Scrubbing vs. Fuel Switching: a Dynamic Approach for U.S. Electricity Market

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October, 2015

Abstract

The Acid Rain Program (ARP) was implemented in 1995. Since then, coal-fired boilers have had to choose among three main compliance alternatives: purchase pollution permits; switch to an alternative lower-sulfur coal; or adopt a scrubber. This decision problem is driven by the evolution of several economic variables and is revised when significant changes (to prices, quality of inputs, output level, technology, transport costs, regulations, among others) occur. Using a structural dynamic discrete choice model, we recover cost parameters and use them to evaluate two different counterfactual policies. The results confirm there is a trade-off between fuel switching and scrubbing costs (with the latter having a higher investment cost and a lower variable cost), and also the existence of regional heterogeneity. Finally, the ARP implied cost savings of approximately \$4.7 billions if compared to a uniform emission rate standard and \$14.8 billions if compared to compulsory scrubbing for the 1995-2005 period.

JEL classifications: L94, D92, Q52

Keywords: scrubbers, fuel switching, coal-fired boilers, sulfur dioxide emissions, dynamic discrete choice

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†I would like to thank Jean Francois Houde, Alan Sorensen, Hector Nuñez, Michael Margolis, Alfonso Miranda, Hernán Bejarano, and seminar participants at University of Wisonsin-Madison and at Centro de Investigacion y Docencia Economicas. All remaining errors are my own.

1 Introduction

According to several studies the main causes of air quality deterioration are the air pollutants generated from burning fossil fuels in industrial and commercial facilities, and in electric power plants. The set of pollutants include: sulfur dioxides (SO_2), nitrogen oxides (NO_x), carbon oxides (CO and CO_2), particulate matters (PM), and toxics like mercury and radio-active materials.[1] In particular, SO_2 is a precursor of the Acid Rain, a well-known threat that affects human health, waters, forests and crops, in both dry and wet depositions.

Title IV of the Clean Air Act Amendments of 1990 (commonly referred to as Acid Rain Program, ARP) created a two-phase scheme for SO_2 emissions reduction and marked a moving-away from command-and-control air quality regulations toward a market-based scheme. Under the ARP, fossil-fuel power plants were assigned allowances (i.e. pollution permits) on an annual basis and were free to select a cost-effective method to keep annual emissions under control. Besides fuel substitution and installation of pollution abatement technologies, a utility may shift allowances among its various electricity generating units (EGUs) or trade them with other utilities. Therefore, the cap-and-trade scheme introduced by the the ARP allows an EGU with relatively high marginal abatement cost to complement its own emissions reduction with the purchasing of allowances from EGUs with lower marginal costs.[2] Overall, a significant global reduction in SO_2 emissions has been reported for most states since the implementation of the program in 1995.[3]

Every period, an EGU has to make two important decisions. First, it has to choose how to comply with the environmental regulation. Clearly, that decision has dynamic implications and

[1] See for example Goldstein and Izeman (1990).

[2] According to Joskow et al. (1998) the ARP is effective since it rests on a well organized mechanism that measures and records pollution emissions (the Allowance Tracking System maintained by the EPA) and because it imposes severe penalties on power utilities when their emissions exceed the number of allowances redeemed. In a recent work, Dardati (2012) evaluates the pros and cons of cap-and-trade systems comparing the ARP implemented in U.S. with the European EU-ETS system.

[3] See for example Butler et al. (2001).

affects the long-run outcomes. It is revised whenever significant changes in the industry occur. For instance, major changes to total number of allowances allocated to firms, new coalmines located nearby, the construction of railroads that facilitate coal transportation, are all episodes that likely impact on delivered coal costs and allowance prices. Those things will ultimately affect the decision to adopt a pollution abatement technology or to switch to a different fuel.

Second, an EGU has to decide the electricity quantity to be generated. That is a short-run decision. Depending on the context, and specifically on whether the EGU operates in a deregulated or regulated market, the EGU may enjoy different degrees of freedom in terms of output choices. In this paper, we will only focus on the first decision problem mentioned before and assume that output level is randomly and exogenously assigned to each EGU every period.[4]

The ARP has largely been studied and several previous works have studied the incentives created by the ARP looking at its pros and cons.[5] To the best of our knowledge, this is the first study to estimate a structural dynamic discrete choice model that contemplates the most relevant compliance strategies: i) burn high-sulfur coal and buy additional permits to cover excess emissions, ii) retrofit the boiler in order to burn low-sulfur coal, or iii) adopt a scrubber.[6] Some of the previous literature closely related to this study includes Carlson et al. (2000) which estimates the marginal abatement cost functions of power plants and evaluate the performance of the SO_2 allowance market; Ellerman et al. (1997) which calculates the average compliance costs for coal switching and scrubbing in 1995; Swinton (2002) which computes the shadow price of emissions reduction for plants located in Florida; Keohane (2002) and Keohane (2006) which propose and estimate a model of scrubber adoption and fuel switching costs. Other pa-

[4]This assumption is not completely arbitrary. The quantity to be produced will be drawn from the distribution of output observed for each EGU in the corresponding sample period.

[5]See the review by (Schmalensee and Stavins, 2013) or the study by Ellerman et al. (2000) for an evaluation of the first three years of ARP implementation in terms of emission reduction, compliance cost evolution, and the allowance market performance.

[6]A scrubber is a capital-intensive pollution abatement technology capable of reducing SO_2 emissions up to 98%.

pers study the technology diffusion mechanism associated to scrubber adoption. For instance, Frey (2013) estimates a duration model to compare the effects of different regulation schemes in the power generation industry. Although her estimation procedure is able to identify different variables that stimulated (or discouraged) scrubber adoption, it is not helpful to compute the relative costs of different environmental compliance alternatives or to answer hypothetical questions or counterfactuals. Bellas (1998) analyzes the cost of scrubbing at coal-fired power plants trying to find evidence of technological change over time. The author studies boilers regulated under the New Source Performance Standards (NSPS) of the 1970 and 1977 Clean Air Acts Amendments, failing to find any effects of scrubber vintage on costs. All this papers are either non-dynamic or reduced form regressions in which policy implications are not invariant to exogenously determined parameters.

