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The Total Cost Effects of the Binding Phase II
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# The Total Cost Effects of the Binding Phase II Title IV $SO_2$ Allowance Market

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By

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**Abstract**

**The Total Cost Effects of the Binding Phase II Title IV $SO_2$ Allowance Market**

**By**

**Howard J. Haas**

The current trend in environmental control regulation is to use marketable allowance systems, or air bubbles, in the place of more traditional single emission standard caps. The reason for the shift is that marketable allowance systems can achieve specified emission goals at substantial control cost savings relative to the more traditional forms of regulation. There are, however, two—not one—cost effects associated with using a marketable allowance system relative to a single emission rule based cap—the abatement cost affect and the external cost effect.

It is the more familiar abatement cost effect that has received the most attention from the proponents of marketable allowance systems—particularly in the case of the Clean Air Act of 1990's $SO_2$ allowance market. However, given the nature of $SO_2$ emission deposition, the marginal external costs of emissions vary across the units participating in the market. Where these costs vary by unit, the reallocation of allowances through trade among these units will impact the total external costs generated by emissions relative to the total external costs where allowance trades are not allowed—as under a traditional emission cap. This change in external costs is the external cost effect of allowance reallocations. Both effects must be considered when estimating the total benefits of using a market rather than a cap. Given the fact that sulfur dioxide emissions have locational effects the failure to include the reallocation of emissions affect

of market trades is a serious oversight on the part of policy makers when calculating the potential net benefits of the title IV market.

This dissertation uses a simulation of the future binding Phase II $SO_2$ Allowance Market, as defined by Title IV of the Clean Air Act, and emission deposition models to calculate the total annual cost effects of the market relative to a more traditional emissions cap. In so doing it finds strong evidence that the annual external cost of allowance reallocations will outweigh the projected annual abatement costs of the market relative to the emissions cap. This loss is due to the miss-specification of the market relative to the nature of the pollutant. The national scope of the Title IV allowance market is too large when used to control a pollutant with regional effects. The models show that smaller regional markets, which reduce the discrepancies in external cost effects across participants and limit the geographic movement of allowance greatly improve the net cost effects of market relative to a cap.

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TABLE OF CONTENTS

**TABLE OF CONTENTS—CONTINUED**

TABLE OF CONTENTS—CONTINUED

TABLE OF CONTENTS—CONTINUED

TABLE OF CONTENTS—CONTINUED

TABLE OF CONTENTS—CONTINUED

**TABLE OF CONTENTS—CONTINUED**

## LIST OF TABLES

## LIST OF TABLES—CONTINUED

## LIST OF TABLES—CONTINUED

## LIST OF TABLES—CONTINUED

## LIST OF FIGURES

## INTRODUCTION

The current trend in environmental control regulation is to use marketable allowance systems, or air bubbles, in the place of more traditional single emission standard caps. The reason for the shift is that marketable allowance systems can achieve specified emission goals at substantial cost savings relative to the more traditional forms of regulation.

The promise of substantial costs savings from the use of a market for emission allowances led to the largest and most ambitious marketable emission allowance program yet—the Title IV $SO_x$ Allowance Market program included as part of the Clean Air Act of 1990. With a goal of reducing emissions from 1986 levels of 16.8 million tons a year to 8.9 million tons by the year 2010. There are, however, two cost effects associated with using a marketable allowance system relative to a single emission rule based cap—the abatement cost affect and the external cost effect.

The abatement costs effect is the total abatement cost savings of meeting the emission goals using a market for allowances rather than a cap. Where the external costs of emissions are dependent on the location of the source of the emissions relative to possible receptors, the marginal external costs of emissions may vary across agents participating in the market. Where these costs vary by agent, the reallocation of allowances through trade will impact the total external cost of the market relative to total external costs where allowance trades are not allowed—as under a traditional emission cap. This change in external costs is the external cost effect of allowance reallocations.

The greater the discrepancy in external costs among market participants, the greater the external cost impact of any trade among the participants. Both effects must be considered when estimating the total benefits of using a market rather than a cap. Unfortunately discussions of marketable permit systems, both theoretical and real, have ignored the external cost effect when promoting the merits of market emission regulation.

The promised cost savings of Title IV are substantial—as great as $1.6 billion a year relative to a cap with the same emission restrictions. In addition, the EPA has estimated that potential health cost savings of the emission cap relative to where emissions would be in 2010 without the cap are around $40 billion a year. Unfortunately, these two estimates of benefits are unrelated. The first measure estimates the cost advantage of the market system over the cap in terms of abatement cost savings to utilities. The second measure estimates the health benefits of using the cap relative to a hypothetical situation where no regulation was passed.

The estimated benefits of the Title IV program do no take into account the effect of allowance reallocations on total external costs—while it was the abatement cost savings of the market reallocations that promoted the program. Given the fact that sulfur dioxide emissions have locational effects (emissions affect areas downwind of sources) the failure to include the reallocation of emissions affect of market trades is a serious oversight on the part of policy makers when calculating the potential net benefits of the title IV market.

This dissertation does three things. First, it examines the possibility that marketable allowance systems can be less efficient than single emission standards when external costs are locationally dependent. Second, it examines the two cost effects of the $SO_x$ marketable allowance system under Title IV of the Clean Air Act of 1990. Third, it shows that reducing the differences in the marginal external costs among market participants—by reducing the size of the markets—will increase the net benefit of allowance reallocation relative to those predicted for the national market.

Chapter 2 of this dissertation discusses the possibility that any marketable allowance system can be less efficient than single emission standards when external costs are locationally dependent. Chapter 3 discusses the Phase II allowance market and the issues surrounding it and sets the stage for the simulation model used in chapter 4 to measure the two cost effects of the binding Phase II market. Chapter 4 presents the simulation model and its results regarding the net cost effect of the binding Phase II allowance market. The Chapter 4 results concur with the estimates of $1.6 billion in annual abatement cost savings of using the market, but indicates strong evidence that all of these savings will drowned out by substantial increases in total external costs due to allowance market reallocations among participants. Chapter 5 indicates that a national market for allowances is inappropriate for a pollutant with regional-dependent external costs. Due to the size of the current market and the nature of $SO_2$ emissions, the marginal external costs of emissions among market participants are very diverse. Therefore trades among participants have strong impacts on total external costs. Chapter 5 simulates the effect of using several regional markets in place of the current national market for allowances and calculates the two cost effects of allowance reallocations in the markets. Regional markets reduce the potential cost savings of any market trades, but they also work to reduce the differences in marginal external costs among each market's participants. The results shows very strong evidence that using regional markets will greatly reduce the negative external cost impacts of allowance market trades relative to the current national market structure.

Chapter 6, the conclusion, reiterates the fact that in designing a market for allowances, regulators must keep in mind the nature of the pollutant that us being regulated. A marketable allowance system may not be the welfare improving option relative to traditional single-emission standard caps when external effects of emissions are location dependent. If the pollutant is equally damaging regardless of source a market will always outperform a cap. Examples of such pollutants take the form of greenhouse and ozone-layer-depleting emissions. In any other case, the potential external cost effects must be examined to determine the true net benefit of a marketable allowance system, like that used in Title IV of the Clean Air Act of 1990.

# CHAPTER 1

# TOTAL COST EFFECTS FROM THE USE OF MARKETABLE ALLOWANCES IN PLACE OF EMISSION CAP REGULATION—THE EFFECTS OF SOURCE DEPENDENT EXTERNAL COSTS

## I. Introduction and Methodology

This chapter examines the net welfare effects of using a market for allowances rather than a single emission rule cap as a means of achieving a given emission goal when there is a locational dependence on the external costs created by emissions. The model presented here indicates that where external costs vary by firm, market reallocations of allowances—relative to initial allowance allocations under a single emission standard cap—cause welfare effects beyond just the abatement cost effects traditionally focused on when examining the relative benefits of market based emission regulation. Given location dependent external costs there is a potential that a single-emission standard will be more efficient than a market for emission allowances among the firms. This is an important issue given the current movement towards the use of markets for emission allowances as a means of reducing the costs of compliance associated with meeting a given emission goal. The most notable example of this new trend is the market for sulfur dioxide allowances set up by Title IV of the Clean Air Act of 1990.

In the course of examining this issue, this chapter presents a theoretical model of a number of firms each facing two regulators—one concerned with total emissions and external costs from all firms and the other concerned with maximizing firm-specific surplus. Section IV introduces a brief review of the externality regulation problem in the literature and how, in most cases, it assumes away or ignores the effects of location dependent external costs on incentive based regulation. Section V presents the two regulators, the firms, the regulatory tools available to the environmental regulator, and the information assumptions of the model. Section V also indicates the existence of the two net cost effects of single-rule externality regulation in the context of emission caps and the markets for allowances, and the conditions under which one form of the regulation could be expected to outperform the other. Section VI presents the conclusion.

## II. Incentive Based Regulation and Command and Control Regulation in the Literature

It is common knowledge that the use of incentive based regulation—such as a market for allowances or an auction—will, all else held equal, lower the compliance costs of achieving a given emission cap goal relative to command and control regulation.[1] Montgomery, for example, proved that under conditions of perfect competition, a market for allowances is superior to command and control regulation.[2] This is not a surprising or unprecedented result. It has been argued since Pigou that incentive based regulation (market-based) have benefits over command and control forms of regulation.[3] In fact, it is noted that economists have a "traditional bias in favor of incentive-based instruments

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[1] If trade occurs in a market for allowances it is assumed that the trading partners are at least as well off after the trade as before. If the trade occurs, the benefit takes the form of reduced compliance costs for the buying agent and revenue for the selling agent.
[2] D.W. Montgomery, "Markets in licenses and efficient pollution control programs", Journal of Economic Theory, 5, 395-418 (1972).
[3] Pigou, The Economics of Welfare (1932).

over standards."[4] Economists interested in environmental, safety, and health regulation have long argued that decentralized, incentive-based (IB) policies are more efficient than centralized, command-and-control approaches (CAC). However, the introduction of externality correcting regulation, either incentive based or command-and-control in nature, can cause shifts in the relative location and volume of emissions in an environment with multiple, spatially segregated firms. Though shifts in the location of some pollutants may affect welfare, most of the current literature does not address this issue when discussing the relative merits of incentive based regulation relative to command and control standards and caps. Within the context of marketable allowances systems relative to single emission rule caps, the issue of location dependent external costs has not yet been examined in any detail.

While the issue of location-dependent externalities has been largely ignored, there has been a considerable amount of literature regarding the circumstances where emission caps and command and control regulation may prove to be more efficient, or at least as efficient, as some incentive based regulation. For example, it is often argued that under perfect information, where "the regulator and the firm are equally informed, standard-setting and emissions taxation approaches are equivalent."[5] This is seen in the work by Baumol (1972), Seneca (1974), and Weiztman (1974). Weitzman argues that the reason often cited for the theoretical superiority of price systems (taxes) above emissions caps—that the use of prices economizes on information requirements—is incorrect. "The main

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[4] Chulho Jung, Kerry Krutilla, and Ron Boyd, "Incentives for Advanced Pollution Abatement Technology at the Industry Level: An Evaluation of Policy Alternatives," Journal of Environmental Economics and Management. 30. 1996. Page 96.

thing to note here is that generally speaking, it is neither easier or harder to name the right prices than the right quantities because in principle exactly the same information is needed to correctly specify either."[6]

The examples where a standard can perform at least as well as incentive-based regulation are not limited to full information cases. In fact, there is literature that demonstrates that where information asymmetric or limited, standards can equal or outperform a tax in efficiency. In the case of a single firm, Weitzman shows a situation where a regulator with limited information about the marginal costs of abatement must choose between a tax and a standard to achieve a policy goal, "there is nothing to recommend one mode of control over the other."[7] Both forms of regulation, when set to achieve the same emission goal, are both sub-optimal unless expected marginal costs are equivalent to actual costs. For example, where the true marginal costs of control prove to be higher than expected by the regulator, the tax is too low and the cap proves to be too restrictive to be efficient—when the marginal benefit line of effluent removal is downward sloping.

Of interest, however, is how the literature treats incentive base regulation when external costs are location dependent on the source. In general, the studies regarding incentive based regulation effects relative to command and control regulation are limited to efficiency comparisons between standards and taxes—and not with regard to whether

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[5] David P. Baron, "Regulation of Prices and Pollution Under Incomplete Information," Journal of Public Economics. 28 (1985) 211-31.

[6] Martin Weiztman, "Prices vs. Quantities," Review of Economic Studies, October, 1974, 41, page 477.

[7] Martin Weiztman, "Prices vs. Quantities," Review of Economic Studies, October 1974, 41, page 477.

or not the marginal external costs are or are not heterogeneous across firms. The major concern with these standards is whether or not there is equalization of marginal abatement costs across all firms.

The work by Weitzman (1974), Seneca and Taussig (1974), Dales (1968), Baron (1985), Spulber (1985), and Jung (1996) is indicative of the studies regarding the efficiency of a single tax relative to a cap or standard. Where there is little homogeneity among the abatement costs of firms, the literature indicates that the single tax is preferred over standards unless, as indicated above, the standards are firm-specific and set to equate marginal abatement costs across all firms. Either implicitly or explicitly, the assumption of the inefficiency of a standard relative to a tax when marginal costs of abatement are not homogenous across firms assumes that the marginal external costs of firms are equal across all firms. The general result that a single tax is more efficient than a standard from Weitzman (1974), Seneca and Taussig (1974), Dales (1968), Baron (1985), Spulbur (1985), and Jung (1996) falls apart in a multi-firm setting when marginal external costs vary by firm.

Under the assumption of heterogeneity of external costs, heterogeneity of marginal abatement costs should be assumed at the optimal solution. What is required for efficiency in this situation is not an equalization of abatement costs across firms, but regulation that sets the marginal benefit of removing emissions form each firm equal to the marginal abatement costs of each firm. A single tax cannot do this, but a single standard, under the right circumstances can, at least in part, achieve this goal. This is seen by Weitzman (1978). In his paper, Weitzman has a regulator choose to employ either a single (pure) tax, a single (pure) cap, or a combination of a quantity and price restraint on a set of firms to control an externality. Weitzman finds that where the marginal costs of abatement are more homogeneous, the single standard is more efficient than the tax. When the marginal external costs are more homogeneous, Weitzman finds the single tax is superior to the single emission standard where marginal abatement costs are heterogeneous. Weitzman indicates that regulation that makes use of both taxes and quantity restrictions can be superior to either a tax or a cap.[8]

However, Weitzman's results (1978) have unexpected implications regarding the efficiency of a market for allowances relative to a cap. They would seem to indicate that the efficiency of a market for a set quantity of allowances, which is by definition a system of both prices and quantities, may depend on the relative homogeneity of the marginal external costs of all firms in the market. Where these costs are similar, the single price mechanism of the market will "correct" the differences that may exist in marginal abatement costs—thus improving efficiency via the results in Weitzman (1974), Seneca and Taussig (1974), Dales (1968), Baron (1985), Spulbur (1985), and Jung (1996).[9] However, where the marginal external costs of the firms are heterogeneous, the single price offered by the market may reduce welfare relative to the cap—via the Weizman's result that a tax may be less efficient than a cap in similar circumstance.

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[8] His regulation achieves better results than either pure regulation by placing more or less weight on a tax or the quantity standard depending on the relative homogeneity of abatement and external costs of the firms. See Martin Weitzman, "Optimal Rewards for Economic Regulation," AER, September 1978, 68, no.4, Pages 683-691.
[9] As noted above, all of these authors indicate that a single tax (price) will be more efficient than a standard when marginal abatement costs are heterogeneous across firms—unless standards are set on an individual basis to equate marginal abatement costs across firms.

The problem with the market for allowances, unlike Weitzman's proposed regulation, is that the proportion of price oriented and quantity oriented effects of the market for permit regulation, as defined, is not adjustable. Where marginal external costs are heterogeneous across firms, the single price offered by the market will be, via Weitzman's analysis of the single tax, less efficient than the single standard. Yet there is no mechanism to reduce the marginal abatement cost smoothing effect of the market when it is inappropriate. This implication of Weitzman's work has been missed by the most current literature regarding the use of a market rather than a single emission rule cap.

Where markets for allowances are specifically examined in the literature, the effect of heterogeneous marginal external costs on the efficiency of the market do not receive much, if any, interest. This is not to say that locational or firm specific externalities are not recognized in the literature, merely that this issue is treated in passing as a side issue, or assumed away. Misiolek and Harold (1989)[10], for example, examine imperfect competition effects on the efficiency of an allowance market. It is implicitly assumed that marginal external costs are constant across the firms in the analysis when arguing that market manipulations by firms are always detrimental to efficiency, relative to a single emission rule cap. When Jung, Krutilla, and Boyd (1996)[11] look at incentives to innovate in abatement technology across various regulatory tools they show that a market may not

[10] Walter S. Misiolek and Harold W. Elder, "Exclusionary Manipulation of Markets for Pollution Rights," Journal of Environmental Economics and Management, 1989, Number 16, Pages 156-166.

[11] Chulho Jung, Kerry Krutilla, and Ron Boyd, "Incentives for Advanced Pollution Abatement Technology at the Industry Level: An Evaluation of Policy Alternatives," Journal of Environmental Economics and Management, 1996, number 30, pages 95-111.

be the most efficient form of regulation in terms of lowering costs over time due to innovation. While they mention that their paper is timely due to the current Title IV market for allowances, their study was made without regard to location dependent external costs of sulfur dioxide emissions.[12] They indicate that an auction is the most efficient means of pollution control in terms of innovation, but that the allocation of allowances is not relevant. Weitzman (1974), takes a look at multiple firms facing a market or a single emission standard cap. In this paper, the market will improve on a cap by equating marginal costs of abatement across firms. As noted previously, this result is only generally true when marginal external costs are homogenous across firms in the market.

In the case where the studies are specifically made in regard to the developing allowance market under title IV, where there is every indication that external cost effects are not homogeneous across firms, the issue of location dependent external costs have received a mixed treatment. One of the most recent examinations of the Title IV allowance market set up by the 1990 Clean Air Act is by Coggins and Smith (1993). In their paper regarding a simulation of a two firm allowance market under two regulators, there is an explicit assumption that the external impact of trades of sulfur dioxide allowances are not dependent on the relative sources of the emissions. It is assumed that since the command and control (CAC) and incentive based (IB) regulation will achieve the

[12] In addition, the fact that they examine an emission standard rather than an emission cap, indicates that their conclusions regarding the relative efficiency of a market in terms of

same emission goals they will be equivalent in external impact:

> "Because the pollution levels for each firm are here held fixed---and because the overall emission standard is assumed to be identical in the CAC and in the allowance trading case—there is no need to account for the environmental damage in the welfare measure...environmental damage is not unimportant; it simply does not change."[13]

Coggins and Smith are implicitly assuming that the relative location of the sources does not impact the costs inflicted by sulfur dioxide emissions. However, in the case of sulfur dioxide emissions, environmental damage does change with the location and levels of emissions. Under these circumstances each and every trade or reallocation of allowances in the market can and will cause some change in environmental damage—thus there is a need to account for environmental damage as a welfare measure. This is a fact recognized by Schmalensee when he states, "permitting allowances to be traded freely anywhere in the United States would be a first-best policy if and only if emissions everywhere in the United States had the same marginal damage, which they plainly do not."[14] However, the effects of trades are beyond the scope of Schmalensee paper and he does not include them in his discussion of the current, early Phase I market. This was beyond the scope of Joskow,

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innovation are suspect in regards to the impact of Title IV.

[13] Coggins and Smith, "Some Welfare Effects of Emission Allowance Trading in a Twice-Regulated Industry", Journal of Environmental Economics and Management 25, 275—297 (1993).

[14] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, Page 54.

Schmalensee, and Bailey (1998) as well.[15] Here, the authors argue that the market for sulfur dioxide emissions (allowances or allowances) is very efficient, so much so that "the frictionless, perfectly competitive ideal is a good approximation to reality."[16] While Joskow (et al) argues that the market lacks much in the way of transaction costs, he does not address the potential impact on external costs of a reallocation of allowances through trade—and what impact this may have on the net efficiency of the market. As of the writing of this paper, there has not been an explicit treatment of location-dependent marginal external costs in a comparison of markets and single-emission rule caps in the literature.

In comparing an allowance market to a single-emission rule cap, this paper follows in the tradition of the previous literature that examines the relative strengths of various forms of externality regulation under varying circumstances. As in Weitzman (1972, 1978), Kwerel (1977), Dales (1968), and Baron (1985), this paper presents a regulator with limited information that must choose between imperfect instruments in attempt to maximize welfare. This paper differs in that it examines the welfare effects of using a market for allowances rather than a single emission rule cap to reach a given emission goal, whereas the bulk of research has been in regards to comparisons of standards and taxes. Unlike the earlier comparisons between single-emissions standards and a market,

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[15] Paul L. Joskow, Richard Schmalensee, and Elizabeth M. Bailey, "The Market for Sulfur Dioxide Emissions," The American Economic Review, Vol. 88, NO. 4, September 1998, 669-683.
[16] Paul L. Joskow, Richard Schmalensee, and Elizabeth M. Bailey, "The Market for Sulfur Dioxide Emissions," The American Economic Review, Vol. 88, NO. 4, September 1998, Page 682.

this paper examines the effect of a locational dependence of external costs on the net welfare of each regulatory form.

## III. Single Emission Standard Caps and Markets for Allowances: The Net Welfare Effects of Market Reallocations of Allowances

This section of the paper is divided into several sections. Part 1 introduces the economic units (firms) that produce an externality along with an output. Each of these units is described as a regional firm with its own firm-specific downward sloping demand curves. This section is further divided into a number of sections that introduce the locationally dependent external costs of each unit, and the abatement (pollution control cost) function. Part 2 is divided into several subsections. The first two sections, a and b, introduce the two independent regulators of the unit: the environmental regulator and the Firm Specific Regulator (FSR). These sections also discuss the setting of the single emission rule cap and the allocation of the allowances. Part c explains the abatement cost and the external cost effects within the context of the model. Part d discusses the effect of the cap on the firms and how the FSR responds to the allowance allocations applied as a cap. Part e discusses the reaction of the firm and the FSR when the cap is applied as set of marketable allowances on the firms. Part f indicates the two distinct welfare effects of market reallocations of allowances—the abatement cost and the external cost effects—relative to the EPA's initial allocations of allowances under the single emission rule cap. Part f briefly describes the conditions under which the market will cause both effects and where a net loss is possible relative to the use of the cap.

## A. The Basic Economic Unit: The Firm.

There exist a number of profit-maximizing firms indexed by i. Each firm is a monopolist in its own market and there is no interdependence of demand functions among the firms for the output ($Q_i$) produced by each firm. Let each firm's demand function be defined by the following: $P_i(Q_i)$.

Where $P_i$ is the price received for each unit for $Q_i$. Price is to be decreasing with respect to output sold:

$$\frac{d}{dQ_i}P_i(Q_i) < 0$$

For simplicity, each firm's demand curve is assumed to be identical.

Let $C_i(Q_i)$ be the cost of producing $Q_i$ units of this output at a firm's production facility. The cost function is assumed to be strictly increasing in terms of $Q_i$ and twice differentiable in terms of $Q_i$. For simplicity, the costs of production are assumed to be identical across all firms. Each firm has an identical fixed physical capacity constraint on its output equal to Qmax. Qmax is equal to the quantity where the identical, firm specific demands return a price equal to zero (at the intersection, if any, of the demand curve with the horizontal axis). Each firm is only able to own one production facility, so Qmax represents the maximum output possible from any one given firm. In addition it is assumed that each firm must satisfy its firm specific demand before attempting to supply another firm's demand (before it attempts to enter another firm's market). These assumptions prevent incumbent firms from successfully entering other markets. In addition, infrastructure requirements allow only one firm to operate in a given area. This can be explained by assuming each firm has exclusive control of each region's only supply of material capable of producing Q. This assumption preserves the assumption that each firm is a monopolist in its own market and there is no interdependence of demand functions among the firms for the output ($Q_i$) produced by each firm. In addition this assumption prevents entry from new firms. The assumption of no entry or exit from the industry is not unusual in the literature regarding comparisons between externality regulation. This last feature simplifies study of an allowance market where allowance allocations are fixed and provided only to incumbent firms.[17]

Each firm's profit function, without regard to abatement and external costs is thus defined as follows:

$$\text{Max w.r.t. } Q \quad \Pi_i \, Q_i = P_i \, Q_i \cdot Q_i \quad C_i \, Q_i$$
$$Q_i \le Qmax$$

**1. The locationally (spatially) dependent external costs of the firms.**

It is assumed that the firms are distributed among several geographic regions indexed by j. Each firm emits a pollutant that imposes costs on the residents of the other geographic regions. The costs are not imposed on the firms. Nor do the pollutants affect the population where they are generated. That is, each regional market and incumbent firm imposes an externality on the residents of other geographic regions.

[17] This assumption is often used in models where an emission goal is being set for the cap. See Chulho Jung, Kerry Krutilla, and Roy Boyd, "Incentives for Advanced Pollution Abatement Technology at the Industry Level: An Evaluation of Policy Alternatives," Journal of Environmental Economics and Management, 30, (1996), 95-111; Martin Weiztman, "Prices vs. Quantities," Review of Economic Studies, October, 1974, 41, 477-91; Martin Weitzman, "Optimal Rewards for Economic Regulation," AER, September 1978, 68, no.4, Pages 683-691; and David P. Baron, "Regulation of Prices and Pollution Under Incomplete Information," Journal of Public Economics. 28 (1985) 211-31.

The external cost of each firm depends on several factors. First of all, the damage caused by a given firm (i) to a given geographic region (j) is dependent on what percentage of the firm's emissions ($\Gamma_{ij}$) hit a given receptor region. As noted in the paragraph above, the percentage of emissions that hit a firm's own region is equal to zero. Each unit of emissions that does make landfall is assumed to do the same amount of damage (d) regardless of its source. Each unit of output ($Q_i$) from any firm is assumed to create a unit of emissions equal to E. E is assumed to be equal across firms before the application of any form of abatement controls, which are defined in the next section. Total emissions from a firm, before abatement, are therefore given as $Q_i \cdot E$. Therefore, what determines the total external cost of a given firm (i) is the total percentage of its emissions that make landfall ($0 \le \sum_{j=1}^{m} \Gamma_{ij} \le 1$) times the amount of emissions generated by a firm

($\sum_{j=1}^{m} d \cdot E \cdot Q_i \cdot \Gamma_{ij}$).

Consider the following functional form for the externality produced by a firm:

$$D(Q_i) = \sum_{j=1}^{m} d \cdot E \cdot Q_i \cdot \Gamma_{ij}$$

Where:

j subscript that identifies a region that receives emissions

i subscript that identifies each unit that produces an eternality through emissions

$\Gamma_{ij}$ represents the percentage of a given unit of pollution from unit i that affects region j.

E represents the units of pollution that each unit of output (Q) generates.

$Q_i$ represents output from unit i.

d represents the damage caused by each unit of pollution generated that makes landfall within regions indicated by j.

For ease, let the damage per emission unit be denoted as equation 1.3:

$$1.3 \quad MD_i = \sum_{j=1}^{m} d \cdot \Gamma_{ij}$$

Where MD stands for the marginal damage caused by each unit of pollution generated by firm i. Total damage from a firm is then given as:

$$D_i(Q_i) = E \cdot Q_i \cdot MD_i$$

Total external costs across all firms is given as:

$$\left[ \sum_{i=1}^{n} D_i(Q_i) = \sum_{i=1}^{n} E \cdot Q_i \cdot MD_i \right]$$

**2. The abatement or emission reduction cost function of firms**

It is assumed that technology to remove emissions from a firm's production process exists. Since the profit maximizing firms do not include the externality in their calculations, the technology is left unused unless the costs of emissions (MD) are internalized through regulation that will be introduced later in this chapter.

Abatement effort is measured in the percentage of emissions that a given level of abatement will remove from the emission stream ($RE_i$). As such, the value of abatement effort ranges from 0 to 100 percent of emissions.

Unlike production costs, the cost to generate a unit of RE (a percentage point of removal) is unit specific and dependent on the retrofit requirements of the individual unit and the amount of emissions removed. It is assumed that each region's available resources have a unique quality that affects the costs of removing emissions from the production process (as various coal types affect the costs of FGD use in utilities). Abatement costs are a function of output (Q) and the percentage of emissions removed (RE). Let $A_i(Q_i, RE_i)$ be the cost of abatement for removing a specific percent (RE) of emissions created with the production of Q in output at a given firm. This cost function is assumed twice differentiable and strictly increasing in terms of output (Q) and abatement (RE). This model of abatement costs is similar that used by Baron (1985), Weitzman (1974, 1978), and Jung (1996). Differentiating $A_i(Q_i, RE_i)$ with respect to abatement (RE):

$$\frac{d}{dRE_i} A_i(Q_i, RE_i) > 0$$

and

$$\frac{d^2}{d\,RE_i^2} A_i(Q_i, RE_i) \geq 0$$

Differentiating with respect to output:

$$\frac{d}{dQ_i} A_i(Q_i, RE_i) > 0$$

$$\frac{d^2}{d\,Q_i^2} A_i(Q_i, RE_i) \geq 0$$

## B. The Two Regulators

This part of section V introduces the two regulators that govern the behavior of the monopolistic unit described above. The first regulator is described as a firm specific regulator (FSR). The FSR is modeled after a firm-specific utility regulator. The objective of each FSR is to maximize the surplus that exists in the regional market it oversees based on the private costs of the regional firm. That is, welfare is maximized without regard to external costs generated by firm under the FSR's jurisdiction. Each FSR's objective function is maximized subject to a break-even constraint on the firm it oversees. This regulator is described in part (a) below. The second regulator, the Environmental Planning Administrator (EPA), is modeled after a stylized Environmental Protection Agency. The objective of the EPA is to maximize total regional surpluses (welfare) by internalizing the external costs generated by the firms. The EPA has limited information regarding the external costs generated by the firms as a whole, as well as limited information regarding industry-wide costs of abatement. In addition, the EPA is limited to two forms of regulatory intervention—a single emission standard cap applied to every firm or a similarly distributed allocation of marketable emissions allowances. The stylized EPA is described in part (b) below. The behavior of both regulators is modeled into two distinct static equilibrium periods—the period before EPA regulation and the period after EPA regulation. This is not an inter-temporal planning model. No reaction functions are modeled between the two regulators due to the fact that neither regulator has information needed to anticipate the others responses. It is assumed that the FSR and the firm cannot anticipate the EPA's regulation before it occurs. Nor can the EPA anticipate the reaction of the FSR to its cap or market regulation of emissions. Part c describes the actions of the

FSR after the EPA has attempted to internalize the costs of emissions by way of a cap or a market for allowances.

### 1. The Firm Specific Regulator: the FSR

Each FSR's objective is to maximize the static equilibrium surplus within a regional market given the private costs of the firm it is regulating. The FSR's objective function is constrained by the fact that revenues must at least cover the private costs of the regulated firm in the market in question in each period. Prior to intervention in from the EPA, external costs are not, by definition, included in the objective function of the FSR. The period before EPA action is referred to as period t-1. The t-1 equilibrium levels of output and emissions are assumed to be historical information for the EPA when the EPA imposes emission regulation in period t, described in the next part of this section. It is assumed that neither the firm nor the FSR can anticipate any action, if any, that will be made by the EPA in period t. The objective function of a FSR in period t-1, before EPA regulatory action is as follows:

1.4 Max w.r.t Q

$$W(Q) = \left( \int_{0}^{Q_i} P(X_i)\, dX_i - P(Q_i) \cdot Q_i \right) + \left( P(Q_i) \cdot Q_i - C(Q_i) \right)$$

Subject to:

$\Pi_i \geq 0$

$Q_i \geq 0$

$Q_i \leq Q_{max}$

The Kuhn Tucker maximization conditions for maximization of the Lagrangian (ζ) with respect to Q and λ1 are as follows:

1.5 $\frac{d}{d\lambda 1_i}\xi(Q_i,\lambda 1_i)=P(Q_i)\cdot Q_i - C(Q_i)\geq 0,\ \lambda 1_i \leq 0$, and $\lambda 1_i\cdot\left(\frac{d}{d\lambda 1_i}\xi(Q_i,\lambda 1_i)\right)=0$

1.6 $\frac{d}{dQ_i}\xi(Q_i,\lambda 1_i)=P(Q_i) - \frac{d}{dQ_i}C(Q_i) + \lambda 1_i\cdot\left[\left(\frac{d}{dQ_i}P(Q_i)\right)\cdot Q_i + P(Q_i) - \frac{d}{dQ_i}C(Q_i)\right]\leq 0$

$Q_i\geq 0$, $Q_i\leq Q_{max}$, and. $Q_i\cdot\left(\frac{d}{dQ_i}\xi(Q_i,\lambda 1_i)\right)=0$

Where the budget constraint is not binding ($\Pi_i>0$ and $\lambda 1=0$), welfare is maximized, subject to the solution satisfying the second order constraints, where quantity is such that price equals marginal cost, seen from 1.6 above:[18]

$$\frac{d}{dQ_i}\xi(Q_i,\lambda 1_i)=P(Q_i) - \frac{d}{dQ_i}C(Q_i)=0$$

or

$$P(Q_i)=\frac{d}{dQ_i}C(Q_i)$$

Where the budget constraint is binding ($\Pi_i=0, \lambda 1_i<0$), the constraint yields the trivial solution that price is set equal to average cost (from 1.5):

$$P(Q_i)=\frac{C(Q_i)}{Q_i}$$

[18] For the second order conditions see Appendix L at the end of this dissertation.

$$\text{with } \lambda 1_i = \frac{-\left(\frac{C(Q_i)}{Q_i} - \frac{d}{dQ_i}C(Q_i)\right)}{\left[\left(\frac{d}{dQ_i}P(Q_i)\right)\cdot Q_i + \frac{C(Q_i)}{Q_i} - \frac{d}{dQ_i}C(Q_i)\right]}$$

Subject to the satisfaction of the familiar second order conditions, which are not given here.

