Public Utility Commission Regulation and Cost Effectiveness of Title IV: Lessons for CAIR*

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I. Introduction

On March 10, 2005, following the legacy of the Title IV (Acid Rain) Program and its apparent success, the EPA issued the Clean Air Interstate Rule (CAIR). This rule envisions a cap-and-trade system that will reduce sulfur dioxide (SO$_2$) and nitrogen oxides (NO$_x$) by 57% and 61% respectively in 2015 from 2003 levels. Much like the Title IV Program’s SO$_2$ allowance market, CAIR has been targeted primarily toward the electric utility industry that remains regulated by state Public Utility Commissions (PUCs) in terms of rate setting and cost recovery in many parts of the United States. Moreover, the new rule is being introduced as a growing body of evidence suggests that while cost savings from cap-and-trade can be significant, much of the potential cost savings have not been realized. A plausible explanation is that state regulatory treatment for cost recovery of compliance options can distort incentives to utility companies, leading them to select more expensive compliance options over less expensive options. Influenced by those incentives, the companies’ decisions could ultimately increase costs above the least-cost level, leaving potential cost savings on the table. The idea that state PUCs can distort incentives to companies for choosing the least-cost compliance options is not a new one. Recently, its relevance has been pointed out by Robert Stavins in his review of the effectiveness of cap-and-trade systems:

More generally, it is important to consider the effects of the preexisting regulatory environment...[B]ecause electricity generation and distribution have been regulated by state commissions, a prospective analysis of SO$_2$ trading should consider the incentives these commissions may have to influence the level of allowance trading.

Yet, in spite of what has been written about the potential impacts of PUC regulatory policy on the cost-effectiveness of the Title IV Program and emissions trading programs in general, the issue remains largely ignored at the policy implementation level. The EPA’s modeling analysis of the Clear Skies and CAIR

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omits the potential impacts of PUC policy on cost-effectiveness of these programs.\textsuperscript{5} Moreover, the potential monetary impacts of PUC regulatory policy have not been quantified until recently.\textsuperscript{6}

In this article, we address the effects of PUC regulation on compliance choices and costs associated with the emissions trading market for the Title IV SO\textsubscript{2} Trading Program for the year 1996. We also highlight the lessons that can be applied from that analysis to future cap-and-trade policies such as CAIR. In our discussion, we address what we believe to be a serious omission in the ongoing policy debate and analysis of CAIR. Specifically, we ask the following question: How much more costly is a cap-and-trade emissions policy in the presence of PUC regulations?

While it can be shown that the existence of PUC regulation may not necessarily lead to deviations from the least-cost compliance outcomes, we show that in 1996 PUC regulations have a significant effect on compliance decisions, resulting in compliance costs that are more than double the least-cost compliance outcome.

\textbf{II. The Attraction of the Title IV Program’s Cap-and-Trade}

The 1990 Clean Air Act Amendments (CAAA) established the Title IV Program to control emissions of SO\textsubscript{2}. The Title IV Program has two phases: Phase I (1995-1999) required only 110 plants that were considered the largest polluters to participate in the SO\textsubscript{2} allowance program. These plants included 263 generating units (also called Table A units) that were designated for participation; however, other units could elect to participate in lieu of, or in addition to, the Table A units through various provisions of Title IV. Phase II, which started in 2000 and is to continue indefinitely or until a different program is implemented, includes all fossil-fuel electric generators with a capacity exceeding 25 megawatts. Each generating unit in Phases I and II received a \textit{gratis} allocation of allowances based on the following formulae. In Phase I, Table A units were initially allocated allowances \textit{gratis} based on average heat input (millions of Btu) during 1985-1987, multiplied by 2.5 lbs. of SO\textsubscript{2}. Phase II allocations are based on average heat input during 1985-1987, multiplied by 1.2 lbs. of SO\textsubscript{2} and the total nationwide cap on SO\textsubscript{2} emissions allowances allocated each year is approximately nine million tons.\textsuperscript{7}

The Title IV Program created a cap- and-trade system for Phases I and II, whereby utilities could buy, sell, or otherwise trade allowances to pollute under an aggregate emissions cap. Along with having flexibility to trade emissions allowances, utility companies could meet their emissions obligations through coal switching or blending, scrubber installation, unit switching via changes in dispatch, unit repowering, unit retirement, or any combination of the above. The overall flexibility enables companies to choose the compliance solution at least cost to them, without necessarily requiring them to participate in the SO\textsubscript{2} allowance market. Companies would participate in the SO\textsubscript{2} allowance market only if it is cost-effective for them to do so. Theoretically, if the market operates efficiently (companies exhaust all profitable trading opportunities), the allowance market will result in an emissions control policy that achieves a lower overall compliance cost than any other emissions control policy for the country and ultimately for customers. The Model Trading Program under CAIR envisions the same flexibility characteristic of, and the associated costs savings supposedly achieved by, the Title IV Program.