A troublesome assumption in static models is that agents' choices are revised only when new regulations are passed (or implemented) without taking into account the different market conditions that arise with higher frequency and not necessary at the time regulations are enacted. Changing market conditions are sometimes quite unpredictable and volatile in nature and clearly affect agents' expectations. An advantage of a dynamic model over a static model is that the former incorporates expectations in a more precise and realistic manner. In the context of the ARP, scrubbing and fuel switching are indisputably dynamic choices. The contribution of this study is twofold. First, we construct and estimate a structural model that provides us with the relative compliance cost parameters associated to each strategy mentioned previously. Second, we use those estimates to evaluate the cost savings achieved by the ARP when compared to the following counterfactual command-and-control policies: i) a uniform emission rate standard of 1.2 pounds of SO_2 per million Btu; b) forced adoption of scrubber systems. These two policies resembles, to some extent, the schemes imposed by the Clean Air Act Amendments of 1970 and 1977, respectively. The methodology used in this paper builds on the line traced by Rust (1987), Hotz and Miller (1993), Arcidiacono and R. (2010), Ericson and Pakes (1995), Aguirregabiria and Mira (2002), among other papers in the dynamic discrete choice literature.[7]

The rest of the paper is organized as follows. Section 2 briefly describes the ARP and the context where coal-fired boilers operated. Section 3 presents a formal model where boilers have to decide among the three compliance strategies described before. Section 4 describes the data to be used in the structural estimation while Section 5 presents the empirical approach and the corresponding estimation results. Section 6 evaluates the cost savings associated to the ARP if compared to the conterfactual command-and-control policies mentioned before. Finally, Section 7 concludes and provides some relevant policy implications.

2 The Acid Rain Program

2.1 A brief description

The ARP established a nationwide cap-and-trade system for SO_2 emissions in the electricity generation market. Since 1995, affected EGU were endowed with allowances on an annual basis. New boilers installed after January 1, 1996 received zero permits.

An allowance authorizes a boiler to emit one ton of SO_2. At the end of each year, the boiler must hold an amount of allowances at least equal to its annual emissions. Allowances are fully marketable commodities that can be banked (saved) to cover future emissions. However, they cannot be used in advance -i.e emissions produced during the year t cannot be covered with future permits issued and entitled in $t+r$ for $r \geq 1$.

The ARP was implemented in two phases. Starting in 1995, Phase I initially affected 263 large and dirty EGUs operating in 21 eastern and mid-western states. Additionally, it included 182 EGUs as substitution or compensating units, bringing the total number of affected boilers

[7] For a complete survey of the different dynamic discrete choice estimation approaches see Aguirregabiria and Mira (2010).

to 445. During phase I, each EGU received allowances sufficient to achieve an emission rate equal to 2.5 lbs of SO_2 per million Btu according to the unit's average heat input registered during the 1985-1987 period. Phase II started in 2000 and virtually included all units with a nameplate capacity of 25 MW or higher. Allowances were allocated according to a more stringent emission rate of 1.2 lbs of SO_2 per mmBtu of heat input using the same baseline period, i.e. 1985-1987.

2.2 Compliance alternatives

There are different compliance alternatives. Each coal-fired boiler can choose among the following options:

i. Switch to a lower-sulfur coal. This option implies some investment to convert or retrofit the boiler.

ii. Reallocate allowances among the EGUs that belong to the same utility.

iii. Trade allowances in private markets or buy them in public auctions.[8]

iv. Adopt a flue gas desulfurization system (scrubber). This option entails an initial investment and also operating and maintenance costs.

v. Sign an agreement with the EPA for a contingent plan while receiving extra allowances. (Most of the times this strategy implies some commitment from the firm to realize future investments in abatement technologies)

The market for allowances has been very competitive and transaction costs negligible. Therefore, the distinction between alternatives ii) and iii) is irrelevant from the perspective of the decision maker. Either buying an additional allowance or transferring it to a boiler that belongs

[8] Allowances obtained through public auctions represent a small fraction of the total number of allowances available each year.

to the same utility represents a similar opportunity cost. The implications of alternative v) are hard to evaluate since different states have instrumented different programs to encouraged scrubber adoption or to stimulate consumption of coal varieties locally produced -with a clear goal of preserving employment and economic activity. Fortunately, a very reduced group of boilers signed this type of agreements with the EPA and therefore this compliance alternative can be ignored without causing major biases in our estimations. As a result, we will only consider three possible choices in our model (i, iii, and iv).[9]

By installing a scrubber system, the boiler decreases pollution variable costs at the expense of an initial investment. According to the reports of specialists, the average lifetime of a scrubber is between 20 to 25 years. In our sample, however, many scrubbers constructed in the early sixties were still functioning in 2005 -i.e. last year in our sample. Based on this empirical evidence, our model of section 3 assumes that a scrubber has an infinite lifespan. Additionally, our measure of variable costs will incorporate part of the depreciation cost and part of the operating and maintenance cost (i.e. feed materials and chemicals, labor and supervision, waste disposal cost, maintenance, etc). Scrubbing costs may vary across EGUs due to the size of the boiler, the quantity and quality of coal consumed, the geographical location of the power plant, and the age (or vintage) of the EGU.

By switching to a different coal variety, one of the main components of the associated cost is the low-sulfur premium (which depends on changing market conditions). Additionally, capital cost of fuel switching vary across boilers and the reason is that coal varieties extracted from different regions differ in features other than sulfur content: btu content, ash content, moisture content, grindability, among others. The larger the difference between the ideal design characteristics of the boiler and the characteristics of the low-sulfur coal, the higher the capital cost needed to retrofit the boiler.

[9]Although relatively important during the first few years of the program, allowance banking will not be considered in our empirical model.