The Q that satisfies 1.5 and 1.6, and the second order conditions, represents the static equilibrium of the ith firm before the EPA sets emission regulation. This level of Q will be referred to as $Q_i^r$ throughout the rest of this paper. Given the assumptions about demand and production costs, $Q_i^r$ is equal across all firms. Total emissions are equal to

$\sum_{i=1}^{n} E\cdot Q_i^r$. Total damage from emissions is equal to

$$\left[\sum_{i=1}^{n} D\left(Q_i^r\right) = \sum_{i=1}^{n} E\cdot Q_i^r\cdot MD_i\right]$$

Total welfare across all regions is given by

$$\left[\sum_{i=1}^{n} W\left(Q_i^r\right) = \left[\sum_{i=1}^{n}\left[\int_0^{Q_i^r}\left(P\left(X_i\right)\right)dX_i - P\left(Q_i^r\right)\cdot Q_i^r\right] + \left[\left(P\left(Q_i^r\right)\right)\cdot Q_i^r - C\left(Q_i^r\right)\right] - D\left(Q_i^r\right)\right]\right]$$

### 2. The Environmental Planning Administrator: The EPA

The stylized EPA modeled here is based on the Title IV allowance program currently being administered by the Environmental Protection Agency. Under the Clean Air Act of 1990's Title IV provisions, the EPA was empowered to permanently reduce total sulfur dioxide emissions of the affected industry by 8 million tons relative to its historical 1985 base emission levels. Historically, the EPA has had effectively one tool—caps on emissions. The 1990 law followed in this tradition. Taking the 1985 emission levels, minus 8 million tons, the law called for total remaining emissions to be distributed to each boiler according to its portion of the total mmbtu of fuel burned by the affected firms in 1985 through 1986. However, unlike earlier regulations, the caps on emissions take the form of marketable allowances. The thought being, as outlined above, that this would lower the costs of compliance, all else being equal. Actual net effect of trading allowances beyond possible abatement costs savings were not considered or known.

In line with these stylized facts, the Environmental Planing Administrator that is modeled here is assumed to have limited authority and information concerning both the firms and the costs caused by emissions. The model of the EPA regulator presented here is similar to those used by Weitzman (1974) and Weitzman (1978). The regulator in this literature faces uncertainty regarding the costs of abatement of the firm(s) and—in the case of Weitzman (1978)—the marginal external costs of emissions. Here, the EPA is assumed to only know the average benefit of reducing emissions and the average costs of industry-wide emissions reduction, as will be illustrated below.

As in Weitzman (1974, 1978), the EPA knows the total damage ( $\sum_{i=1}^{n} D\left(Q_i^r\right)$ ) caused by the emissions generated by the firms in t-1. The EPA also knows the historical (t-1) output ($Q_i^r$) of the firms and the total emissions ( $\sum_{i=1}^{n} E\cdot Q_i^r$ ) generated in t-1, like the EPA under the Clean Air Act.[19] The EPA does not know the damage that occurs at a specific location, nor which firms are responsible for what portion of the damage that does occur. That is, firm specific MD is hidden from the EPA. However the information available to it is sufficient to determine the historical (t-1) average damage per unit of emissions: $D_{avg} = \dfrac{\sum_{i=1}^{n} D\left(Q_i^r\right)}{\sum_{i=1}^{n} E\cdot Q_i^r}$.

It follows that each unit of emissions removed by the industry from its emission stream will, increase welfare on average by $D_{avg}$. Thus total estimated benefit of emission removal is measured as $D_{avg}\cdot \sum_{i=1}^{n} E\cdot Q_i^r\cdot RE_{ind}$ , where $RE_{ind}$ is an industry wide abatement effort.

[19] Strategic behavior by firms anticipating the EPA's action is assumed away. In the case of the 1990 Clean Air Act, historical output levels, from before the legislative process for the act began, were used as the base year to limit the ability of firms to make use of strategic behavior.

As mentioned above, the EPA knows the average industry-wide costs of abatement, given historical output levels $Q_i^r$.[20] This industry-wide abatement cost for an industry emission reduction target $(RE_{ind})$ is given as $A_{avg}(RE_{ind})$.

Using this information, the EPA's goal is to maximize welfare. It is assumed that the EPA's only influence upon the firms and the FSRs is through the use a cap of marketable emission allowances. This total emission limit will then be divided among the firms according to their historic output $(Q_i^r)$ from t-1. This allocation method is used to for two reasons. The first and most important reason is that this method of allocation mimics that used under Title IV—the law this model is designed to illustrate. The second reason is that baring more specific information, the EPA modeled here has no better means of allocating the allowances among the firms—as recognized by Weiztman (1978) and Senecca and Taussig (1979), and Dales (1968). This is seen in Dales (1968) when he writes:

> "The first problem that arises (when using a standard) is how the total amount of waste reduction should be allocated between the firms...equity criteria suggests that each firm share the targeted reduction equally, and thus each firm would be required to reduce wastes (proportionally)...regardless of any underlying cost differentials."[21]

Baring a better allocation method, the literature proposes an allocation method based on some measure of equity.

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[20] The cost estimates available to the EPA are based on present control measures with and best guesses of potential suppliers, holding output constant at the base year—an explanation also used by Baron: David P. Baron, "Regulation of Prices and Pollution Under Incomplete Information," Journal of Public Economics. 28 (1985), page 213.

It is further assumed that once the emission allocations are set, the EPA cannot adjust them.[22] [23] The EPA will not be able to react to any adjustments or trades that the FSR makes in period t as it is committed to its emission allocations once set. This means that the period t, which occurs after the EPA allocates emissions allowances and the FSR responds to the change in perceived private costs, will be solved as a static equilibrium model. The model presented here is therefore similar to the models developed by Baron (1985), Weitzman (1974, 1978), Jung (et al) (1996), and Coggins (et al) (1996). There are many justifications for the use of a single-period model presented in the literature, which are applicable here. In Baron (1985), "if a regulator can commit to a multi-period policy and the private information of the firm is the same in each period, a stationary regulatory policy is optimal...a finite horizon model is thus equivalent to a single to a single-period model under these circumstances."[24] Similarly, if the emission goal set here by the EPA is credible over the foreseeable future, the perceived price of the regulation to the firms will be constant over time, and the single period model will be equivalent to a multi-period model's outcome. In addition, it has been argued that a single, non-adjustable form of regulation is representative of actual environmental policies due to the

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[21] Joseph J. Seneca and Michael K. Taussig, Environmental Economics, Pretice-Hall, Inc. Englewood Cliffs, New Jersey 07632, 1979, 1974.

[22] This is not to say that there would be no need to have an adjustment process, nor is it assumed that adjustment processes are unimportant. The adjustment process of the EPA is a long one based on precedent, administrative rules, and more often than not actual court proceedings. Modeling of such behavior, for the sake of presenting the problems at hand, is not relevant.

[23] The output and emissions of the base year are considered a historic record for the model. Thus, the firms and their immediate economic regulator do not have the opportunity to anticipate the actions of the EPA during the single cap setting period presented above—therefore the concept of a base year output.

costs of adjusting them. Weitzman argues that is inappropriate to view the regulation as a "process of continual fine-tuning…there are costs to adjusting regulations, and they are likely to be substantial."[25] The possibility that a given regulation, once set, will not be as efficient as hoped is one of the risks that must be examined when studying regulation. Weitzman writes, "a basic principle of regulation is that the regulators are forced to make decisions in an uncertain environment and they must lie with the consequences for some time."[26]

The EPA's welfare maximization problem is then:

$$W_{EPA}(RE_{ind}) = D_{avg} \cdot \sum_{i=1}^{n} E \cdot Q_i^r \cdot RE_{ind} - A_{avg}(RE_{ind})$$

Subject to

$$RE_{ind} \geq 0$$
$$RE_{ind} \leq 1$$

Taking the first order condition in terms industry wide abatement ($RE_{ind}$):

$$1.6 \quad \frac{d}{dRE_{ind}} W_{EPA}(RE_{ind}) = D_{avg} \cdot \sum_{i=1}^{n} E \cdot Q_i^r - \frac{d}{dRE_{ind}} A_{avg}(RE_{ind}) = 0$$

[24] David P. Baron, "Regulation of Prices and Pollution Under Incomplete Information," Journal of Prices and Pollution Under Incomplete Information, 28, 1985, 211-231.
[25] Martin Weitzman, "Optimal Rewards for Economic Regulation," AER, September 1978, 68, no.4, Page 684.
[26] Martin Weitzman, "Optimal Rewards for Economic Regulation," AER, September 1978, 68, no. 4, Page 685.

Equation 1.6 states that the welfare maximizing level of emission reduction occurs where the marginal benefit of the industry-wide abatement ($D_{avg} \cdot \sum_{i=1}^{n} E \cdot Q_i^r$) equals the industry's average marginal cost of abatement ($\frac{d}{dRE_{ind}} A_{avg}(RE_{ind})$).

In order for the solution to 1.6 to be sufficient to maximize the EPA's welfare function, the $RE_{ind}$ found must satisfy the second order condition given in 1.7 below:

1.7 $$\frac{d^2}{dRE_{ind}^2} W_{EPA}(RE_{ind}) = -\frac{d^2}{dRE_{ind}^2} A_{avg}(RE_{ind}) < 0$$

Denoting the $RE_{ind}$ that satisfies both 1.6 and 1.7 as $RE_{ind}^{EPA}$, the EPA determines the target level of emissions ($E_{target} = \left[\sum_{i=1}^{n} \left[E \cdot Q_i^r \cdot \left(1 - RE_{ind}^{EPA}\right)\right]\right]$) which will maximize welfare.

Since the EPA must follow a single emission rule cap, the EPA gives a portion of the total emission allowances to each firm in proportion to the firm's regulated output relative to the total output of the industry in the base year:

1.8 $$\Lambda_i = \frac{E_{target}}{\sum_{i=1}^{n} Q_i^r} \cdot Q_i^r$$

Since $Q_i^r$ is equal across all firms, as outlined in the previous section, 1.8 indicates that the emission cap set on each firm is identical ($\Lambda_i$). $\Lambda_i$ represents the number of tradable allowances allocated to each firm.

Given the need to assign the caps according to each firm's proportion of the total output in the base year and the information available, the cap assigned by the EPA will maximize the perceived benefit relative to any other single emission rule cap that the EPA may implement. The proof of this is straightforward. Since the caps assigned to each firm must be in proportion to its share of the total base year output, any change the cap assignments to each firm requires a change in the target emission level. But, as noted above, the target emission chosen by the EPA, in satisfying 1.6 and 1.7, maximizes welfare. Therefore any deviation from this emission target will, given the information available to the EPA, reduce welfare.

### 3. EPA's forced hand: the possibility of a welfare loss from market trades

As in the case of the actual EPA enforcing the 1990 Title IV regulation, it is assumed that the cap allocations represented by $\Lambda$ are tradable among the firms. That is, the decision to use a market rather than a cap is predetermined by the legislation that allows the EPA to reduce emissions via single-emission-standard-cap-allocations. This is not inconsistent with the welfare-maximizing objective of the EPA, given the information available regarding emissions and abatement costs—as outlined above. Without specific information as to the relative distribution of the firm's MD and abatement costs, the EPA is indifferent about whether or not allowances are marketable or not. However, as discussed briefly in the introduction, where the external costs of emissions and the costs of abatement vary across firms, whether or not the allowance allocations are tradable or not will affect the total surplus generated under the EPA's emission reduction regulation. This section briefly describes how the market for allowances can cause a loss in total welfare relative to a more traditional cap with the same total emission goal.

Both the marketable and unmarketable form of allowances, as presented in this paper, will improve total welfare over the case where neither regulatory form is used to curb emissions (where MD effects are, on average, greater than zero). Both regulatory forms work by indirectly internalizing the external costs created by the firms. How well one form of the cap performs in terms of total welfare effects is dependent how closely the internalized costs of emissions under the cap or the market mimic the actual MD of the firms. What determines whether or not the market or the cap better internalizes MD across all firms, is whether or not internalized (shadow prices) of emissions regulation is closer or further away from the actual MD of the firms after trades.

The reallocation of allowances through trade has two effects. The first effect is in terms of relative abatement costs. The second effect is in terms of relative external costs. The sum of the two effects determines whether not allowing allowances to be marketed will improves or degrade total surplus (welfare) relative to the case where allowances remain unmarketable (imposed as a cap). This net effect of trades is equivalent to the measure of the reduction or increase in the dead weight loss caused by the shadow prices of emission regulation moving closer or further away from the actual MD of the firms after potential allowance trades.

The first effect of the trades in a market is the abatement costs savings relative to a cap. For trade to occur there must be differences in the abatement costs across firms. The end result of trade is that it reduces the heterogeneity in the marginal costs of abatement across all firms. This is due to the fact that each firm will have an incentive to use abatement until its marginal cost of abatement equals the market price for allowances. Therefore at the market-clearing price for allowances, the marginal costs of abatement will be equal across all firms. This has the effect of reducing the total costs of abatement for a given emission goal, relative to the single emission rule cap. Holding external costs constant with trade, this reduction in total abatement costs improves total welfare relative to the cap. It is this effect that has sold marketable allowance systems in the 1990 Clean Air Act.

The second effect of allowance trades is the impact that the reallocation of emissions has on external costs. In order for total external costs to be the same before and after trade, the marginal external costs must be identical across all allowance trading firms—assuming total emissions remain the same under both the cap and the market.[27] If the marginal external costs do vary by firm, the absolute value of second effect of the market on welfare is greater than zero. The greater the differences among the external costs among the firms, the greater the value of the externality effect on total welfare. This is due to the fact that any trades and reallocations of allowances will affect the external costs of emissions relative to the allocation under the cap. Unlike the abatement cost effect, the externality effect of trades can be either positive or negative relative to total welfare under the cap.

Where the sum of differences in marginal external costs across the firms is greater than the differences in the marginal abatement costs, the absolute value the externality effect of allowance trades will be greater than the abatement cost savings effect of the trades in the allowance market. In this situation, the sign of the external cost effect will

[27] Where the emission constraints are binding on all firms, as they are in this model, total emissions will remain constant under both the cap and the market—assuming well-behaved firm specific costs.

determine whether or not the market for allowances is superior or inferior to the single emission rule cap in terms of total welfare improvement.

Without specific information as to the relative distribution of the firm's MD and abatement costs, the EPA cannot foresee the possible net effect—positive or negative—of allowing allowances to be marketable or not before trades occur. The EPA is, therefore indifferent about whether or not the allowances it allocates are marketable or not at the time it allocates them among the firms. However, as discussed above, the homogeneity and distribution of abatement and external costs—which are hidden from the EPA—will determine the total welfare of the emission cap set by the EPA. The fact that allowances are tradable may increase or decrease welfare relative to the level predicted by the EPA. The impact of whether or not allowances are marketable on the FSR's decisions is discussed in the next two sections.

### 4. The FSR's reaction to the single emission rule allowance allocations where allowances are not tradable

This section discusses the affect of applying the allowance allocations in their more traditional form as non-tradable emission caps. The impact of this cap on the FSR and the firm is used to examine the how allowing the trade of allowances affects the shadow price of the emission regulation imposed by the EPA.

When the cap is applied to the firms, the costs of complying with the emission cap must be included in the profit function of the firm. The FSRs must, in turn, adjust their output and prices in order to achieve their objectives as outlined in the sections above. The

FSR's objective function, which now includes abatement costs, is now maximized subject to an emission constraint given by $\Lambda$.

The FSR's objective function is as follows:

1.9 Max w.r.t. Q,RE

$$W_i(Q_i,RE_i) = \int_0^{Q_i} P(X_i)\, dX_i \quad P(Q_i)\cdot Q_i \quad [P(Q_i)\cdot Q_i \quad C(Q_i) \quad A(Q_i,RE_i)]$$

subject to

$\Pi_i \;\; 0$

$Q_i \;\; 0$

$Q_i \;\; Q_{max}$

$E\cdot Q_i\cdot 1 \;\; RE_i \;\; \Lambda_i \;\; 0$

$RE_i \;\; 0$

$RE_i \;\; 1$

The emission constraint is assumed to be binding on all firms, given the fact that emissions before abatement are equal across firms and allowance allocations are equal across firms as well—therefore $E\cdot Q_i\cdot 1 \;\; RE_i \;\; \Lambda_i = 0$.

The Kuhn-Tucker maximization conditions for the Lagrangian ($\zeta$) with respect to Q, RE, $\lambda 1$, and $\lambda 2$ are as follows:

1.10 $\frac{d}{d\lambda 1_i}\xi(Q_i,RE_i,\lambda 1_i,\lambda 2_i) = P(Q_i)\cdot Q_i \; C(Q_i) \; A_i(Q_i,RE_i) \;\; 0$, $\lambda 1_i \;\; 0$, and

$$\lambda 1_i \cdot \frac{d}{d\lambda 1_i}\xi(Q_i,RE_i,\lambda 1_i,\lambda 2_i) = 0$$

1.11 $\quad \frac{d}{d\lambda 2_i}\xi\left(Q_i, RE_i, \lambda 1_i, \lambda 2_i\right) = E \cdot Q_i \cdot \left(1 - RE_i\right) - \Lambda_i \geq 0,\ \lambda 2_i \geq 0$, and

$$\lambda 2_i \cdot \left(\frac{d}{d\lambda 2_i}\xi\left(Q_i, RE_i, \lambda 1_i, \lambda 2_i\right)\right) = 0$$

1.12 $\quad \frac{d}{dRE_i}\xi\left(Q_i, RE_i, \lambda 1_i, \lambda 2_i\right) = -\frac{d}{dRE_i}A_i\left(Q_i, RE_i\right) - \lambda 2_i \cdot E \cdot Q_i - \lambda 1_i \cdot \frac{d}{dRE_i}A_i\left(Q_i, RE_i\right) \leq 0,\ RE \geq 0,$

$RE \leq 1$, and $RE \cdot \left(\frac{d}{dRE_i}\xi\left(Q_i, RE_i, \lambda 1_i, \lambda 2_i\right)\right) = 0$

1.13

$$\frac{d}{dQ_i}\xi\left(Q_i, RE_i, \lambda 1_i, \lambda 2_i\right) = P\left(Q_i\right) - \frac{d}{dQ_i}C\left(Q_i\right) - \frac{d}{dQ_i}A\left(Q_i, RE_i\right) + \lambda 2_i \cdot E \cdot \left(1 - RE_i\right) + \lambda 1_i \cdot \left[\left(\frac{d}{dQ_i}P\left(Q_i\right)\right) \cdot Q_i + P\left(Q_i\right) - \frac{d}{dQ_i}C\left(Q_i\right) - \frac{d}{dQ_i}A_i\left(Q_i, RE_i\right)\right]$$

$Q_i \geq 0$, $Q_i \leq Q_{max}$, and $Q_i \cdot \left(\frac{d}{dQ_i}\xi\left(Q_i, RE_i, \lambda 1_i, \lambda 2_i\right)\right) = 0$

The values of Q, RE, λ1, and λ2 that satisfy the 1.10 through 1.13 and the second order conditions (not given here) maximize welfare subject to the emission constraint.[28] Where the budget constraint is binding (Π=0, λ1<0), the constraint yields the trivial solution that price will set equal to average cost (from 1.10 where Q and RE satisfy the Kuhn Tucker maximization conditions):

1.14 $\quad P(Q) = \frac{C(Q) + A(Q, RE)}{Q}$

Note that total costs now include the costs of abatement required to meet the emission constraint. The output and abatement levels that satisfy 1.14 must also satisfy 1.11 through 1.13. Condition 1.12 requires that the marginal cost of abatement effort per unit of emissions, subject to the budget constraint (captured in λ1) must equal the shadow price of the emission constraint (λ2):

1.15 $\lambda 2_i = \frac{(1-\lambda 1_i)}{E\cdot Q_i}\cdot\frac{d}{dRE}A_i(Q_i, RE_i)$

or, equivalently,

1.16 $\lambda_2\cdot E\cdot Q = (1-\lambda_1)\cdot\frac{d}{dRE}A(Q,RE)$

Equation 1.16 shows that abatement effort is set, subject to the budget constraint, where the marginal costs of abatement equals the marginal effect of abatement on the of the shadow price of the emission constraint ($\lambda_2\cdot E\cdot Q$) on the firm.

Similarly, from 1.13, the output of the firm is set where the net marginal costs of Q (net of revenues generated by the sale of Q)—divided by the number of emission units generated per unit of output (E-E*RE)—equals the shadow price of the emission constraint subject to the budget constraint:

1.17 $\lambda_2 = \frac{\left(\frac{d}{dQ}P(Q)\cdot Q + P(Q) - \frac{d}{dQ}C(Q) - \frac{d}{dQ}A(Q,RE)\right)}{(E - E\cdot RE)}\cdot\lambda_1 + \frac{\left(P(Q) + \frac{d}{dQ}C(Q) + \frac{d}{dQ}A(Q,RE)\right)}{(E - E\cdot RE)}$

Equation 1.17 is written as

1.18

$$\lambda_2\cdot(E - E\cdot RE) = \left(\frac{d}{dQ}P(Q)\cdot Q + P(Q) - \frac{d}{dQ}C(Q) - \frac{d}{dQ}A(Q,RE)\right)\cdot\lambda_2 + \left(P(Q) - \frac{d}{dQ}C(Q) - \frac{d}{dQ}A(Q,RE)\right)$$

Equation 1.18 shows that the marginal cost of the emission constraint on the firm, is dependent on the level of abatement (RE). The higher the level of RE, the lower the marginal cost of the emission constraint on the firm per unit of output produced, which in turn means that output increases as RE increases—subject to the budget constraint. That

[28] The second order conditions are given in Appendix L.

maximum output increases with abatement (RE) can be seen in the emission constraint itself:

1.19 $$E \cdot Q \cdot (1 - RE) - \Lambda = 0$$

Solving 1.19 for Q:

$$Q = \frac{\Lambda}{(E - E \cdot RE)}$$

Output (Q) is constrained by the level of abatement (RE) and the number of allowances held ($\Lambda$). As RE increases, Q increases, and vice-versa.

Where the budget constraint (1.10) is not binding ($\Pi$>0), the shadow price of the budget constraint is zero ($\lambda 1=0$). Again, condition 1.12 requires that the marginal cost of abatement effort per unit of emissions must equal the shadow price of the emission constraint ($\lambda 2$):

1.20 $$\lambda_2 \cdot E \cdot Q = \frac{d}{dRE} A(Q, RE)$$

Similarly, from 1.13, the output of the firm is set where the net marginal costs of Q per unit of emission each unit of Q generates, equals the shadow price of the emission constraint:

1.21 $$\lambda_2 = \frac{P(Q) - \frac{d}{dQ} C(Q) - \frac{d}{dQ} A(Q, RE)}{(E - E \cdot RE)}$$

Alternatively, Q is set such that price is equal to the marginal cost of production, including the marginal cost of the emission constraint:

1.22 $$P(Q) = \frac{d}{dQ} C(Q) + \frac{d}{dQ} A(Q, RE) + \lambda_2 \cdot (E - E \cdot RE)$$

Both equations 1.21 and 1.22 again show that the marginal cost of the emission constraint on the firm, is dependent on the level of abatement (RE). The higher the level of RE, the lower the marginal cost of the emission constraint on the firm per unit of output produced, which in turn means that output increases as RE increases—subject to the budget constraint. The solution to 1.9 for an individual firm shall be referred to as RE*,Q*, $\lambda 1^*$,and $\lambda 2^*$.

How efficient the cap is in the case of the individual firm is dependent on how closely the shadow price of the emission constraint ($\lambda 2$) is to the actual MD of that firm. Where the emission cap is set such that $\lambda 2_i = MD_i$, the output and abatement decisions of the FSR, subject to the emission cap, will maximize welfare.

Take, for example, the case above where the budget constraint is not binding. If $\lambda 2_i = MD_i$, then the FSR will set abatement effort so that the marginal costs of abatement, per unit of emissions, equals the marginal cost the externality per unit of emissions[29]:

1.23 $$MD_i = \frac{\frac{d}{dRE_i} A(Q_i, RE_i)}{E \cdot Q_i} = \lambda 2_i$$

Output will set where the price for output (P(Q)) equals the marginal social cost of output:

1.24 $$P(Q) = \frac{d}{dQ} C(Q) + \frac{d}{dQ} A(Q, RE) + MD_i \cdot (E - E \cdot RE)$$

Therefore where $\lambda 2_i = MD_i$, there is no dead weight loss (DWL) associated with the FSR's choice of RE and Q when faced by the emission cap set by the EPA. If, on the

[29] MD is the marginal cost of emissions per unit of emissions, as seen in equation 1.3 above.

other hand $\lambda2_i \neq MD_i$, it follows that the FSR's choice of RE and Q will cause some amount of DWL relative to the optimal solution. For the cap to provide the first best outcome across all firms, $\lambda2_i = MD_i$ must hold true for all firms from 1 to n.

Note that allowance allocations are equal across all firms ($\Lambda_i = \Lambda_{i \neq j}$). Given this, if abatement costs vary across firms, such that the marginal costs of abatement vary across firms at Q* and RE*, then where the emission constraint is binding the shadow price of the constraint also varies across firms. That is, $\lambda2_i \neq \lambda2_{j \neq i}$. For the non-tradable allowance allocations to provide the first best outcome, it must also be true that $MD_i = \lambda2_i$ and $MD_{j \neq i} = \lambda2_{j \neq i}$. This in turn requires that $MD_i \neq MD_{j \neq i}$ when $\lambda2_i \neq \lambda2_{j \neq i}$. Not only must MD also vary across firms, but they must also vary exactly as marginal abatement costs so that $MD_i = \lambda2_i$ and $MD_{j \neq i} = \lambda2_{j \neq i}$. Where this does not hold, the allocation of non-tradable allowances will cause DWL relative to the situation where $\lambda2_i = MD_i$ holds true across all firms.

### 5. The single rule emission cap applied as marketable allowances

After the EPA distributes the allowances to each firm according to the single emission rule cap, the firms and their individual economic regulators must adjust their output and price in order to achieve their objectives as outlined in the above sections. The welfare function of the regional firm regulator must once again include the emission constraint represented by the number of allowances assigned to the firm and the costs of the abatement technology. But unlike the situation under the unmarketable cap, the regional firm regulator faces a market for allowances which will influence the welfare maximizing abatement and output decision through the market equilibrium price for allowances ($P_a$).

Firm profits now include net revenues from activity in the allowance market. The revenue/expense of selling/buying allowances is expressed by the net demand for allowances ($E_i \cdot Q_i \cdot (1 - RE_i) - A_i$) times the market determined price for allowances ($P_a \cdot [E_i \cdot Q_i \cdot (1 - RE_i) - A_i]$). It is assumed in this model that the firm is a price taker in the allowance market due to the large number of firms that participate in it. The market clearing allowance price is determined externally to the firms, as is defined by the price that sets the sum of all firm's net demands equal to zero ($\left[\sum_{i=1}^{n} \left[E_i \cdot Q_i \cdot (1 - RE_i) - A_i\right]\right] = 0$)[30]. Including the market for allowances, the FSR's welfare function is now written:

1.25 Max w.r.t. $Q_i, RE_i$:

$$W_i(Q_i, RE_i) = \left(\int_0^{Q_i} P(X_i)\, dX_i - P(Q_i)\cdot Q_i\right) + P(Q_i)\cdot Q_i - C(Q_i) - A_i(Q_i, RE_i) - P_A \cdot \left[E \cdot Q_i \cdot (1 - RE_i) - A_i\right]$$

subject to:

$\Pi_i \ge 0$

$Q_i \ge 0$

$Q_i \le Q_{max}$

$RE_i \ge 0$

$RE_i \le 1$

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[30] Where $Qmkt_i$ and $REmkt_i$ are the equilibrium output and abatement level for a given firm at a given market price for allowances. The market-clearing price for allowances is defined as the price sufficient to make the industry's net demand for allowances to equal zero.

Taking derivatives of the Lagrangian ($\zeta$) in terms of Q, RE, and provides the Kuhn Tucker maximization conditions as follows:

$$1.26\ \frac{d}{d\lambda_i}\xi\left(Q_i,RE_i,\lambda_i\right)=P\left(Q_i\right)\cdot Q_i-C\left(Q_i\right)-A_i\left(Q_i,RE_i\right)-P_A\cdot\left[E\cdot Q_i\cdot\left(1-RE_i\right)-A_i\right]\geq 0,\ \lambda_i\leq 0,\ \text{and}$$

$$\lambda_i\cdot\left(\frac{d}{d\lambda_i}\xi\left(Q_i,RE_i,\lambda_i\right)\right)=0$$

$$1.27\ \frac{d}{dRE_i}\xi\left(Q_i,RE_i,\lambda_i\right)=\frac{d}{dRE_i}A_i\left(Q_i,RE_i\right)-P_A\cdot E\cdot Q_i+\lambda_i\cdot\left(\frac{d}{dRE_i}A_i\left(Q_i,RE_i\right)+P_A\cdot E\cdot Q_i\right)\leq 0,$$
$$RE_i\geq 0,\ RE\leq 1,$$

$$\text{and } RE_i\cdot\left(\frac{d}{dRE_i}\xi\left(Q_i,RE_i,\lambda_i\right)\right)=0$$

$$1.28\ \frac{d}{dQ_i}\xi\left(Q_i,RE_i,\lambda_i\right)=P\left(Q_i\right)-\frac{d}{dQ_i}C\left(Q_i\right)-\frac{d}{dQ_i}A_i\left(Q_i,RE_i\right)-P_A\cdot E\cdot\left(1-RE_i\right)+\ldots$$

$$\ldots+\lambda_i\cdot\left[\left(\frac{d}{dQ_i}P\left(Q_i\right)\right)\cdot Q_i+P\left(Q_i\right)-\frac{d}{dQ_i}C\left(Q_i\right)-\frac{d}{dQ_i}A_i\left(Q_i,RE_i\right)-P_A\cdot E\cdot\left(1-RE_i\right)\right]\leq 0,$$

$$Q_i\geq 0,\ Q_i\leq Q_{max},\ \text{and } Q_i\cdot\left(\frac{d}{dQ_i}\xi\left(Q_i,RE_i,\lambda_i\right)\right)=0$$

Conditions 1.26 through 1.28 describe a Q, RE, $\lambda$ set that maximizes welfare according to the private costs of the firm—subject to the satisfaction of the second order conditions (not given here).[31]

Where the budget constraint is binding ($\Pi$=0, $\lambda$<0), the constraint yields the trivial solution that price will set equal to average cost (from 1.26 where Q and RE satisfy the Kuhn Tucker maximization conditions). Note that revenues from the allowance market

[31] The second order conditions are given in Appendix L.

depend on the number of allowances ($\Lambda$) the firm has been allocated. Rearranging 1.26 shows the FSR will have the firm invest in abatement until the marginal cost of abatement over uncontrolled emissions (E*Q) is equal to the costs of each unit of emissions in terms of allowances ($P_A$):

1.29 $$P_A = \frac{\frac{d}{dRE_i} A_i(Q_i, RE_i)}{E_i \cdot Q_i}$$

or

1.30 $$P_A \cdot E \cdot Q = \frac{d}{dRE} A(Q, RE)$$

Equation 1.30 shows that abatement will be set such that the marginal cost of abatement equals the marginal benefit of abatement to the firm. Each unit of RE will change the revenue/cost of allowances by $P_A \cdot E \cdot Q$.

Whether or not the firm is buying or selling at the point described by 1.17 is determined by the level of abatement which is occurring at that price relative to the number of allowances that was granted the firm. In other words, it depends on whether or not the firm's net demand for allowances is positive or negative at the market clearing price. In either case, the marginal cost of abatement, per unit of emissions without controls, equals the marginal cost of allowances in the market ($P_A$). Note that this is also true in the case where the budget constraint is not binding on the firm.

Similarly, equation 1.28 shows that the FSR will set the price and output of the firm at a point where the price for the output $Q_i$ will equal the marginal cost of producing it. Note that this marginal cost of production now includes the marginal cost of output in terms of changes in allowances and the marginal cost effect of output on abatement costs.

Again, where the budget constraint is binding, $Q_i$ will be set (for a given $RE_i$) such that price equals the marginal costs of production:

1.30 $$P(Q_i) = \frac{\lambda_i}{1+\lambda_i}\cdot\left(\frac{d}{dQ_i}P(Q_i)\cdot Q_i\right) + \left(E\cdot(1-RE_i)\cdot P_A + \frac{d}{dQ_i}A_i(Q_i,RE_i) + \frac{d}{dQ_i}C(Q_i)\right)$$

Where the budget constraint is not binding, equation 1.30 can be written as:

1.31 $$P(Q_i) = E\cdot(1-RE_i)\cdot P_A + \frac{d}{dQ_i}A_i(Q_i,RE_i) + \frac{d}{dQ_i}C(Q_i)$$

Equation 1.31 simply states that output and price will be set by the FSR to the point, where for a given level of abatement ($RE_i$), price ($P(Q_i)$) equals the marginal cost of output in terms of production, abatement, and allowance costs. An increase in output causes an increase in the number of allowances required to cover the emission requirements of the firm. Each unit of Q requires $E - E\cdot RE$ in allowances, at a cost of $P_A$.

