i.e. emissions in the absence of regulation) are below their historic emissions and hence their allowance allocation. Other units have opted in because they have low marginal control costs, say, below allowance prices. While the latter effect reduce today's aggregate cost of compliance by shifting reduction from high cost affected units to low cost units (the flexibility effect), the first effect increases today's emissions and emissions in the future (the adverse selection effect). An *ex post* cost-benefit analysis suggests that the adverse selection effect dominates, in part because low allowance prices.

It is important to understand that the adverse selection effect was particularly pronounced in this program by the unanticipated expansion of the market area of low-sulfur coal from PRB. Therefore, the motivation in this paper has been by no means to ignore the merits of voluntary provisions, but rather call attention for the careful design of programs like this. We finish saying that it is hard to predict the evolution of this provision and the effect of excess allowances overtime. Provided that the allocation rule remains the same, there are several factors to consider. As utilization goes up, excess allowances should decrease. However, as units become retired and more PRB coal continues to move East, excess allowances should increase. We leave this analysis for future research.

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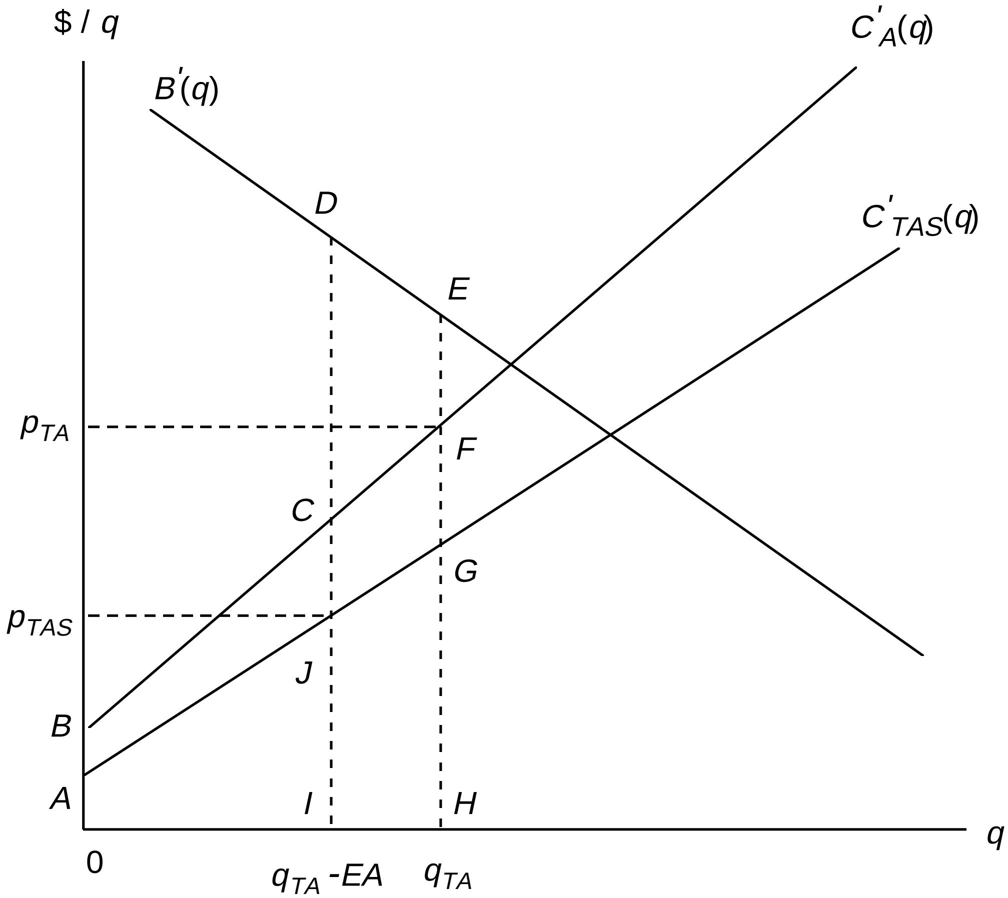