3 The model

The decision unit is a coal-fired electricity generating unit (henceforth referred to as *boiler*). For simplicity, assume that there are two coal types available in each geographical region and three possible compliance alternatives for each boiler: burn high-sulfur coal; burn low-sulfur coal; and adopt a scrubber.[10] At the beginning of period t, a boiler chooses among these three options depending on the previous period decision. Hence, for a boiler that used high-sulfur coal during period $t-1$ (and was originally designed to burn high-sulfur coal) all three alternatives are available. Switching to low-sulfur coal or adopting a scrubber require some initial investment in order to retrofit the boiler. The compliance alternatives at time t for a boiler that used low-sulfur coal in $t-1$ are only two: either keep burning low-sulfur coal or adopt a scrubber.[11] Finally, we assume that a boiler which already adopted a scrubber in $t-1$ has no further choices to make at t and will continue to operate the scrubber forever. The latter assumption transforms the decision problem into an optimal stopping problem in which two of the choices are non-reversible (low-sulfur coal and scrubber adoption) and one of them ends the decision problem (scrubber adoption).[12]

We consider different boiler types. Each type is the result of combining three things: 1) generator's nameplate capacity, 2) boiler's fuel efficiency, and 3) boiler's geographical location. In our sample, capacity ranges from 25 to 1300 MW, efficiency is approximated by the average heat rate which goes from 8000 to 16000 btu per KWh, and coal-fired boilers are located in one of the five regions that will be defined later in this study. For simplicity, we assume that the quantity of electricity to be generated in each period is exogenously given and follows

[10] Exit decision is not contemplated in this paper. Empirically, less than 1% of coal-fired generating units exited during the period of analysis.

[11] In our sample, none of the boilers switched from low- to high-sulfur coal. Accordingly, we do not include it as an option.

[12] Models with similar characteristics are also used in other fields of the literature, for instance models that address the job search process (see for example Mortensen and Pissarides (1994)). In a recent paper Murphy (2010) studies housing supply in a dynamic environment using a non-reversible optimal stopping model similar in spirit to the one developed in our study.

some specific random process. Coal characteristics for the same coal type (low- or high-sulfur) are assumed to be common within an electricity producing region but may vary considerably between regions. However, even boilers located in the same geographical region burning the same coal variety may face distinct delivered coal costs. One possible reason is that transportation costs represent a significant portion of the cost and power plants are located at different distances from coal mines. Another possible reason is that contracts between coal mines and power plants are signed at different dates and for different terms (with the option of purchasing at the spot market as well). Therefore, market conditions may differ considerably.

The flow profits for a boiler j in period t are:

$$\begin{aligned} U^1_{jt} &= P^e_{jt}Q_{jt} - P^h_{jt}X_{jt} - P^a_t\left(E^h_{jt} - \hat{E}_{jt}\right) \\ U^2_{jt} &= P^e_{jt}Q_{jt} - P^l_{jt}X_{jt} - P^a_t\left(E^l_{jt} - \hat{E}_{jt}\right) \\ U^3_{jt} &= P^e_{jt}Q_{jt} - P^h_{jt}X_{jt} - P^a_t\left(E^h_{jt}\left[1-\phi\right] - \hat{E}_{jt}\right) - m\left(E_{jt}\right) \end{aligned} \tag{1}$$

where U^1, U^2, and U^3 are the flow profits associated to each of the three compliance alternatives: burn high-sulfur coal, burn low-sulfur coal, or use a scrubber, respectively. Electricity price is P^e, coal prices are P^h and P^l with subscripts h for "high-sulfur" and l for "low-sulfur". P^a is the annual average allowance price. Q is the quantity of electricity generated in MWh, and X represents the annual quantity of heat consumed measured in mmbtu. E is the annual emission of pollution measured in short tons of SO_2 while $\hat{E}$ is the quantity of grandfathered allowances annually allocated. The coefficient ϕ is the emission reduction percentage achieved by scrubbed units (e.g. 95%), and the function $m(E)$ represents the scrubber operating and maintenance cost (O&M).

At time t, the dynamic problem for a boiler j that used high-sulfur coal and had no scrubber installed in $t-1$ can be represented by the Bellman equation in expression (2). We assume that the problem can be characterized as a first order markovian decision process. Profit functions and transition probabilities are stationary -i.e. they do not depend on the time period the action is taken. As a result, we can omit subscripts and use the superscript $'$ to represent next period value of observed and unobserved state variables.[13]

$$\begin{aligned}V_1(s,\varepsilon) = \max_{d\in\{1,2,3\}} \Big\{ & U_1(s) - \varepsilon_1 + \beta \int V_1(s',\varepsilon'_1) f(s'|s) g(\varepsilon'_1) ds' d\varepsilon'_1; \\ & U_2(s) - \varepsilon_2 - q(K) + \beta \int V_2(s',\varepsilon'_2) f(s'|s) g(\varepsilon'_2) ds' d\varepsilon'_2; \\ & U_3(s) - \varepsilon_3 - n(K) + \beta \int V_3(s',\varepsilon'_3) f(s'|s) g(\varepsilon'_3) ds' d\varepsilon'_3 \Big\}\end{aligned} \tag{2}$$

Observed state variables are represented by the vector $s_{jt} = \{P^h_{jt}, P^l_{jt}, P^a_t, CF_{jt}\}$, where CF is the boiler's capacity factor. The evolution of CF is important since it determines both Q and X.[14] The possible choices are $d \in \{1,2,3\}$, where 1 =“Burn high-sulfur coal”, 2 =“Burn low-sulfur coal” which has an associated retrofitting cost given by $q(K)$, and 3 =“Use a scrubber” which initially implies an investment cost $n(K)$. Similarly, at year t the decision problem for a boiler that consumed low-sulfur coal and did not used a scrubber during $t-1$ is given by

$$\begin{aligned}V_2(s,\varepsilon) = \max_{d\in\{2,3\}} \Big\{ & U_2(s) - \varepsilon_2 + \beta \int V_2(s',\varepsilon'_2) f(s'|s) g(\varepsilon'_2) ds' d\varepsilon'_2; \\ & U_3(s) - \varepsilon_3 - n(K) + \beta \int V_3(s',\varepsilon'_3) f(s'|s) g(\varepsilon'_3) ds' d\varepsilon'_3 \Big\}\end{aligned} \tag{3}$$

Lastly, the value function for a boiler that already adopted a scrubber in $t-1$ is

$$V_3(s,\varepsilon) = U_3(s) - \varepsilon_3 + \beta \int V_3(s',\varepsilon'_3) f(s'|s) g(\varepsilon'_3) ds' d\varepsilon'_3 \tag{4}$$

where there is no choice to make. The cost shocks, ε, depend on the choice variable d and are supposed to be $i.i.d$. Assuming conditional independence it is possible to factor the conditional

[13] To simplify notation $V_1(s_{jt}, \varepsilon_{jt}) = V(s_{jt}, d_{jt-1} = 1, \varepsilon_{jt})$ and similarly for $d_{jt-1} = 2$ and $d_{jt-1} = 3$.