In the following sections, the combination of Q and RE that maximizes 1.25 will be referenced as $Q_i^{mkt}$ and $RE_i^{mkt}$.

As noted in the discussion above, it is the price for allowances ($P_A$) that acts as the internalized cost of emissions via the EPA's allocation of allowances ($\Lambda$). How efficient the market for allowances is in the case of the individual firm is dependent on how closely the price of allowances ($P_A$) is to the actual MD of the firm. Where allowance allocations across all firms are such that $P_A = MD_i$, the output and abatement decisions of the FSR will maximize welfare.

Take for example, the case above where the budget constraint is not binding. If $P_A = MD_i$, then the FSR will set abatement effort of the firm so that the marginal costs of abatement ($\frac{d}{dRE_i} A_i(Q_i, RE_i)$) equals the marginal benefit of each unit of emission reduction (MD):

$$1.32 \qquad MD_i \cdot E \cdot Q_i = \frac{d}{dRE_i} A_i(Q_i, RE_i) = P_A \cdot E \cdot Q_i$$

or

$$MD_i = \frac{\frac{d}{dRE_i} A_i(Q_i, RE_i)}{E \cdot Q_i} = P_A$$

Output will be set where the price for output (P(Q)) equals the marginal social costs of output:

$$1.33 \qquad P(Q_i) = \frac{d}{dQ_i} C(Q_i) + \frac{d}{dQ_i} A_i(Q_i, RE_i) + MD_i \cdot (E - E \cdot RE_i)$$

Therefore, where $P_A = MD_i$, there is no dead weight loss (DWL) associated with the FSR's choice of RE and Q under the market created by the allowance allocations set by the EPA. If, on the other hand, $P_A \neq MD_i$, it follows that the FSR's choice of RE and Q ($Q_i^{mkt}$ and $RE_i^{mkt}$) will cause some amount of DWL relative to the optimal solution. For the allowance market price ($P_A$) to provide the first best outcome across all firms, $P_A = MD_i$ must hold true for all firms 1 to n. It is necessary then, that MD be constant across all firms 1 to n, for the allowance market to provide the optimal allocation of resources (zero DWL) for a given allowance market clearing price $P_A$.

### *6.* Comparing tradable and non-tradable allowances

Both tradable and non-tradable allowances have some potential inefficiency where external costs are locationally dependent. Which incarnation of the allowance allocations better internalizes the external costs of emissions will depend on the relative heterogeneity and distribution of the firm abatement cost functions relative to the heterogeneity and distribution of the external costs of each firm. As discussed in section C above, there are two cost affects associated with the trades of allowances where external costs are firm dependent—the abatement cost effect and the external cost effect. The sum of these two effects determines whether or not allowing market trades increases or decreases welfare relative to the initial allocation of allowances. The change in welfare takes the form of decreasing or increasing dead weight loss (DWL) associated with the allowance reallocations—relative to the case where the actual marginal external costs are internalized. What determines the size of the DWL is whether or not the internalized cost of emissions is closer to the actual (MD) to each firm before or after allowances trades.

The size of the abatement cost savings effect from the reallocation of the allowances ($\Lambda$) among the firms is dependant on the magnitude of the differences in marginal abatement costs across all firms evaluated at where the emission constraints are just satisfied by each firm. Note that allowance allocations are equal across all firms ($\Lambda_i = \Lambda_{i \neq j}$). If abatement costs vary across firms when they just satisfy these allowance allocations (a firm keeping emissions within it's allowance allocation perceives a shadow price of the constraint equivalent to the $\lambda 2$ discussed above), allowance trades will occur among the firms. Trading allowances reduces the difference among the marginal abatement costs of the firms—reducing the differences among the shadow price of the emission constraint among the firms. Trade continues until all differences in marginal abatement costs are exhausted (all trade opportunities are used). This occurs, by definition, at $P_A$—the allowance-market-clearing price. At $P_A$ the shadow price of the emission constraint is equal across all firms and the supply of allowances equals the demand for allowances.

Whether or not the allowance market trades improve welfare or not is depedent on whether of not the shadow price of emissions is closer to the actual costs of emissions (MD) before or after trades. Where trades moves the sum of internalized prices of emissions away from the actual MDs of the firms, the cost savings of the market are exceeded by the increases in external costs caused by trades. This is represented by DWL growing under the market relative to the DWL under the initial allocation of the allowances. If the opposite is true, DWL is lower under the market than under the initial allocation of allowances.

Assuming a continuous, well behaved abatement cost function, the magnitude of the cost effect is determined by the absolute magnitude of the differences between the internalized cost of emissions at the initial allocation of allowances and the average marginal cost of abatement among all firms at that allocation. This relationship is dependent on how the EPA determines the welfare-maximizing cap on total emissions. The EPA sets the total allowance allocations at the point where the average of these marginal abatement costs equals the average MD of the firms. The greater the absolute value of differences between the actual marginal costs of abatement at this point, the greater the magnitude of the absolute value of the differences between $\lambda 2_i^{cap}$ and the average marginal costs of abatement at $\Lambda_1$ for firms 1 to n. The greater this difference, the greater the movement that will occur along the marginal abatement costs curves as trades equalize marginal abatement among the firms at the equilibrium price $P_A$. Therefore, the larger the absolute value of the difference between the $P_A$ and $\lambda 2_i^{cap}$, the greater the abatement cost savings effect of trade.

This cost effect is measured as the difference in the total welfare, as measured by the FSAs, under the cap and the market, at the solution set found for each firm under both the cap and the market. Abatement cost savings affect on welfare is measured as follows in equation 1.34:

$$1.34 \quad A\left(P_A - \lambda 2_i^{cap}\right) = W_i\left(Q_i^{mkt}, RE_i^{mkt}\right) - W_i\left(Q_i^{cap}, RE_i^{cap}\right)$$

Where

$$W_i\left(Q_i^{mkt}, RE_i^{mkt}\right) = \left[\int_0^{Q_i^{mkt}} P\left(X_i\right) dX_i - P\left(Q_i^{mkt}\right) \cdot Q_i^{mkt}\right] + \left[P\left(Q_i^{mkt}\right) \cdot Q_i^{mkt} - C\left(Q_i^{mkt}\right) - A\left(Q_i^{mkt}, RE_i^{mkt}\right) - P_A \cdot \left[E \cdot Q_i^{mkt} \cdot \left(1 - RE_i^{mkt}\right) - A_i\right]\right]$$

And

$$W_i\left(Q_i^{cap}, RE_i^{cap}\right) = \left[\int_0^{Q_i^{cap}} P\left(X_i\right) dX_i - P\left(Q_i^{cap}\right) \cdot Q_i^{cap}\right] + \left[P\left(Q_i^{cap}\right) \cdot Q_i^{cap} - C\left(Q_i^{cap}\right) - A\left(Q_i^{cap}, RE_i^{cap}\right)\right]$$

Where $P_A \neq \lambda 2_i^{cap}$, the firm i will participate in the allowance market and the abatement costs effect will be greater than or equal to zero. This effect will never be negative as the external costs effects are not reflected in the welfare measures used by the FSA's, as seen above in 1.34. Summing across all firms provides the total abatement savings effect of the market for allowances relative to the cap:

$$1.35 \quad \sum_{i=i}^{n} A\left(P_A - \lambda 2_i^{cap}\right) \geq 0$$

The external cost effect of trades, on the other hand, can be either positive or negative, depending on how the market relocates allowances relative to initial allocations among the firms—assuming firm specific external costs ($MD_i$). The greater the differences in the MD across firms, the greater the potential affect of allowance reallocations on total external costs. The magnitude of the external cost effect is the effect of allowances trades on the size of the dead weight loss relative to the loss under the cap. It is measured as the difference between the total external costs of emissions under market trades and the external costs generated under the cap, as follows in equation 1.36:

$$1.36 \quad \sum_{i=1}^{n} D\left(P_A - \lambda 2_i^{cap}\right) = \sum_{i=1}^{n} \left[ MD_i \cdot EQ_i^{mkt} \cdot \left(1 - RE_i^{mkt}\right) - MD_i \cdot EQ_i^{cap} \cdot \left(1 - RE_i^{cap}\right) \right]$$

Again, trades only occur where $P_A \neq \lambda 2_i^{cap}$, 1.36 is therefore dependent on differences in the marginal abatement costs across firms at the point of compliance with the cap. When no trades occur in the market, equation 1.36 equals zero, as the market has not effect on total external costs relative to a cap.

Where marginal external costs are equal across firms ($MD_i = MD_{j \neq i}$), total external costs with or without market trades are identical—assuming emissions totals are equal with or without allowance trades. In this case, equation 1.36 is equal to zero. If allowance trades cause emissions to increase at firms with MD's higher than average, while lower than average MD firm's lower their emissions, equation 1.36 will be positive. If the opposite occurs, equation 1.36 will be negative as the market allocation of allowances will produce a lower amount of external costs than the cap.

Taking the difference between the external cost effect (1.36) and the abatement costs effect (1.35) across all firms provides the net welfare effect of market reallocations of allowances in terms of dead weight loss (DWL):

$$1.37 \quad DWL = \sum_{i=1}^{n} D \left( P_A - \lambda 2_i^{cap} \right) - \sum_{i=i}^{n} A \left( P_A - \lambda 2_i^{cap} \right)$$

Where equation 1.37 is negative, the internalized costs of emissions in the market ($P_A$) have moved closer to the actual individual MDs of the firms, relative to the internalized price under the cap ($\lambda 2_i$). The negative value of 1.37 indicates that market allocations have reduced any deadweight loss associated with the initial allowances allocations set by the EPA. This situation will obviously occur if $P_A \neq \lambda 2_i^{cap}$ and $MD_i = MD_{j \neq i}$, as allowance reallocations under the market have no effect on external costs and any trades provide costs savings relative to the cap. However, when the MD's of the firms are homogeneous it is possible that the external cost effect will be both positive (1.36) and of sufficient magnitude to cause 1.37 to be positive as well. If this occurs, it indicates that the market reallocations of allowances have increased dead weight loss (reduced welfare) relative to initial allowance allocations.

It is possible, therefore, that market reallocations of allowances will cause a welfare loss relative initial single emissions standard allocations of allowances when external costs are firm location (firm) dependent. This possibility exists when external costs are emission dependent and the marginal abatement costs vary across firms.

## IV. Conclusion

When external effects from emissions are location dependent, allowance market regulation of emissions may not be as efficient as more traditional single-emission standard caps. This goes against the common wisdom that incentive based regulation—which reduces total abatement costs relative to single emission standard caps—is always superior to single emission standard caps or regulations. The common wisdom, however, assumes—either implicitly or explicitly—that external costs are constant across sources. Under such circumstances the common wisdom is correct, as indicated above. Where MDs are constant across firms, any trades in the allowance market have a strictly positive effect on total welfare in the form of reduced abatement costs. However in many cases where allowance markets are in use or have been suggested—such as with regard to sulfur and nitrous oxides—the location of the emission source is of primary concern in determining the external cost effect of emissions. Under these circumstances, caution may need to be exercised in defining the market.

The possibility that the Title IV sulfur dioxide allowance market will cause a net welfare loss relative to a cap is explored in chapters 2, 3, and 4 of this paper. Where allowance trades could cause a net welfare loss relative to a cap, steps would need to be taken to minimize or eliminate the potential negative external cost effect of allowance reallocations through trade. This could be a as simple as reducing a larger market into a series of smaller geographic markets—thereby reducing the disparity among the external costs of emissions among each markets participants. Reducing the size of the markets would have the effect of reducing the possible savings of a market system, but at the benefit of reducing the negative impacts of trades. The impact of geographically defined sub-markets is explored in relation to net welfare effects of the Title IV market in chapter 4 of this paper.

In conclusion, the commonly held assumption that market-based emission control systems are superior to command and control regulation can not be generally applied when external costs of emissions are location dependent. The relative efficiency of the market will depend on the nature of the externality. If the pollutant is equally damaging regardless of source (MDs are constant or based on total ambient emissions) a market will always outperform a cap. Examples of such pollutants take the form of greenhouse and ozone layer-depleting emissions (carbon dioxide and CFCs). In any other case, the potential external cost effects must be examined to determine the true net benefit of a marketable allowance system, like that used in Title IV of the Clean Air Act of 1990.

# CHAPTER 2

# THE TITLE IV ALLOWANCE MARKET

## I. Introduction: Cause for Concern

Chapter 1 indicates that there are two effects associated with market reallocations of allowances when external costs of emissions and marginal abatement costs vary across units in the market. These two effects are the abatement costs savings effect and the external cost effect. The sum of the two effects provides a measure of whether or not a market for allowances improves or reduces welfare relative to a single emission standard cap with the same total emission goal. The existence of the external cost effect is of concern given the Title IV allowance market created with the passage of thee Clean Air Act of 1990. Sulfur dioxide emissions, the pollutant of concern under Title IV, have location based cost effect due to their means of distribution and deposition rate out of the atmosphere. Of particular interest then, is how efficient this market will be when the allocation of allowances becomes a binding constraint on emissions in the near future under Phase II of the Title IV statute. At this point, assuming the full exploitation of trading opportunities, there is an expectation of a large amount of allowance relocation among a affected firms—and therefore a potentially large change in external costs relative to the initial allocation of allowances.

The Focus of chapter 2 is to provide an introduction to the Phase II binding allowance market and the simulation model used in chapter 3 to emulate it. The purpose of the model presented later in chapter 3 will be to measure the potential welfare effects of allowance relocations relative to a cap. To prepare for that discussion, this chapter explains the technologies, the policies, and the expectations involved with the Title IV allowance program, as well as current market activity and how it has affected expectations regarding the long-term binding phase II market that is modeled in chapter 3. In discussing these issues, this chapter outlines the singular importance of FGD in the future Phase II market and how it will play a central role in determining the reallocation of allowances in a future binding allowance market under Title IV. The chapter will discuss the possible impact of FERC order 888 on compliance strategies in the foreseeable future, as well as the impact of Powder River Basin coal price shock that occurred recently. This chapter is therefore an introduction to an examination of the potential net cost of the future phase II allowance market under Title IV of the Clean Air Act of 1990 that occurs in chapter 3.

## II. Introduction to Title IV, the Market for Allowances, FGD, FERC order 888, and Recent Developments in the Allowance Market

This paper introduces a number of issues and background material essential to understanding Title IV and the issues that will affect the long-run allocation of allowances in the Phase II allowance market relative to a Phase II compliant cap. This discussion will outline the need to use a simulation to model the long-run Phase II market, the role of FGD in the long-term allowance market given recent developments in the coal markets, and the expected impact of FERC order 888 among Title IV units in terms of load served, FGD, and after-market allowance allocations. In the course of this discussion, this paper provides the background for the theoretical model with regard to assumptions regarding FGD technology and native load allocations used in the simulation model—in the context of the goals of Title IV and recent developments in the utility industry.

The introduction to Title IV and FERC order 888 is split into several parts. Part III discusses the goals and mechanics of the allowance market set up under Title IV—and the expectation that FGD will allow compliance with Phase II in the long run. Part IV discusses the reasons for concern regarding the reallocation of allowances under the binding phase II allowance market. Part V outlines current phase I market behavior and the adjustments and revised expectations the market has made in response to unexpectedly low prices for Powder Basin Low-Sulfur Coal. Evidence indicates that the market is recovering quickly from the minor shock in long-term demand for allowances—allowance prices are rebounding as the market accesses the impact of lower priced low sulfur coal. Earlier expectations that FGD will be the defining technology of the Phase II market have remained intact given coal use-projections over the next 20 years and expected long-term allowance price trends. Part VI discusses the impact of low-price, low-sulfur coal on the long-term demand, long-term supply, the use of FGD, and long-term price of allowances. Part VII discusses the effect of Powder Basin Coal on expected trades and the use of FGD in Phase II, relative to trade and FGD expectations before the price of Powder Basin Coal dropped. Part VIII discusses FERC order 888 with regard to the behavior it may cause in units affected by Phase II regulation. Part IX discusses the current nature of allowance trading under Phase I—and why there is a concern in terms of external cost effects under Phase II. Part X outlines the need for a simulation to model the binding Phase II allowance market. Part XI explains the use of FGD as the pivotal compliance technology in the binding Phase II market. Part XII provides a survey of the current literature regarding the Title IV market and how it has not, until now, examined the potential effect of locational external costs on allowance trades when calculating the costs savings of the market for allowances relative to a more traditional cap on emissions. Part XIII is the conclusion.

## III. Title IV: Background and FGD

Title IV does two things. First, it reduces the total sulfur emissions from all utility generators from the 1985 baseline emission levels—of around 16.8 million tons annually—to around 8.9 million tons of annual emissions by assigning annual emission allotments. Second, it allows a market for annual pollution allotments in the form of marketable allowances. The intent of the market is to reduce the costs of compliance with the annual 8.6 million-ton emission goal in the long-term. It is important to note that allowances are allocated, free of charge, to each utility on an annual basis, based on their 1985 baseline emission levels. Each allowance represents the right to produce one ton of $SO_2$ emissions. Once used to cover a ton of emissions, it is considered "spent" and is eliminated from the records.

The emission goal of Title IV is to be reached in two phases—Phase I and Phase II. Phase I took effect in 1995 and ends in the year 2000. This phase of title IV affects about 1/3 of the total number of units that will be affected by under phase II. Phase I is an introductory phase with limited emission reduction goals and a large number of bonus allowance programs designed to encourage early over-compliance. Phase II, which begins in the year 2000, tightens the annual emissions limits imposed on the phase I affected units, eliminates bonus allowance programs, and also sets restrictions on smaller, cleaner plants—encompassing over 2,000 units in all. While the program affects all existing and future utility units serving generators with an output capacity of greater than 25 megawatts, the EPA will only allocate allowances to units that existed by 1986. New units that produce emissions must annually buy allowances to meet be in compliance with Phase II rules. This assumes that some Phase II units allocated allowances will over-comply and sell allowances.

Both Phase I and Phase II limit the total amount of emissions from units by assigning a set amount of allowances annually. Each allowance allows one ton of sulfur dioxide to be emitted by a party that holds the allowance. As such, the total number of allowances acts as a cap on emissions in that year. All allowances are marketable—that is they can be bought and sold between parties. These parties need not be utilities or related to the utility industry. However, as noted above, only utilities in operation by 1986 or emitters of sulfur dioxide emissions who opted into title IV by 1995 are eligible for direct EPA allocations. Thus new load capacity is not allocated allowances under these provisions. Once allocated, the holders of allowances are free to trade the allowances.

The ability to trade allowances is expected to lower the costs of compliance with the emission goals set up by Title IV. Cost savings projections under phase II restrictions are expected to be in the neighborhood of $700 million to $2 billion annually, by many estimates, with prices for allowances ranging from $150 to $300.[1] These are substantial savings and the greatest selling point of the market when it was going through Congress in 1990. All of these cost saving estimates assumed FGD as the primary means of emission compliance with Phase II restrictions. As will be discussed below, only FGD will allow both compliance with Phase II compliance requirements and enough over-compliance to allow the trading of allowances—and the cost savings advertised by proponents of Title IV—when Phase II becomes binding on emissions.

## IV. Reasons for Concern under Phase II

The estimated cost savings of the Title IV allowance market are quite substantial. However, these cost savings occur due to market reallocations of allowances among units with heterogeneous FGD abatement costs. The reallocation of allowances indicates the reallocation of emissions among units. Those units holding more allowances after trades will generate more emissions than those units holding fewer allowances after trades—assuming a binding allowance market. This is cause for concern given the fact that external costs associated with $SO_2$ emissions are location dependent—based on an area population, the concentration of emissions, and a number of other factors. As indicated in chapter 1, where external costs are location dependent, caution must be exercised when implementing an allowance market as a means of achieving a total emission goal. Where external effects are locationally dependent, external effects of allowance trades may more than offset the savings in abatement costs across units.

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[1] ICF Resources, Inc., "Economic analysis of Title IV of the administration's proposed Clean Air Act Amendments (HR 3030/S 1490), Report prepared for the U.S. EPA (1989); Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach

There is a significant amount research regarding the locational concentration effects of $SO_2$.[2] In addition, there is strong evidence that the location of the source of $SO_2$ emissions in the United States will affect the regional concentrations of $SO_2$—thus affecting external costs associated with $SO_2$ emissions.[3] Despite the recognition that external costs of $SO_2$ emissions are location dependent, nothing has been done—until the writing of this paper—to catalogue the effects of potential allowance trades on external costs.

The concern over trade directions and allowance allocations is caused by the fact that FGD technology has demonstrated decreasing average costs with regard to emission reductions. The bigger the plant and the greater the sulfur content per Btu of coal burned, the cheaper it is to remove each ton of $SO_2$. This fact is born out in the regression results given in appendix G, based on FGD cost data from the Shawnee test bed and the Integrated Air Pollution Control System Technical Documentation Manuals, volumes 2 and 3.

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to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, 58-72.

[2] See Abbey, D.E., M.D. Lebowitz, P.K. Mills, F.F. Peterson, W.L. Beeson and R.J. Burchette, "Long-term Ambient Concentrations of Particulates and Oxidants and Development of Chronic Disease in Cohort of Nonsmoking California Residents," Inhalation Toxicology 7, 1995, pages 19-34; Abbey, D.E., F.F. Peterson, P.K. Mills and L. Kittle, "Chronic Respiratory Disease Associated with Long Term Ambient Concentrations of Sulfates and Other Air Pollutants," Journal of Exposure Analysis and Environmental Epidemiology, 1993, pages 99-115; American Lung Association, Health Effects of Air Pollution, New York, New York. 1978; D.V. Bates and R. Sizto, "Associations Between Ambient Particulate Sulfate and Admissions to Ontario Hospitals for Cardiac and Respiratory Diseases," American Journal of Epidemiology 142 (1), May, 1995, pages 15-22; and others. See bibliography for a more complete listing.

[3] See J.S. Chang, R.A. Brost, I.S.A. Isaken, S. Madronich, P. Middleton, W.R. Stockwell, and C.J. Walcek, "A Three Dimensional Eulerian Acid Deposition Model: Physical Concepts and Formulation," Journal of Geophysical Research, Vol. 92, No.D12, December 20 1987, Pages 14,681-14,700.

There is concern, therefore, that high sulfur states of the mid-west and east will—through the decreasing average costs of FGD—be in a position to sell allowances to lower sulfur coal states.[4] Allowance demand is expected to be concentrated among units that use lower sulfur coal due to geographic position—units in states to the west of many high sulfur coal states.[5]

If net allowance trades do shift net allowance allocations to the west relative to initial Phase II allocations, external costs associated with $SO_2$ emissions would increase relative to emissions that would occur without trade. This is due to the fact that emissions travel from west to east in the continental United States. Reducing emission in the east and increasing them in the more westerly units will increase total emissions that make landfall in the United States—therefore increasing the external costs of emissions. Therefore, there is cause for concern about allowance reallocation effects of an $SO_2$ allowance market given the fact that external costs associated with $SO_2$ emissions are location dependent.

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[4] As mentioned previously in this paper, the structure of FGD costs is described and estimated in great detail in appendix G and later in this paper.
[5] Smaller units will also have higher abatement costs than larger plants, causing another source of cost differentials among units—and incentives to trade allowances.

## V. Phase I Market Activity: Inter-temporal Adjustments in the Demand and Supply of Allowances

When the Clean Air Act of 1990 was passed, FGD was the major source of projected allowance supplies in any market that developed under binding Phase II restrictions. Based on earlier implementation costs of FGD (made prior to the development of the ADVOCATE FGD process) estimates indicated that allowance prices be around $500 a ton when phase II requirements come into play in the year 2000. These projections were still prevalent in 1994, when the New York State Energy Commission's New York State Energy Plan projected that allowances prices would "peak around the year 2000 at about $500 a ton."[6] Other estimates had indicated even higher prices for phase II allowances—ranging from $500 to $700 a ton.[7] The short-term Phase I market was expected to see prices ranging from $250 to $350 a ton[8], in an environment where emission restraints were lax and bonus allowances were going to be awarded. The common consensus in the early 1990's was than the costs of abatement would be fairly high—around $500 a ton. It was also estimated that phase I would see a significant level over-compliance and the banking of allowances. This was due to the fact that phase II restrictions were to be much tighter and the price for allowances was expected to be much higher than in Phase I—100% more expensive in most estimates. As long as the expected price for allowances was greater then the average cost of adding Fluidized Gas

[6] New York State Energy Office, New York State Energy Plan, Volume III: Supply Assessments, October 1994, Page 538.
[7] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, page 55
[8] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, page 55.

Desulfurization (FGD) or switching to low sulfur coal, it made sense to reduce emissions to free up allowance for sale in the more lucrative phase II market.

There were, and are, are several reasons to expect some discrepancy between the long-run phase II prices and prices which were expected to show up under phase I. The most important reason for a discrepancy between the two price projections is the fact the two markets are, in fact, different. Phase I rules affect less than 1/3 the total number of units which will be affected by Title IV under phase II. In addition, Phase I units, on average, are dirtier plants than their phase II counterparts—as discussed in more detail later in this paper. As such they are expected to have much lower costs of abatement than the units to be brought in under phase II.[9] In addition, Phase I allowance allocations are generous relative to phase II allocations which begin in the year 2000. In 1997, for example, the 417 phase I affected boiler units received over 6.9 million allowances. In the year 2000, total allocations under phase II will be 8.9 million allowances divided among more than 2,000 units. There is, therefore, reason to believe that there will be a difference between observed phase I market prices and the prices seen in phase II. It was this reason that it was expected that active phase I units would, for the most part, be preparing for participation in the Phase II allowance market—indicating that there should be some evidence of inter-temporal planning among phase I units.

Early market activity, however, indicated that initial allowance price and abatement cost projections for the Phase I market might be high. Even the spot auction that took place before Phase I took effect in 1995 seemed to indicative of this. Two spot auctions for allowances held in 1993, for example, indicated that the costs of compliance

[9] The characteristics of boilers which affect the costs of abatement are explained in great detail in appendix G at the end of this chapter.

were lower than anyone had officially anticipated. The first auction that took place in 1993 was for 50,000 allowances earmarked for use in 1995 or later. The second auction was for 100,000 allowances earmarked for use in the year 2000 or later. In the course of the auctions, "The lowest successful bid price was $131 and the highest was $450."[10] The highest price actually paid by an investor owned utility was $201—well within the mid-range of the phase II allowance projections made by the long-run phase II market simulation.[11] A full 98% of the "phase I allowances auctioned by the Chicago Board of Trade were sold for $130 to $200 per ton."[12] "The weighted-average price for all bidders was $156.63."[13] Prices were slightly higher in private negotiation, with "$180 to $200 price range observed for allowances."[14] These prices are all well within the mid-range price estimates generated by this paper's market simulation model, but lower than earlier estimates. In the advance auction of year 2000 allowances, the lowest successful bid was $122 dollars. The highest utility bid was $171 dollars[15]—again within the price estimate range of the simulation model. The weighted average of the utility bids was $146—at the lower end of the allowance price projections of the simulation.

As might be expected, the existence of allowances prices lower than earlier expectations was an indication that the costs of compliance might be much lower than

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[10] NRRI, Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowance, December 1993, page 21.
[11] NRRI, Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowance, December 1993, page 22.
[12] New York State Energy Office, New York State Energy Plan, Volume III: Supply Assessments, October 1994, Page 536.
[13] NRRI, Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowance, December 1993, page 22.
[14] Timothy N. Cason and Charles R. Plott, "EPA'S New Emissions Trading Mechanism: A Laboratory Evaluation," Journal of Environmental of Economics and Management, 30, 1996, page 145.

previously anticipated. Schmalensee recently estimated that, among the 27 phase I plants that installed and ran scrubbers in 1995 and 1996, the average cost of scrubbing to remove emissions cost around $265 a ton among current phase I plants—though there was considerable variation about this average.[16] This average cost is significantly lower than the $500 a ton estimate made only 4 years prior. In fact these costs "are at the lower end of the range of earlier estimates, which varied from $180 to $307 a ton."[17] In addition, Schmalensee found that the short-run marginal cost of running existing FGD equipment averages "roughly" around $65 a ton.[18] Both of these cost Diagrams are well within the cost estimates made by this paper's simulation of the phase II market and participants.

Schmalensee credits some of the difference between earlier and current estimates of the costs of FGD to "induced innovation."[19] Such innovations over earlier FGD cost estimates were uncovered in the course of developing the data base used in this paper through a number of interviews with the staff at various power plants in New York State. Alongside these innovations Scmalensse also notes that there has been "higher than expected utilization of scrubbed units…which reduces the capital costs per ton of sulfur

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[15] NRRI, Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowance, December 1993, page 23.

[16] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, page 64.

[17] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, Page 64.

[18] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, page 65.

[19] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, page 65.

removed."[20] That is, FGD units are being run at capacity. This is a result anticipated in this paper, given the decreasing average cost found in FGD technology, and the constant marginal costs of operation over the majority of the operating range. As long as prices are higher than the short-run operating expenses, FGD equipment will be operated flat out. As indicated by Scmalensee's results, and those in this paper, as long as prices are greater than $65 to $70 it makes sense to operate FGD at capacity.

Another reason for the discrepancy between predicted prices, both by the simulation of phase II presented here and by other sources, and the current phase I allowance pricing involves the issue of coal switching. Coal switching has proven to be an easier and cheaper short-term option than previously thought.[21] The cost of reducing sulfur dioxide emissions through coal switching has "an average cost of $187 per ton."[22] This is a figure echoed, to the penny, by Coggins and Swinton (1996).[23] This cost estimate includes the instances where the switch to low sulfur coal incurred zero and even negative costs to the plant in question. Lower than expected prices for low and lower sulfur coal was made possible due to greatly reduced transportation costs in the west and increased productivity with regard to lower sulfur coal.

While the price of allowances is lower than expected, they are also lower than the estimated and projected long-term costs of abatement and compliance in the industry.

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[20] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, page 65.
[21] The limitations of coal switching as a long term compliance option are discussed in appendix H at the of this dissertation.
[22] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, page 64.

According to Coggins and Smith (1996), "the average value of allowances should equal approximately \$292."[24] Coggins and Swinton (1996) make a point to emphasize that this value is signicantly higher than current prices. "At current observed prices, it appears that allowance purchases are an attractive compliance alternative...utilities that have purchased allowances to date appear to have achieved considerable compliance savings."[25] An evaluation shared many in the utility industry, where prices of \$150 in the mid 1990s was considered "quite a bargain." [26] The 1996 phase I market prices are also lower than the average cost of scrubbing found by Schmalensee. In addition current phase I prices are lower than the average cost of reducing emissions via lower sulfur coal. This would seem to indicate that current phase I prices are not representative of the long-term equilibrium price for allowances.

There is still a question, in some eyes, as to why the prices dropped as low as they did during phase I, when it is assumed that rational agents would be reacting to longer-term compliance cost estimates. The central reason for the unexpectedly low prices of allowances during phase I is one identified by Schmalensee—the current levels of oversupply of allowances are even greater than anticipated by phase I active units. The reason for the unexpected oversupply in the short-term is the shock of the Powder River

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[23] Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, page 60.
[24] Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, page 60.
[25] Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, page 60.
[26] Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, page 60.

Basin price drop on long-term expectations based on pre-market predictions of the prices of allowances and the size of future demand for allowances.

The expectation going into Title IV was that the long-term price for allowances was going to range from $250 to $700 on the open market, with prices increasing as time went on. Given these estimates, many utilities invested in long term coal contracts for lower sulfur coal and in new FGD equipment. Under such expectations it would make sense to do so. Indeed, Schmalensee uncovered evidence that "the expectation of allowance prices in the $300 to $400 range were 'very important' in the choice of scrubbing."[27]

Then, as indicated above, the price fell in the western coal market. Transportation costs fell as rail lines consolidated, but more importantly there were great labor productivity gains in many of the Powder River-Basin mines. This allowed deeper penetration of lower sulfur coal as among phase I and phase II plants than previously expected. The long-term result in the phase II market would be expected to be lower costs of compliance and lower allowance needs for units able to take get access to and use the lower sulfur coal—in other words, an downward shift in the long-term demand for allowances. Those units, which had made long-term contracts for Powder Basin low-sulfur-coal[28] and/or invested in FGD, found themselves with more excess supply than

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[27] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, page 65.

[28] As opposed to low sulfur coal from other regions, which have significantly higher levels of sulfur per btu. As will be discussed below, only Powder Basin Coal is capable of allowing coal switching to be a viable long-term compliance option, and this is only a practical solution in a hand-full of units. Other coal switching efforts only work to reduce the need for allowances relative to compliance requirements—thus reducing the

they originally intended due to the shock to the long-term demand for allowances. This downward shift in demand pushes back the date at which it is expected that allowances banked under phase I will be used up and the phase II allowance allocations become binding in the market. Earlier estimates had the banked supply of allowances being exhausted between 2005 and 2010.[29] Since the shift in coal prices, and the subsequent reduction in long-term demand for allowances, it is expected that the supply of banked allowances will occur closer to the year 2010.[30]

The unexpected shift in long-term demand for allowances would be expected to have some downward pressure on allowance prices in the near term, particularly within the short-run time period surrounding the shock. Given the time involved adjusting FGD plans and long-term contracts for coal, adjustment to the shock from the supply side has been slow at first, but there is strong evidence that rapid adjustments are being made. This is seen in the fact that prices have not only stabilized, but they have dramatically increased since the low coal price shock went through the market. Prices started to recover in February of 1996, after the steady fall from expectations in 1993, the time of the first auction. Current prices have since risen back to $170 and $180 as of June 1998—sufficient to cover long-term average costs of both coal switching and FGD at

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magnitude of demand at units where this an option. The end result is reduced long-term demand for allowances from plants that have not considered FGD.