The adoption of a cap-and-trade scheme as the preferred method of reducing emissions in CAIR should come as no surprise. For example, former EPA Administrator Carol Browner observed in 1997: “…during the 1990 debates on the Clean Air Act’s acid rain program, industry initially projected the costs of an emission allowance…to be approximately $1,500…Today those allowances are selling for less than $100.”\textsuperscript{8} The former Chair of the Council on Environmental Quality, Katie McGinty, noted during a White House briefing on President Clinton’s global climate change plan in 1997: “We’ve reduced the emissions that cause acid rain by more than 40 percent of what was required under the law for less than a tenth of the price that was predicted…we will put [the same] market forces to work to help us take on this[climate change] objective.”\textsuperscript{9} This enthusiasm has carried over to the Bush Administration’s support of cap-and-trade policies that underpin the proposed Clear Skies Act of 2005.\textsuperscript{10}
III. The Title IV Cap-and-Trade Program: Workings, Analysis, and Evidence

A. Incentives Under Cap-and-Trade

We noted above that flexibility is one of the attractions of the Title IV Program’s cap-and-trade system. If a generating unit has low abatement costs, that unit can reduce emissions below its allowance allocation and sell the remaining allowances or simply bank them for future use. For example, as long as the marginal (incremental) cost of abatement (emissions reduction) is less than the allowance price, it pays the generating unit to further reduce emissions and sell the freed-up allowance. This can be seen in Figure 1 below.

**Figure 1: Benefits from Emissions Trading**

![Figure 1](image_url)

$MCALow$ represents a low marginal abatement cost source. Being allocated $A^*$ allowances, if the market price of allowances is $P^*$, it pays a generating unit that has low abatement costs to reduce emissions until it reaches $E^*Low$. The revenue from allowance sales is the rectangle with the width $A^* - E^*Low$ and height $P^*$. The cost to the utility company is the area under $MCALow$ between $A^*$ and $E^*Low$. The net profit from the allowance sale is the area of the revenue rectangle above $MCALow$. Conversely, a unit may have high abatement costs, represented by $MCAHigh$. Rather than reduce pollution, that unit may find it less expensive to buy allowances in the open market, and use the purchased allowances, along with the allowance allocation, to cover its emissions obligation. Units will continue buying allowances as long as the marginal (incremental) cost of abatement (emissions reduction) is greater than the allowance price. A more formal way of expressing this idea is that the unit with high abatement costs (Figure 1) will buy $E^*High - A^*$ allowances in the market at the price $P^*$. That unit’s expenditure on allowances is the rectangle with width $E^*High - A^*$ and height $P^*$. Because its reduction in abatement costs, the area between $A^*$ and $E^*High$ and below $MCAHigh$, is greater than the expenditure on allowances, the unit with high abatement costs will benefit. Also note that the allowance market leads to the equalization of the marginal costs of abatement across generating units.

B. Analysis and Evidence from the Title IV Program

Researchers at Resources for the Future (RFF) and MIT’s Center for Energy and Environmental Policy Research (CEEPR) conducted formal analyses to estimate the cost savings from full trading under Phases I and II of the Title IV Program, as compared to the scenario of a command and control approach that specified compliance strategies and was the basis of New Source Review. RFF’s study estimated the cost savings from implementation of cap-and-trade rather than command-and-control to be approximately $250 million per year in Phase I and $780 million to $1.6 billion per year in Phase II. MIT’s study estimated the cost savings to be $360 million per year in Phase I and about $1.92 billion per year in Phase
II. In percentage terms, the cost savings are up to 55% of the estimated command-and-control cost in Phase II.\textsuperscript{11} Such results confirm the superiority, at least in terms of cost savings, of cap-and-trade over command-and-control approaches. In the context of Figure 1, these cost savings correspond to the reduced abatement expenditure, net of allowance purchases for the unit with high abatement costs plus the profit from allowance sales, net of increased abatement expenditure for the unit with low abatement costs.