Figure 1. Net benefits from voluntary compliance

TABLE 1

Statistics of Table A, Substitution and Eligible Units for Selected Years

Variables	Table A Units	Substitution Units[a]	Other Eligible Units[b]
No. of Units	263	182	438
Total Capacity (MW)	88,007	41,643	97,812
No. of Coal-Fired Units	257	154	299
Units with NSPS Scrubbers (before 1990)	1	25	31
Units with Title IV Scrubbers	26	0	0
Baseline8587 (10^{12} Btu)	4,363	1,740	3,223
Heat Input 90 (10^{12} Btu)	4,391	1,847	3,574
Heat Input 93 (10^{12} Btu)	4,395	1,718	3,890
Heat Input 95 (10^{12} Btu)	4,551	1,931	4,579
SO_2 Emissions 1985 (10^3 ton)	9,302	1,377	2,104
SO_2 Emissions 1990 (10^3 ton)	8,683	1,272	2,386
SO_2 Emissions 1993 (10^3 ton)	7,579	973	2,505
SO_2 Emissions 1995 (10^3 ton)	4,445	853	2,884
Average SO_2 Rate 1985 (#/mmBtu)	4.24	2.32	1.29
Average SO_2 Rate 1990 (#/mmBtu)	3.76	1.99	1.15
Average SO_2 Rate 1993 (#/mmBtu)	3.30	1.68	1.10
Average SO_2 Rate 1995 (#/mmBtu)	2.10	1.21	1.06
1995 Allowances (10^3)[c]	7,215	1,329	-

a. It includes 7 compensating units.

b. These are eligible units that did not opt in.

c. It does not include auction allowances.

TABLE 2
OLS Estimates for Heat Input (HT95) Equation

Variables	Model(1)	Model(2)	Model(3)	Model(4)	Model(5)
HT93	0.887	0.887	0.790	0.790	0.878
	(25.662)	(25.650)	(4.704)	(4.702)	(24.479)
COAL·HT93	0.211	0.212	0.458	0.458	0.227
	(5.257)	(5.280)	(2.777)	(2.776)	(4.927)
SCRUB·HT93	-0.065	-0.070	-0.182	-0.182	-0.100
	(-2.046)	(-2.238)	(-3.971)	(-3.955)	(-2.141)
SUB·HT93	0.053	0.060	0.005	0.004	0.055
	(1.226)	(1.375)	(0.105)	(0.089)	(1.145)
TAPLT·HT93	0.149	0.151	0.092	0.092	0.140
	(3.546)	(3.582)	(2.021)	(2.001)	(3.351)
HIGHRTE·HT93	-0.124		-0.204		-0.129
	(-3.170)		(-4.449)		(-2.6389)
HIGH12·HT93		-0.149		-0.203	
		(-3.532)		(-3.676)	
HIGH25·HT93		-0.023		-0.208	
		(-0.420)		(-3.997)	
RETIRE·HT93	-1.027	-1.031	-1.768	-1.766	-0.906
	(-21.100)	(-20.556)	(-7.184)	(-6.971)	(-19.856)
COAL					-0.340
					(-1.066)
SCRUB					1.202
					(1.349)
SUB					-0.066
					(-0.191)
TAPLT					0.196
					(0.651)
HIGHRTE					0.126
					(0.344)
RETIRE					-0.534
					(-5.125)
Intercept	0.472	0.479	0.387	0.385	0.587
	(5.447)	(5.554)	(2.836)	(2.675)	(5.483)
R^2	0.90	0.90	0.94	0.94	0.90
No. observations	1852	1852	620	620	1852

t-statistics, shown in parenthesis, were calculated using heteroscedastic-consistent estimates for the standard errors.