[29] NRRI, Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowance, December 1993, page 539; EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997; EPA, 1996 Compliance Report, Acid Rain Program, Office of Air and Radiation, June 1997; and "Looking back on $SO_2$ Trading: What's Good for the Environment is Good for the Market," Public Utilities Fortnightly, October 1997.

[30] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997; EPA, Office of Air and Radiation, 1996 Compliance Report, Acid Rain Program, June 1997; and"Looking back on $SO_2$ Trading:

many units.[31] The peak price, prior June of 1998, was in excess of $210—further evidence of adjustments in the market. The most recent price trend is seen in Diagram 1 below.[32] An increase in prices was to be expected given the long-run average prices of abatement in the market, and the fact that allowance allocations will become a binding constraint on the industry under phase II—though at a later date than previously expected.

In addition to the rebound of prices after an adjustment of expectations among utilities, there have been increases in emissions rates that, in Scmalensee's word, "can be interpreted as movement towards an efficient equilibrium time-path of emissions."[33] While emissions have increased, and prices have rebounded, banking continues in the expectation of even higher prices in the future. The State of New York, for example, is still suggesting that "an allowance price of $450 per ton (be) recommended for energy planning purposes during the early years of Phase II."[34] In fact allowance prices are well within original trend-line projections again regarding long-term allowance prices, assuming interest rates of 5 to 10 percent. Prices since August of 1994 (the opening bids) are given in Diagram 2.1 below, along with a 5% and a 10% interest trend line. Note the quick rebound after the Powder Basin Coal price shock.

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What's Good for the Environment is Good for the Market," Public Utilities Fortnightly, October 1997.

[31] As Scmalensee points out, average FGD costs vary considerably around his average of $265, with many units with costs much lower than this. This is true of many units that have not installed FGD, as indicated in the simulation in this paper.

[32] Diagram 1 indicated the monthly average price of a current vintage year allowance, as reported by two brokerage firms and Fieldston Publications' market survey.

[33] Scmalensee (et al) (September 1998, page 66.)

[34] New York State Energy Plan, Volume III: Supply Assessments, page 539.

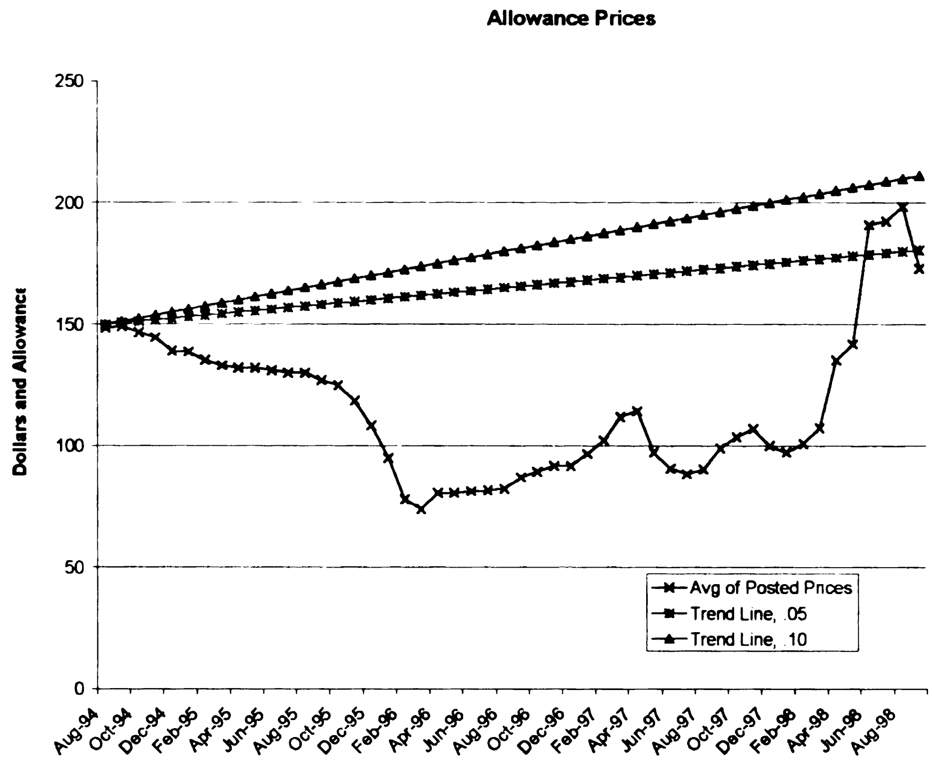


**Diagram 2.1: Allowance Prices over Time**

The strength of the market is that it allows adaptability to changing developments. The unexpectedly low price of powder basin coal was a shock to price expectations and to long-term demand expectations in the allowance market. As in any market, a shock in a market requires an adjustment period as expectations are reevaluated and supply and demand bring themselves back into long-term equilibrium. Given the apparent efficiency of the market,[35] it is expected that long-term supply and demand in the market would adjust to any shocks in time. This seems to be the case here. Prices, and the expectations of prices, have rebounded quickly.

[35] Paul L. Joskow, Richard Schmalensee, and Elizabeth M. Bailey, "The Market for Sulfur Dioxide Emissions," The American Economic Review, Vol. 88, NO. 4, September 1998. Pages 669-685.

## VI. Expectations of Long Term Allowance Prices: Long Term Demand and Supply of Allowances

While there is no denying the fact that the low price of Powder Basin Coal sent a shock through the allowance market, the market appears to be recovering quickly towards a long-term trend-line regarding allowance prices. The general impact of the low price of Powder Basin Coal should take the form of a slight decrease in long-run allowance demand. This would indicate a lower long-run equilibrium price of allowances, but not the elimination of the need for a market—nor for the need for FGD. The allocation of allowances will still become binding under phase II requirement, but the year that this happens has been moved back. This simple fact is indicated in Diagram 2 through 4 below. Both diagrams show that coal consumption, of both lower and high sulfur varieties, is increasing annually. Coal use is increasing relative to 1986 levels when $SO_2$ emission exceeded 16.8 million tons. Given that Phase II requires a maximum $SO_2$ production of 8.9 million tons, the continued and growing use of coal guarantees that Phase II will become binding in the near future and that FGD will be needed for the industry to achieve compliance.

Under these expectations, the prices for allowances would be expected to increase from the average low of around \$100 found while the market was still adjusting at the end of 1995. As the evidence has indicated, the market has accounted for the penetration of Powder Basin coal, and prices are again increasing towards long-run compliance costs. In the long run, prices would have to increase relative to the unprecedented low of \$100, given the long-term costs of compliance evidenced in the market. This is seen in the fact that prices have made a dramatic recovery towards long-term cost—jumping as high as $210 over the last six months.

The quick rebound in allowance prices was not unanticipated. The cost of reducing emissions via coal switching has an average cost of $180 a ton.[36] The cost of new FGD can (and does) run below $150 a ton—but the current industry average so far has been around $250. In addition, Coggins and Swinton (1996) have estimated the shadow price of compliance under phase I restrictions is around $229 a ton—a "number commensurate with other recent estimates of the marginal cost of abatement for coal plants in the Midwest region".[37] Under Phase II, Coggins and Swinton (1996) "expect that shadow prices will be driven up" from there to "at least $350".[38] As indicated by Coggins and Swinton, and earlier comments, there is reason to believe that phase II plants, being cleaner on average, will have compliance costs higher than this. Thus, an expectation of higher prices in the long-term appears to be a sound expectation.

The reason that lower than expected prices of coal have not had a deeper impact on the market for allowances is the fact that coal switching alone will not allow units to meet compliance in phase II. There will be a need for FGD, as under previous expectations. The reason is simple. Coal switching, as an industry-wide compliance strategy, will not be sufficient to satisfy the stricter Phase II rules which take effect in

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[36] It is important to note that reducing emissions via coal switching is not synonymous with meeting Phase II compliance requirements. Among current phase I units, the use of low sulfur and lower sulfur coal (non-Powder River Basin coal) has met Phase II compliance requirements in only 13% of the units. Coal switching is not a long-term compliance option for the industry, as explained in the text.

[37] Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, Page 70.

2000. Only FGD allows sufficient reductions to meet phase II standards in the long run and only FGD will allow continued growth in fossil fuel use as a means of generating electricity—see Diagram 2 below.[39]

Schmalensee determined that 55% of emission reductions from 1993 to 1995 and 1996 were attributable to fuel switching—including the use of lower sulfur coal. [40] [41] However, only 13 percent of the difference between actual and counterfactual emissions at Phase I units were due to true low sulfur coal (from the Powder River Basin, for example).[42] The rest of the fuel switching was to lower sulfur coals from eastern or mid-western mines or to other fuels such as natural gas. [43] However, of the mandated and voluntary phase I units which had emission rates in excess of 1.2 lbs per mmbtu[44] in 1985, only 13% reduced emission rates via coal switching alone to a level sufficient to guarantee compliance under Phase II rules.[45] [46] Reductions using lower sulfur coal—that

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[38] Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, Page 70.

[39] New power plants (built after 1990) are not granted allowances. Any allowances needed to cover emissions must be purchased from the market. In any event, New power plants face stricter standards under codes pre-dating the 1990 Clean Air Act.

[40] Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey; "An Interim Evaluation of Sulfur Dioxide Emission Trading", Journal of Economic Perspectives, 12, No. 3, Summer 1998, Page 54.

[41] In 1997 roughly 80% of the phase I affected units (including substitution units) total emission reductions are attributable to reducing the rate of emission per mmbtu from 1985 levels—that is due to coal switching and scrubbing. The other 20% of reductions can be traced to reduced utilization of the boilers in question relative to 1985 utilization rates.

[42] Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey; "An interim Evaluation of Sulfur Dioxide Emission Trading", Journal f Economic Perspectives, 12, No. 3, Summer 1998, Page 59.

[43] Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey; "An interim Evaluation of Sulfur Dioxide Emission Trading", Journal f Economic Perspectives, 12, No. 3, Summer 1998, Page 59.

[44] 1.2 pounds of so2 per mmbtu burned in 1985 is the basic emission rule under Title IV.

[45] Data from EPA's compliance reports for 1995, 1996, and 1997.

is, Powder Basin Coal—will not, and are not, sufficient to meet phase II requirements. The 87% of phase I plants not using Powder Basin Coal will have to either find access to even lower sulfur coal mixtures or make the move to FGD. A realization echoed by Coggins and Swinton (1996) when they note that "the plants in (their) sample (which have been using lower sulfur coal to achieve phase I compliance) will need to reduce their emissions still further."[47]

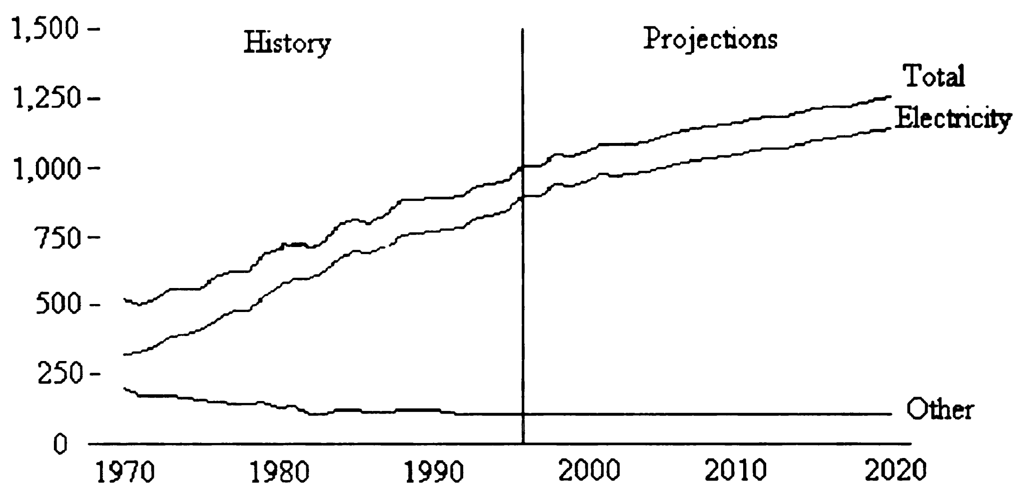


**Diagram 2.2: Total Consumption of Coal by Use.**[48]

The prospect of using even lower sulfur mixtures of coal at plants as an abatement option "depends in many ways upon the properties of each boiler and on the various

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[46] Assuming utilization rates (mmbtu annual burn totals) consistent with levels evidenced from 1985 to 1990 generation levels.
[47] "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances", Jay S. Coggins and John R. Swinton. Journal of Environmental Economics and Management, 30, Page 70, 1996.
[48] DOE. Annual Energy Outlook 1998—Market Trends—Coal. [Online] Available http://www/eia.doe.gov/oiaf/aeo98/fig102.html, January, February 1999.

properties of different coals."[49] But, there is an expected limit to coal blending and switching as a compliance option based on both costs, particularly in areas more distant from Powder Basin,[50] and technical considerations. Technical considerations and engineering costs of coal switching go beyond price per Btu differentials. "Fuel switching can entail a loss of both net generating capability and generating efficiency as well."[51] "In practical effect, fuel switching (to low sulfur coal) results in the effective downsizing of the affected unit…in some instances by 10-15%."[52] In addition, the use of western coal also causes heat-rate deterioration: "Since part of the heat content of western coal acts to drive off moisture rather than to produce electricity, boilers using high moisture (western) coal will suffer heat rate deterioration."[53]

The limited implementation of low sulfur coal us reflected in current projections on coal use. "Presently, neither New York, Pennsylvania, nor Indiana coal-fired units

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[49] Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, Page 67.

[50] See Joseph Daubenmire and Peter Kakela, "Great Lakes Shipping and Clean Air: Interactions," Impact Assessment, Volume 15, No. 3, September 1997; Joseph Daubenmire and Peter Kakela, "Clean Air Compliance Strains Great Lakes Ship Capacity", working paper, Ohio State University and Michigan State University, April 16, 1997.

[51] Jeffrey P. White, Assistant General Counsel, "Impact of Clean Air Act Amendments on the Electric Industry, The Utility Perspective," American Electric Power Service Corporation; Columbus, Ohio; Washington, D.C.; February 21, 1991, Addendum V, page 8.

[52] Jeffrey P. White, Assistant General Counsel, "Impact of Clean Air Act Amendments on the Electric Industry, The Utility Perspective," American Electric Power Service Corporation; Columbus, Ohio; Washington, D.C.; February 21, 1991, Addendum V, page 8.

[53] Jeffrey P. White, Assistant General Counsel, "Impact of Clean Air Act Amendments on the Electric Industry, The Utility Perspective," American Electric Power Service Corporation; Columbus, Ohio; Washington, D.C.; February 21, 1991, Addendum V, page 9.

have plans to use Western coal (all high sulfur burning states)."[54] Ohio, a state with a great number of heavy $SO_2$ producing units, has "just begun to receive a modest amount (of western coal)."[55] Indications are that high sulfur coal consumption will at least hold steady over the next decade. As seen in Diagram 2 above, coal use as a means of generating electricity has been on a steady increase for the last several decades. More importantly, this trend is expected to continue at a steady rate well into the next century. Coal will continue in importance due to the fact that "utilities regard coal plants as their crown jewels...as the cheapest, most reliable source of electricity, these plants, which now often run far below capacity, are expected to play a sizable role in bringing rates down as the industry deregulates."[56]

Since all coal contains some sulfur, the continued growth of coal use guarantees that even with the use of western coal, the utility industry will exceed the Phase II total annual allowance cap. This fact is more readably apparent when looking the present and projected composition of total coal consumption over the same time frame, as shown in Diagram 3 below.

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[54] "Clean Air Compliance Strains Great Lakes Ship Capacity". Joseph Daubenmire and Peter Kakela. Ohio State and Michigan State University, respectively. April 16, 1997. Page 7.

[55] "Clean Air Compliance Strains Great Lakes Ship Capacity". Joseph Daubenmire and Peter Kakela. Ohio State and Michigan State University, respectively. April 16, 1997. Page 7.

[56] "Coal May Become a Better Choice", by Agis Salpukas. The New York Times, Business Day, Friday, January 2, 1998. Page C1.

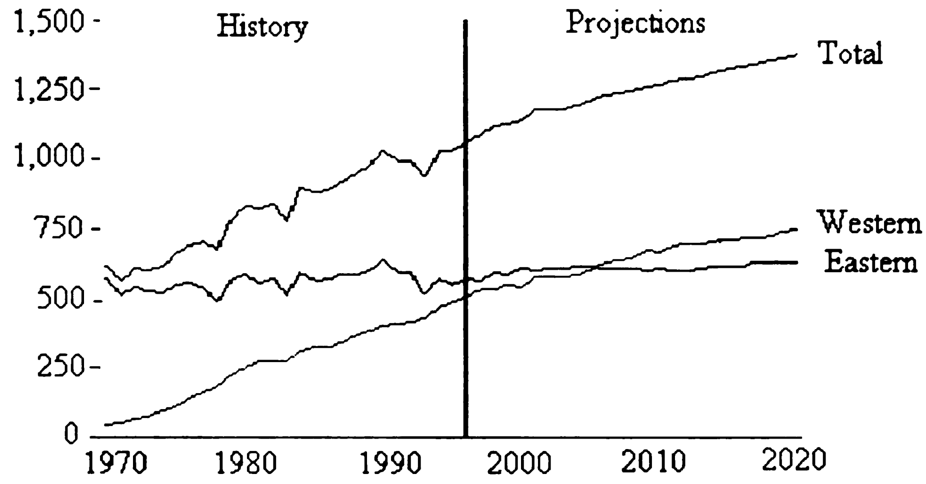


**Diagram 2.3: Total Consumption of Coal by Source (Type)[57]**

Diagram 2.3 shows the trend line of the change in total composition of coal consumption in terms of western and eastern coal. As can be seen, western coal use has been increasing since the 1970 (with the passage of the first Clean Air Act). Eastern coal has been increasing as well, but at a much slower rate. Even if Eastern coal consumption plateaus completely in the next century, FGD will be required to reduce emissions to within compliance with Phase II of Title IV. At current consumption levels of both coal types, and without the use of FGD, the industry will not meet Phase II requirements. At 1986 levels of coal consumption (seen above), emissions exceeded 15 million tons a year—almost twice the level allowed under phase II restrictions. Projections indicate much higher total coal usage by 2010—with no decline in high sulfur coal use in the foreseeable future. Even when holding eastern coal consumption constant, emissions will continue to increase as total coal consumption increases—thus the problem of matching

[57] DOE. Annual Energy Outlook 1998—Market Trends—Coal.
[Online] Available
http://www/eia.doe.gov/oiaf/aeo98/fig95.html, January, February 1999.

total emissions with total allowances only grows with time under coal switching. This problem is compounded by the fact that high sulfur coal consumption levels are actually expected to rise with time.

Diagram 2.4 shows the actual and projected break down of coal consumption as high sulfur, medium sulfur (lower sulfur eastern coal), and low sulfur (western coal) for the years 1996, 2000, and 2020. The Diagram indicates a growth of not only low sulfur coal, but of the higher sulfur grades as well.[58]

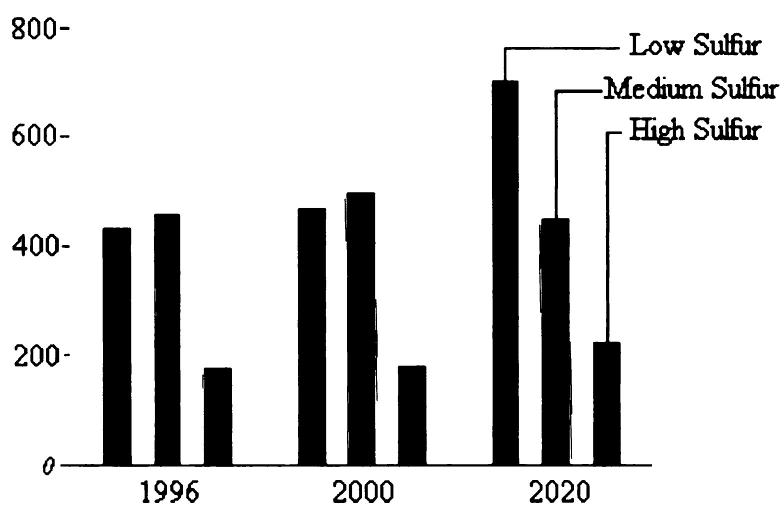


**Diagram 2.4: Composition of Coal Consumption**[59]

Coal switching, though wide spread among Phase I units so far, has proven to be of little use in preparing for the long-term compliance requirements of Phase II. And it will prove to be inadequate as an industry-wide phase II compliance strategy.

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[58] In the end, the increase in consumption of high sulfur coal may occur due to the fact that a high sulfur content is associated with lower average and marginal costs of emission removal under FGD systems—as will explained in the next section of the paper.

[59] DOE. Annual Energy Outlook 1998—Market Trends—Coal.
[Online] Available
http://www/eia.doe.gov/oiaf/aeo98/fig105.html, January, February 1999.

FGD, on the other hand, is the effective long term strategy in terms of a means of meeting and exceeding Phase II requirements. Given continued growth in coal consumption as a means of generating electricity, exceeding requirements will be a necessity to free up allowances for new units and greater generation at older units. While Schmalensee found that fuel switching of some sort was responsible for a significant decrease in emissions from 1993 to 1995 and 1996, in terms of effectiveness on a per unit scale, coal switching has had a limited impact relative to the use of scrubbers. Schmalensee found that the "27 'table A' units that began operating scrubbers in 1995 or 1996 accounted for about 45 percent of the total reduction in emissions—(with) almost two-thirds of the reduction from due to scrubbing in 1995 and 1996...contributed by seven units at three large plants." [60] All of these units will be well within Phase II compliance with FGD—along with the other 30 or so phase II affected units with FGD capacity installed.

This is not to say that coal switching will not play a role in the Phase II market, as indicated in current market activity. Coal switching will find a use among those plants which, at the long-term equilibrium market price for allowances, will choose to buy rather than sell allowances. To a prospective buyer of allowances, the use of coal switching will be a low cost way to reduce the number of allowances needed to cover their compliance needs. For plants with scrubbers (i.e., units that will be in a position to sell allowances), the use of higher sulfur coal will actually lower both the marginal and

[60] Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey; "An interim Evaluation of Sulfur Dioxide Emission Trading", Journal f Economic Perspectives, 12, No. 3, Summer 1998, Page 59.

average cost of emission reduction—allowing for the economic use of greater amounts of high sulfur coal.[61]

The effect of coal switching on the long-term market would thus be expected to decrease (shift in long-term demand) the demand and lower the price for allowances relative to a situation where no coal switching occurred. This does not change the fact that the prime mover abatement technology under the long-term phase II market will be FGD.

## VII. Effect of Powder Basin Coal on Phase II Expected Trades

Given the unexpected low cost of Powder Basin Coal, long-term allowance prices are expected to be lower than originally thought, but the relationship between potential buyers and sellers will remain relatively unchanged. That is, the majority of the units that would have been suppliers under old expectations will still be in a position to supply allowances. That is, there is still concern that high sulfur states will—through the decreasing average cost regarding FGD—be in a position to sell allowances to lower sulfur coal states—where FGD was already considered a second choice to purchasing allowances.[62]

The units that would have been demanders of allowances in the long-term allowance market prior to the coal-price-shock, will still be in a position where buying allowances makes more sense than abatement effort.[63] The difference is that the

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[61] This is discussed in the next section of the paper regarding the costs of FGD abatement technology.
[62] As mentioned previously in this paper, the structure of FGD costs is described and estimated in great detail in appendix G and later in this dissertation.
[63] The exception to this is the 13% of phase I units that have been able to use Powder Basin Coal to achieve compliance with Phase I.

existence of low sulfur coal at low prices will reduce the demand for allowances in the long-run, at every price. This due to the fact that coal switching can, in certain circumstances, be used as a way to reduce the number of allowances needed to cover their compliance needs. It does not, however, eliminate the demand for allowances in the long-term given that fact that coal-blending alone will not allow a unit to achieve phase II compliance. In addition, the ability to use coal blending and switching will be limited to areas that have access and the ability to use more expensive, lower sulfur coal and cheap Powder Basin Coal. The existence of low sulfur coal does not eliminate the need to buy allowances among units that choose to use it over FGD. Nor does it allow these units to become suppliers of allowances without the use of FGD.

Thus, the long-term effect of lower cost coal switching on the long-term allowance market is a slight decrease in the long-term demand for allowances relative to expectation where Powder Basin Coal prices did not fall. This decrease in demand will tend to be concentrated among utilities that were already in a position to use lower sulfur coal due to geographic position. These units more often than not were low sulfur emitters at the offset of the allowance market due to geographic location. Under the decreasing average cost of FGD, these units would have preferred buying allowances rather than invest in FGD given long-term projections of allowance prices. Thus the existence of low-cost, low-sulfur coal only enforces the incentive to buy allowances rather than invest in FGD in cases where FGD was not being considered.

For units considering scrubbers prior to the introduction of low cost Powder basin coal may change some long-term decisions to scrub, based on a reduced demand for allowances on the margin. However, in most cases where scrubber technology was seriously being considered prior to lower prices for Powder Basin coal, Powder Basin Coal and lower sulfur coals are not an option—like the high sulfur east and mid-east. In these cases, the decreasing average cost associated with FGD will still make FGD an attractive long-term compliance option under Phase II. Thus, the existence of low-cost, low-sulfur coal may reduce the use of FGD on the margin, but it will not eliminate the need to use FGD, nor will it alter the long-term decisions to use FGD where FGD was considered as the best option before the shock.

Therefore the existence of low-cost, low sulfur coal is not expected to change the basic breakdown between buyers and sellers in the allowance market. It will reduce demand for allowances relative to earlier expectations, but it will not change the structure of that market.

## VIII. Title IV and FERC Order 888: Impact on Phase II Units and the Future of Coal, Nuclear Power, and Natural Gas, the next 20 years.

FERC order 888 is expected to have little impact on the abatement control decisions under the long-term Phase II allowance market in the transition period modeled in this paper—relative to the case where the order has not been made. There are two reasons for this. First of all, the loads of Phase II units are not expected to change under FERC 888. Second, the source and scope of much of the competitive pressure that led to FERC 888 would indicate that full implementation of spirit of FERC 888 would actually improve the position of incumbent utilities relative to QF's, IPP's, and other by-pass options threatening non-core customers.[64]

[64] The impact and issue surrounding FERC order 888 and the deregulation debate is discussed in greater detail in Appendix A: FERC order 888 and in a number of papers on

**A. The Expected Effect of FERC 888 on Native Phase II Unit Loads—the Next 20 years**

The only reason there would be any concern about FERC order 888 with regard to the simulation results is if it caused a significant portion of the Title IV affected units to shut down or lose load due to the intrusion of non-phase II units—such as by IPP's with new natural gas combined cycle generators. Current emission regulation, both state and Federal, implicitly favors the development of electricity generation based on fuels which have reduced environmental impact. Current regulation places additional costs on proposed units that must be included when new load capacity is considered. In Title IV, consideration of $SO_2$ emission control costs can make alternate fuels look attractive—particularly given the fact that new units (units installed after 1986) are not allocated allowances. New plants must either buy allowances to cover $SO_2$ emissions or have zero emissions. Regulations concerning particulate emissions and $NO_x$ emissions add additional costs to opening new capacity. These restrictions make lower impact energy sources—ranging from natural gas to nuclear power—increasingly attractive relative to new coal capacity in terms of start-up and operating costs.

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the subject: Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995. Pages 1-81; Before the Michigan Public Service Commission, Case No. U-10143, Case No. U-10176, April 11, 1994: The application of ABATE for approval of an experimental retail wheeling tariff for Consumers Power, "Opinion and Interim Order Remanding to the Administrative Law Judge for Further Proceedings"; Ronald R. Braeutigam and John C. Panzar, "Effects of the Change from Rate-of-Return to Price-Cap Regulation," AER 83, No 2 , May 1993. Pages 191-198; Robert D. Glynn, "Offering Customers Direct Access: Using Choice to Stimulate Competition", The Electricity Journal, December 1994, Volume 7, Number 10. Pages 52-57, and others. For a more complete listing see the bibliography at the end of this chapter.

Be that as it may, coal is still the prime source of fuel for electricity generation—accounting for 57% of generation in 1997.[65] In comparison, nuclear power accounted for 20%, hydroelectric 11%, natural gas 9%, oil 2.5%, and geothermal and 'other' 0.2%.[66] Not only is coal the leading power source for electric generation, it is expected to continue in this role—as indicated in Diagram 2 above. Coal consumption in 1998 was the highest ever recorded, and is expected to increase annually—with the vast majority (89%) being used by electric utilities.[67] The central reason for coal's central role in electric generation is the fact that coal-fired plants are the lowest cost producers of electricity in the United States. It is expected that coal will maintain its prominent position under a deregulated environment due to its "fuel cost advantages over oil and natural gas."[68] "As the cheapest, most reliable sources of electricity, these plants, which now often run far below capacity, are expected to play a sizable role in bringing rates down as the industry deregulates."[69]

Despite the low-cost status of coal, natural gas is expected to increase in its share of electricity generation over the next twenty years. In light of the current emissions regulation, natural gas is a desirable fuel. "In the 'long-run (through 2020), U.S. natural gas production is expected to increase sharply as a result of rising prices, abundant

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[65] United States Energy Information Administration, United States of America, Quarterly Energy Report, April 1998, page 9.
[66] United States Energy Information Administration, United States of America, Quarterly Energy Report, April 1998, page 9.
[67] United States Energy Information Administration, United States of America, Quarterly Energy Report, April 1998, page 8.
[68] United States Energy Information Administration, United States of America, Quarterly Energy Report, April 1998, page 8.
[69] "Coal May Become A Better Choice", The New York Times. Page C1, Friday, January 2, 1998.

reserves, and improved unconventional and offshore recovery technology."[70] Gas consumption is also expected to "expand substantially through 2020, with the fastest growth resulting from additional gas-fired electric power plants." But gas powered generation is not expected to replace coal burning units. Natural gas plants, even combined cycle plants, are considerably more expensive to build and operate than the large coal plants which make up the core generating capacity of the majority of utilities in the United States.[71] Where natural gas generation is expected to grow is in terms of meeting new load demand on the margin of the opening electricity markets—and to replace aging nuclear power capacity in many states.

Currently, the second largest source of electric generation in the United States—far behind the amount of electricity supplied by coal burning facilities—is nuclear powered generators. Given the political environment, and the issues of nuclear waste disposal, it is unlikely that new nuclear power plants will be used to meet increasing load demands in the next twenty years.[72] "The long-term (through 2020) nuclear power outlook in the United States is for nuclear capacity to decline sharply, with no new nuclear units expected to come on-line during the forecast timeframe."[73] The Unite States "is expected to have 45 nuclear unit (compared to the 110 at the end of 1996) providing only 8% of total electricity generation"—down from nuclear power's current

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[70] United States Energy Information Administration, United States of America, Quarterly Energy Report, April 1998, page 7.
[71] New York State Energy Office, New York State Energy Plan, Volume III: Supply Assessments, October 1994, Page 479-81.
[72] New York State Energy Office, New York State Energy Plan, Volume III: Supply Assessments, October 1994, Page 300-07, 491-2.
[73] United States Energy Information Administration, United States of America, Quarterly Energy Report, April 1998, Page 10.

20% share of total load.[74] Some of nuclear power's current load will be absorbed by existing coal-fired plants—as seen in the increase in coal-fired generation in Diagram 2 above—but even more will be absorbed by new gas-fired generators due to the fact that they are $SO_2$ emission neutral.

Title IV and other emission regulation has made alternate fuels more attractive as potential fuel for future generating capacity in the United States. However, through 2020—the limit of current projections—coal will provide a consistent lion's share of BTUs used to generate electricity. Even with current legislation and regulation, coal-fired plants still represent the lowest cost, most reliable producers of electricity in the Unites States. This fact will insure that coal-fired units will be central to utility competitiveness in the deregulated electricity market.

What impact order 888 will have should be restricted, in the long-term, to the load supplied by the more expensive generating units on the grid. This implies competition among higher cost utility assets—natural gas and nuclear power generators—and gas fired IPP and QF's. Expected competition is, therefore, restricted among units not considered to be active in the Phase II market under Title IV. These are units that are not allocated allowances under Title IV, and which do not require allowances to cover their non-existent $SO_2$ emissions. This is a second indication that FERC 888 would not affect the load served by the baseline, low-cost load generators that make up the core of the Phase II units—the coal burning generator units. Therefore, assuming that the load served by the core Phase II units is will not change due to FERC 888, implies that FERC order 888 will have limited impact in the abatement decisions of Phase II units.

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[74] United States Energy Information Administration, United States of America, Quarterly Energy Report, April 1998, page 10.