However, policy makers and industry analysts should approach the use of cap-and-trade policies for CAIR with caution. Actual compliance costs for Phase I of the Title IV Program have only been slightly lower than the estimates and do not match the hyperbolic estimates cited by officials in the Clinton administration.\textsuperscript{12} Moreover, a growing body of evidence indicates that at least through Phase I of the Title IV Program, compliance costs under SO\(_2\) allowance trading are in excess of least-cost implementation strategies. For example, the RFF study estimates that under full trading the least-cost solutions for the years 1995 and 1996 total $552 million and $571 million respectively. However, the RFF study also estimates the actual compliance costs for 1995 and 1996 to be $832 million and $910 million respectively. The RFF study concludes that the differential between the least-cost solution and actual compliance costs could be due to “[a]djustment costs associated with changing fuel contracts and capital expenditures as well as regulatory policies (our italics).”\textsuperscript{13} Exploiting the idea that marginal abatement costs should be equalized across firms in a cap-and-trade system as shown in Figure 1, we note that empirical work by John R. Swinton shows insufficient evidence of the convergence of marginal abatement costs, at least in Phase 1. Swinton concludes that affected utilities have not taken advantage of possible gains from trade. He speculates that long-term coal contracts or state regulations (our italics) could be an explanation for what appears to be a lack of cost-minimizing behavior.\textsuperscript{14}

Swinton’s conjectures are bolstered by a 2002 study that concludes that without the presence of PUC regulations, many generators would have continued to use high sulfur coal and buy allowances to minimize costs, rather than switch to low sulfur coal which was the compliance option of choice during Phase I.\textsuperscript{15} In the context of Figure 1, such a conclusion suggests that units with high abatement costs continued to reduce emissions in spite of the cost when it would have been less expensive for them to buy allowances.

IV. Regulatory Treatment of Compliance Options and Utility Incentives—Theory and Intuition

Incentives embedded in PUC cost recovery rules may contribute to compliance costs in excess of the least-cost solution in three ways: 1) through the design of incentives provided through ratemaking mechanisms; 2) through a lack of uniformity in their regulatory schemes; and 3) disallowance or discouragement of the use of “innovative” compliance mechanisms that have uncertain results.

A. Incentives through Ratemaking Mechanisms

Below we will consider, for the ease of exposition, an example where there are only two compliance options for utility companies: participation in the allowance market and pollution abatement. In our example, we will formally express utility company investment behavior for each option under two cost allocation regimes—rate-of-return and cost-sharing. Let \(C(A)\) be the costs or revenues associated with participation in the allowance market and let \(C(E)\) be the cost emissions abatement. By construction, the change in costs associated with activity in the allowance market, \(\Delta C(A)\), is equal to the price of allowances in the market, \(P\). The change in the cost of emissions abatement, \(\Delta C(E)\), is the marginal cost of abatement. From our discussion in the previous section we know that the marginal cost of abatement is equal to the price of allowances, or \(\Delta C(E)=P\).

Traditionally, PUCs specify the rate of return permitted on investment and define the costs to be considered in calculating the utility company’s return on investment. In particular, PUCs determine the prudence of costs, whether already incurred or proposed, and the portion of those costs to be passed through to ratepayers. Let \(\Phi_A\) and \(\Phi_E\) be the fraction of costs borne by utility shareholders where the shares can range from 0 to 1. The problem facing the utility company is to minimize the shareholder
portion of the cost of compliance, $\Phi_A C(A) + \Phi_E C(E)$, such that its emissions are covered by the allowances it holds and that electricity demand is served. Companies will still reduce emissions up to the point where the shareholder fraction of the marginal cost of abatement equals the shareholder fraction of the allowance price, $\Phi_E \Delta C(E) = \Phi_A P$.

Companies subject to traditional “cost-of-service” or “rate-of-return” regulation would pass on all prudently incurred variable costs (or cost savings) to ratepayers on a dollar-for-dollar basis. Also, capital expenditures would be fully recovered plus they would be allowed a regulated rate-of-return. In the context of our example, this would imply that both $\Phi_A$ and $\Phi_E$ are equal to zero. This also implies that there are no shareholder costs to be minimized!! So the only conditions the utility company must satisfy is that demand is met and that the company has enough allowances to cover its emissions. In other words, any outcome is cost- minimizing for shareholders, though not for customers or society as a whole.