[14] More precisely, $Q_{jt} = 8760 \cdot (K_j \cdot CF_{jt})$ and $X_{jt} = 8.76 \cdot (K_j \cdot CF_{jt} \cdot HR_j)$, where HR is the heat rate defined above.

density function as $f(s', \varepsilon' | s, \varepsilon_t, d) = q(\varepsilon' | s') f(s' | s, d)$. We assume that boilers are price takers and that capacity factor is exogenously given. Additionally, we assume that the evolution of prices and capacity factor are independent of the alternative selected by the boiler. As a result, the transition probabilities that govern the dynamic process can be simplified and represented by the following conditional density function $f(s' | s)$.

4 Data

The sample period is 1995-2005. We use data from different sources. The Form 423 of the Federal Energy Regulatory Commission (FERC) provides monthly delivered coal data at the power plant level. It includes monthly delivered costs and quantities, type of transaction (i.e. spot or contract), coal characteristics, mine location and mine characteristics. The Energy Information Administration (EIA) supplies disaggregated annual data at the boiler level. Concretely, Form EIA F-767 provides data on plant operations and equipment design for boilers, generators, cooling systems, flue gas desulfurization units, flue gas particulate collectors, and stacks. It also provides financial information of power plants and electric utilities. The U.S. Environmental Protection Agency (EPA) provides data on allowances assigned to each facility in both phases of the program. We also retrieve annual allowance prices by averaging spot market data.

We only consider boilers with no scrubber installed at the beginning of 1995 -i.e. the year at which the ARP was effectively implemented. Also, observations with severe inconsistencies or missing data problems are deleted. As a result, the dataset used in our estimations has 736 coal-fired generating units.

In our analysis we use the following geographical regions:

1. **Northeast**: PA, NY, NJ, CT, RI, MA, VT, NH, ME

2. **Great Lakes**: IL, IN, OH, MI, WI

3. **West North Central**: IA, KS, MN, MO, NE, ND, SD

4. **South**: AL, AR, DE, FL, GA, KY, MD, MS, NC, OK, SC, TN, TX, VA, WV, LA

5. **West-Mountains**: AZ, CA, CO, ID, MT, NV, NM, OR, UT, WA, WY.

Table 1 presents some summary statistics for the main variables describing the coal consumed and the EGUs.

Table 1: Summary statistics: boiler-generator and coal characteristics

	Coal characteristics				Boiler-Generator characteristics		
	Heat content (btu/lbs)		Emission rate (lbs of SO_2/mmbtu)		Capacity	Capacity factor	Heat rate
Region	HS coal	LS coal	HS coal	LS coal	(MW)	(%)	(btu/KWh)
Northeast	12533	12461	2.74	1.06	486	66.7%	9992
	(659)	(876)	(0.49)	(0.34)	(285)	(14.3%)	(601)
Great Lakes	11472	9944	2.99	0.97	509	65.9%	10177
	(822)	(1370)	(1.25)	(0.52)	(308)	(13.4%)	(647)
W. N. C.	8800	8627	1.90	0.73	486	68.3%	10579
	(1590)	(555)	(0.68)	(0.33)	(217)	(12.7%)	(703)
South	12025	10889	2.34	1.05	570	67.1%	10039
	(1303)	(1876)	(0.92)	(0.38)	(304)	(12.2%)	(611)
West-Mtn.	10832	10561	0.90	0.76	510	73.9%	10654
	(661)	(1467)	(0.12)	(0.14)	(261)	(10.7%)	(584)
Total	11892	10329	2.59	0.96	534	67.1%	10157
	(1231)	(1792)	(1.01)	(0.43)	(296)	(12.8%)	(660)

Note: Mean values for each region. Standard deviations are shown in parenthesis.

Coal characteristics are presented for low-sulfur coal (LS) and high-sulfur coal (HS) separately. LS has typically lower btu content than HS. This trade off between the two most relevant characteristics of coal is particularly significant for EGUs located in the South and Great Lakes regions. The highest quality coal (i.e. the one with the highest btu content) is consumed in the Northeast region and almost entirely comes from the Central and Northern Appalachia mining basins. Additionally, the varieties of coal burned in the Northeast, Great Lakes, and South regions are dirtier on average (i.e. has higher sulfur content) than the ones burned in the West North Central and West-Mountain regions. Coal extracted in the Powder River Basin and in the West region (especially in Wyoming, Colorado, Utah, and New Mexico) is characterized by having lower sulfur content and by being of medium (to low) quality. The western coal is mainly consumed in the West-Mountain region and, to a lower extent, in the West North Central region.[15]

Looking at boiler-generator characteristics, no major differences are detected in terms of nameplate capacity -i.e. relatively similar averages with substantial standard deviations, meaning that EGUs of different sizes are found in each region. Capacity ranges from 25MW to 1300MW.[16] The average capacity factor is similar across regions, between 65.9% and 73.9%. The heat rate is defined as the ratio between the total amount of btu consumed and the quantity of KWh generated.[17] Again, no major differences are found in the average heat rates across regions but considerably dispersion exists within each region.