**B. The Source and Impact of Competitive Pressure Before and After FERC 888**

In addition, there is reason to believe that FERC order 888 will only have a limited impact on the price and distribution of load among utilities in general. The source and nature of competitive pressure that led to order 888 castes doubt that there will be a great deal of customer loss in the transition period. In electric markets, the current drive towards self-generation and bypass among big-users is an example of where agents are reacting to both technological changes and old institutional distortions.[75] New small, low cost gas turbines generators are now available, making self-generation, municipalization, and non-utility generators (NUG's) more viable and attractive options to utility power for big customers.[76] Large industrial customers are targets for bypass because they are often saddled with the costs of Demand Side Management (DSM) projects, rate tilt, taxes, and other programs (like PURPHA) that artificially raise the prices of electricity relative to these alternative sources. "With the combination of institutional distortions and rate rigidity, it is not possible to determine whether technological changes are removing the natural monopoly status of the utility or if the changes have just reduced the amount of subsidization and excess baggage which can be sustained by an individual utility's gas

[75] Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995. Pages 1-81; Before the Michigan Public Service Commission, Case No. U-10143, Case No. U-10176, April 11, 1994: The application of ABATE for approval of an experimental retail wheeling tariff for Consumers Power, "Opinion and Interim Order Remanding to the Administrative Law Judge for Further Proceedings"; Ronald R. Braeutigam and John C. Panzar, "Effects of the Change from Rate-of-Return to Price-Cap Regulation," AER 83, No 2 , May 1993. Pages 191-198; Robert D. Glynn, "Offering Customers Direct Access: Using Choice to Stimulate Competition", The Electricity Journal, December 1994, Volume 7, Number 10. Pages 52-57, and others. For a more complete listing see the bibliography at the end of this chapter.

[76] Charles E. Bayless, "Less is more: Why Gas Turbines Will Transform Electric Utilities", Public Utilities Fortnightly, December 1, 1994. Pages 21-24.

and electric markets."[77] Retail competition has become "increasingly prevalent, especially with respect to those customers, primarily industrial, that have viable options to substitute for electricity".[78]

The size of this rate tilt is not small. William R. Gregory, President of the Edison Sault Electric Company, provides an illustrative example:

> "The subsidy issue prevents Michigan Utilities from being competitive challengers. For example, in our company commercial kilowatt hours sell for approximately 6.5 cents: compared to residential kilowatt hours of 6 cents. Yet, the residential rate of return is 'break-even' while the commercial rate of return is in the range of 18%." [79]

The actual numbers involved with rate tilt can be staggering, as ABATE witness Phillips attested to during a rate review in 1994. Phillips "calculated that there would be an industrial class overcharge of $73 million in 1994 and that the overcharge has grown in the last 15 years from $26.6 million." [80]

Utilities are pointing at the social engineering and rate tilt pricing policies of their respective commissions as being the cause of much of the bypass threats they are facing.[81] Rate schedules and subsidies "prevent Michigan utilities from being

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[77] Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995. Page iv.
[78] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, Page 43.
[79] Comments of William R. Gregory, President of the Edison Sault Electric Company, December 12, 1994. Letter to MEGA.
[80] Before the Michigan Public Service Commission, Case no. U-10335, Page 159.
[81] Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995.

competitive and meeting competitive challenges."[82] According to a recent study by Ojure: "increases in utility bills in New York have been greatly impacted by mandatory DSM incentives..."[83] In New York, PURPA and something known as the '6 cent law' has caused a considerable amount to incumbent utilities. Under these laws, the NY investor owned utilities must pay QF's either the avoided cost of new power or 6 cents, whichever is higher. This welfare for independent power producers has been blamed for a large amount of many New York utilities financial woes—Niagara Mohawk's in particular.[84] "Data from Niagara Mohawk and NYSEG indicate that power purchases payments by their utilities to QF's may be the single largest reason for recent customer bill increases."[85] In 1994 alone, Niagara Mohawk paid out $1 billion to QF'sunder the 6 cent law, $350 million of which was overpayment relative to current avoided costs."[86] Part of the problem that New York and other state's utilities are having is that they are suddenly sitting on huge excess capacity, while still being "tied into contracts pushed by NYPSC, based on LRAC estimates that were overstated."[87]

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[82] Douglas A. Houston, "Can Energy Markets Drive DSM?," The Electricity Journal, November 1994, 7, No. 9, Page 47.
[83] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, page 42.
[84] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, page 42.
[85] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, page 48.
[86] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, page 48.
[87] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, page 48.

Taxes are another factor that has slanted the playing field against the incumbent utilities. In New York, the state and local taxes account for 1/5 of an average customer energy bill and this burden is distributed unevenly among its customers.[88] New York regulated utilities pay three times more in local taxes than do their counterparts in other states and they pay 500% of the property tax per MW than unregulated New York non-utility generators pay.[89] In addition, due to rate tilt, a majority of this burden is placed on the industrial and commercial customers of the utility in question.[90] Of the 3.9 cents more per kWh that New York's rates exceed the national average, 1.7 cents are due to the tax burden. Of this, tax bill, 60% are local taxes.[91]

Competition under these circumstances is an institutional matter, not a technological one. Attempts to stop bypass have been blocked or hampered in the past by the regulators. Michigan utilities have been forced the use of special rates to stop the bypass—but these have been difficult to impossible to use under current regulation. Michigan's regulators used the language in their rate-making statute[92] to refuse special

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[88] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, pages 41-53.

[89] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, pages 41-53.

[90] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, pages 41-53.

[91] Tom U. Ojure, "Competitive Pricing of Energy Services in New York State: Current Trends and Issues," The Electricity Journal, January/February 1994/1995, 8, No. 1, pages 41-53.

[92] "The rates of an electric utility shall be just and reasonable and a consumer shall not be charged more or less than other consumers are charged for like contemporaneous service rendered under similar circumstances and conditions…an electric utility doing business within this state shall not, directly or indirectly by special rate, rebate, draw-back, or other device, charges, demands, collects, or receives from a person, partnership, or corporation, a greater or lesser compensation for a service rendered than the electric

rate requests by utilities in the face of potential bypass of high revenue customers—such as rate K.[93] It is Consumer's Power's strong belief, for example, that if it were not for rate tilt and DSM programs in its rates to its industrial and commercial customers, the company "could match the 'independent power producers' price of 4 and ½ cents a kWh."[94]

Price tilt has been used to protect captive, core customer—those customers with very inelastic demand for electricity. However, "policies designed to 'protect' captive customers at any cost are counterproductive when they ultimately result in substantial welfare losses...the irony of the consumerist approach is that their aversion to offering a flexible rate is based on the objective of minimizing the total bill of the inelastic customer; yet, such a stance has a high probability of resulting in higher rates."[95] Where utilities are struggling to get permission to change rates and divest PURPHA contracts and keep customer to pay for remaining agreements, IPP's and QF's are free to skim the lucrative customers away from the utilities. "Uneconomic bypass hurts core customers because, as more and more big customers are lured away by other sources of energy, the share of common costs increases for all the remaining customers. This increase in per kwh cost translates, of course, into either lower profits for the utility or higher rates or both...it may also translate into more firms finding it in their interest to leave the system,

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utility charges, demands, collects or receives from any other person, partnership, or corporation for rendering, a like contemporaneous service," Michigan Statute on Electric Ratemaking, Pages 4 and 5, 03975'93 c *.

93 Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995. Page 12.

94 Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995. Page 11.

further exacerbating the problem for the utility, the regulators, and the core customers."[96] "By pass can, on a per kwh hour basis, lead to actual embedded costs being higher than market prices—more involved with stranded cost than after-the-fact inefficient investment."[97]

Though order 888 was set on April 24, 1996, movement has been slow towards actually restructuring the market. As indicated above, there are a lot of issues to resolve regarding economic and uneconomic by-pass and the transmission tariffs before open transmission competition can take place.[98] States "with relatively high electricity rates, such as California and those in the Northeast, have compelling reasons to promote competition in order to lower rates to consumers."[99] Many of these states, such as California, New York, New Jersey, Massachusetts have had a history of stricter emission standards, DSM programs, PURPHA projects, and large taxes on electricity which have

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95 Public Utilities Fortnightly, "Evaluating Flexible Pricing Alternatives: A Strategic Response for Electric Utilities," July 5, 1990, 126, No. 1, page 17.

96 Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995. Page 22.

97 Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995. Page 23.

98 See Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995, Pages 1-81; Before the Michigan Public Service Commission, Case No. U-10143, Case No. U-10176, April 11, 1994: The application of ABATE for approval of an experimental retail wheeling tariff for Consumers Power, "Opinion and Interim Order Remanding to the Administrative Law Judge for Further Proceedings"; Ronald R. Braeutigam and John C. Panzar, "Effects of the Change from Rate-of-Return to Price-Cap Regulation," AER 83, No 2 , May 1993. Pages 191-198; Robert D. Glynn, "Offering Customers Direct Access: Using Choice to Stimulate Competition", The Electricity Journal, December 1994, Volume 7, Number 10. Pages 52-57 and others. For a more complete listing see the bibliography.

99 United States of America, Quarterly Energy Report, United States Energy Information Administration. Page 9.

made by-pass a consistent pressure in the market. The stricter emission standards have also caused the development oil, natural gas, and nuclear power that have, on average, much higher operating costs than coal burning plants.[100] [101] Of these states, only California has taken steps to force its transmission grid open to competition, finalized as of October 30th, 1997.

If letter and the spirit of FERC order 888 is applied across states, it is generally assumed that where deregulation does occur, competition will occur only on the margin—between utilities and IPP's. Freeing up of rate-making and eliminating the uneven playing field will enable to challenge the current pressures of uneconomic by-pass. In general, however, the majority of customers will not see a change in their price of service. Even in California, where complete deregulation has occurred on paper: "Analysts believe that due to technicalities in implementing the law, results of this deregulation on consumer prices will most likely be limited, at least in the short-term."[102] The California deregulation effort has only seen minor movement of customers to new sources: "As of March 31, 1998, only about 50,000 of nearly 10 million customers in CA had chosen alternative power suppliers."[103] In addition, movement to new sources has

[100] Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995. Pages 1-81 and New York State Energy Office, New York State Energy Plan, Volume III: Supply Assessments, October 1994.
[101] In many cases higher prices are the product of regulatory mandates, rather than actual differences in generating costs—thus leading the problem of uneconomic by-pass. Niagara Mohawk is one of many utilities with complaints on record regarding this development. See Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets", MEGA. April 23, 1995.
[102] United States Energy Information Administration, United States of America, Quarterly Energy Report, April 1998, page 9.
[103] United States Energy Information Administration, United States of America, Quarterly Energy Report, April 1998, page 9.

been limited to a few large customers—as had been predicted in earlier studies of deregulation.[104]

There are several reasons, both technical and economic, that movement of load to alternate sources is expected to be limited for some time. Anticipation of deregulation efforts has forced utilities to slim down costs and/or acquire potential competitors—reducing rate differentials among potential competitors. Where deregulation is being implemented, rate tilt is being reduced—the major source of by-pass pressure. Competition will also be limited by the physical capacity of the transmission grids. There is a limit to the amount of power that can be transferred across the gird, from utility to utility. This provides a physical limitation to an open electricity market until interconnectivity issues, transmission tariffs, reliability concerns are addressed, and transmission grid investment are resolved.[105]

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[104] See Howard J. Haas, "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets," MEGA, April 23, 1995, Pages 1-81; Before the Michigan Public Service Commission, Case No. U-10143, Case No. U-10176, April 11, 1994: The application of ABATE for approval of an experimental retail wheeling tariff for Consumers Power, "Opinion and Interim Order Remanding to the Administrative Law Judge for Further Proceedings"; Ronald R. Braeutigam and John C. Panzar, "Effects of the Change from Rate-of-Return to Price-Cap Regulation," AER 83, No 2 , May 1993. Pages 191-198; Robert D. Glynn, "Offering Customers Direct Access: Using Choice to Stimulate Competition", The Electricity Journal, December 1994, Volume 7, Number 10. Pages Pages 52-57 and others. For a more complete listing see the bibliography.

[105] See "The Need for Change: Practical and Efficient Solutions to the Problems of Rate of Return Regulation Through Flexible Pricing and Competitive Markets", Howard J. Haas, MEGA. April 23, 1995. Pages 1-81; "Opinion and Interim Order Remanding to the Administrative Law Judge for Further Proceedings", Before the Michigan Public Service Commission, Case No. U-10143, Case No. U-10176, April 11, 1994. The application of ABATE for approval of an experimental retail wheeling tariff for Consumers Power; "Effects of the Change from Rate-of-Return to Price-Cap Regulation." AER 83, No 2 (May 1993). Pages 191-198; "Offering Customers Direct Access: Using Choice to Stimulate Competition", The Electricity Journal, December 1994, Volume 7, Number 10. Pages 52-57 and others. For a more complete listing see the bibliography at the end of this chapter.

## C. Net Impact of FERC order 888 on Phase II Unit's Native Load Will Be Minimal

It is unlikely, therefore, that FERC order 888 will cause a significant migration of load away from incumbent utilities. It is even less likely that this load will be diverted from the low-cost coal-fired units that make up the majority of the Phase II units. It is therefore unlikely that FERC order 888 and the opening of competition in the electricity market will impact the outcome of the Phase II market. In short, FERC order 888 is expected to have little impact on the abatement control decisions under the long-term Phase II allowance market. Title IV restrictions are not expected to cause costs of generation to increase significantly among Phase II units, certainly not enough to make new gas-powered generating capacity to compete directly with baseline load generators.[106] What impact order 888 will have should be restricted, in the long-term, to load supplied by the more expensive generating units on the grid, not the baseline, low-cost load generators which make up the core of the Phase II units—the coal burning generator units. The expansion of the share of natural gas in electric generation, made possible by FERC order 888, is expected to go towards load growth and to replace aging nuclear power—as discussed earlier in the introduction.[107]

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[106] New York State Energy Office, New York State Energy Plan, Volume III: Supply Assessments, October 1994, Page 479-81, United States Energy Information Administration, United States of America, Quarterly Energy Report, Page 7, April 1998.
[107] New York State Energy Office, New York State Energy Plan, Volume III: Supply Assessments, October 1994, Page 479-81, United States Energy Information Administration, United States of America, Quarterly Energy Report, Page 7, April 1998.

## IX. Potential Problems with the Market—The Need for an Examination of External Costs Under Long Term Title IV, Phase II Market Allocations of Allowances

It is apparent, from the evidence presented above, that a market for allowances does exist. The fact that the trades are causing a relocation of emissions and abatement is well documented.[108] Most of these trades are resulting in the net reallocation of the sources of emissions relative to an emission cap. Between March of 1994 and March of 1997, of the 27 million allowances were transferred within utilities or groups of utilities, 91.4% were reallocations of allowances between economically distinct parties.[109] In addition, "as of January 1996, allowances had been transferred across the borders of all 24 states with Phase I affected units and of 10 of the 23 states with only Phase II units."[110] The problem is that, up to this point, the external cost impact of these reallocations has not been examined.

External costs associated with $SO_2$ emissions are location dependent—based on an area population, the concentration of emissions, and a number of other factors. There is a significant amount research regarding the locational concentration effects of $SO_2$.[111]

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[108] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997; EPA, 1996 Compliance Report, Acid Rain Program, Office of Air and Radiation, June 1997; "Looking back on $SO_2$ Trading: What's Good for the Environment is Good for the Market," Public Utilities Fortnightly, October 1997.

[109] "Looking back on $SO_2$ Trading: What's Good for the Environment is Good for the Market," Public Utilities Fortnightly, October 1997, page 4.

[110] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, 63.

[111] See Abbey, D.E., M.D. Lebowitz, P.K. Mills, F.F. Peterson, W.L. Beeson and R.J. Burchette, "Long-term Ambient Concentrations of Particulates and Oxidants and Development of Chronic Disease in Cohort of Nonsmoking California Residents," Inhalation Toxicology 7, 1995, pages 19-34; Abbey, D.E., F.F. Peterson, P.K. Mills and

In addition, there is strong evidence that location of the source of $SO_2$ emissions in the United States will affect the regional concentrations of $SO_2$—thus affecting external costs associated with $SO_2$ emissions.[112] Despite the recognition that external costs of $SO_2$ emissions are location dependent, nothing has been done—until the writing of this paper—to catalogue the effects of potential allowance trades on external costs.

As indicated in chapter 1, where external costs are location dependent, caution must be exercised when implementing an allowance market as a means of achieving an total emission goal. Where external effects are locationally dependent, external effects of allowance trades may more than offset the savings in abatement costs across units. There has been one study on the potential external cost benefits of the law—Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, EPA, October, 1997. However, this study only focuses on the potential benefits of the title IV emission cap goal in terms of health care savings relative to the case where law was not passed. This study does not examine the potential impact of reallocation of allowances, though the authors recognize the existence of such effects: "Uncertainty...exists in predicting the specific location of emission reductions because

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L. Kittle, "Chronic Respiratory Disease Associated with Long Term Ambient Concentrations of Sulfates and Other Air Pollutants," Journal of Exposure Analysis and Environmental Epidemiology, 1993, pages 99-115; American Lung Association, Health Effects of Air Pollution, New York, New York. 1978; D.V. Bates and R. Sizto, "Associations Between Ambient Particulate Sulfate and Admissions to Ontario Hospitals for Cardiac and Respiratory Diseases," American Journal of Epidemiology 142 (1), May 1995, pages 15-22; and others. See bibliography for a more complete listing.

[112] J.S. Chang, R.A. Brost, I.S.A. Isaken, S. Madronich, P. Middleton, W.R. Stockwell, and C.J. Walcek, "A Three Dimensional Eulerian Acid Deposition Model: Physical Concepts and Formulation," Journal of Geophysical Research, Vol. 92, No.D12, December 20 1987, Pages 14,681-14,700.

emissions allowances can be traded among emitting facilities".[113] Other studies regarding the benefits of allowance trades have focused exclusively on the compliance cost savings under marketable permits relative to command and control standards.[114]

There is, therefore, a need for an examination of the potential external health affects of allowance trades in terms of changes in $SO_2$ concentrations relative to initial allowance allocations under Title IV.

## X. The Use of a Simulation to Model the Long-Run Binding Phase II Allowance Market

A number of reasons exist for using a simulation to model the long-run phase II market set up by Title IV, rather than use current phase I market activity to examine the affects of allowance reallocations. The most important is the fact that the current phase I market activity is not representative of the long-run impact of expected Phase II market activity. The full potential reallocations of allowances through trade are not seen in Phase I behavior. Given this it is also reasonable to assume that the net reallocation of Phase I allowances will not be indicative of any net reallocation of allowances under a binding Phase II allowance allocation. This means that current Phase I market activity would not be indicative of the full potential of the Phase II allowance market to reduce the costs of

[113] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997.
[114] ICF Resources, Inc., "Economic analysis of Title IV of the administration's proposed Clean Air Act Amendments (HR 3030/S 1490), Report prepared for the U.S. EPA (1989) and Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, 58-72.

compliance through allowance trades with Title IV emission goals.[115] In addition, this means that the current Phase I market activity would not be indicative of the full potential of the Phase II allowance market to change the net allocation of allowances and therefore change the external costs of $SO_2$ emissions relative to Title IV as a cap. There is, therefore, the need for a simulation of the potential Phase II allowance market to examine the potential cost savings and external cost effects of a market under the binding Phase II allowance allocations.

The reasons for the differences between phase II expectations and current phase I activity are outlined above, and are reiterated briefly here. The most important reason for a difference in the structure between Phase I and phase II is the fact the two markets are, in fact, different. Phase I of Title IV is not designed to create an equilibrium market for allowances. It is a transitory set of allowance allocations which only last 5 years. It is designed to be a grace or transition period during which the dirtiest plants are given time and an incentive to have control measures in place by the time phase II takes effect. The break takes the form of larger allowance allocation than will occur under phase II. Early compliance thus provides a bonus number of annual allowances that can be sold in phase II to alleviate the costs of abatement incurred by the dirtier plants. In addition, early compliance results in additional one-time bonus allowance allocations that can be sold in phase II.

It is, and was, expected that Phase I units, which account for less than 1/3 of the existing units affected by Title IV, would take advantage of these incentives and overcontrol their emissions. The term overcontrol is used to mean emission abatement in

[115] The fact that a market for allowances will reduce the costs of emissions is generally accepted. The relative efficiency of an allowance market to a cap is discussed in detail in

excess of an amount needed for a unit to meet annual emission requirements—as indicated by annual allowance allocations. The reason for expected overcontrol and allowance build-up under in Phase I was two-fold—the relative low costs of compliance of Phase I units relative to Phase II units and the generous allowances allocations granted during the five years of Phase I.

First, phase I units are dirtier, on average, than the general population affected only by phase II restrictions. It is generally understood that the bigger and the dirtier the unit, the cheaper it is to remove emissions on a per ton basis.[116] The average phase I unit is expected to have lower abatement costs than the average phase II-only unit.[117] Given this expectation, it is expected that Phase I units will, on average, expect to play the role of suppliers of excess allowances in the Phase II market. The costs of abatement of Phase II-only units will, in general, be higher than those exhibited by Phase I designated units. Phase II units will therefore, in general, play the role of demanders of allowances in Phase II. It is expected that, given Phase II price expectations—which are higher than the long-run costs of the average Phase I unit's FGD equipment—some Phase I units will have an incentive to invest in FGD and overcontrol emissions. Thus rather than representing an equilibrium distribution of allowances, Phase I is and was expected to exhibit a significant build-up of allowances—with an expectation of selling these allowances in the Phase II market. As indicated in the previous sections, this is the behavior seen in the current Phase I market. There has been a significant, annual banking

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Chapter 1 of this paper.

[116] <u>Integrated Air Pollution Control System Technical Documentation Manuals</u>, volumes 2 and 3.

[117] It is important to understand that Phase II requirements affect the general population of generating units greater than 50MW in size. Phase I units will fall under the Phase II

of allowances throughout the first four years of Phase I. As indicated earlier, the amount of banking has exceeded earlier expectations, due to the unexpected low price of Powder Basin Coal. However, the market has since adjusted to the price shock. Prices are again showing indications of higher Phase II equilibrium prices and banking continues, but at a reduced rate—evidence of inter-temporal planning where the date of a binding Phase II emission constraint has been pushed back.[118]

Second, the bonus allowance program and the generous allowance allocations provided an incentive to overcontrol emissions. The more overcontrol a unit has, the more allowances it has available to sell in phase II when the prices of allowances are expected to increase dramatically. These generous allowance allocations end in the year 2000, when Phase II begins.

Both the generous allowance allocations and the expectations of relatively low compliance costs of Phase I units generates a condition where a significant portion of allowances are banked, rather than traded. Given the relatively low costs of compliance among Phase I units, there is an expectation that Phase I units will, on average, be suppliers in the upcoming Phase II market. Thus the allocations and reallocations of allowances in the short-term Phase I market should not be expected to indicate the actual or potential reallocations of allowances under the long-run Phase II market. Since the full potential reallocations of allowances are not seen in Phase I behavior, it is also reasonable to assume that the net reallocation of Phase I allowances will not be indicative of any net reallocation of allowances under a binding Phase II allowance allocation. This means that

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requirement in the year 2000, however, not all units that are affected by Phase II are Phase I units.

current Phase I market activity would not be indicative of the full potential of the Phase II allowance market to reduce the costs of compliance through allowance trades with Title IV emission goals.[119] In addition, this means that the current Phase I market activity would not be indicative of the full potential of the Phase II allowance market to change the net allocation of allowances and therefore change the external costs of $SO_2$ emissions relative to Title IV as a cap. There is, therefore, a need to use a simulation of long-term Phase II market behavior in order to study the potential long-term effects of Title IV. Current Phase I market activity is insufficient to draw long-term conclusions regarding long-term reallocations effects of allowance trades where Phase II allowance allocations are binding.

This is not to say that Phase I activity can be ignored. Given the assumption of some degree of inner-temporal planning on the part of the units, a simulation of the Phase II market should indicate general behavior among Phase I designated units that is consistent with actually observed Phase I unit behavior. That is, Phase I designated units in the simulation of Phase II should be acting as suppliers in the Phase II market results. In addition, the costs of abatement predicted by the FGD estimation model should be reasonably close to the abatement costs exhibited by current FGD effort. In addition, the long-term prices predicted by the model should be higher than those currently seen in the market, but within a reasonable range of expectations of a time-trend line. Phase I

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[118] Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, Page 66.

[119] The fact that a market for allowances will reduce the costs of emissions is generally accepted. The relative efficiency of an allowance market to a cap is discussed in detail in Chapter 1 of this paper.

behavior should therefore be used as a test for the accuracy of the Phase I simulation model.

## XI. The Focus on FGD

As indicated above, this paper assumes that each unit's decision regarding abatement in the long-run Title IV market is modeled around the estimated long-term costs of Fluidized Gas Desulfurization (FGD) abatement of actual boiler units granted allowances under Phase II of Title IV. FGD and the long-run cost of FGD are therefore the central focus of the simulation of a long-run allowance market under Title IV.

Modeling behavior based on individual estimates of FGD cost was assumed for a number of reasons. As indicated in the discussions above, compared to nuclear power, natural gas, and coal switching, FGD is the single most cost-effective means of meeting long-term Title IV emission requirements. Relative to coal switching, FGD is the only option that allows the use of coal and long-term compliance with Title IV. Expanding Nuclear power, despite the fact that it is a zero emissions solution, is not an option due to the current political atmosphere. Nuclear power is the second largest source of power in the country, far behind coal, but the current move to decommission rather than upgrade or expand their use as the existing population ages. Natural Gas generators have been looked upon as potential solution to the long-run Phase II compliance. However, as indicated in the discussions above, gas is a limited option due to its high cost of generation relative to coal—even under Phase II compliance costs. Natural Gas generation represents the fastest growing source of generation capacity, however, as indicated, it is being used to replace aging nuclear capacity—rather than lower cost coal-fired units. Of the options available to the utility industry, FGD is not only recognized as the least cost means of long-term compliance with Title IV emission restrictions, but the only option consistent with long-term plans for the continued use of the cheapest fuel source available—coal.

In addition, the use of FGD allows a means of inexpensive and reliable emission over-compliance requirements at individual boiler units. This provides an efficient means of industry-wide compliance through the allowance market mechanism. Coal switching alone would not allow industry-wide compliance with Phase II requirements. Nor would coal switching free up allowances for sale in the long-run allowance market. Without FGD, coal burning units where low sulfur coal is either not a technically feasible option (particularly given possible entry if coal units were to lose their cost advantages over other fuels) or is unavailable, would either have to reduce their output drastically or shut down.

Another reason to base the simulation model of FGD is that there is a considerable amount of data regarding actual FGD implementation costs from private and government sources due to a long-history of its use as a compliance technology. The use of FGD can, therefore, be predicted based on individual unit characteristics given expectations regarding long-term allowance prices. This is not the case with coal-switching on a unit by unit basis. The problem with finding data regarding the characteristics of coal switching are not confined to this study. So far no researcher or government agency has been able to satisfactorily describe what makes one unit more likely to be able to use lower sulfur coal than another. As Coggins and Swinton write:

"data sources are insufficiently detailed to permit a comprehensive examination of this question."[120]

The inability to model coal switching is not crippling to the analysis, however. As outlined above, coal switching, as an abatement option, is not competitive with FGD in terms of long-run compliance options under Title IV. It is, instead, a complimentary option where it is feasible. Units that would not invest in FGD before cheap low sulfur coal was available will not invest in FGD now that it is. These units will use it to reduce their demand for allowances—when it is technically and financially feasible to do so. Units that would invest in FGD—mainly in the high sulfur states due to FGD's decreasing average cost—will still invest in FGD. Coal switching is not considered an option in most of these states—as indicated in the previous discussions. If it is, it can be used to lower emissions even further once FGD is installed—complementing FGD abatement on the supply side.

As indicated above, low-cost-low-sulfur coal has reduced long-term allowance demand from earlier estimates, but this will only affect FGD decisions among units at the margin. There is not, therefore, an indication that coal switching will alter the supply and demand relationships generated by relative FGD costs—as indicated repeatedly above.

Of the options available to the utility industry, FGD is not only recognized as the least cost means of long-term compliance with Title IV emission restrictions, but the only option consistent with long-term plans for the continued use of the cheapest fuel source available—coal. FGD is the central focus of past and current studies of potential cost savings regarding the Phase II allowance market. FGD is assumed to be the driving force

[120] Jay S. Coggins and John R. Swinton; "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances." Journal of Environmental Economics and Management 30,

in the costs savings to be found in the Title IV allowance market, and it is the heterogeneity among FGD costs which will form the underlying reason for allowance trades under a binding Phase II emission requirement. Relative FGD costs among units are therefore an appropriate focus of a simulation of the long-run Phase II market. FGD and the long-run cost of FGD are therefore the central focus of the simulation of a long-run allowance market under Title IV.

## XII. Current Literature on Title IV and Locational External Costs.

In the case where the studies are specifically made in regard to the developing allowance market under title IV, where there is every indication that external cost effects are not homogeneous across firms, the issue of location dependent external costs have received a mixed treatment. One of the most recent examinations of the Title IV allowance market set up by the 1990 Clean Air Act is by Coggins and Smith (1993). In their paper regarding a simulation of a two firm allowance market under two regulators, there is an explicit assumption that the external impact of trades of sulfur dioxide allowances are not dependent on the relative sources of the emissions. It is assumed that since the command and control (CAC) and incentive based (IB) regulation will achieve the same emission goals they will be equivalent in external impact:

> "Because the pollution levels for each firm are here held fixed---and because the overall emission standard is assumed to be identical in the CAC and in the allowance trading case—there is no need to account for the environmental damage in the welfare measure...environmental damage is not unimportant; it simply does not change."[121]

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1996, Page 67.

Coggins and Smith are implicitly assuming that the relative location of the sources does not impact the costs inflicted by sulfur dioxide emissions. However, in the case of sulfur dioxide emissions, environmental damage does change with the location and levels of emissions. Under these circumstances each and every trade or reallocation of allowances in the market can and will cause some change in environmental damage—thus there is a need to account for environmental damage as a welfare measure. This is a fact recognized by Schmalensee when he states, "permitting allowances to be traded freely anywhere in the United States would be a first-best policy if and only if emissions everywhere in the United States had the same marginal damage, which they plainly do not."[122] However, the effects of trades are beyond the scope of Schmalensee paper and he does not include them in his discussion of the current, early Phase I market. This was beyond the scope of Joskow, Schmalensee, and Bailey (1998) as well.[123] Here, the authors argue that the market for sulfur dioxide emissions (allowances or allowances) is very efficient, so much so that "the frictionless, perfectly competitive ideal is a good approximation to reality."[124] While Joskow (et al) argues that the market lacks much in the way of transaction costs, he does not address the potential impact on external costs of a reallocation of allowances through trade—and what impact this may have on the net

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[121] Jay Coggins and Smith, "Some Welfare Effects of Emission Allowance Trading in a Twice-Regulated Industry", Journal of Environmental Economics and Management, 25, 275—297 (1993).

[122] "Richard Schmalensee, Paul Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey, "An Interim Evaluation of Sulfur Dioxide Emissions Trading," Journal of Economic Perspectives, 12, num. 3, Summer 1998, Page 54.

[123] Paul L. Joskow, Richard Schmalensee, and Elizabeth M. Bailey, "The Market for Sulfur Dioxide Emissions," The American Economic Review, Vol. 88, NO. 4, September 1998, 669-683.

[124] Paul L. Joskow, Richard Schmalensee, and Elizabeth M. Bailey, "The Market for Sulfur Dioxide Emissions," The American Economic Review, Vol. 88, NO. 4, September 1998, Page 682.

efficiency of the market. As of the writing of this paper, there has not been an explicit treatment of location-dependent marginal external costs in a comparison of markets and single-emission rule caps in the literature.

## XIII. Conclusion: The Need to Examine the Net Cost Effect of the Title IV Allowance Market Relative to a Title IV Compliant Cap

It should be clear from the above discussions that a simulation model of phase II units, using FGD technology and assuming a native load will provide a reasonable framework in which to examine the potential reallocation of allowances and costs savings generated by a future Phase II binding allowance market. Using these reallocation results, it should be possible to estimate emissions before and after trades so as to estimate potential the external cost effect of the binding phase II market. In comparing an allowance market to a single-emission rule cap, chapter 3 will follow in the tradition of the literature outlined in chapter 1 that examines the relative strengths of various forms of externality regulation under varying circumstances. Chapter 3 uses the general conclusions described in chapter 1 to examine the potential effect of allowance trades in a simulation of the long-run Title IV, Phase II market. Chapter 3 will make use of a simulation model of the binding phase II allowance market, using FGD as the prime mover technology in determining allowance trading patterns and abatement cost savings, as outlined above. Unlike the earlier discussions of Title IV efficiency relative to a cap, the presentation made in this paper, and specifically in chapter 3 includes the effect of documented locational-dependent-external costs of $SO_2$ on the potential long-term net welfare effect of Title IV under phase II rules.

# The Total Cost Effects of the Binding Phase II Title IV $SO_2$ Allowance Market

VOLUME II

By

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## CHAPTER 3

## THE PHASE II ALLOWANCE MARKET RELATIVE TO A PHASE II COMPLIANT CAP: A SIMULATION OF BINDING TITLE IV ALLOWANCE ALLOCATIONS

### I. Introduction

Chapter 1 indicates that there are two effects associated with market reallocations of allowances when external costs of emissions and marginal abatement costs are heterogeneous across units in the market. These two effects are the abatement costs savings effect and the change in external cost effect. The sum of the two effects provides a measure of whether or not a market for allowances improves or reduces welfare relative to a single emission standard cap with the same total emission goal.

The Focus of chapter 3 is the examination of the potential abatement cost and external cost effects of the binding phase II allowance market under Title IV of the Clean Air Act of 1990. This act and the issues surrounding it were introduced in chapter 2. This paper uses a simulation of the future binding, long-run phase II allowance market to examine the net cost effects of the Title IV relative to an emission standards cap with the same total emissions goal.[1] To this end, the model developed in this paper is designed to provide a measure of both the abatement costs savings provided by the market and the net effect on external costs caused by the reallocation of allowances with trade. Both cost

[1] The term long-run-phase-II-market is used to refer to the point in time when the allowance allocations under Phase II of title IV become binding on emissions.

measures are given relative to the case where the allowance allocations are applied as a cap (non-marketable allowances).