Beginning in the 1980s, PUCs responded to companies’ tendencies to over-invest and incur cost overruns under cost-of-service or rate-of-return regulation by disallowing some or all of the costs deemed in excess of “prudent” investments. In other cases, in an attempt to induce “cost- minimizing behavior,” PUCs have required that companies receive pre-approval for their clean air compliance plans. In addition, many PUCs have implemented various incentive mechanisms that would reward companies for keeping costs down. To provide companies with cost- minimizing incentives, PUCs may authorize sharing mechanisms; both the companies and ratepayers could then benefit from the induced cost-minimizing behavior. Suppose the PUC implements the cost-sharing mechanism as described above in our example so that to minimize shareholder cost, $\Phi_E \Delta C(E) = \Phi_A P$. So long as cost shares for compliance options $\Phi_A$ and $\Phi_E$ are equal to each other and greater than zero, companies have the incentive to minimize cost not only to shareholders, but also to customers and society as a whole.

However, if $\Phi_A > \Phi_E$, the company has a bias in favor of emissions reduction over allowance purchases when allowance purchases would have been cheaper. Likewise, if $\Phi_A < \Phi_E$ the company has a bias in favor of allowance purchases over emissions reductions when emissions reductions would have been cheaper. In general, when recovery treatment is not symmetric over compliance options, companies will not minimize costs to society as a whole.

### B. Lack of Uniformity in Regulatory Schemes

In the aggregate, PUC regulatory treatment of compliance options across states, or even within the same state, are likely to differ along some dimension. Certain utility companies do not face PUC regulation, such as federal power agencies like the TVA, or they may not face total or any PUC oversight, such as state and local electric cooperatives and municipal utility companies. These public companies may be subject to completely different incentive regimes than their regulated investor-owned counterparts. The variations in regulatory regimes across state lines and among the different kinds of utility companies may be more pronounced in states experiencing electric utility restructuring compared to states that have not implemented it.

Therefore there may be potentially large deviations from the least-cost solution under the SO2 emissions trading program or any other cap-and-trade program that targets the electric utility industry. Intuitively, differential regulatory treatment may effectively alter companies’ perceived marginal abatement costs relative to those of other companies and the allowance price, thereby turning utility companies that should be sellers into buyers and utility companies that should be buyers into sellers. Let us suppose, referring to our example from Figure 1, that the generating unit with high abatement costs faces a cost recovery bias so that the company perceives it will be less expensive to reduce pollution than to buy allowances or even that it should sell allowances, if $\Phi_A > \Phi_E$. Moreover, let us assume that the unit with low abatement costs in Figure 1 is biased in favor of purchasing allowances, or at least not selling as many, if $\Phi_A < \Phi_E$. In this case, the unit with high abatement costs perceives itself to have a lower abatement cost, relative to the allowance price, and the unit with low abatement costs perceives itself to have a higher cost of abatement, relative to the allowance price.
Not all differences in cost recovery treatment may lead to cost deviations. If all PUCs treated compliance options symmetrically, as discussed above, regardless of what the approved cost sharing mechanism is in each state, then utilities should achieve the cost savings promised by emissions trading, all things equal. Additionally, if all PUCs could coordinate their actions and introduce the same bias into their cost allocation schemes, that is, $\Phi_A$ is the same across all PUCs and $\Phi_E$ is the same across all PUCs, then utility companies will minimize compliance costs to the greatest extent possible.

C. Disallowance or Discouragement of Innovative Compliance Alternatives

Even though the SO$_2$ cap-and-trade program afforded utility companies greater flexibility in meeting pollution reduction requirements, not all utility companies or PUCs were certain about the effectiveness of the innovation of using allowance purchases and sales as a compliance strategy. From the company’s perspective, the possibility existed that PUCs could disallow, ex ante or ex post, costs for investments in innovative compliance technologies or actions, such as emissions trading, that have the expectation of lower costs but are also surrounded by uncertainty in terms of authorized cost recovery. Consequently, faced with such uncertainty, companies might be more inclined to invest in older, more costly, but proven, technologies and methods. In the context of our example, this implies the introduction of a bias against participation in the allowance market and toward emissions reductions, or $\Phi_A > \Phi_E$.