Table 2: Fuel switching and scrubber adoption during the period 1995-2005

	Initial Situation		From high-sulfur to:			From low-sulfur to:		
Region	high-sulfur	low-sulfur	high-sulfur	low-sulfur	scrubber	low-sulfur	scrubber	Total
Northeast	56	19	38	13	5	18	1	75
Great Lakes	119	92	50	58	11	92	0	211
W.N.C.	51	44	5	46	0	44	0	95
South	220	101	88	115	17	96	5	321
West-Mtn.	2	32	0	2	0	20	12	34
Total	448	288	181	234	33	270	18	736

Table 2 shows the observed transitions among the three compliance strategies we defined

[15] Coal extracted from mines located in the Powder River Basin is commonly known as “compliance coal” since thresholds imposed by the New Source Performance Standards after the Clean Air Act Amendments of 1970 and 1977 can be reached without the need of installing a scrubber.

[16] The ARP only affects units larger than or equal to 25MW. Hence, generating units with capacity lower than 25MW are not included in our sample.

[17] Heat rate may be used as proxy for boiler’s efficiency: the lower the heat rate, the more efficient a boiler is.

before ($d = 1,2,3$). In the table, boilers are said to switch from high- to low-sulfur coal when the average emission rate in two or more consecutive years remains below 1.5 lbs of SO_2 per mmbtu. Similarly, a boiler is said to adopt a scrubber when the device is effectively operating. The interpretation of Table 2 is as follows: in our sample the Northeast region has 75 boilers. Initially, 56 were burning high-sulfur coal and 19 low-sulfur coal. Between 1995 and 2005, from the "high-sulfur group", 38 stayed as high-sulfur, 13 switched to low-sulfur, and 5 adopted a scrubber. From the low-sulfur group, 18 remained as low-sulfur and only 1 installed a scrubber.

Considering all regions together, 285 boilers changed their status out of 736 during the period of analysis. Some interesting facts are: there was no scrubber adoption in the West North Central region; boilers with a "low-sulfur" status are less prone to adopt a scrubber; however, the West-Mountain region (i.e. a region characterized by cheap access to low-sulfur coal) shows the highest scrubber adoption rate (12 adopters out of a total of 34 boilers). Finally, it is clear that scrubbing was the least popular alternative among the three options. Only 51 boilers installed a scrubber in the sample period.

5 Estimation

5.1 Estimation approach

In this section we describe how we estimate the structural model using a nested fixed point maximum likelihood algorithm (NFXP) similar in spirit to the one introduced by Rust (1987). We assume ε follows a type I extreme value distribution centered at zero. By discretizing the state space and considering a transition probability matrix $F_{(s'|s)}$, we are able to express the integrated (expected) value functions as:

$$W_1(s) = \log\left\{\exp\left[U_1(s) + \beta F_{(s'|s)} W_1(s')\right] + \exp\left[U_2(s) - q(K) + \beta F_{(s'|s)} W_2(s')\right] + \exp\left[U_3(s) - n(K) + \beta F_{(s'|s)} W_3(s')\right]\right\} \tag{5}$$

$$W_2(s) = \log\left\{\exp\left[U_2(s) + \beta F_{(s'|s)} W_2(s')\right] + \exp\left[U_3(s) - n(K) + \beta F_{(s'|s)} W_3(s')\right]\right\} \tag{6}$$

$$W_3(s) = \left[I - \beta F_{(s'|s)}\right]^{-1} U_3(s) \tag{7}$$

where W_i for $i = 1,2,3$ is a vector with all the expected continuation values for all possible current states. Notice that $V_3 = W_3$ because the process becomes irreversible once the scrubber is adopted. As a result, W_3 has a closed-form solution. The transition probabilities in matrix $F_{(\cdot|\cdot)}$ are computed using the methodology introduced by Tauchen (1986). For each geographical region, $r = 1,...,5$, we assume P^h_{rt} and P^l_{rt} follow a vector autoregressive process. As explained before, the effective delivered cost of coal may differ considerably across power plants, even for those located in the same region. The estimation routine is therefore based on a Panel Data technique similar to the one introduced by Holtz-Eakin and Rosen (1988), which responds to the need of computing unique prices for each region-time pair.[18] With regards to allowance prices, we only count with eleven data points -i.e. annual averages for the sample period 1995-2005- and assume P^e evolves as an independent autoregressive process. Similarly, capacity factor, CF, is assumed to evolve independently of coal costs and allowance prices.

For a given set of parameter values, the inner algorithm in the NFXP first computes W_3 and then performs fixed-point iterations over W_2 and W_1. Once the expected value functions are computed, we are able to retrieve the conditional logistic probabilities $\Pr(d_t = l|d_{t-1} = k, s_t)$,

[18] For a recent review on Panel Vector Autoregressive techniques see Canova and Ciccarelli (2013)

i.e. the probability of choosing l in period t given that the observed states variables are s_t and that the choice made in $t-1$ was k.

$$\Pr(1|1,s) = \frac{\exp[U_1(s) + \beta F W_1(s)]}{\exp[U_1(s) + \beta F W_1(s)] + \cdots + \exp[U_3(s) - n(K) + \beta F W_3(s)]}$$

$$\Pr(2|1,s) = \frac{\exp[U_2(s) - q(K) + \beta F W_2(s)]}{\exp[U_1(s) + \beta F W_1(s)] + \cdots + \exp[U_3(s) - n(K) + \beta F W_3(s)]}$$

$$\Pr(3|1,s) = \frac{\exp[U_3(s) - n(K) + \beta F W_3(s)]}{\exp[U_1(s) + \beta F W_1(s)] + \cdots + \exp[U_3(s) - n(K) + \beta F W_3(s)]}$$

$$\Pr(2|2,s) = \frac{\exp[U_2(s) + \beta F W_2(s)]}{\exp[-C_2(s) + \beta F W_2(s)] + \exp[-C_3(s) - n(K) + \beta F W_3(s)]}$$

$$\Pr(3|2,s) = \frac{\exp[U_3(s) - n(K) + \beta F W_3(s)]}{\exp[-C_2(s) + \beta F W_2(s)] + \exp[-C_3(s) - n(K) + \beta F W_3(s)]}$$