## II. Outline of this Chapter

This chapter presents the components of the economic model that make up the core of the phase II allowance market simulation. The chapter is divided into several parts. Part III reiterates the scope of the model, as discussed in chapter 2. Part IV defines the time scope of the model in terms of abatement technology. Part V defines the time scope of the model in terms of electric generation capacity. Part VI Introduces the Boiler Unit, its annual costs of electric generation and annual emissions per unit of generation. Part VII presents the costs of emission reduction in the form of FGD. Part VIII presents the unit profit function under both the Phase II compliant cap and the binding Phase II allowance market. Part IX discusses the determination of allowance price estimates of the future binding Phase II market. Part X presents the results of the market and cap simulation, presenting price, costs savings, and geographic reallocations of allowances. Part XI compares the Phase II model's results with current Phase I activity to test the veracity of the model. Part XII presents the models to calculate effect of binding Phase II market on external costs. Part XIII presents the external cost results of emission trades under a binding Phase II market. Part XIV presents the conclusion.

## III. The Scope of the Phase II Binding Regulation Simulation Model

The Focus of chapter 3 is the examination of the potential net cost of the phase II allowance market under Title IV of the Clean Air Act of 1990. This paper uses a simulation of the future binding, long-run phase II allowance market to examine the net cost effects of the Title IV relative to an emission standards cap with the same total emissions goal.[2] To this end, the model developed in this paper is designed to provide a measure of both the abatement costs savings provided by the market and the net effect on external costs caused by the reallocation of allowances with trade. Both cost measures are given relative to the case where the allowance allocations are applied as a cap or non-marketable allowances. The model presented here is a single period static equilibrium representation of the intermediate/long-run Title IV allowance market where Phase II allowance restrictions are binding on emissions.

The simulation models the predicted behavior of the actual individual boiler units affected by Title IV based on actual generation costs, emission rates, historic generation load, and estimated costs of abatement via Fluidized Gas Desulfurization (FGD). Unit behavior is modeled under both a market and a cap with Title IV specifications. With a market for allowances, each unit has a choice in how it meets its phase II compliance requirements—and whether or not to be a supplier or demander of allowances in a binding phase II market. In the market, the choice regarding abatement is made based on each unit's long-run costs of FGD equipment relative to the long-run price for allowances in the binding phase II market.

[2] The term long-run-phase-II-market is used to refer to the point in time when the allowance allocations under Phase II of title IV become binding on emissions.

Abatement costs savings of the Phase II market are measured relative to the abatement costs incurred under the hypothetical case where Phase II allowance allocations are applied as a non-marketable cap on each unit's emissions. Cost savings are in the form of avoided FGD costs to units buying allowances, and positive net revenues from the sale of allowances from those that invest in FGD. The net external cost affects of Title IV are set up to measure the total external costs incurred under the market's reallocation of allowances relative to total external costs incurred if no trade was allowed to occur.[3] Unlike the abatement cost savings effect, the external cost effect of trades can be positive or negative, depending on the net reallocation of allowances, given location dependent external costs. The sum of the two effects determines the net cost effect of the Title IV market relative to the Title IV as a cap.

The model was limited to considerations of FGD for a number of reasons. Foremost among these is the fact that FGD has been identified, since the passage of the Clean Air Act of 1990, as the least cost compliance technology available to coal burning units under binding Phase II restrictions.[4] FGD (ADVOCATE) "is one of the few low cost technologies capable of achieving 90 percent $SO_2$ control."[5] Due to this early

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[3] Where each unit must reduce emissions to meet its initial allowance allocation.
[4] Frank T. Princiotta, "Acid Rain Control Options," Director of the Air and Energy Engineering Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, MD-60; Research Triangle Park, NC 277111 to The Electric Power Industry and the New Clean Air Act Conference, December 10-11, 1990, Washington, D.C.; T. Emmel and M. Maibodi, "Retrofit Costs for $SO_2$ and $NO_x$ Control Options at 200 Coal-Fired Plants," EPA contract No. 68-02-4286; National Acid Rain Precipitation Assessment Program, 1990 Integrated Assessment Report, pages 408-433; New York State Energy Office, New York State Energy Plan, Volume III: Supply Assessments, October 1994, Page 565; Integrated Air Pollution Control System Technical Documentation Manuals, volumes 2 and 3.
[5] Frank T. Princiotta, "Acid Rain Control Options," Director of the Air and Energy Engineering Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, MD-60; Research Triangle Park, NC 277111 to The

identification of a least-cost means of Title IV compliance, and the fact that the technology was already in place at many units prior to the passage of Title IV, there is considerable data available regarding the actual costs of implementing FGD abatement. The same can not be said of coal switching.[6] Unlike coal switching, FGD will allow industry-wide compliance with Title IV, and significant levels of overcontrol which will allow the development of an allowance market. The assumption that FGD is the only abatement option consistent with long-term compliance is not expected to reduce the effectiveness of the simulation in estimating long-term allowance allocations of the Title IV market relative to the case where load switching was modeled. The superiority and projected dominance of FGD as a compliance option and driving force in the Phase II market is discussed in Chapter 2 with respect to Title IV goals, coal-use projections, relative costs of fuel alternatives, and recent developments in the allowance market in the introduction to Title IV and FERC order 888. This issue is also revisited in Appendix G at the end of this chapter.

This model is not intended to describe potential load reallocation effects of the recent FERC order 888, which orders utilities to open their transmission grids up to potential suppliers of electricity. In fact, this paper assumed each Phase II boiler unit

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Electric Power Industry and the New Clean Air Act Conference, December 10-11, 1990, Washington, D.C., Page 5.

[6] Frank T. Princiotta, "Acid Rain Control Options," Director of the Air and Energy Engineering Research Laboratory, Office of Research and Development, U.S. Environmental Protection Agency, MD-60; Research Triangle Park, NC 277111 to The Electric Power Industry and the New Clean Air Act Conference, December 10-11, 1990, Washington, D.C.; T. Emmel and M. Maibodi, "Retrofit Costs for $SO_2$ and $NO_x$ Control Options at 200 Coal-Fired Plants," EPA contract No. 68-02-4286; National Acid Rain Precipitation Assessment Program, 1990 Integrated Assessment Report, pages 408-433; New York State Energy Office, New York State Energy Plan, Volume III: Supply Assessments, October 1994, Page 565; Integrated Air Pollution Control System Technical Documentation Manuals, Volumes 2 and 3.

keeps its native load under Title IV during the period modeled and is treated as regulated natural monopoly where revenue must be cover long-run costs. As will be discussed in the following sections regarding Title IV and FERC order 888, this assumption is not expected to reduce the effectiveness of the simulation in estimating long-term allowance allocations of the Title IV market relative to the case where load switching was modeled.

## IV. Defining the Time Frame of the Model in terms of Abatement Costs—the next 20 years

The simulation is set up single period, static equilibrium model. If time t represents a state without Title IV regulation, time t+1 represents the period in which the emission constraint is applied as either a set of marketable allowance allocations or as an equivalent set of non-marketable allowance allocations. In period t+1, the units under Title IV must choose their long-run abatement strategy based on the static equilibrium allowance price where Phase II restrictions are binding.

The nature of the time period defined as t+1 used in this model is largely technology dependent. In terms of abatement decisions, the market model assumes that t+1 is a transition period where decisions are being made in reference in to long-run allowance price and abatement costs expectations. This is assumed appropriate given that abatement technology in the form of FGD takes six months to a year to implement and the long-run impact of the Phase II emission constraint is not expected for seven to ten years.

The long-run allowance price is defined here as the allowance market equilibrium price when the allowance allocations in the market become binding on emissions. There is a current expectation that this will occur between the year 2007 and 2010. Abatement decisions are therefore made in terms of long-run abatement costs relative to the long-run price for allowances in the market. Where the price is higher than long-run abatement costs, the unit will invest in abatement technology. Where the price of allowances is lower than long-run abatement costs, the unit will buy allowances to cover its emissions requirements. The long-run equilibrium price for allowances is internally determined by the model using the long-run abatement cost curves of the Phase II units. The equilibrium allowance price is defined as the allowance price that equates annual long-run supply and annual long-run demand for allowances.

The internally determined long-run price for allowances will determine which units are potential suppliers or demanders of annual allowance allocations in the long-run Phase II market. This, in turn, will provide the annual reallocation of allowances under the long-run Phase II market. The equilibrium price and unit decisions allows an estimate of the annual abatement costs savings provided by trade in the long-run Phase II market, as well as projected changes in external costs—as will be discussed later in this chapter.

## V. Defining the Time Frame of the Model in terms of the Electricity Market—the next 20 years

In terms of unit decisions regarding load demand and capacity, period t+1 in the model is assumed to represent intermediate-run in terms of costs and technology. That is, the unit's generating capacity is assumed fix and the price for electricity must be sufficient to cover annual costs of providing the annual load demand of the units. Each unit has a specified annual load demand that is sensitive to the average intermediate-run cost of electricity generation of the unit. This implicitly assumes that each unit keeps its native load over the next 20 years, with or without FERC order 888. This is not a limiting assumption, given the discussion presented in the chapter 2 regarding Title IV and competition.

### VI. The Simulation: The Use of the Boiler Unit as the Basic Economic Unit

The basic economic unit in the simulation is the boiler unit used to generate electricity. Besides simplifying the programming of the market and tracking changes in emissions, the main reason for this convention was that Title IV is a boiler unit specific piece of legislation—assigning allowances to individual units based on each unit's historic average baseline output from 1985 to 1987. At the end of a given year, each boiler unit must have enough allowances in its specific account to cover its emissions for that year. Any trades among boiler units—whether within the same utility or plant or across state lines—must be registered and recorded in the accounts at the EPA. Decisions to buy allowances or remove emissions are made on a boiler-by-boiler basis within a plant. This is due to the fact that abatement costs via FGD are dependent on the characteristics of individual boiler units at a plant—particularly the size of the unit and the average grade and volume of the fuel it uses. Assuming that all agent in the market are price-taker in a perfectly competitive allowance market[7] [8], there is no difference

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[7] That is, assuming, perfect information and zero transactions costs among the traders in the market. This is not a limiting assumption given that the EPA's use of continuously and publicly updated allowance accounts and transactions prices on computer networks brings the allowance market closer to the ideal than most in terms of information and transactions costs. In fact, a study by Paul Joskow, Richard Schmalensee, and Elizabeth M. Bailey concluded "that the frictionless, perfectly competitive ideal is a good

between trades between boilers at different plants and between boilers at a specific plant. Modeling decisions based on each boiler unit's individual costs is therefore ideal when examining long-run Title IV allowance market behavior.

## A. Plant and Boiler Data: Defining Annual Costs of Generation and Annual Load

Data was collected on the Phase II affected coal and oil fired electric plants, both public and private, and their boilers in the United States. This represents the population of boilers that will be affected by Phase I and Phase II[9] and which will be granted allowances under Title IV.[10] Each of the plants possesses a number of Title IV affected boiler units.

All of the data used in this simulation regarding boiler characteristics is available from the Energy Information Administration surveys.[11] Data on each plant's published

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approximation to reality (with regard to the phase I allowance market)." See "The market for Sulfur Dioxide Emissions." The American Economic Review, September 1998, Vol. 88 No. 4. Pages 669-685.

[8] Assuming a perfectly competitive allowance market has several advantages. First it eliminates any distortions in the market which may be caused by monopolistic power. It thus eliminates the need to model a Cournout or Nash-equilibrium model for in excess of 1,500 agents. It also eliminates the need to treat a given power plant as the basic entity. There is no reason, on a transactions or information cost basis, to treat a boiler at a single boiler plant any differently than each boiler at a 10 boiler plant in terms of behavior in the allowance market given the perfect competition model for the allowance market.

[9] It does not include boilers under 50 MW, those boilers that do not burn coal or oil, and emission sources that may volunteer to be included.

[10] Boilers with less than 50 MW capacity and co-generating are excluded by Title IV unless their owners opt to be included. It is assumed that such boilers will not participate and they have been excluded for this reason as well as the fact that information on such boilers, particularly in the case of co-generating units, is very limited.

[11] Energy Information Administration, Cost and Quantity of Fuels for Electric Utility Plants (annual: 1985,1986,1987,1989,1990,1991).
Energy Information Administration, Plant Cost and Power Production Expenses (annual: 1985,1986,1987,1988,1989,1990,1991).

costs was used to determine the individual boiler unit's cost of generation, annual output demand, capacity, size, cooling source, fuel characteristics, and existing emission abatement technology. As with any published accounting cost data, caution must be exercised when using it to determine actual economic relationships. In terms of affecting the results of the simulation, the distortion effect is minimized by the fact that the data used for the simulation of the allowance market is engineering based—annual heat rates, boiler unit sizes, boiler unit type, cooling sources, and fuel characteristics. In addition, data on the delivered cost and Btu content of a unit's fuel was used to directly determine each unit's annual fuel related generation costs of supplying annual average load demand. Other annual costs had to be taken as given, but fuel costs make up the majority of a boiler unit's annual costs—mitigating accounting distortions in annual costs. Given the relatively small costs of compliance and the inelasticity of annual electricity demand, small distortions in annual unit costs is assumed to have an insignificant impact on the results of the allowance market simulation in terms of abatement and external cost effects.

Using the approximation of the actual annual costs of generating each unit's annual electricity load demand, a simple cost curve for each boiler was constructed. The cost curve depicts the intermediate-run, as described above—it is assumed that the generating capacity (capital) of each boiler unit is fixed and can not be changed in the time-frame covered by the model. Each unit's cost curve is made up of costs that vary with the annual output of the plant and costs that do not vary with annual output.

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Energy Information Administration, Electric Power Monthly, (Monthly, 1985, 1986,1987,1994).

### 1. Fixed costs in the intermediate term

The fixed portion of costs is made up of the fixed capital stock in terms of generation, property taxes, rents, administrative overhead, fixed common costs and other costs that do not vary with output (K).[12] Each unit of fixed capacity K represents the ability to generate one unit of kWh a given hour, which in turn provides the maximum load capacity of a unit for a given year. The sum of this fixed cost is given as Z in the model below for a set amount of K. The portion of Z (and fixed K) assigned to each boiler unit at a plant is dependent on a given boiler unit's share of the nameplate capacity of the plant—which is used to define each unit's share of the plant's output. That is, if the nameplate capacity of a plant is 400 MW and there is one boiler, the full annual Z of the fixed K and the entire annual load demand is assigned to the boiler unit. If the same plant had two 200 MW boilers, both the fixed cost and the load demand would be split evenly between the two. The limitations of the data make any other split of the capital and other common costs difficult. This method assumes that each boiler is assigned costs according to how much output it can produce relative to total plant capacity—assuming that there is a positive relationship between these inputs and the capacity of the boiler.

[12] Or, more appropriately, it assumed a stock of sunk generating capital. It is assumed that the plant cannot change its capital generating stock. Given the model is set up to examine a static equilibrium model of the market for allowance this is not a limiting assumption. The sunk generating capital defines the generating capacity of the boilers in question, and thus places a cap on possible output at the plant in a given time period, and thus within a given year. The MW rating of a plant defines the full output capacity of a plant, where capacity is defined as "the full-load continuous rating of a generator, prime mover, or other electric equipment under specified conditions as designated by the manufacturer."

### 2. The heat rate (H)

Fuel costs make up the largest portion of a boiler unit's annual costs. Within the defined capacity of a boiler unit, it is assumed that the boiler's annual conversion of fuel BTUs into kWh is based on the plant's average annual heat rate (H)—determined for each boiler using the plant's average ratio of mmbtu to kWh generated for a given year.[13,14] It is generally known that the heat rate (H) of a boiler tends to increase as it reaches it capacity. However, cases where extreme loads may adjust this relationship are assumed to average out in the annual nature of the data used to estimate costs. The model in no way takes into account load losses due to overtaxed transmission lines. Hourly fluctuations in load demand that affect the costs of transmission are also assumed to average out over the 365-day period. Appendix A, at the end of this chapter, treats the matter of an average annual heat rate in greater detail.

Using the heat rate, annual mmbtu consumption (F) needed by a boiler unit to generate an annual amount of kWh would be given as follows: $kWh \cdot H = F$.

[13] Given the research on this topic and the fact that the plants in the study are run at loads which represent, on average, less than 65% of their operational capacity in the course of a year, this is not an unreasonable assumption. Cases where extreme loads may adjust this relationship are assumed to average out in the annual nature of the data used to estimate costs. The model in no way takes into account load losses due to overtaxed transmission lines. The basis of the study is on the emissions of the plant in a given year and this implies a need to know the amount of fuel burned at the plant annually to cover its annual demand requirements. Hourly fluctuations in load demand that would affect the costs of transmission are also assumed to average out over the 365-day period. Appendix A treats this matter in greater detail.

### 3. Fuel costs

It is assumed that each plant's fuel mix applies to each of its boilers, unless more specific data was available.[15] Thus, if 95%, 2%, and 3% of a plant's annual Btu's came from coal, gas, and oil—respectively—it was assumed that each boiler in the plant used the same proportion of fuel over the course of the year. This assumption was used where more specific information was unavailable on the actual boiler specific proportions of fuels used. In general, this assumption will have little impact on the outcome of the model with regard to total abatement and external costs under the Title IV market. Any distortion caused by this assumption is minimized by the fact that the majority of the boilers in a given plant are homogenous in their annual fuel use, as well as annual capacity and heat rate. For example, in plants where coal-fired units (Title IV affected units) are used, 87.2% of the coal burning plants have 98% or more of their total annual mmbtu's supplied by coal in a given year.[16] Appendix A treats the matter of an average annual fuel mixes in greater detail.

The percentage of BTUs that come from coal and oil is denoted by $\alpha 1$ and $\alpha 2$ in the model, respectively. The remaining proportion, if any, is assigned as a non-sulfur-

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[14] kWh refers to the boiler portion of the total kWh production of the plant as a whole. That portion is determined by the capacity of the boiler relative to that of the whole plant. See Appendix C for a complete list of definitions.

[15] Given that the majority of the boilers in a given plant are of similar capacity and fuel use, it seems reasonable to make this assumption. Appendix A provides a more complete discussion of the implications of using the boiler as the basic economic agent in the model and briefly discusses how changes in annual load is expected have little impact on the input to output ratios with respect to L (variable costs).

[16] Energy Information Administration, <u>Cost and Quantity of Fuels for Electric Utility Plants</u> (annual: 1985,1986,1987,1989,1990,1991); Energy Information Administration, <u>Plant Cost and Power Production Expenses</u> (annual: 1985, 1986, 1987, 1988, 1989, 1990, 1991); Energy Information Administration, <u>Electric Power Monthly</u>, (Monthly, 1985, 1986,1987,1994). Also see Appendix A for a discussion of the impacts of the assumptions regarding the heat rate and fuel mixture of a boiler over a year.

producing source.[17] Fuel prices are in terms of cents per Btu, so annual kWh are converted to a Btu equivalent in the model.[18] The price of Fuel ($P_F$) for the boiler unit is then $P_F = P_C \cdot \alpha 1 + P_O \cdot \alpha 2 + P_G \cdot (1 - \alpha 1 - \alpha 2)$, where the price of coal ($P_C$), oil ($P_O$), and natural gas ($P_G$)[19] are given in terms of cents per mmbtu.

Annual fuel costs are therefore dependent on the annual amount of electricity annually supplied by the boiler:

**Annual Fuel Cost=kWh*H*$P_F$**

**4. All other variable costs of generation**

All other inputs which vary with annual output are included in an all encompassing variable, L.[20] [21] Each unit of L represents the amount of these other inputs needed to increase the annual output of kWh by one unit. This number is based on the plant's annual average of these inputs. This component of costs is insignificant relative to fuel costs, but it is included for completeness. (The average price of the entire L component per unit, on the other hand, is .00183 per kWh.[22]) Appendix A provides a more complete discussion of how changes in annual load caused by Title IV compliance

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[17] In most cases this is natural gas. Two plants burn wood as a third source of power.
[18] Based on the heat rate, H, of the boiler in question. See Appendix C for a complete list of terms and definitions.
[19] Again, gas also includes other non-sulfur producing fuel sources where appropriate.
[20] Costs associated with coolant, some labor (monitoring and operating), etc are captured by this variable.
[21] Appendix A briefly discusses how changes in annual load are expected have little impact on the input to output ratios with respect to L.
[22] Energy Information Administration, Cost and Quantity of Fuels for Electric Utility Plants (annual: 1985,1986,1987,1989,1990,1991); Energy Information Administration, Plant Cost and Power Production Expenses (annual: 1985,1986,1987,1988,1989,1990, 1991); Energy Information Administration, Electric Power Monthly, (Monthly: 1985, 1986,1987,1994).

costs is expected to have minimal impact on the input to output ratios with respect to L (variable costs).

### 5. The annual production function for electricity in the intermediate term

With an assumption of fixed capacity in generation, the annual electricity output of a boiler unit is dependent on variable inputs. The annual output of a boiler can be represented, for convenience, as a Leontief production function. That is, the minimum of either the fixed or the variable inputs determines the level of annual output of the generator.[23] This annual production function is written as follows:

$kWH = \min\left(K, \frac{F}{H}, L\right)$. The Leontief form limits the substitution between the inputs, but given the fixed capital of each unit and the use of annual averages for inputs, this is not a limiting assumption.

### 6. The total cost of annual generation

Assuming that the boiler will choose the minimum cost combination of inputs to produce a given level of kWh, the amount of annual L needed to produce a given amount of kWh in a year is as follows: (3.2) $kWh = L$. Similarly the fuel needs of the boiler (F) are re-written in terms of kWh and the heat rate (H). Solving $kWh = \frac{F}{H}$ for F results in (3.3) $kWh \cdot H = F$. As the capital generating capacity stock (and other fixed costs associated with generation) are fixed in the short-run focus of this model, the annual costs of the K

[23] Since the fixed component is, by definition, fixed the amount of the variable component will determine the output level of the generator. The fixed inputs, in terms of the size of the boiler, determines the maximum capacity of the generator.

component is expressed as a constant (Z). Re-writing total production costs of the (3.1) as a function of kWh:

(3.4) $TC(kWh)=Z + P_F*kWh*H + P_L*kWh$

Total costs (3.4) of annual electric generation can be consolidate by setting

$P_{FL} = P_F \cdot H + P_L$

(3.5) $TC(kWh)=Z + P_{FL}*kWh$

### 7. Annual load demand

The next piece required by the model is the structure of annual load demand for each boiler unit. This paper assumes each boiler is a regulated natural monopoly where annual revenue must cover annual costs. This assumption simplifies the model and forces the simulated unit to use the least cost compliance option where Title IV emissions restrictions are applied as a cap or as marketable allowances. As indicated above and in the introduction, this assumption allows individual treatment of each unit's abatement decisions based on the least cost compliance choices. As indicated above, unit decisions are made without regard to possible load loss or shifts due FERC 888. As indicated above this should not affect the abatement decisions of the units relative to real world phase II reactions due to the nature of Phase II units as the least cost producers of electricity.

The assumption of a natural monopoly provides a downward sloping annual load demand curve that identifies a load-clearing price that covers total annual costs in the intermediate run. The annual load of each unit is responsive to the annual average price required to cover the costs under Title IV with respect to long-run demand elasticities. Knowing annual load demand before Title IV provisions, the costs of providing this load, and the long-term demand elasticities provides the pieces needed to generate unit specific annual load demand curves.

This paper makes use of the long-term twenty-year-horizon demand elasticity estimates used by the New York State Energy Office in their October 1994 New York State Energy Plan. These long-run demand elasticities are assumed to range from -.01 to -.09—with .03 being the central value. These numbers indicate that aggregate long-run electricity demand is relatively insensitive to changes in price. While short-term electricity use is highly volatile due to business cycle changes, the long-term trend in electricity has shown remarkable stability on a mmbtu per unit of national product basis. While energy intensity (the cost of energy as a percentage of total costs of production) has dropped over the last 20 years, the use of electricity has not. Over the 1970 to 1993 period, energy consumption per unit of gross national product has decreased by 29 percent.[24] However: "electricity consumption per unit of gross state product, however, has remained relatively constant over the same period."[25] This is despite the fact that real and nominal electricity prices have varied substantially over this same period.

It is important to note that the actual sensitivity to electricity prices will vary by state and region—due to such things as differences in industries that form the core of each state's economy. State specific long-run demand elasticity has proven elusive. It

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[24] New York State Energy Office, New York State Energy Plan: Volume II: Issue Reports, October 1994, page 3.
[25] New York State Energy Office, New York State Energy Plan: Volume II: Issue Reports, October 1994, page 3.

is assumed that an elasticity of -.03 makes up the central, reference estimate—as this is the average assumed by the New York State Energy Office.

In determining each unit's demand curve, each unit is assigned a portion of the plant's total annual load demand[26], based on its portion of the plant's total annual generating capacity. Assuming that a regulator that imposes a break-even budget constraint on each boiler, the total cost of producing the boiler's share of the annual kWh will provide the unit specific total annual cost figure—and thus the total annual revenue requirement.[27] Dividing total annual revenue by annual kWh produced provides a price per kilowatt ($P_{kWh}$).[28] Using this price ($P_{kWh}$), the level of output sold (kWh), and the spot elasticity of demand with respect to price (E) at the point where a linear demand curve equals the output of the unit[29], a linear demand curve[30] for electricity for the unit is generated.[31] Given that the unit demand curve has a slope that is dependent on the elasticity assumption, a range of elasticities is used to capture any sensitivity in the model's result due to the demand elasticities. Given the very small elasticities involved,

[26] Annual load demand is determined from the average load of each unit from 1989 though 1991—the years around the passage of the 1990 Clean Air Act.
[27] Here total costs include any investor expected rate of return.
[28] For the sake of simplicity, neither the utility nor the regulator is able to differentiate among its customers. Thus there is a single linear price for all customers. This is not to say that the issue of price discrimination would not have some measurable effect on the impact of emission regulation, however, it is considered to be a secondary issue removed from the central focus of this paper.
[29] This is not a constant elasticity demand curve. The demand curve is assumed to be linear and thus the chosen elasticity is only applicable at the point where this demand curve equals the annual output point from the data set.
[30] This is not a compensated demand curve.
[31] The simple linear demand curve is used for its simplicity in the model and the ease of solving a very large market model. It is not intended to declare anything in particular about the plant or boiler specific demand for electricity other than it is, by some measure, affected by the price of electricity. Sensitivity analysis on the elasticity is performed in the model's results to account for any distortions this structure may cause.

sensitivity was very limited in the results. The slope of the demand function (b) is found as follows:

$$b = \frac{1}{E} \cdot \frac{P_{kWh}}{kWh}$$

And the intercept for a linear demand equation (a):

$$a = P_{kWh} + b \cdot kWh$$

The demand curve is then written as (3.6) $P_{kWh} = a - b \cdot kWh$.

The profit function (3.7) of a unit can now be written as a combination of 3.5 and 3.6:

(3.7) $\Pi(kWh) = P_{kWh}(kWh) * kWh - Z - P_{FL}(kWh)$

## VII. Annual Abatement Costs: FGD

Since abatement cost savings in the simulation are in the form of avoided FGD costs to units buying allowances, and positive net revenues from the sale of allowances from those that invest in FGD, it is important to define abatement costs in terms of FGD. This is done in this section, and in more detail in Appendix F at the end of this chapter.

### A. Total FGD abatement cost (A(RE, kWh)

Abatement effort in the form of FGD scrubber removal efficiency (RE) is not cost-less to the unit. Any increase in removal efficiency (RE=%removed) requires both capital and consumable expenditures. The regression analysis that illustrates the underlying equations and engineering relationships involved with FGD are discussed in greater detail in Appendix F at the end of this chapter.

The estimated abatement cost equations for new FGD scrubber capacity determined in Appendix F indicate that some of the costs are dependent on the level of abatement chosen by the boiler in question. Those costs not directly related to removal efficiency are determined by the unit's characteristics in terms of fuel quality, heat rate, size, and other factors.[32]

Capital costs are made up of two components—a portion that is dependent on the level of abatement removal efficiency and a portion which are not. In the equation below, KapA represents the portion of capital equipment that is dependent on the level of removal efficiency (RE) used at a given boiler. The remainder of abatement capital is given as KapB. The existence of KapB from the regression results indicates that FGD has decreasing average costs in terms of removal efficiency. That is, average costs of per ton of $SO_2$ removed falls as more scrubber capacity (removal efficiency) is added. The annual, cost (price) of abatement capital equipment is given by r. The price of capital used ranges from .05 to .16—the range of the nominal rate of return in the regulated energy industry from 1977 to 1996 according to the Annual Energy Review of the Department of Energy. The average nominal rate of return over this period was around 11.5%, and this value is used to generate the central estimate of the model.

In addition to the capital component, the regression results indicate that the abatement technology also requires a certain amount of consumable elements in order to operate. The regressions indicate that consumable costs are made up of two parts—the portion that is dependent of the amount of emissions removed and the portion that is incurred simply by operating the scrubber.

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[32] Appendix C provides the underlying equations and relationships that provide the definitions of the sulfur dioxide/hr and other engineering components of the abatement

The annual, uncontrolled $SO_2$ emissions generated by a unit are determined by two things—the amount of electricity it generates in a year (kWh) and the amount of $SO_2$ generated per unit of kWh (Em). Total tons of $SO_2$ emissions, before FGD, is then given as the product of kWh*Em. The variable (consumable) cost of removing a ton of $SO_2$ using FGD is given as $P_{alw}$. This cost is in terms of the adipic acid, the limestone, and the waste disposal required when removing one ton of $SO_2$ via FGD. The portion of consumables cost attributable to the annual removing of emissions via FGD is thus a product of the percent of emissions removed annually (RE) times annual emissions (kWh*Em) times the cost of removing a ton of FGD ($P_{alw}$)[33]:

(3.8) $P_{alw} \cdot (Em \cdot kWh \cdot RE)$

The portion of variable (consumable) cost unrelated to the actual emission tonnage removed, but required to operate FGD is called indirect consumable costs. These costs take the form of water and electricity required when operating the FGD unit. According to the regression analysis these costs are linearly related to the annual electric output of the unit. The indirect operating costs ($P_{kh}$) are incurred per unit of kWh produced. This portion of costs is therefore the product of $P_{kh}$ and kWh:[34]

(3.9) $P_{kh}$*kWh

The total cost of abatement is the combination of capital and consumable costs (3.8) and (3.9). Total annual FGD abatement costs (A(RE,kWh)), where RE>0, is then a function of kWh and RE. A(RE,kWh) is written as equation 3.10 below:

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cost structures and terms.

[33] See Appendix C for definitions and explanations of the variable names and notations.

**(3.10)** $A(RE, kWh) = r \cdot (KapA \cdot RE + KapB) + P_{alw} \cdot (Em \cdot kWh \cdot RE) + P_{kh} \cdot kWh$

Where no abatement effort is made (RE=0), abatement costs are equal to zero:

**(3.11)** $A(kWh, RE = 0) = 0$

Abatement costs over the technical range of RE via FGD (0 to .9)[35] is therefore represented by a combination of 3.10 and 3.11. This combined FGD abatement cost function is given as 3.12 below:

$$\textbf{(3.12)}\ A(kWh, RE) = \begin{bmatrix} RE = 0 & 0 \\ RE \geq 0 & r \cdot (KapA \cdot RE + KapB) + P_{alw} \cdot (Em \cdot kWh \cdot RE) + P_{kh}(kWh) \\ RE > .9 & \infty \end{bmatrix}$$

## VIII. The Unit Profit Function

Due to the fact that this unit is a natural monopoly, a regulator will subject the profit-maximizing boiler to a break-even budget constraint. The use of a natural monopoly facing a break-even constraint here is a simplifying assumption to force average cost pricing and least costs Phase II compliance. In the absence of Phase II emission restraints and/or the market for allowances, the profit function of the unit is as follows (from 3.7 above):

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[34] Appendix F discusses the engineering derivation and estimation of these relationships in detail.
[35] The technical range of FGD is discussed and documented in the introduction to this section above.

$$(3.7)\ \Pi(kWh)=P_{kWh}(kWh)*kWh - Z - P_{FL}(kWh)$$

Subject to $kWh>0$

$\Pi(kWh)\leq 0$

Of interest to this analysis, however, is how each unit reacts to the inclusion of unit specific Phase II emission constraints. The inclusion of such constraints changes the profit function of the unit. Each unit must comply with Phase II emission constraints defined by unit-specific Phase II annual allowance allocations. Unit specific allowance allocations are given as $\Lambda$, with a subscript i indicating a specific unit. If emissions are greater than the allowance allocations, the unit must either invest in FGD to reduce its emissions or buy allowances. If the allowance allocations are applied as a cap, that is they are not tradable among units, the units must use FGD to meet their Phase II compliance requirements. If Phase II is applied as a cap, the annual costs of FGD sufficient to match emissions to annual Phase II allowance allocations is the unit's costs of compliance with Phase II cap requirements. The profit function and behavior of units where Phase II is applied as a cap is discussed in part A below. The abatement and output decisions of the units under the cap are used to determine unit specific emissions under a Phase II compliant cap and the total abatement costs of compliance with this cap. These values are recorded by the simulation for comparison with emissions and abatement costs under Phase II as a market.