V. Regulatory Treatment of Compliance Options and Utility Incentives—Practice and Policy

A. Incentives for Capital Intensive Compliance Options (Scrubbing)

Post combustion control such as scrubber installation is a possible although very expensive compliance option for sulfur dioxide abatement. In general, whenever scrubbers have been installed, state regulators have given pre-approval to scrubber installations as a part of a utility company’s integrated resource plan or clean air compliance plan. Moreover, in states where scrubber installations were approved and cost recovery allowed, other issues, such as the protection of local coal industries, were instrumental in ensuring installation approval. The implication of such pre-approval policies is that regulators are biasing utilities toward more expensive capital options, when fuel switching or allowance purchases might be the less expensive compliance strategy. Indeed, scrubbers can be thought of as another method to abate pollution, so that the cost share on that activity $\Phi_E$ is less than the cost share on allowances $\Phi_A$, especially because scrubbers, as capital assets, will also earn a rate of return, whereas other compliance options are merely expensed and earn no rate of return.

B. Incentives on Allowance Trading and Fuel Switching

Under traditional rate-of-return or cost-of–service regulation, state regulators typically pass through to ratepayers variable costs such as fuel, allowance purchases, and allowance sales on a dollar-for-dollar basis. The traditional pass through of variable costs is the general rule during the time period we investigate. In a few cases, however, some form of revenue-sharing was authorized in which a share of allowance revenues (sales) could be kept (borne) by the utility company and its shareholders and the remaining share by ratepayers. In each of these cases, the cost share factor on allowances is greater than the cost share on pollution abatement ($\Phi_A > \Phi_E$). For allowance sales, shareholders may keep some fraction of allowances freed-up and sold as a result of pollution abatement at a relatively lower cost. In the case of allowance purchases, the incentive is to abate pollution when it may be cheaper to buy allowances. In one case the PUC provided incentives to companies to keep fuel costs down, a decision that again favored abatement over allowances.
C. Overall Implication

With the exception of a few policies authorizing revenue-sharing noted above, PUCs generally applied the traditional pass-through method of cost recovery to generating units affected by Phase I in simulation year, 1996. As we discussed in the previous section, such policies tend not to induce any kind of cost-minimizing behavior on the part of utility companies, since shareholders for the most part do not bear any compliance costs, whether the company opts for fuel switching or allowance trading. In addition, the PUCs’ cost recovery rules for scrubbers in Phase I would likely result in the installation of too many scrubbers and at suboptimal locations (facilities). Given the large costs associated with scrubber retrofits, the misallocation of scrubbers in both number and location is most likely the reason for the erosion of the potential cost savings from emissions trading and for costs in excess of the lowest possible compliance cost.

VI. Simulating the Effects of PUC Regulation on the SO\(_2\) Trading Program\(^{22}\)

A. Model

In Sections IV and V, we explain how PUC regulatory policy can lead to deviations from cost-minimizing behavior in cap-and-trade emissions systems. In this section we ask the following question: How great is the effect of PUC regulatory rules on the ability of cap- and-trade emissions program to achieve least-cost abatement and maximum cost-saving? We attempt to answer that question through a simulation model of the SO\(_2\) allowance market. The model includes data for the 431 generating units at 162 plants that participated in the SO\(_2\) Program in 1996. The model is run under two scenarios that exhaust the full set of trading opportunities: (1) generating units that do not face any PUC regulation; and (2) generating units that are subject to representative PUC cost recovery rules in place in 1996. In addition to those two scenarios, we also compute the actual costs of compliance based on the actual emissions and generation (heat input) at each of the 431 units. Table I reflects the assumptions used for those scenarios in our simulation exercise. We restrict our analysis so that emissions in aggregate will equal actual total emissions in 1996. The allowance allocation for each unit, as reflected in Table 1, is the actual observed emissions at each of the 431 units participating in the program in 1996.

<table>
<thead>
<tr>
<th>Simulation</th>
<th>Allowance Allocation</th>
<th>Unrestricted Emissions</th>
<th>Scrubber Costs</th>
<th>Scrubber Choice</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>5,433,351 tons</td>
<td>7,269,411 tons</td>
<td>Historical</td>
<td>No. 46 scrubbers given.</td>
</tr>
<tr>
<td>B</td>
<td>5,433,351 tons</td>
<td>8,943,481.77 tons</td>
<td>Engineering(^a)</td>
<td>Yes. 17 scrubbers given.</td>
</tr>
<tr>
<td>Actual</td>
<td>5,433,351 tons</td>
<td>7,269,411 tons</td>
<td>Historical</td>
<td>No. 46 scrubbers given.</td>
</tr>
</tbody>
</table>

First we compare the two full trading scenarios to see the effects of PUC regulatory policy when all market participants fully exhaust their trading opportunities. This comparison provides us with the distortion of PUC regulation where shareholder cost shares are not set to encourage cost minimization as described above. Next we compare the full trading outcome to the actual compliance cost outcome. This comparison will capture the potential cost savings that have not been achieved as well as identify other potential effects of PUC regulatory policy.