Suppose there are J boilers, and for each boiler $j = 1,2,\ldots,J$, we have data for the years $\{t_0, t_1, \ldots, T_j\}$. Hence, for a given set of parameters θ the computation of boiler j's likelihood function is as follows

$$\begin{aligned}
& L_j\left(d_{jt_1}, \ldots, d_{jT_j}, s_{jt_1}, \ldots, s_{jT_j} | d_{jt_0}, s_{jt_0}, \theta\right) \\
&= \prod_{t=t_0}^{T_j} \Pr\left(d_{jt}, s_{jt} | d_{jt_0}, \ldots, d_{jt-1}, s_{jt_0}, \ldots, s_{jt-1}, \theta\right) \\
&= \prod_{t=t_0}^{T_j} \Pr\left(d_{jt}, s_{jt} | d_{jt-1}, s_{jt-1}, \theta\right) \\
&= \prod_{t=t_0}^{T_j} \Pr\left(d_{jt} | s_{jt}, \theta_1\right) \times \Pr\left(s_{jt} | d_{jt-1}, s_{jt-1}, \theta_2\right) \\
&= \prod_{t=t_0}^{T_j} \Pr\left(d_{jt} | s_{jt}, \theta_1\right) \times \Pr\left(s_{jt} | s_{jt-1}, \theta_2\right)
\end{aligned}$$

where the second equality comes from the markow property assumption, the third equality comes from the conditional independence assumption, and the last one comes from the assumption that state variables (i.e. capacity factor, coal costs and allowance price) are independent of the choice variable, d_t. This considerably simplifies the computation of the likelihood function. The log-likelihood is therefore additively separable in two components

$$\log(L) = \sum_{j=1}^{J}\sum_{t=t_0}^{T_j} \log\left[\Pr\left(d_{jt}|s_{jt},\theta_1\right)\right] + \sum_{j=1}^{J}\sum_{t=t_0}^{T_j} \log\left[\Pr\left(s_{jt}|s_{jt-1},\theta_2\right)\right] \tag{8}$$

and the factorization of the likelihood function allows us to estimate the parameters in two steps. First, we estimate the parameters governing the transition probabilities for prices, θ_2 -this can be executed separately. Second, we estimate the partial log-likelihood in the first term of equation 8 which requires the implementation of the NFXP in order to calculate θ_1, i.e. the parameters associated to boiler retrofitting costs and scrubber adoption costs. For estimation purposes, we assume these empirical functional forms:[19]

$$m(E_{jt}) = \alpha_r E_{jt} \tag{9}$$

$$h(K_{jt}) = \delta_r K_{jt} \tag{10}$$

$$q(K_{jt}) = \gamma_r K_{jt} \tag{11}$$

where the scrubber operating cost parameter, α_r, the scrubber adoption fixed cost parameter, δ_r, and the fuel switching cost parameter, γ_r, are enabled to vary across geographical regions. Based on the empirical evidence in Table 2, boilers located in the West North Central region do not have the scrubbing option and boilers in the West-Mountain region are (almost) all low-sulfur coal at the beginning. In sum, there are 12 parameters to be estimated. They are summarized in the following vector: $\theta_1 = \{\alpha_1,\alpha_2,\alpha_4,\alpha_5,\delta_1,\delta_2,\delta_4,\delta_5,\gamma_1,\gamma_2,\gamma_3,\gamma_5\}$.

[19]Other functional forms (not reported here) that include quadratic terms have also been estimated.

5.2 Estimation Results

This section presents the estimates for the structural parameters in the three functions of interest: scrubber adoption cost, scrubber operating and maintenance cost, and fuel switching cost. The parameters to be estimated are unrestricted in the sense that we do not impose any monotonicity conditions. Table 3 presents the maximum likelihood estimates of θ_1 over the 1995-2005 period using the partial likelihood function in the first term of expression 8. The asymptotic standard errors are computed using the outer product of gradients estimator for the five geographical regions considered in this study.

It is difficult to identify the exact value of β. However, ratio likelihood tests decisively reject the hypothesis that power plant managers use discount rates lower than 3% and higher than 10%. For the results presented here, the discount rate is assumed to be constant and equal to 7.5% -i.e. $\beta = 0.925$.[20]

Table 3: Scrubbing cost and fuel switching cost estimates

Cost parameter	Northeast	Great Lakes	W.N.C.	South	West-Mountain
Scrubber O&M (α) [(1)]	11.90***	31.24***		19.96***	14.69
	(0.47)	(0.21)		(0.34)	(11.06)
Scrubber adoption (δ) [(2)]	128.47***	164.70***		134.34***	63.71
	(42.14)	(18.60)		(33.84)	(59.36)
Fuel switching (γ) [(3)]	119.02***	68.93***	9.86	40.65*	
	(17.07)	(26.22)	(8.55)	(19.64)	

(1) Scrubber operating and maintenance cost is in USD per ton of SO_2
(2) Scrubber capital investment cost is in thousand USD per MW of capacity
(3) Fuel switching capital cost is in thousand USD per MW of capacity
(4) Standard errors are shown in parenthesis

As it is apparent from Table 3, coefficient estimates for the West-Mountain and West North

[20] EIA's reports typically use discount rates that fluctuate between 5% and 10%. When the discount rate is not uniform and a distinction between investor owned utilities and state or municipally owned utilities is made, the higher discount rate is associated to IOU to reflect different exposure to risk.

Central regions are not statistically significant and will not be analyzed. Starting with the scrubber O&M cost parameter, the cost of treating a ton of SO_2 ranges from \$12 in the Northeast region to \$31 in the Great Lakes region. O&M costs rise with increasing sulfur content since more reagent is required to treat the same volume of gas.[21] Table 1 clearly shows that the average implicit emission rate for coal consumed in the Great Lakes region is the highest.