TABLE 3
OLS Estimates for Emissions Rate Equation

	Model(1) RTE95	Model(2) RTE95	Model(3) RTE95	Model(4) RTE93	Model(5) RTE93
RTE93(88)	1.490	0.177	1.615	1.065	-0.328
	(6.173)	(0.243)	(4.773)	(5.262)	(-0.517)
SUB·RTE93(88)	-0.213	-0.233	-0.261	-0.014	-0.001
	(-2.943)	(-3.650)	(-2.207)	(-0.346)	(-0.026)
DRRB·RTE93(88) (10^3)	-2.132	2.403	-2.451	-1.804	1.536
	(-2.709)	(1.154)	(-2.316)	(-2.406)	(0.875)
$DRRB^2$·RTE93(88) (10^6)	2.230	-2.370	2.540	2.280	-0.478
	(2.869)	(-1.233)	(2.490)	(2.900)	(-0.300)
$DRRB^3$·RTE93(88) (10^9)	-0.709	0.748	-0.805	-0.776	-0.022
	(-2.954)	(1.311)	(-2.616)	(-3.128)	(-0.047)
SCRUB·RTE93(88)	-0.499	-0.071	-0.698	-0.379	-0.230
	(-6.776)	(-1.247)	(-10.719)	(-2.631)	(-2.665)
TAPLT·RTE93(88)	0.030	-0.008	0.062	-0.011	0.032
	(0.485)	(-0.113)	(0.685)	(-0.234)	(0.663)
STATELIM·RTE93(88)	-0.052	-0.163	-0.135	-0.082	-0.086
	(-0.555)	(-1.709)	(-0.913)	(-1.040)	(-0.980)
RETIRE·RTE93(88)	-0.665	-0.826	-0.581	-0.616	-0.561
	(-6.390)	(-15.167)	(-4.709)	(-5.325)	(-3.982)
SUB			0.099		
			(0.751)		
DPRB (10^3)			0.498		
			(0.943)		
$DPRB^2$ (10^6)			-0.376		
			(-0.664)		
$DPRB^3$ (10^9)			0.101		
			(0.552)		
SCRUB			0.378		
			(8.514)		
TAPLT			-0.086		
			(-1.038)		
STATELIM			0.148		
			(1.142)		
RETIRE			-0.074		
			(-3.437)		
Intercept	0.076	0.050	-0.171	0.187	0.281
	(5.721)	(1.389)	(-1.116)	(8.290)	(7.325)
R^2	0.75	0.78	0.76	0.61	0.69
No. observations	1852	620	1852	1852	620

t-statistics, shown in parenthesis, were calculated using heteroscedastic-consistent estimates for the standard errors.

TABLE 4
Summary Statistics for Eligible and Reduced Samples

	Eligible Sample(620)				Reduced Sample(316)			
Variable	Mean	Std. Dev.	Min	Max	Mean	Std. Dev.	Min	Max
SUB	0.294	0.456	0	1	0.361	0.481	0	1
EXALLOW	0.075	34.797	-355	235	0.450	34.794	-111	235
COMSTACK	0.072	13.145	-54	165	-0.271	17.884	-54	165
RTE93	1.268	1.188	0.0	5.7	1.701	1.260	0.0	5.7
DPRB (10^3)	1.170	0.316	0.0	1.7	1.146	0.259	0.5	1.7
MGCOST					883	707	188	5000
SCRUB	0.090	0.287	0	1	0.111	0.314	0	1
CONTRACT	0.438	0.371	0	1	0.558	0.330	0	1
GROUP1	0.565	0.496	0	1	0.661	0.474	0	1
MCNOXG1					711	2012	0	25581
MCNOXHG					0.244	0.430	0	1
NOXPH1	0.150	0.175	0.0	1.1	0.172	0.157	0.0	0.8
GENCNPLT	0.103	0.224	0	1	0.123	0.234	0	1
UNCERT	13.101	13.832	1	100	9.254	9.414	1	67