Each affected unit in this model takes full advantage of trading opportunities and minimizes costs to shareholders, subject to both satisfying demand for generation (as represented by heat input) and satisfying the emissions obligations (all emissions are covered by allowances). The Ph.D. Dissertation by Paul Sotkiewicz, upon which this work is based, summarizes the data sources used in the model and
explain the methodologies used to select values for the model’s parameters. We assume as well that the regulatory treatment for cost-recovery of fuel and allowances was the most typical one in effect in 1996: the pass through of these costs on a dollar-for-dollar basis, leading to shareholder cost shares of zero and ratepayer cost shares of 100 percent. However, with cost shares of zero, the model cannot be computed, so we must assume that instead of zero, the shareholder cost shares are 0.0001, to reflect costs that may be borne by shareholders in the case of a lag in cost recovery.

Simulation A examines our two regulatory scenarios basing allowance allocations on actual 1996 emissions and takes all scrubbers as given (46 affected units had installed scrubbers as of 1996) regardless of whether the scrubbers were installed in response to the 1990 CAAA or the 1977 New Source Performance Standards (NSPS). Simulation A limits the affected utility companies’ compliance choices to either fuel switching or emissions trading. Simulation B, like Simulation A, examines our two regulatory scenarios and bases the allowance allocation on actual emissions in 1996, but assumes that units’ compliance strategies could include investments in scrubbers, in addition to fuel switching and emissions trading. We incorporate scrubbers as a compliance option in Simulation B because scrubbers are expensive; therefore, we expect them to have a large effect on compliance costs. Simulation B also assumes that this investment option applies only to units that had not installed scrubbers as of 1990, because 17 units had already installed scrubbers in response to the 1977 NSPS and therefore should not be considered a compliance choice for the 1990 CAAA. Finally, the cost of scrubbers in Simulation B is the annualized cost of the scrubber based on engineering estimates of scrubber retrofits for 1996. Simulating the Actual compliance cost simply requires us to compute the excess fuel cost and scrubber cost necessary to achieve the observed level of emissions and meet generation demand in 1996.

B. Results and Discussion

Table 2 reflects our simulation results with the scenarios of PUC regulation and no regulation for full trading and for scrubber installation.

<table>
<thead>
<tr>
<th>Simulation</th>
<th>Compliance Costs</th>
<th>Scrubbers Installed as Choice</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PUC Regulation</td>
<td>No PUC Regulation</td>
</tr>
<tr>
<td>A</td>
<td>$549,858,553</td>
<td>$527,085,258</td>
</tr>
<tr>
<td>B</td>
<td>$553,068,881</td>
<td>$421,841,367</td>
</tr>
<tr>
<td>Actual</td>
<td>$989,982,990</td>
<td></td>
</tr>
</tbody>
</table>

In Table 2 we note that in the absence of PUC regulation (Simulation A), compliance costs are about $527 million. This amount reflects the least-cost solution under full trading. We note that our figure for the hypothetical least-cost solution compares favorably with the RFF study, mentioned above, that computed a least-cost solution of $571 million for 1996. Given our assumption that shareholder cost shares of zero would be changed to 0.0001 to compute the model, it should not be surprising that the solution under PUC regulation -- $549 million -- is not terribly different (4.5% difference) from the least-cost solution. The reason is that almost all PUCs treat fuel and allowances identically which should result in cost-minimizing behavior on the part of utility companies as discussed above. However, in Simulation A, we have not accounted for the option of scrubber installation.

Accounting for scrubber choice in Simulation B, we note that the least-cost solution falls to approximately $422 million and only 18 scrubbers are installed. Accounting for PUC regulation and the ex ante approval of scrubbers at certain units, compliance costs increase to $553 million, a 31% increase in compliance costs over the least-cost solution and the installation of 28 scrubbers. When considered along with the symmetry of cost shares for fuel and allowances assumed as in Simulation A, it seems that PUC cost recovery treatment of scrubbers would be the most plausible explanation for the erosion of potential cost savings from the SO2 Trading Program.
A closer examination of the scrubber choices of Simulation B without any regulation in Table 3 reveals the potential distortions on the pre-approval of scrubbers. First, only 18 scrubbers are installed in this case compared to the 29 scrubbers actually installed in response to Title IV. Of those 29 scrubbers, only 9 would have been installed in the least-cost solution at their current locations. Consequently, 9 scrubbers should have been installed at other locations, according to our simulations, that were not installed in reality in 1996. In summary, it is not simply the number of scrubbers that can lead to compliance cost increases, but their installation at the “wrong” locations.