If allowances are tradable among units, the costs of compliance that appear in the profit function must include net revenues from allowance trades in addition to any annual costs associated with FGD. If the unit buys allowances to meet its emission requirements, and does not invest in FGD (RE=0), its Phase II compliance costs are based on the number of allowances the units purchases times the price of the allowances. If the unit invests in FGD (RE>0), annual emissions will fall below annual allowance allocations. Allowances are therefore freed up for sale, generating annual revenues equal to the number of annual excess allowances times the price of allowances. Total annual compliance costs are therefore equal to annual FGD costs plus net revenues generated by the sale of allowances. The profit function under a marketable binding set of Phase II Allowance Allocations is presented in part B below. The reactions of units subject to a binding Phase II market for allowances are used to calculate total and unit specific emissions and abatement costs under a binding Phase II market for allowances. These numbers are then used to compare the Phase II market for allowances with a Phase II compliant cap for net cost effects, as outlined above.

### A. The Profit Function Under the Phase II Compliant Cap

This section presents the case of Phase II compliant allowance cap. Allowance allocations ($\Lambda_{ik}$) are not traded among units and each unit must meet compliance obligations by investing in appropriate levels of FGD. The purpose of this model is to present a benchmark by which to measure cost savings caused by allowing allowance trades in a binding Phase II market for allowances. It is assumed that each unit has the emission rate it possessed in 1990[36], the year Title IV was passed.

The model is set up roughly along the lines presented in chapter 1. There, the economic regulator must include the emission cap on the emissions of the boiler in its

[36] The emission rate used is the lowest of the three year period from 1989 through 1991.

decision making process. Here, the unit[37] must include the cap on emissions—and thus abatement technology—into its decision making. The emission constraint limits total annual emissions (Em*kWh*(1-RE)) to the number of allowances allocated to each unit ($\Delta$). The emission constraint (3.13) takes the following form:

3.13 $Em \cdot kWh \cdot (1 - RE) - \Lambda \leq 0$

Note that the emission constraint (3.13) indicates that emissions can start below the level of allowances for a given kWh. (Emissions can be less than allowance allocations). In addition it is possible that abatement effort can reduce emissions below the allowance level. There is, however, no incentive to reduce emissions below allowance levels without the existence of a market. Where the constraint is binding on emissions, abatement in the form of FGD is required to reduce emissions (or kWh can be reduced to lower emissions). It is also possible that the constraint is not binding for any kWh where no FGD is used. In this case the emission constraint is not binding and the costs of FGD abatement are not included in the unit's profit function—as FGD is not required to achieve compliance. In both cases the annual profit of the boiler is subject to a break-even revenue constraint with regard to costs.

The profit function of the unit under the Phase II compliant emission restraint is then as follows:

(3.14) Max w.r.t. kWh, RE $\Pi(kWh, RE) = (a - b \cdot kWh) \cdot kWh - Z - P_{FL} \cdot kWh - A(kWh, RE)$

Subject to:

$\Pi(kWh) \leq 0$

$kWh > 0$

---

[37] Subject to a break-even budget constraint.

$RE \geq 0$

$RE \leq .9$

$(kWh \cdot Em(1 - RE) - \Lambda) \leq 0$

Showing the cases where the emission constraint (3.13) is and is not binding on unit emissions facilitates the discussion of the solution to 3.14. Part 1 below discusses the case when the emission cap (3.13) is not binding on emissions. Part 2 below discusses the case when the emission cap (3.13) is binding on emissions.

**1. The cap: the case when the emission constraint is not binding**

Where the emission constraint (3.13) is not binding on the unit, the profit function of the unit is simply 3.7 from above, subject to a break-even constraint. Output is therefore not affected by the emission constraint:

(3.15) Max $\Pi(kWh)=P_{kWh}(kWh)*kWh - Z - P_{FL}*kWh$
w.r.t. kWh

Subject to

$\Pi(kWh) \leq 0$
$kWh>0$.

The first order (Kuhn-Tucker) conditions of the Lagrangian in terms of kWh and $\lambda$:

(3.16) $\frac{d}{d\lambda}\zeta(kWh,\lambda)=(a - b\cdot kWh)\cdot kWh - P_{FL}\cdot kWh - Z \leq 0 \qquad \lambda \leq 0$ and $\lambda \cdot \left(\frac{d}{d\lambda}\zeta(kWh,\lambda)\right)=0$

(3.17) $\frac{d}{dkWh}\zeta(kWh,\lambda)=-2\cdot b\cdot kWh + a - P_{FL} + \lambda\cdot(-2\cdot b\cdot kWh + a - P_{FL}) \leq 0$ kWh>0 and

$$kWh\cdot\left(\frac{d}{dkWh}\zeta(kWh,\lambda)\right)=0$$

Since kWh must be greater than zero, the relationship $kWh \cdot \left( \frac{d}{dkWh} \zeta(kWh, \lambda) \right) = 0$ indicates

that $\frac{d}{dkWh} \zeta(kWh, \lambda)$ must equal zero in order for 3.17 to be satisfied. This allows 3.17 to

be solved for a value

of $\lambda$:

$$\frac{d}{dkWh} \zeta(kWh, \lambda) = -2 \cdot b \cdot kWh + a - P_{FL} + \lambda \cdot \left( -2 \cdot b \cdot kWh + a - P_{FL} \right) = 0$$

Solving 3.17 for $\lambda$, results in $\lambda = -1$.

This indicates that in order for $\lambda \cdot \left( \frac{d}{d\lambda} \zeta(kWh, \lambda) \right) = 0$ from 3.13 to hold true, the budget

constraint must be binding. Therefore it must be true that

$$\frac{d}{d\lambda} \zeta(kWh, \lambda) = (a - b \cdot kWh) \cdot kWh - P_{FL} \cdot kWh - Z = 0.$$

Solving 3.16 (a quadratic in terms of kWh) for kWh, where the budget constraint is binding provides two solutions for 3.15 that satisfy the budget constraint, where the larger value of kWh is of interest—the solution that satisfies the second order conditions. The unit specific solution to 3.15 will be referenced as $kWh_i^*$ below. Note that unit specific abatement ($RE_i^*$) in response to a non-binding Phase II emissions cap is equal to zero.

Diagram 3.1 below shows the solution to 3.15 where the emission constraint on the unit is not binding. The budget constraint is given as the heavy dotted line ABC. The area above the budget line represents negative profits, while the area below it indicates economic rents. This line indicates the locus of RE and kWh combinations that satisfy the budget constraint. Note that at the technology constraint (RE=.9), the budget constraint becomes a vertical line. Also note that the budget constraint is downward sloping with regard to abatement (RE). This means that total costs increase as abatement technology is added to the unit. Abatement costs are small relative to total costs, so the impact on total costs is small for any change in RE. Given a downward sloping demand curve for output, the level of annual kWh production is higher at point A (RE=0) than at point B (RE=.9). The area under the emission constraint line indicates the locus of RE and kWh combinations that are within compliance with the annual Phase II allowance allocations of the unit. Note that this unit is within emission compliance over the entire range of FGD technology when conforming to the budget constraint. The feasible solution area, where the budget constraint, emission constraint, and the technology constraint are satisfied is given as the shaded region. Points along the budget line, however, represent the profit-maximizing locus of points given the budget constraint. The unit will choose the highest kWh point along the budget line—at point A. Point A represents an extremum value of kWh found in the solution set defined by 3.18 above, at the intersection of the minimum technology (the kWh axis) the budget constraint.

The solution indicated by 3.18 ($kWh_i^*$) provides the information required to calculate the annual emissions and annual abatement costs of the unit where the Phase II compliant emission constraint (defined as 3.13 above) is not binding. These two values are needed to estimate the net effect (net external cost and abatement savings effect) of Phase II allowance allocations applied as a market relative to the case where the allocations are applied as a cap on emissions for the unit.

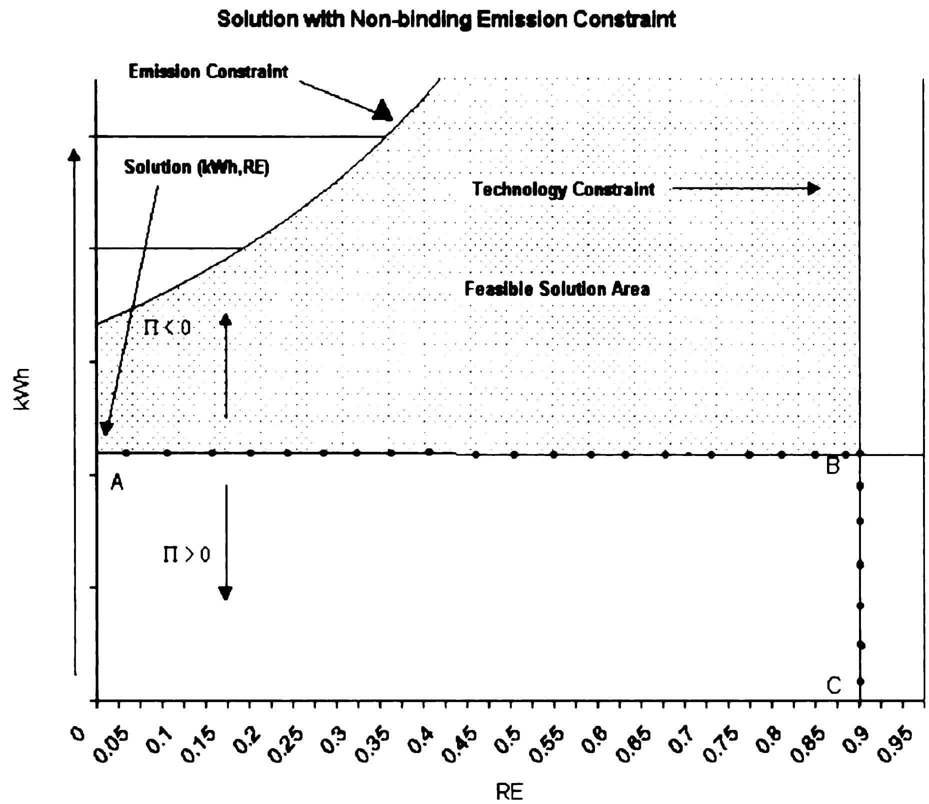


**Diagram 3.1: Solution with Non-binding Emission Constraint**

Annual emissions (AE) from the unit are calculated as indicated above:

(3.19) $AE_i = Em_i * kWh^* * (1 - RE_i)$

Where $RE_i = 0$, given a non-binding emission constraint (3.13).

Using 3.19 allows the calculation of the externality effects of emissions from the unit later in this chapter, allowing a comparison with external cost results of the unit where allowances are marketable.

Given that RE=0 under the non-binding cap, abatement compliance costs (CA) are non-existent for this unit under a Phase II compliant cap:

(3.20) $CA_i(kWh_i^*, RE_i^*) = A(kWh_i^*, RE_i^*) = 0.$

Where RE=0, given a non-binding emission constraint.

**2. The unit with a binding Phase II emission cap**

Where the emission constraint (3.13) is not binding on the unit, 3.14 above gives the profit function of the unit. The once change is that the emissions constraint, being binding, is not given as an inequality. In addition, RE must be greater than zero. Output is therefore affected by the emission constraint and some level of abatement is required to achieve compliance:

(3.21) Max w.r.t. kWh, RE $\Pi(kWh, RE) = (a - b \cdot kWh) \cdot kWh - Z - P_{FL} \cdot kWh - A(kWh, RE)$

Subject to:

$\Pi(kWh) \leq 0$

$kWh > 0$

$RE > 0$

$RE \le .9$

$(kWh \cdot Em \cdot (1 - RE) - \Lambda) = 0$

Taking the binding emission constraint $(Em \cdot kWh \cdot (1 - RE) - \Lambda = 0)$ and solving for the necessary abatement level (RE) for a given output level (kWh) results in:

3.22 $$RE = \frac{(Em \cdot kWh - \Lambda)}{(Em \cdot kWh)}$$

Substituting 3.22 for RE in the boiler's objective function and maximizing with respect to kWh and $\lambda$ (for the relevant FGD range 0<RE<=.9) provides the Kuhn-Tucker (first order) conditions:

(3.23)

$$\frac{d}{d\lambda_1}\zeta(kWh, \lambda_1) = (a - b \cdot kWh) \cdot kWh - Z - P_{FL} \cdot kWh - r \cdot \left[ KapA \cdot \frac{(kWh \cdot Em - \Lambda)}{(kWh \cdot Em)} + KapB \right] - P_{alw} \cdot (kWh \cdot Em - \Lambda) - P_{kh} \cdot kWh \le 0$$

$$\lambda_1 \le 0 \quad \text{and} \quad \lambda_1 \cdot \left( \frac{d}{d\lambda_1}\zeta(kWh, \lambda_1) \right) = 0$$

(3.24)

$$\frac{d}{dkWh}\zeta(kWh, \lambda_1) = -2 \cdot b \cdot kWh + a - P_{FL} - r \cdot \left[ \frac{KapA}{kWh} - KapA \cdot \frac{(kWh \cdot Em - \Lambda)}{(kWh^2 \cdot Em)} \right] - P_{alw} \cdot Em - P_{kh} + \dots$$

$$\dots + \lambda_1 \cdot \left[ -2 \cdot b \cdot kWh + a - P_{FL} - r \cdot \left[ \frac{KapA}{kWh} - KapA \cdot \frac{(kWh \cdot Em - \Lambda)}{(kWh^2 \cdot Em)} \right] - P_{alw} \cdot Em - P_{kh} \right] \le 0$$

kWh>0 and $kWh \cdot \left( \frac{d}{dkWh}\zeta(kWh, \lambda_1) \right) = 0$

Where kWh>0, it follows from $kWh\cdot\left(\frac{d}{dkWh}\zeta(kWh,\lambda_1)\right)=0$ that $\frac{d}{dkWh}\zeta(kWh,\lambda_1)=0$.

Equation 3.24 can then be solved as an equality for λ:

$$\lambda=-1$$

The fact that $\lambda=-1$ indicates that $\frac{d}{d\lambda_1}\zeta(kWh,\lambda_1)=0$ for the condition

$\lambda_1\cdot\left(\frac{d}{d\lambda_1}\zeta(kWh,\lambda_1)\right)=0$ to hold true in equation 3.23 above. The budget constraint expressed in 3.23 must therefore be binding. Solving 3.23 for kWh involves solving a cube root problem. (Equation 3.23 is a third order polynomial equation in terms of kWh). This is seen when 3.23 is simplified by collecting terms out of the component parts as follows:

Where $X1=a-P_{FL}-P_{alw}\cdot Em-P_{kh}$

$$X2=-Z-r\cdot KapA-r\cdot KapB+P_{alw}\cdot\Lambda$$

$$X3=r\cdot KapA\cdot\frac{\Lambda}{Em}$$

3.23 becomes:

$$\frac{d}{d\lambda_1}\zeta(kWh,\lambda_1)=-b\cdot kWh^3+X1\cdot kWh^2+X2\cdot kWh+X3=0$$

As in the case of solving for the kWh that satisfies 3.15 above, this structure provides multiple possible answers in the form of extremums. However, only one of the solutions is a real value that satisfies the constraints, including the second order conditions. The solution to 3.23 determines the output of the unit when the emission constraint is binding. This in turn determines the level of FGD abatement required to meet compliance with the cap emission constraint (3.13):

$$RE = \frac{(Em\,kWh - \Lambda)}{(Em\,kWh)}$$

The solution to 3.14 with a binding emission cap is presented in Diagram 3.2 below. Annual kWh are measured along the Y axis, with values increasing with distance from the origin. Abatement (RE) is measured along the X axis, with values increasing with distance from the origin. The dotted area under the emission constraint shows set of kWh and RE combinations that comply with the unit-specific Phase II cap. The heavy dotted line represents the budget constraint. The area above the budget constraint indicates the kWh and RE combinations that cause unit profits to be negative. Note that at the technology constraint for abatement (RE>.9), the budget constraint becomes a vertical line—as indicated by structure of the abatement costs curve given in 3.12 above. Profit maximization (subject to the budget constraint) occurs for the locus of kWh and RE points defined by the budget constraint line in Diagram 3.2. The technology constraint with regard to abatement technology is defined by the area to the right of the Y axis and to the left of line labeled technology constraint (RE=.9). Area ABC defines the feasible locus of kWh and RE that satisfy the budget, emission, and technology constraints (RE<.9). Note that with the existence of positive abatement costs with increasing RE, the budget constraint is (slightly) downward sloping with regard to RE. Therefore kWh levels are higher closer to the Y axis. The emission restraint limits the feasible combinations of RE and kWh, however. The solution to 3.14 (the solution to 3.23 and the binding emission constraint) is the extremum point B in the diagram. This point represents the largest value of kWh that satisfies all three constraints (budget, emission, and technology).

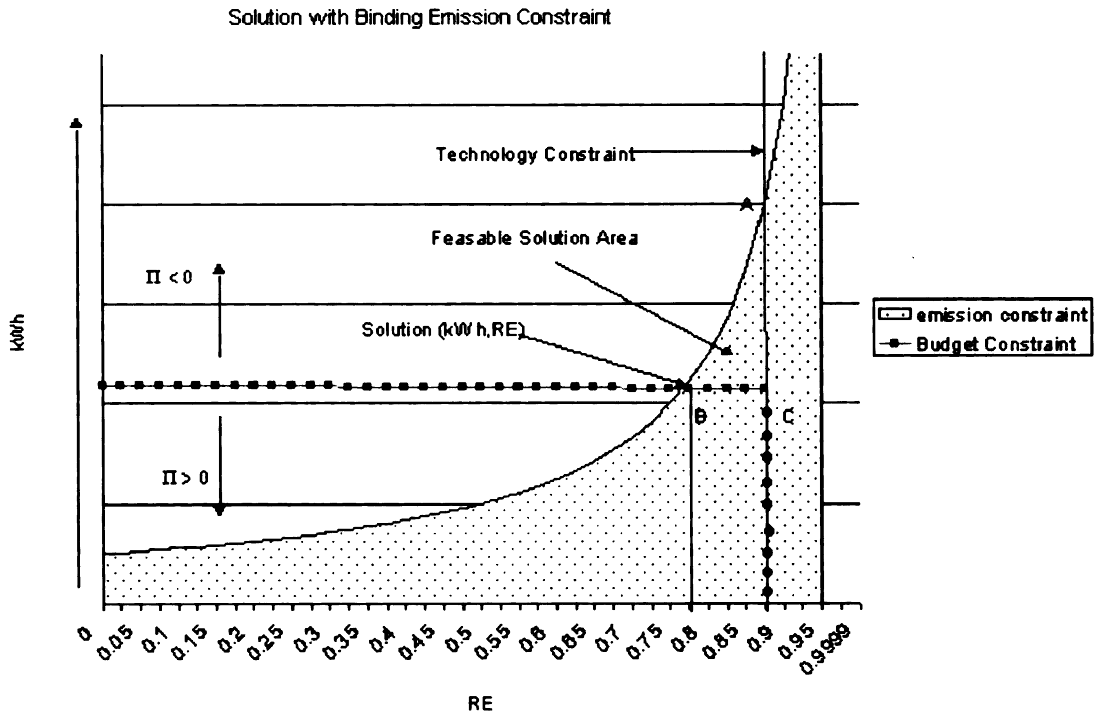


**Diagram 3.2: Solution with Binding Emission Constraint**

Where the technology constraint is binding (RE=.9) (in addition to the emission constraint) on the unit's decisions regarding RE and kWh, the solution to 3.14 involves a corner solution to the unit's profit maximization problem where RE=.9. Note that for RE>.9, the abatement cost function shows infinite cost (vertical line). This changes the shape of the budget constraint at the technology constraint to a vertical line. This is shown as the vertical line segment AC in Diagram 3.3 below. The feasible solution area is now a single point on the diagram, at point B. Point B is the solution to the unit's problem given a binding emission, budget, and technology constraint. This point occurs at the intersection of the technology constraint (RE=.9), the budget constraint (the vertical portion), and the emission constraint. This straightforward result is presented in the Diagram 3.3 below.

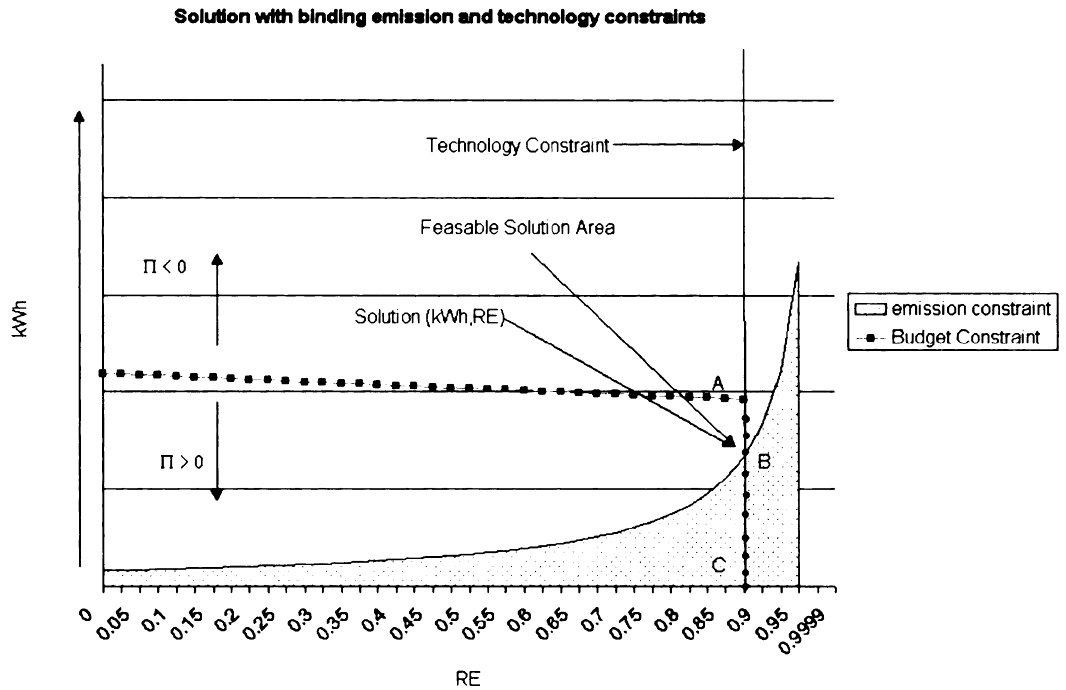


**Diagram 3.3: Solution with Binding Emission and Technology Constraints**

The unit specific solution to 3.21 (the solution to 3.14 where the emission constraint is binding) with regard to kWh and RE, referenced as $kWh_i^*$ and $RE_i^*$, is used to calculate the annual emissions and total compliance costs of the unit under the cap. Annual emissions (AE) from the unit are calculated as indicated above:

(3.19) $AE_i = Em_i * kWh_i^* * (1 - RE_i^*)$

Using 3.19 allows the calculation of the externality effects of emissions from the unit later in this chapter, allowing a comparison with external cost results of the unit where allowances are marketable.

Given that RE>0 (under a binding emission cap), abatement compliance costs (CA) are positive for this unit under a Phase II compliant cap:

$$(3.20)\ CA_i(kWh_i^*, RE_i^*) = A(kWh_i^*, RE_i^*) > 0.$$

**3. Summing abatement costs and emissions for the Phase II compliant cap**

The unit specific solutions to 3.14 with regard to kWh and RE, referenced as $kWh_i^*$ and $RE_i^*$, are used to calculate the annual emissions and total compliance costs of each unit under the cap. Annual emissions (AE) from the unit are calculated as indicated above using (3.19):

$$AE_i = Em_i * kWh_i^* * (1 - RE_i^*)$$

Using 3.19 allows the calculation of the externality effects of emissions from the unit later in this chapter, allowing a comparison with external cost results of the unit where allowances are marketable. Total emissions under the cap ($E_{cap}$) are calculated by summing emissions across all units (units are numbered 1 to n):

$$E_{cap} = \sum_{i=1}^{n} AE_i(kWh_i^*, RE_i^*)$$

The value of $E_{cap}$ is used to compare total annual emissions of a Phase II compliant cap relative to a binding Phase II allowance market. It is generally felt that emissions will be higher under the binding Phase II Allowance Market and this measure will allow a test of that assumption. While $E_{cap}$ is of interest, the important information is the unit specific emissions, since the location of emission sources plays a major role in determining external effects of sulfur dioxide emissions later in this chapter.

The value of the individual $RE_i^*$ determines the abatement compliance costs (CA), if any, of the individual unit in meeting the Phase II compliant cap:

$$CA_i(kWh_i^*, RE_i^*)=A(kWh_i^*, RE_i^*)$$

Whereas the individual unit emission values of interest in determining net external cost effects, it is the total abatement compliance costs of all units under the cap that is of interest for determining total abatement cost effects of the Binding Phase II market relative to a Phase II compliant cap. Total abatement costs from all units are summed as $CA_{cap}$:

$$(3.24) \qquad CA_{cap} = \sum_{i=1}^{n} A_i\left(kWh_i^*, RE_i^*\right)$$

The value of $CA_{cap}$ is compared with total compliance costs under a binding Phase II market to determine net abatement cost effects of the tradable allowance system.

## B. The Profit Function Under the Binding Phase II Market

This section presents the model of a binding Phase II allowance market imposed on units. Here, allowances allocations ($\Lambda_i$) are tradable among units, but each unit must have enough allowances after annual trades to cover annual emissions. As in section B above, it is assumed that each unit starts with the emission rate it possessed in 1990, the year Title IV was passed. Due to the existence of the market, however, units can choose to meet their emission requirements by buying allowances, investing in abatement, or both. While individual boilers can be buyers or sellers of allowances, the sum of the net annual emissions of the entire title IV affected population of boilers must be less than or equal to the total number of annual allowance allocations. Thus, the total number of allowances held and assigned under title IV acts as a cap on emissions in a given year. The Phase II allowance market is considered binding when total annual emissions equal total annual allowances across all units after annual market trades—assuming all trade opportunities and economies are realized. Therefore unit specific emission constraint, in the form of initial individual allowance allocations (equation 3.13 above), no longer holds. It is replaced by the market-wide emission constraint that sets total annual-allowances allocations equal to total annual emissions across all units.

Net allowances held by a unit can be either positive or negative after market trades. The net annual allowances held by a unit is determined by equation 3.25:

$$(3.25)\quad \eta(kWh, RE) = Em \cdot kWh \cdot (1 - RE) - \Lambda$$

Equation 3.25 is used to determine in the following model to determine the annual revenues of a unit from allowance market trades and the annual emissions of the unit under the binding market.

Given 3.25, the market-wide emission constraint is written as 3.26 below:

$$(3.26)\quad \sum_{i=1}^{n} \eta_i\left(kWh_i, RE_i\right) = 0$$

Equation 3.26 is instrumental in determining the market clearing allowance price for allowances ($P_A$) in the binding allowance market. It will be discussed again in that context later in section VII when the market clearing allowance prices are determined.

The unit model presented here is set up along the lines presented in chapter 1. Here, the unit must include the total costs of compliance in its profit function under the Phase II market. Compliance costs with the market include the net revenues from allowance trades in addition to any annual costs associated with FGD. Given the existence of a marketable allowance and a price for allowances, $P_A$, the total costs of abatement to the individual unit boiler is given by equation (3.10) and the revenue generated by allowance trades ($P_A \cdot \eta_i\left(kWh_i, RE_i\right)$).

The profit function of the unit must now include the net revenues from allowances trades. The unit is again subject to a break-even profit constraint by a regulator. Where the unit is a potential seller of allowances, the regulator allows the unit to retain a portion (s) of revenues as profit. The remainder of allowance generated revenues (1-s) is applied as rate relief by the regulator. This profit sharing is added to the unit's profit function to insure that the minimum cost compliance strategy be used under the Phase II allowance market. If the unit is a net purchaser of allowances at the market-clearing allowance price (RE=0), the regulator allows a full recovery of all costs since allowances revenues will be negative. In this case, s=0. This treatment is consistent with current suggested oversight of compliance options by regulators.[38] The profit function is then as follows.

(3.27)
Max w.r.t. kWh,RE:

$$\Pi(kWh,RE)=\left[(a-b\cdot kWh)\cdot kWh-Z-P_{FL}\cdot kWh\right]+s\cdot\left[P_A\cdot(-\eta(kWh,RE))-A(kWh,RE)\right]+x\cdot\left[P_A\cdot(-\eta(kWh,RE))\right]$$

Where $s(RE)=\begin{pmatrix} RE=0 & 0 \\ RE>0 & s \end{pmatrix}$

And $x(s)=\begin{pmatrix} s=0 & 1 \\ s>0 & 0 \end{pmatrix}$

$$A(kWh,RE)=\begin{bmatrix} RE=0 & 0 \\ RE\geq 0 & r\cdot(KapA\cdot RE+KapB)+P_{alw}\cdot(Em\cdot kWh\cdot RE)+P_{kh}(kWh) \\ RE>.9 & \infty \end{bmatrix}$$

Subject to:

$$(a-b\cdot kWh)\cdot kWh-Z-P_{FL}\cdot kWh+(1-s)\cdot(1-x)\cdot\left[P_A\cdot(-\eta(kWh,RE))-A(kWh,RE)\right]+x\cdot\left[P_A\cdot(-\eta(kWh,RE))\right]\leq 0$$

kWh>=0

$RE\geq 0$

$RE\leq .9$

Taking derivatives of the Lagrangian in terms of kWh, RE, and λ provides the Kuhn Tucker maximization conditions for 3.27:

3.28

$$\frac{d}{d\lambda}\xi(kWh,RE,\lambda)=(a-b\cdot kWh)\cdot kWh-Z-P_{FL}\cdot kWh+(1-s)\cdot(1-x)\cdot\left(-P_A\cdot\eta(kWh,RE)-A(kWh,RE)\right)-x\,P_A\cdot\eta(kWh,RE)\leq 0$$

[38] See NRRI, Regulatory Treatment of Electric Utility Clean Air Act Compliance Strategies, Costs, and Emission Allowance, December 1993.

$$\lambda \le 0 \text{ and } \lambda \cdot \left( \frac{d}{d\lambda} \xi(kWh, RE, \lambda) \right) = 0$$

$$3.29 \quad \frac{d}{dRE} \xi(kWh, RE, \lambda) = s \cdot \left( -P_A \cdot \frac{d}{dRE} \eta(kWh, RE) - \frac{d}{dRE} A(kWh, RE) \right) - x \cdot P_A \cdot \frac{d}{dRE} \eta(kWh, RE) + \dots$$

$$\dots + \lambda \cdot \left[ (1-s) \cdot (1-x) \cdot \left( -P_A \cdot \frac{d}{dRE} \eta(kWh, RE) - \frac{d}{dRE} A(kWh, RE) \right) - x \cdot P_A \cdot \frac{d}{dRE} \eta(kWh, RE) \right] \le 0$$

$$0 \le RE, \ RE \le .9, \text{ and } RE \cdot \left( \frac{d}{dRE} \xi(kWh, RE, \lambda) \right) = 0$$

3.30

$$\frac{d}{dkWh} \xi(kWh, RE, \lambda) = -2 \cdot b \cdot kWh + a - P_{FL} + s \cdot \left( -P_A \cdot \frac{d}{dkWh} \eta(kWh, RE) - \frac{d}{dkWh} A(kWh, RE) \right) - x \cdot P_A \cdot \frac{d}{dkWh} \eta(kWh, RE) + \dots$$

$$\dots + \lambda \cdot \left[ -2 \cdot b \cdot kWh + a - P_{FL} + (1-s) \cdot (1-x) \cdot \left( -P_A \cdot \frac{d}{dkWh} \eta(kWh, RE) - \frac{d}{dkWh} A(kWh, RE) \right) - x \cdot P_A \cdot \frac{d}{dkWh} \eta(kWh, RE) \right] \le 0$$

$$kWh > 0 \text{ and } kWh \cdot \left( \frac{d}{dkWh} \xi(kWh, RE, \lambda) \right) = 0$$

Equations 3.28 through 3.30 define the profit maximizing Kuhn Tucker solution set for 3.27. The shape of the feasible solution set is directly dependant on the price of allowances ($P_A$) relative to the average annual costs of abatement (RE). The discussion of the solution to 3.27 will be facilitated by discussing the case where RE>0 and the case where RE=0, given the structure of abatement costs (A(kWh,RE) and the dummy variables s and x.

### 1. Where RE>0

Where RE>0, s>0, and x=0—from the conditions above. Moreover, where RE>0, the conditions outlined by 3.29 indicate that $\frac{d}{dRE}\xi(kWh,RE,\lambda)=0$, since the maximization conditions require $\left(\frac{d}{dRE}\xi(kWh,RE,\lambda)\right)\cdot RE=0$. Solving 3.29 for λ:

$$\lambda=\frac{s}{(-1+s)}$$

Since 0<s<1, λ<0.

Since λ<0,it must be true that $\frac{d}{d\lambda}\xi(kWh,RE,\lambda)=0$, via the Kuhn Tucker conditions that require $\lambda\cdot\left(\frac{d}{d\lambda}\xi(kWh,RE,\lambda)\right)=0$. The budget constraint is therefore binding. This presents a locus of points in terms of kWh and RE that will satisfy $\frac{d}{d\lambda}\xi(kWh,RE,\lambda)=0$

Where kWh>0, $kWh\cdot\left(\frac{d}{dkWh}\xi(kWh,RE,\lambda)\right)=0$ indicates that $\frac{d}{dkWh}\xi(kWh,RE,\lambda)=0$-- which with a discreet value for λ, presents one of the extremum points of the model when conditions are sufficient for RE>0. This level of kWh and RE will be referenced as kWh* and RE*. Where RE* is within the technology constraint. As will be shown below, however, the extremum (kWh*,RE*) is not the profit maximization point of the unit, as this point does not satisfy the second order conditions for a maximum with abatement costs included and the technology constraint binding. As will be shown, this point is, in fact, the profit minimizing point when the price of allowances ($P_A$) is sufficient to keep RE* within the technology constraint.