The investment cost associated with scrubber adoption is \$128 per MW of capacity in the Northeast, \$134 in the South, and \$165 in Great Lakes. Scrubber adoption costs may vary significantly between sites and depend on space limitations, major modifications to existing equipment (e.g. ductwork and stack) and the operating condition of the associated boiler (e.g. temperature, flowrate, etc.). In general, the addition of a scrubber causes a loss of energy available for generating steam due to the evaporation of water and the energy required to drive the reaction. That additional cost cannot be separately identified in this study. As a result, both coefficients related to scrubbing cost (i.e. α and δ) are indirectly capturing the output reduction effect.[22]

Lastly, the coefficient of coal switching cost is as low as \$41 per MW of capacity in the South region and as high as \$119 per MW in the Northeast region. Coals from different regions differ along other features than their sulfur content: btu content, ash content, and grindability are some of the most relevant factors. The larger the difference in design characteristics of the boiler, the higher the capital cost needed to convert (retrofit) the boiler.

The results above (partially) confirm the idea that there is a trade-off between fuel switching and scrubbing. Fuel switching entails, on average, a higher marginal cost of emission reduction and a lower capital cost. Also, there are significant regional disparities in terms of the SO_2 regulation compliance costs.[23]

[21] Typical reagents such as lime and limestone are not expensive. However, the use of proprietary reagents, enhancers, or additives can significantly raise O&M costs.

[22] According to Srivastava and Josewicz Srivastava and Josewicz (2001) new scrubber designs result in an energy penalty of approximately 1% of the total electricity generated.

[23] The initial investment per MW of capacity necessary to retrofit a scrubber is more expensive than the corre-

There are other factors that might play a role in the relative compliance cost associated to each of the three alternatives without affecting the capital cost or the O&M cost in a direct manner. Some examples are: prior experience with scrubbing; state regulation biases that favor one alternative or the other; the quantity of coal purchased in advance under long term contracts; the ownership type (private companies versus state or municipally owned utilities), among others.

5.3 Goodness of fit

Table 4 compares the predictions of the dynamic programming model to the data. Following Rothwell and Rust (1997), we define the nonparametric (NP) and the parametric (PP) estimates of the conditional choice probability $\Pr(d|S,d_{-1})$ as follows:

$$
\begin{aligned}
\hat{\Pr}(d|S,d_{-1}) &= \int_{s\in S} \hat{\Pr}(d|s,d_{-1})\,\hat{\mathrm{F}}(\mathrm{d}s|S,d_{-1}) \\
&= \frac{1}{N_{d_{-1}}} \sum_{j=1}^{N} \mathbb{I}\left\{d_j = d, s_j \in S, d_{j,-1} = d_{-1}\right\} && \text{(NP)} \\
\Pr(d|S,d_{-1}) &= \int_{s\in S} \hat{\Pr}\left(d|s,d_{-1},\hat{\theta}\right)\hat{\mathrm{F}}(\mathrm{d}s|S,d_{-1}) \\
&= \frac{1}{N_{d_{-1}}} \sum_{j=1}^{N} \Pr\left(d_j = d|s_j, d_{j,-1} = d_{-1}, \hat{\theta}\right)\mathbb{I}\left\{s_j \in S\right\} && \text{(PP)} \qquad (12)
\end{aligned}
$$

The model predicts correctly 96.1% of the observed choices made by the 736 electricity generating units during the entire sample period. The goodness of fit can be tested by the usual χ^2 statistic which in this case has 4 degrees of freedom and is equal to 1.5725, with an associated p-value equal to 0.1863. Consequently, we are not able to reject the null hypothesis, i.e. there is not enough evidence to conclude that NP and PP conditional choice probabilities differ.

sponding expenditure necessary to convert the boiler from high- to low-sulfur coal, with the only exception being the Northeast region, although the mean differences in this region are not statistically significant.

Table 4: Predicted versus actual choice probabilities

	$d_{t-1}=1$		$d_{t-1}=2$	
	NP	PP	NP	PP
$d_t=1$	0.9042	0.8678		
$d_t=2$	0.0840	0.1157	0.9973	0.9603
$d_t=3$	0.0118	0.0166	0.0027	0.0397

Notes: Number of observations: 7303. $\chi^2_{(4)}=1.5725$

6 Acid Rain Program: the gains from the allowance market

As a natural exercise derived from the theoretical analysis that proclaim market-based (incentive-based) regulations as unambiguous winners over the traditional command-and-control environmental regulations, this section compares the estimated compliance costs under the ARP with two alternative scenarios. First, we quantify the additional compliance cost to generating units that would result if they were required to meet a uniform emission standard of 1.2 lbs of SO_2 per mmbtu. Second, we compute the additional costs that would emerge with a policy that mandates compulsory scrubber adoption. Notice that the former counterfactual policy allows a $d_t=1$ boiler to choose between two options: fuel switching or scrubbing, whereas the latter only contemplates one alternative: scrubbing. Additionally, under compulsory scrubbing, generating units already burning lower-sulfur coal varieties (i.e. $d_t=2$) are still required to install a scrubber system. As a result, the total cost imposed by the environmental regulation is (on average) larger.

Let us consider the following three measures for a boiler j with $d_{t-1}=1$

$$
\begin{aligned}
A_{jt} &= P_t^a(E_{jt}-\hat{E}_{jt}) \\
B_{jt} &= (P_{jt}^h-P_{jt}^h)X_{jt}+\gamma K_j\frac{r}{1+r} \\
C_{jt} &= \alpha E_{jt}+\delta K_j\frac{r}{1+r}
\end{aligned}
$$