Table 3: Simulation B Scrubber, No PUC Regulation Summary

<table>
<thead>
<tr>
<th>Actual Number of Scrubbers Installed in 1996 in Response to Title IV</th>
<th>Number of Scrubbers Installed in the Simulation</th>
<th>Number of Scrubbers Installed in the Simulation that are Actually Installed</th>
<th>Number of Scrubbers Actually Installed in Response to Title IV but Not Installed in the Simulation</th>
</tr>
</thead>
<tbody>
<tr>
<td>29</td>
<td>18</td>
<td>9</td>
<td>20</td>
</tr>
</tbody>
</table>

So far in our discussion we have assumed that utility companies have taken full advantage of the trading opportunities afforded to them. If the compliance costs in our simulation of Actual compliance costs closely match those of Simulations A and B, we could conclude that utility companies are indeed taking full advantage of trading opportunities and minimizing costs. However, the Actual costs, of almost $990 million (Table 2) indicate that utility companies are not minimizing costs. If anything, the Actual costs support the idea that almost any cost outcome is possible when there is a dollar-for-dollar pass-through of costs related to fuel and allowances because, from the utility shareholder perspective, it does not matter what the companies spend or save on these compliance options. Therefore, we conclude that the predominant PUC regulatory policy of fully expensing fuel and allowances may be as important, or according to our simulations, more important than treatment of capital intensive compliance options such as scrubbers in explaining costs in excess of the least-cost compliance.

Table 4: Allowance Market Price and Volume

<table>
<thead>
<tr>
<th>Simulation</th>
<th>PUC Regulation Price</th>
<th>No PUC Regulation Price</th>
<th>PUC Regulation Volume</th>
<th>No PUC Regulation Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>$161.88</td>
<td>$149.64</td>
<td>1,599,380</td>
<td>1,565,862</td>
</tr>
<tr>
<td>B</td>
<td>$179.46</td>
<td>$179.46</td>
<td>1,640,642</td>
<td>1,722,529</td>
</tr>
</tbody>
</table>

No analysis of the SO₂ cap-and-trade program would be complete without a discussion of allowance prices and trading activity. In Simulation A, the equilibrium allowance price without regulation is about $150/ton and is $162/ton with regulation, as seen in Table 4. These allowance prices reflect the marginal cost of abatement in the market. These prices are considerably higher than the published allowance prices for 1996 of about $90 on average, but are much closer to prices in trading up through 1995. However, the allowance price is not a good measure of compliance costs, contrary to statements from Clinton Administration officials cited above and as reflected in Tables 2 and 4. In spite of our simulated prices in excess of the allowance price prevailing in 1996, the actual compliance costs are much greater in Actual than in Simulations A and B. Simulation B in Table 4 offers another example showing the disconnect between allowance prices and compliance costs with the same allowance price of about $180/ton with and without regulation, but a 31% difference in compliance cost as shown in Table 2.
Finally, the trading volumes we report in Table 4 further confirm our finding that significant cost savings have not been realized. Recall that we use the actual emissions at each unit as the allowance allocation. Had all or most of the potential cost savings from trading been realized, we would see no trading volume or very little volume. However, in both Simulations A and B trading volumes for the purposes of compliance are approximately 30% of total emissions signifying there were significant gains from trade left on the table.

VII. Conclusions, Cautions, and Looking Toward CAIR

A growing body of evidence, supported by our analysis above, suggests that the cost savings potential of the Title IV SO₂ cap-and-trade program is not being reached. PUC regulatory treatment of compliance options appears to provide one very plausible explanation for this finding. However, this may not be the only explanation because emissions compliance involves dynamic, multi-period decisions on the part of companies. For example, long-term coal contracts may prevent companies from fuel switching. Or scrubbing may be undertaken to bank allowances for future use when prices are likely to be higher so that cost-minimization might occur over time rather than in one year.