TABLE 5

ML Logit Estimates for Participation with the Substitution Provision Equation

	Model(1)		Model(2)		Model(3)		Model(4)	
Variable	Coef	Odds	Coef.	Odds	Coef.	Odds	Coef.	Odds
EXALLOW	0.050	1.051	0.053	1.055	0.066	1.068	0.069	1.071
	(7.185)		(5.151)		(5.983)		(6.090)	
COMSTACK	0.128	1.136	0.147	1.158	0.157	1.170	0.150	1.162
	(3.830)		(3.223)		(3.458)		(3.313)	
RTE93	0.730	2.075			1.170	3.223	1.246	3.477
	(5.621)				(5.128)		(5.205)	
DPRB (10^3)	-1.374	0.253			-0.749	0.473	-0.605	0.546
	(-3.693)				(-1.214)		(-0.927)	
MGCOST (10^3)			0.265	1.304				
			(1.264)					
SCRUB	1.044	2.840	0.618	1.856	1.694	5.440	1.547	4.695
	(2.975)		(1.424)		(3.259)		(2.850)	
CONTRACT	-0.579	0.560	0.521	1.683	-0.335	0.716	-0.429	0.651
	(-1.728)		(1.053)		(-0.616)		(-0.771)	
GROUP1	0.408	1.504						
	(1.150)							
MCNOXG1 (10^3)			0.287	1.333	0.262	1.300		
			(2.536)		(2.314)			
MCNOXHG							1.657	5.241
							(3.992)	
NOXPH1	-1.445	0.236	2.008	7.452	1.461	4.312	0.331	1.392
	(-1.472)		(1.977)		(1.352)		(0.282)	
GENCNPLT	-0.867	0.420	-1.673	0.188	-3.647	0.026	-4.104	0.017
	(-1.448)		(-2.181)		(-3.389)		(-3.647)	
UNCERT	-0.068	0.934	-0.046	0.955	-0.099	0.906	-0.093	0.911
	(-4.662)		(-1.828)		(-3.025)		(-3.007)	
Constant	0.643		-1.218		-0.904		-1.184	
	(1.167)		(-2.533)		(-0.992)		(-1.240)	
Log-Likelihood	-264.1		-139.2		-122.7		-118.5	
Percent Correctly Classified (percent)	81.3		79.8		81.7		81.3	
Test statistics for								
H_0: (i)	75.81		43.75		50.04		49.79	
H_0: (ii)	40.01		4.48		28.10		28.13	
H_0: (iii)	2.20		13.27		8.31		18.85	
No. Observations	620		316		316		316	

Notes: Asymptotic normal test statistics in parenthesis. The three null hypothesis are: (i) H_0: $a_{EXALLOW}$ = $a_{COMSTACK}$ = 0, (ii) H_0: a_{RTE93} = a_{DPRB} (or a_{MGCOST} instead of both) = $a_{CONTRACT}$ = a_{SCRUB} = 0; and (iii) H_0: a_{GROUP1} (or either $a_{MCNOXG1}$ or $a_{MCNOXHG}$) = a_{NOXPH1} = 0.

TABLE 6

Estimated Impacts on Opting-in Probability for Statistically Significant Coefficients

Row	Example Eligible Unit (in reduced sample) with:	Estimated Participation Probability (percent)	Increase (percent)
1	All characteristics at sample means	32.2	-
2	Sample means + 1 st.dev. higher EXALLOW	83.9	161
3	Sample means + 1 st.dev. higher COMSTACK	87.4	171
4	Sample means + 1 st.dev. higher EXALLOW and COMSTACK	98.7	207
5	Sample means + 1 st.dev. higher RTE93	69.6	116
6	Sample means + 1 st.dev. higher SCRUB	43.6	35
7	Sample means + 1 st.dev. higher RTE93 and SCRUB	78.8	145
8	Sample means + 1 st.dev. higher MCNOXHG	49.2	53
9	Sample means + 1 st.dev. lower UNCERT	53.4	66
10	Sample means + 1 st.dev. lower GENCNPLT	55.4	72