Then, the additional cost of a uniform emission rate standard is computed as follows

$$CC1_{jt} = A_{jt} - min\{B_{jt}, C_{jt}\} \tag{13}$$

Similarly, for a boiler j with $d_{t-1} = 1$ or $d_{t-1} = 2$, the extra cost of compulsory scrubbing is

$$CC2_{jt} = A_{jt} - C_{jt} \tag{14}$$

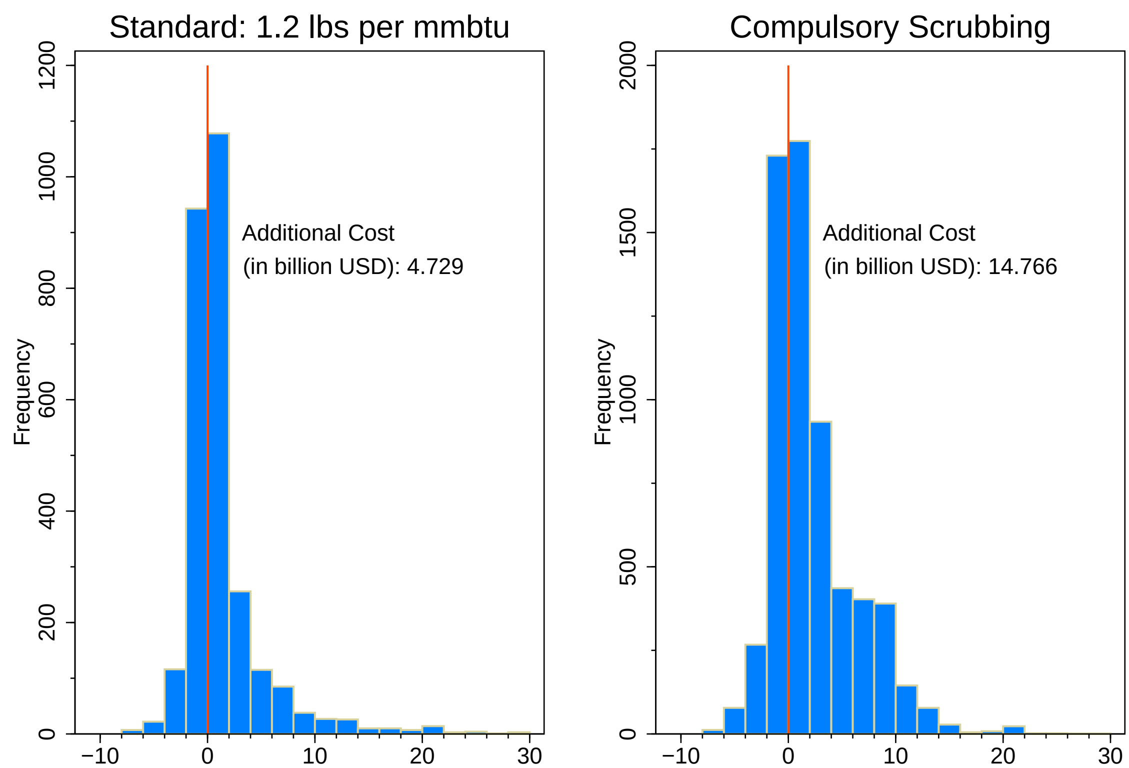
The application of a uniform emission rate standard would generate an extra total cost for the period 1995-2005 of approximately 4.7 billions of dollars. As expected, if the most restrictive policy (i.e. mandatory scrubbing) were implemented total compliance cost would amount to 14.8 billions of dollars in the same period. Table 5 summarizes these results and also emphasizes the larger compliance costs that would be observed during the second phase of the Acid Rain Program (2000-2005).

Table 5: Additional cost from command-and-control policies (in billions of U.S. Dollars)

Period	Uniform Emission Standard	Compulsory Scrubbing
1995-1999	0.438	4.478
2000-2005	4.291	10.288
Total	4.729	14.766

Lastly, Figure 1 presents the distributions of additional compliance costs derived from the two counterfactual policies described before. There is a small number of boilers that would benefit from the application of the counterfactual policies analyzed here. For the vast majority of coal-fired generating units, command-and-control regulations would represent larger compliance costs.

Figure 1: Distribution of additional annualized compliance costs associated to alternative command-and-control regulations (1995-2005)



7 Conclusions and policy implications

The Acid Rain Program created a cap-and-trade system where electric utilities could freely trade allowances in order to cover sulfur dioxide emissions generated during each calendar year. In practice, the environmental program implied coal-fired boilers had to choose among three medium- to long-term compliance strategies: i) burn high-sulfur coal and purchase additional permits to cover excess emissions; ii) retrofit the boiler to burn low-sulfur coal; iii) install a flue gas desulfurization device in order to reduce emissions at the flue-gas stack.

The decision problem of the previous paragraph is inherently dynamic and the possible choice alternatives depend on agents' expectations about future environmental regulations (e.g.

stringency level, scope, enforcement, etc.) and future input and output market conditions (e.g. coal costs, allowance prices, electricity prices, output levels, input quality, etc.). Previous literature that estimates the ARP compliance costs does not incorporate the dynamic structure that a realistic analysis calls for. This paper fills the gap by developing a structural dynamic discrete choice model that is estimated using a rich dataset that combines publicly and readily available information.

Our estimation results confirm the existence of a trade-off between fuel switching and scrubbing in terms of the associated capital and operating costs of each compliance alternative. The former strategy typically has a higher variable pollution abatement cost. However, the initial capital investment associated to scrubber adoption is, on average, higher than the corresponding coal switching capital cost. Some regional disparities in terms of costs help explain the observed investment patterns without affecting the main findings mentioned above: the initial investment per MW of capacity necessary to retrofit a scrubber is more expensive than the corresponding expenditure necessary to convert the boiler from high- to low-sulfur coal. Scrubber adoption rate was particularly low during the period of analysis, an empirical fact supported by the parameter estimates of our structural model. Higher scrubber investment costs make this compliance option less attractive than fuel switching, specially in a period marked by considerable uncertainty about the possible emergence of more stringent future environmental policies, and changing conditions for energy markets (in particular the emergence of natural gas as a serious competitor for coal-based generation).

Finally, the most important result in this study is that cost savings obtained with the implementation of the cap-and-trade program after the CAAA-1990 were substantial if compared to the *old-fashioned* command-and-control environmental regulations implemented in the seventies. According to our estimations, the application of a rigid emission rate standard of 1.2lbs of SO_2 per mmbtu (similar to the one implemented with the CAAA-1970) would have represented an additional cost of 4.7 billion dollars for the 1995-2005 period. Similarly, the application of forced scrubbing (CAAA-1977) would have represented 14.8 billion dollars of extra compliance costs for the same sample period.

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