Still, PUC regulatory rules that do not treat compliance options symmetrically or that are not coordinated across jurisdictions can induce utility companies to deviate from cost-minimizing behavior from the perspectives of ratepayers and society as a whole. Moreover, regulatory treatment that permits dollar-for-dollar pass through of allowance costs and revenues and fuel costs provides utility companies with absolutely no incentive to minimize their compliance costs. If we take the actual costs we have simulated seriously and simply compare them to the least-cost solution taking scrubbers as given, we see almost an 88% increase over the minimum cost needed to attain the emissions level actually achieved in 1996 in the Title IV Program.

If we were to extrapolate that 88% figure to the estimated costs to the power industry for complying with CAIR -- $2.36 billion in 2010 and $3.57 billion in 2015 -- we would witness a significant impact on electricity rates going forward. However, CAIR has been issued only recently and utility companies have just begun to work with PUCs on compliance plans and the cost recovery for those plans. Guided by the findings outlined above, PUCs and utility companies would be well advised to work together to develop incentive plans that will encourage cost minimizing behavior for compliance with CAIR.

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1 Basic Facts on Clean Air Interstate Rule 2005, available at http://www.epa.gov/air/basic.html. In the final rule, the Model Trading Program “allows the CAIR Program to build on the successful Acid Rain Program. See Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NOx SIP Call: Final Rule, March 10, 2005, at 549, available at http://www.epa.gov/cair/pdfs/cair_final_preamble.pdf.


7 Not all allowances are allocated free of charge, but there is a set-aside of about 3% of total allowances allocated that are auctioned each year.


referred to in the text as the RFF Study. The MIT Study is by Denny A. Ellerman, Richard Schmalensee, Paul Joskow, Juan Pablo, and Elizabeth M. Bailey, Market for Clean Air: The U.S. Acid Rain Program (New York: Cambridge University Press, 2000), Chapters 9 and 10.


17 Kenneth Rose, Alan S. Taylor, and Mohammad Arrunuzzaman, Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emissions Allowances, NRRI 93-16, National Regulatory Research Institute, Columbus Ohio, 1993. Rose et al. suggest that compliance actions and costs be benchmarked to the allowance price. For actions taken that result in per-ton reduction costs below the allowance price, utility companies and ratepayers would share the gains. For actions leading to per-ton reduction costs exceeding the allowance price, utility companies and ratepayers would share the cost.

18 For an early overview of deregulation, see Paul L. Joskow, Restructuring, Competition, and Regulatory Reform in the U.S. Electricity Sector, JOURNAL OF ECONOMIC PERSPECTIVES, 11:3 (1997), at 119-138. For a summary of states that have moved to “deregulate”, see www.eia.doe.gov/cneaf/electricity/chg str/restructure.pdf.


21 For example, the Massachusetts PUC allowed Western Massachusetts Electric to keep 20% of revenues from allowance sales so that the company has an incentive to sell allowances, but the company has no apparent incentives to reduce fuel costs. As another example, Union Electric in Missouri was allowed to retain half its revenues from allowance sales, again with no apparent incentives to reduce fuel costs. New Jersey’s PUC “strongly discouraged” allowance purchases, thus effectively signaling it will force the utility shareholders to bear the cost of purchases. Wisconsin had incentives in place that allow utility companies to keep all cost savings from reduced fuel expenditures (presumably on cheaper high sulfur coal), but this is tempered by a countervailing incentive to keep emissions below a certain level.

Engineering costs are for those units that did not have scrubbers installed as of 1996. We used observed historic costs for units that had scrubbers installed.


The annualized capital cost is based on a 20-year economic life and a discount rate of 10%.

We need not worry about allowance sales and purchases as these should cancel out in the aggregate.

The costs reported here do not include the costs of some units using high sulfur coal when it would have been cheaper, even in the absence of the Acid Rain Program, to use low sulfur coal. If those costs are included, then the cost would have been close to $1.3 billion. We likely observe this phenomenon not because of PUC regulatory policy, but rather due to the inability of some utility companies to renegotiate or terminate long-term coal contracts for more expensive high sulfur coal.

Comparing our result to the RFF study makes sense since we both use actual emissions and take scrubbers as given. The main differences, other than technique, are our treatment of scrubber costs and our baseline for uncontrolled emissions.

The volumes reported for Simulation B are part of a “quasi-equilibrium” in which the amount sold exceeds the number bought due to discrete jumps in the market demand and supply that arise from scrubbing decisions. The numbers reported are amount sold.