### 2. Where RE=0

Where RE=0, A(kWh,RE=0)=0, s=0, x=1—via the conditions above. Where kWh>0, it follows from $kWh\cdot\left(\frac{d}{dkWh}\xi(kWh,RE,\lambda)\right)=0$, that $\frac{d}{dkWh}\xi(kWh,RE,\lambda)=0$. This allows 3.30 to be solved for λ:

$\lambda=-1$.

If $\lambda=-1$, then by condition 3.28, $\frac{d}{d\lambda}\xi(kWh,RE,\lambda)=0$, the budget constraint is binding and forms a quadratic in terms of kWh, where RE=0. This provides two extremum solutions to 3.27 in terms of kWh where RE=0, but only one of which satisfies second order conditions for the maximum profit.

### 3. The solution set to 3.27

All three sets of conditions (3.28 through 3.30) define a number of possible extreme point solutions to 3.27 that will satisfy the conditions. However, the constraint qualifications and the second order conditions allows this field of answers to be narrowed. The second order conditions of 3.27 in terms of λ, kWh, and RE are given below.

$$\begin{vmatrix} 0 & \frac{d}{d\lambda_i}\frac{d}{dRE_i}\xi(kWh_i,RE_i,\lambda_i) & \frac{d}{d\lambda_i}\frac{d}{dkWh_i}\xi(kWh_i,RE_i,\lambda_i) \\ \frac{d}{d\lambda_i}\frac{d}{dRE_i}\xi(kWh_i,RE_i,\lambda_i) & \frac{d^2}{dRE_i^2}\xi(kWh_i,RE_i,\lambda_i) & \frac{d}{dRE_i}\frac{d}{dkWh_i}\xi(kWh_i,RE_i,\lambda_i) \\ \frac{d}{d\lambda_i}\frac{d}{dkWh_i}\xi(kWh_i,RE_i,\lambda_i) & \frac{d}{dRE_i}\frac{d}{dkWh_i}\xi(kWh_i,RE_i,\lambda_i) & \frac{d^2}{dQ_i^2}\xi(kWh_i,RE_i,\lambda_i) \end{vmatrix} >0$$

The Kuhn Tucker constraint qualification also requires that, where the constraints are exactly satisfied (binding), that , in the case of the budget constraint:

$$\frac{d}{d\lambda}\frac{d}{dRE}\xi(kWh, RE, \lambda) + \frac{d}{d\lambda}\frac{d}{dkWh}\xi(kWh, RE, \lambda) \le 0$$

In terms of the technology constraint ($0 \le RE \le .9$), which can be written as $t(RE, kWh) \equiv E \cdot kWh \cdot (1 - RE) - .1 \cdot E \cdot kWh \ge 0$, the Kuhn Tucker constraint qualification requires that, where the technology constraint is binding:

$$\frac{d}{dkWh}t(RE, kWh) + \frac{d}{dRE}t(RE, kWh) \le 0$$

The solution that satisfies 3.28 through 3.30 and the secondary conditions is dependent on the market price for allowances relative to the annual costs of abatement for the unit. The importance of allowance prices in the decision process is obvious, as it changes the shape and slope of the budget constraint. The shape of the budget constraint is dependent on the revenue generated by allowances, for a given allowance price, relative to the costs of abatement. This shape will determine whether or not the extremum formed by the intersection of the technology and budget constraint, is a maximum or minimum point solution to the conditions outlined in 1.28 through 1.30 above. This is discussed in more detail below.

Where the revenues from allowances are greater than or equal to the annual costs of abatement, an RE>0 is required to satisfies the above conditions. This is due to the fact that when net revenues from allowance market participation are positive ($P_A(-\eta(kWh, RE)) - A(kWh, RE) \ge 0$), and this allows the unit to keep a portion of revenues as profit (s):

$$\left(P_A(-\eta(kWh, RE)) - A(kWh, RE)\right) \cdot s \ge 0$$

Revenues from allowance sales are therefore non-negative so long as

$$P_A \geq \frac{A(kWh, RE)}{-\eta(kWh, RE)}.$$

That is, net revenues are nonnegative as long as the price for allowances is greater or equal to the cost of abatement averaged over the number of surplus allowances sold. Under these circumstances, using an RE>0 increases revenue. The profit maximizing solution requires an RE>0. More importantly, where the price of allowances makes net revenues from allowances positive, the unit has an incentive to increase the difference between allowance revenues ($P_A(-\eta(kWh, RE))$) and the costs of supplying allowances (A(kWh,RE)). Given that the unit's maximum potential supply of allowances (allowances that it can free up for sale on the allowance market) is fixed ($\Lambda$), the unit must reduce emissions (RE>0) and/or reduce the cost of supplying allowances, to increase revenues. Since the average annual costs of abatement are everywhere decreasing with respect to tons of $SO_2$ removed—up to the technological constraint RE=.9—the lowest average annual cost of removing a ton of $SO_2$ occurs at RE=.9, for given kWh.[39] Setting RE=.9 provides the largest possible revenue (it provides the largest surplus of allowances for sale) and the largest positive net profit from allowance sales for a given value of kWh. Equation 3.28 limits the feasible solution (kWh, RE=.9) point to those that satisfy the budget constraint. Solving equation 3.28 for kWh when RE=.9 provides the (kWh, RE=.9) combination that satisfies conditions 1.28 through 1.30 provides one of the extremum solutions to 1.27—at the intersection of the budget and technology constraints. This value of kWh, where RE=.9 will be referenced as $kWh_{max}$. In the case mentioned here, the extremum ($kWh_{max}$,RE=.9) is a maximization point.

If, on the other hand, the price of allowances is such that at ($kWh_{max}$, RE=.9) $P_A < \frac{A(kWh,RE)}{-\eta(kWh,RE)}$, the net revenue from allowance market activity is negative. The point ($kWh_{max}$, RE=.9) is therefore a minimum. Since for any RE>0, the unit is keeps a share of the revenues, the unit is operating at a loss since net revenues are negative. In order to reduce the loss, the unit must either increase the surplus of allowances ($-\eta(kWh,RE)$) and/or reduce the costs of abatement (A(kWh,RE)). At RE=.9, RE cannot be increased, as this is the technological constraint. The ratio of abatement costs to surplus allowances sold cannot be reduced except by setting RE=0, where A(kWh,RE=0)=0, while satisfying 3.28 through 3.30.

This brings the discussion to another extremum point solution to 3.27—the intersection of the kWh axes (minimum technology constraint RE=0) and the budget constraint (3.28). Where $P_A < \frac{A(kWh,RE)}{-\eta(kWh,RE)}$ at ($kWh_{max}$, RE=.9), the extremum (kWh,RE=0) point that satisfies 3.28 through 3.30 at the intersection of the two constraints (the kWh axis and the budget constraint), is the maximum solution point to 3.17, with economic profit equal to zero. Where $P_A \geq \frac{A(kWh,RE)}{-\eta(kWh,RE)}$ at ($kWh_{max}$, RE=.9), the extremum defined as (kWh,RE=0) is a maximum as well, but it is inferior to the extremum provided by ($kWh_{max}$, RE=.9), since the profit at ($kWh_{max}$, RE=.9) greater than zero.

The graphical solution to 3.17 is provided in Diagrams 3.4 and 3.5. Diagrams 3.4 shows the case where $P_A \geq \frac{A(kWh,RE)}{-\eta(kWh,RE)}$ at ($kWh_{max}$, RE=.9) and Diagram 3.5 shows the

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[39] This is indicated in Appendix F, as well as earlier in this chapter.

case where $P_A < \frac{A(kWh, RE)}{-\eta(kWh, RE)}$ at ($kWh_{max}$, RE=.9). The heavy dotted line in both diagrams represents the locus of points that satisfy 3.28. The blue line represents the profit of the unit at each point along 3.28. Both diagrams show the two extremums ($kWh_{max}$,RE=.9) and (kWh,RE=0) as points B and A, respectively. As indicated above, when $P_A \geq \frac{A(kWh, RE)}{-\eta(kWh, RE)}$, both A and B are maximums, however, point B, where RE=.9 is the superior point in terms of profit maximization. Point E, a minimum extremum, only occurs when within the tech constraint when $P_A \geq \frac{A(kWh, RE)}{-\eta(kWh, RE)}$. Point E represents the point (kWh*, RE*) described above. When $P_A < \frac{A(kWh, RE)}{-\eta(kWh, RE)}$ at ($kWh_{max}$, RE=.9), there is only one extremum that qualifies as a maximum, point A where RE=0—as discussed above. Profit is maximized, according to the budget constraint where s=0 (when RE=0) at zero profit.

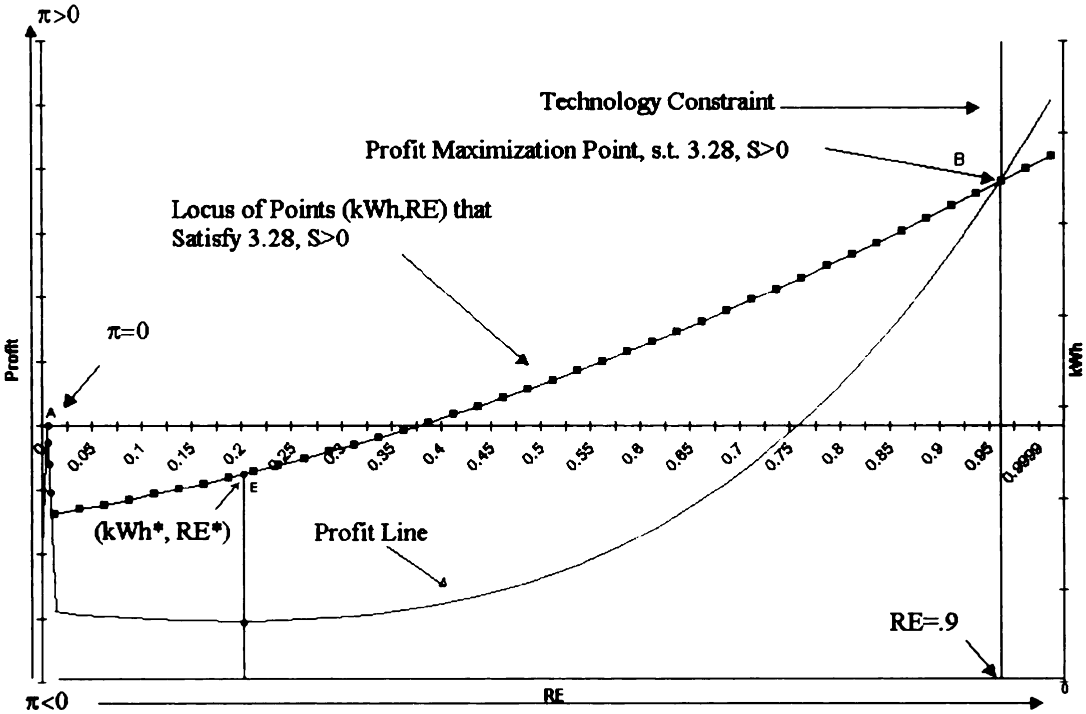


**Diagram 3.4: Solution where Allowance Prices Support Abatement Effort (RE>0)**

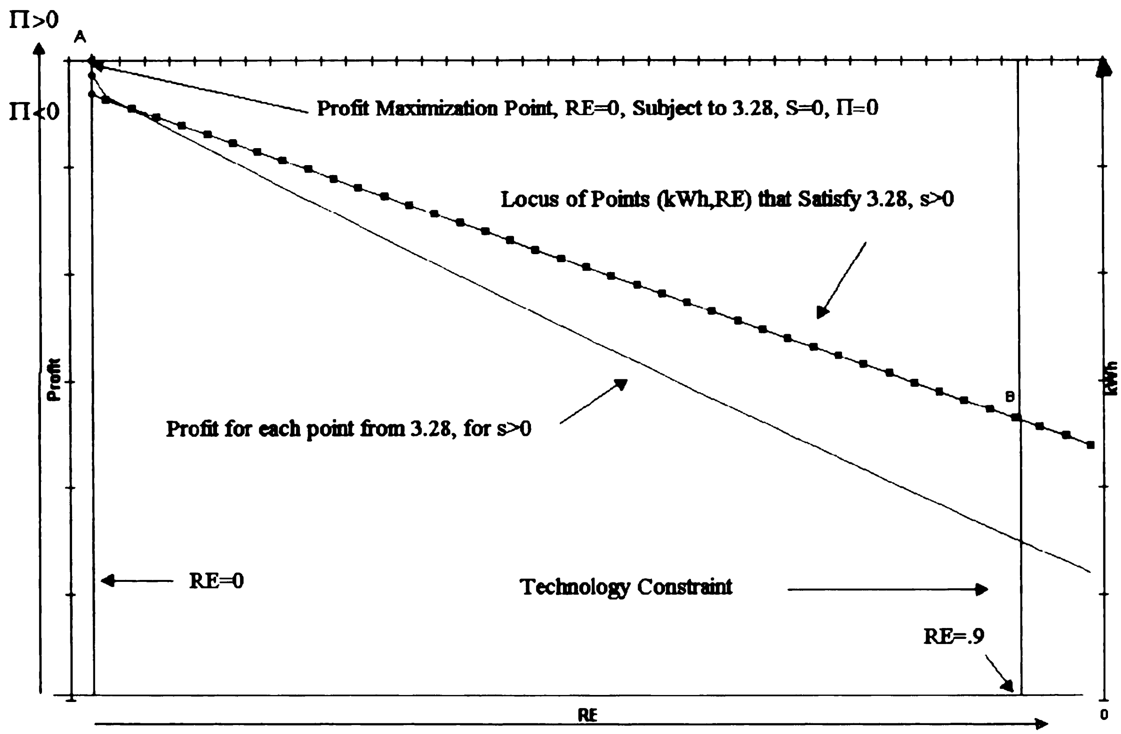


**Diagram 3.5: Solution where Allowances Prices do not Support Abatement Effort**

### 4. Summing the solution to 3.27

The unit specific solution to 3.27 with regard to kWh and RE, referenced as $kWh_i^{mkt}$ and $RE_i^{mkt}$, is used to calculate the annual emissions and total compliance costs of the unit under the cap. Annual emissions (AE) from the unit are calculated as indicated above:

$$(3.31)\ AE_i = Em_i * kWh_i^{mkt} * (1 - RE_i^{mkt})$$

Using 3.31 allows the calculation of the externality effects of emissions from the unit later in this chapter, allowing a comparison with external cost results of the unit where allowances are applied as a cap.

Total emissions under the binding market ($E_{cap}$) are calculated by summing emissions across all units (units are numbered 1 to n):

$$E_{mkt} = \sum_{i=1}^{n} AE_i\left(kWh_i^{mkt}, RE_i^{mkt}\right)$$

The value of $E_{mkt}$ is used to compare total annual emissions of a Phase II compliant cap relative to a binding Phase II allowance market. It is generally felt that emissions will be higher under the binding Phase II Allowance Market and this measure will allow a test of that assumption. While $E_{mkt}$ is of interest, the important information is the unit specific emissions, since the location of emission sources plays a major role in determining external effects of sulfur dioxide emissions later in this chapter.

The value of the individual $RE_i^{mkt}$ and $kWh_i^{mkt}$ determines the abatement compliance costs (CA), if any, of the individual unit in under the binding Phase II market:

$$(3.32)\ CA_i^{mkt} = P_A \cdot \left(-\eta\left(kWh_i^{mkt}, RE_i^{mkt}\right)\right) - A\left(kWh_i^{mkt}, RE_i^{mkt}\right)$$

Whereas 3.32 provides the individual unit costs of compliance costs, the costs of all units under the market is of interest for determining total abatement cost effects of the Binding Phase II market relative to a Phase II compliant cap. Total abatement costs from all units are summed:

$$(3.24)\ CA_{mkt} = \left[\sum_{i=1}^{n} P_A \cdot \left(-\eta\left(kWh_i^{mkt}, RE_i^{mkt}\right)\right) - A\left(kWh_i^{mkt}, RE_i^{mkt}\right)\right]$$

The value of $CA_{mkt}$ is compared with total compliance costs under the cap to determine net abatement cost effects of the tradable allowance system.

## IX. Determining the Market Clearing Price for Allowances in the Binding Phase II Market for Allowances

As discussed above, the market price of allowances is central to determining whether or not a particular boiler should invest in abatement or buy allowances. At the boiler level, a change in the market price for allowances causes a change in the number of allowances sold or bought by the boiler.[40] As such, each boiler has a supply and demand

[40] Besides determining whether or not a boiler invests in scrubber capacity or not, the price for allowances will determine how many allowances are bought or sold. The price of allowances will help determine the output level (kWh)—without or without abatement investment—by contributing to the costs of operation.

for allowances that is determined by the boiler's costs of abatement relative to the market price for allowances. Adding the net demands for allowances from all boilers for a given market price provides the market's demand for allowances at that market price. Adding the net supply of allowances from all buyers for a given market price provides the market supply of allowances at that market price. When the model's demand and supply for allowances is tallied for a range of prices, a market supply and demand curve for allowances is generated. At the allowance price where net supply of allowances equals the net demand for allowances from all boilers in the market ( $\sum_{i=1}^{N} \eta_i(kWh_i, RE_i) = 0$) the market is in equilibrium. This point of intersection is found by running the each boiler through a series of prices for allowances until the total supply of allowances in the market equals the total demand of allowances in the market.

However, the market-demand and supply curves for allowances are not smooth over their entire range. This is due to the fact that at some particular price some boilers may cease to rely on buying allowances to meet their emission requirements (RE=0) and begin to actively abate emissions (RE=.9). Due to the step shape to the market supply and demand curves, the market clearing condition may not be obtainable as a strict equality. That is, there may not be a unique equilibrium price. Where a strict equality between supply and demand is not obtainable, a less stringent market clearing condition is used to find the "equilibrium" market price for allowances for a given set of market assumptions. The lowest price that prevents a shortage in the market for allowances is assumed to be the equilibrium price of the market.[41] . The only problem this presents is that fact that unplanned banking may occur in the model. The effect of this is to reduce annual emissions by the amount banked in this way. This will not detract from the results of the model. This is due to the fact that the allowance system is set up so that utilities will err on the side of over-compliance rather than incur penalties due to shortfalls in allowances held at the end of a year.

## X. Results of the Market Simulation Model.

### A. The Estimated Equilibrium Phase II Allowance Prices

The simulation was run for a range of parameters discussed above. Each set of parameters defines a setting for the simulation of the market for allowances under phase II allocations and for a cap on emissions. It is assumed that the boiler's 1990 output and emission levels define their pre-clean air act start levels in the simulation. Any changes from these levels are assumed to be due to the impact of the compliance requirements imposed by the Clean Air Act of 1990's Phase II emission requirements and/or market for allowances. At each set of parameters, the market model is given a series of possible allowance prices until the market-clearing price is found—as defined above. In order to simulate the effect of an emission cap with the phase II emissions requirements, the simulation is run for the same parameters defined above.[42]

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[41] Due to the nature of the cap, a shortage of allowances to cover emission requirements is not possible. Banking, on the other hand, is a possibility. It is assumed that the boilers and utilities will err on the side of banking rather than allowing there to be too few allowances to cover their emission requirements.

[42] Note that, as explained earlier in this chapter, the data used to define the cost structures, heat rate, and other characteristics of each boiler in the simulation is available from the Energy Information Administration. Sources such as the Coal Monthly, the

The result of each simulation run is a boiler specific level of output, emissions, remaining allowances, cost of compliance, and what form compliance takes for a given market price for allowances. This information is recorded for each boiler for the phase II allowance price that places the annual phase II allowance market in equilibrium.

The predicted phase II equilibrium allowance prices for the central set of parameters are given in table 3-1 below. Using the central values for each parameter value results in nominal prices that range from $194 to $221 an allowance—well within current projections of nominal allowance prices. The upper and lower bounds of the simulation parameter settings show extreme potential prices ranging from $124 to $277 an allowance.

Table 3-1
Simulation Equilibrium Prices for Allowances for Various Costs of Capital

| R | E=.03 |
|---|---|
| 0.16 | $276 |
| 0.12 | $221 |
| 0.11 | $207 |
| 0.1 | $194 |
| 0.05 | $125 |

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Electric Power Monthly, and other publications of the EIA have proved very good sources of data regarding the operational and output statistics of power plants.

## B. Projected Annual Costs Savings of the Binding Phase II Market Relative to Phase II Compliant Cap: Simulation Results

As would be expected, the market for emissions allows for significant abatement cost savings over the emission cap form of regulation under every permutation of the market model.[43] The net cost of abatement of a boiler that chooses abatement (RE=.9) at a particular allowance market price and for a particular level of output (kWh) is given by equation 3.16 above. The net cost of the boiler that chooses to set RE=0 at a given market price and level of output is given by equation 3.17 above. Where FGD equipment exists as sunk capacity, the costs of abatement are given by equation 3.18 above. Summing the costs of all the boilers in the model for a given market price determines the net cost of meeting the emission requirements under the market for allowances.

The costs of meeting each boiler's emission cap[44] is given by equation 3.10 where FGD is an investment decision, for the equilibrium level of output. Summing over all boilers provides the industry-wide cost of compliance with the binding Phase II compliant cap for all phase II units for a given set of simulation parameters.

The simulation estimated an annual abatement cost savings of the market under Title IV, phase II requirements ranging from \$348 million to over \$1.6 billion a year—depending on the price of capital used in the model. Effects of varying demand elasticities are marginal due to very small magnitudes, and they are therefore not included in the table. As might be expected, the higher the cost of abatement capital[45], the greater

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[43] The model, as introduced in chapter 1, predicts that the market will lower the costs of meeting a given emissions cap except under very specialized conditions.

[44] Where there is no market, the allowance allotments act as a cap on the emissions of each boiler which must be met.

[45] The higher the interest rate, the higher the cost of abatement capital, all else held equal, at a given boiler.

the savings afforded by the market due to the fact that the market increases the amount of avoided cost relative to the cap. The cost savings under the different assumptions are shown in table 3-2 below. The central estimate of cost savings ranges from $917 million to $1.14 billion a year in cost savings from using a market rather than a cap to reach the phase II emission goals—which is well within current estimates by the EPA.

Table 3-2

| Simulation Cost Savings of the Allowance Market for Various Output Demand Elasticities and Cost of Capital, Millions of Dollars | |
|---|---|
| R | e=.03 |
| 0.12 | $1,144 |
| 0.10 | $917 |

As noted, these projected cost savings are from a Title IV allowance market under a binding Phase II allowance allocation. Current market activity under Phase I provisions has been far more limited for the reasons discussed in Chapter 3.

**C. The Market Allocation of Allowances Relative to a Cap: Geographic Reallocation Effects**

The net allocation of the market is captured by the model for each market equilibrium and for each individual boiler in the market. The market allocation of allowances determines the level of abatement achieved by each boiler, which in turn, determines the location of the source and volume of emissions for that market equilibrium. When compared to the emissions produced by each boiler under the cap, this provides information on which utilities are net sellers or buyers of allowances, and the extent to which the market has caused a geographical shift in the origin of emissions. These results can then be used to estimate the geographic shift in the external effect of emissions. Table 3-3 provides the central estimate of the geographic shifts caused by modeled market versus the cap for emissions. Where emissions under the allowance market are less than under the cap in a given region, that region is considered a potential net exporter of allowances under title IV, phase II. Where emissions under the market are greater than under the cap, that region is considered a potential net importer of allowances under title IV, phase II.

Net regional emission volumes can change with respect to output demand elasticity—but these effects are small. Where such a change causes a net supplying region to become a net buying region (or vice versa) indicates a region that, on average, has estimated abatement costs that are near the mean. Such regions are indicated by very small differences between emissions under the market and under the cap. A comparison of this model's phase I results is made with those of the EPA's in the next section. Of interest, in terms of allocation issues after trades, are the relative geographic positions of the buyers and the sellers. If enough boilers are selling or buying in a geographic region to make that region a net buyer or seller, it will affect the external costs of emissions under the market relative to the cap. Assuming that winds tend west to east, the existence of net seller regions that are east of net buyers would be expected to increase the external costs relative to the costs found under the cap. Given that the Mid-Atlantic, New England, and South Atlantic regions are consistently indicated as potential net sellers of allowances, and the other regions—other than the East North Central Region—are consistent buyers, would indicate that there may be some welfare losses associated with the market relative to the cap. East North Central status as a net buyer or seller is sensitive to the setting of the market model. As is examined again below, the boilers in this area have, on average, the market average cost of compliance. Thus small changes in the market may affect the net outcome of this region. It must be noted that these net changes are small relative to the volume of allowances allotted and used in this region.

What determines whether or not a given region is a net seller or buyer of allowances is dependent on the abatement costs of the region relative to the market as a whole, as indicated in the simulation model section above. Regions with average abatement costs less than the equilibrium price of allowances will be a potential supplier of allowances. Likewise, a region with higher than average abatement costs will be a potential buyer of allowances. See the discussion of the mechanics of abatement choice above.

As indicated there, the abatement decision is an investment decision. As such, the annual per ton cost of emission removal via FGD is compared to the price of allowances to determine whether or not it makes sense to invest in FGD or buy allowances to cover emission requirements.[46] In Appendix F it is noted that the higher the sulfur-content of the fuel burned at a boiler, the larger the boiler, and the greater the amount annual fuel burned, the lower the average costs of removing each unit of $SO_2$ via FGD will be—all else held equal. This means that the bigger the plant, the greater the volume of sulfur to remove, the lower the average costs of abatement. As a region the SA, MA, and NE tend to have bigger, more coal dependent plants than the rest of the country. In addition these

[46] The mechanics of FGD abatement are discussed in detail in Appendix F at the end of this chapter.

plants are closest to high sulfur coal and thus have a higher than average sulfur content in their fuels. These two regional features combined would tend to reduce the projected average costs of using FGD for compliance relative to the rest of the market. In addition, and equally important, large dirty plants tend to have a greater annual endowment of allowances under Title IV—their allowance allocations are based their baseline emissions. This means that the use of FGD can free up a large number of allowances for sale on the market—as seen in the fact that these heavy polluting states are predicted to be net suppliers of allowances under phase II rules. This last fact about allowances is more important than it may appear at first glance. An examination of the allowances allocation rules shows that plants that were already in compliance by 1990 and in the base-line years used by the law are only given a number of allowances sufficient to keep their emissions relatively constant. In all cases these allowance allocation rules are less generous than in the case where a boiler had to lower its emissions under title IV. A simplified outline of the original allowance allocation rules is given at the end of this chapter. Thus the SA, MA, and NE regions are estimated to be potential supplier of allowances in a phase II allowance market under Title IV.

It is important to note that the units predicted to have the lowest cost of FGD relative to the rest of the phase II population are the units which receive the greatest number of allowances in phase II. Thus the supplier status of many of the dirtiest plants is ensured by two factors—relatively low costs of abatement and a large number of allowances.

Table 3-3
Central Phase II Emission Estimate of the Model
All estimates in 1000s, R=.115

| | Total Cap Emissions | Total Market Emissions | Total Emissions Difference |
|---|---|---|---|
| NE | 263 | 186 | 76 |
| MA | 882 | 846 | 36 |
| ENC | 2,158 | 2,133 | 25 |
| WNC | 746 | 1,012 | (266) |
| SA | 2,003 | 1,513 | 490 |
| PSC | 1,074 | 1,190 | (116) |
| WSC | 787 | 1,338 | (551) |
| Mountain | 548 | 626 | (79) |
| Pacific | 46 | 20 | 26 |
| | 8,505 | 8,865 | (360) |

## XI. Testing the Simulation Model against Observable Behavior: Comparing Prices, General Emission Patterns, and Allowance Activity.

As indicated in Chapter 2, current Phase I activity can be expected to be much different from the shape and performance of the allowance market under binding Phase II allowance allocations by the year 2007 or so. Each market has different allowance allocation rules, time horizon, different types of participating units, and greatly varying number of units. That Phase I and Phase II are so different is not surprising given that they were designed to be that way. Phase I is designed to be a short (5 year) introductory phase during which the dirtier plants can prepare for the stricter standards that go into affect under Phase II (from the year 2000 on). While very different in scope, scale, and purpose, current Phase I activity provides two pieces of information that can be used to examine the results of the Phase II binding simulation model.

First, current market prices for allowances and trends should be moving towards the prices predicted by the long-term model as Phase II draws near. That is, prices for allowances should be gravitating towards the long-term prices predicted by the simulation. This is not to say that Phase I prices will be equivalent to the Phase II predictions, just that they should be somewhere near a trend-line towards those prices. In a perfect world, with perfect information and no external shocks, one could expect current allowance prices to move along a trend line—with allowance prices rising at the rate of return between now and the future expected equilibrium price under a binding Phase II allocation market, that occurs in some period. Therefore the allowance price at some time t before T (when the allowance allocations become binding) would equal the market clearing market price for allowances at time T, discounted back to t. However the real world is uncertain and is subject to external shocks, as in the case of the unexpectedly low price of Powder Basin Coal (low sulfur coal). In addition the actual time T (when the Phase II market becomes binding) is uncertain as is the actual price of allowances at time T, based on the industries costs of abatement at time T. This uncertainty will generate a positive "convenience yield" during the period where the allowance allocations are not binding, which will reduce the expected rate of allowance price increases until time T. However, prices should be in the low end of the neighborhood of avoided costs of abatement provided by the market.

Second, the model predicts that Phase I units will be, on average suppliers of allowances under a binding phase II market. This is due to the fact that Phase I units are, on average, dirtier and larger than Phase II only units. Since the annual average costs of $SO_2$ removal decreases with the volume of $SO_2$ removed, and decreases with the size of the plant, phase I units are expected to have lower costs of removal than phase II plants in general. This fact was the reason that Phase I units were designated—to provide them time to implement FGD technologies prior to the tighter Phase II allowance allocations. With this in mind, Phase I units should be reducing emissions and/or banking current allowances allocations (saving allowances) for later sale in the Phase II market. In terms of simulation results, Phase I units should be net suppliers of allowances—indicating a net surplus of allowances among Phase I units relative to Phase II allowance allocations.

**A. Comparing Phase I Prices and Trends, Third Party Estimated Avoided Costs, and The simulation Price Results.**

The current market price for allowances have returned to projected trend lines regarding expected allowance prices. In addition, these prices are well within the central price estimate of the simulation model.

As indicated in Chapter 2, there is no denying the fact that the low price of Powder Basin Coal sent a shock through the allowance market. The unexpected shift in long-term demand for allowances would be expected to have some downward pressure on allowance prices in the near term, particularly within the short-run time period surrounding the shock. Given the time involved adjusting FGD plans and long-term contracts for coal, adjustment to the shock from the supply side has been slow at first, but there is strong evidence that rapid adjustments are being made. This is seen in the fact that allowance prices have not only stabilized, but they have dramatically increased since the low coal price shock went through the market. Prices started to recover in February of 1996, after the steady fall from expectations in 1993, the time of the first auction. Current prices have since risen back to $189 and $208 as of August 1998—sufficient to cover long-term average costs of both coal switching and FGD at many units.[47] The peak price, prior June of 1998, was in excess of $210—further evidence of adjustments in the market. The most recent price trend is seen in figure 6 below.[48]

An increase in prices towards the long-run expectations was to be expected given the long-run average prices of abatement in the market, and the fact that allowance allocations will become a binding constraint on the industry under phase II—though at a later date than previously expected. Indeed, there is strong evidence that prices have returned to the long-term trend line started when allowance trades started in 1995. Assuming a range of interest from 5 to 10%--the current range of interest rates found on the market—current prices are well within long-term trend line expectations. This is seen in Diagram 3.6 below, where lower (.05 interest) and upper (.1 interest) trend lines are indicated.

The quick rebound in allowance prices was not unanticipated. The cost of reducing emissions via coal switching has an average cost of $180 a ton.[49] The cost of new FGD can (and does) run below $150 a ton—but the current industry average so far has been around $250. In addition, Coggins and Swinton (1996) have estimated the shadow price of compliance under phase I restrictions is around $229 a ton—a "number commensurate with other recent estimates of the marginal cost of abatement for coal

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[47] As Scmalensee points out, average FGD costs vary considerably around his average of $265, with many units with costs much lower than this. This is true of many units which have not installed FGD, as indicated in the simulation in this paper.
[48] Figure 1 indicated the monthly average price of a current vintage year allowance, as reported by two brokerage firms and Fieldston Publications' market survey.
[49] It is important to note that reducing emissions via coal switching is not synonymous with meeting Phase II compliance requirements. Among current phase I units, the use of low sulfur and lower sulfur coal (non-Powder River Basin coal) has met Phase II compliance requirements in only 13% of the units. Coal switching is not a long-term compliance option for the industry, as explained in the text.

plants in the Midwest region".[50] Under Phase II, Coggins and Swinton (1996) "expect that shadow prices will be driven up" from there to "at least $350".[51] As indicated by Coggins and Swinton, and earlier comments, there is reason to believe that phase II plants, being cleaner on average, will have compliance costs higher than this. Thus, an expectation of higher prices in the long-term appears to be a sound expectation.

Both the trend lines and actual prices fall within the central estimate range ($170-245) of the binding Phase II allowance prices generated by the simulation. This is strong evidence that the market simulation model is capturing the costs and avoided costs of long-term abatement decisions relative to the binding Phase II market.

[50] Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, Page 70.
[51] Jay S. Coggins and John R. Swinton, "The Price of Pollution: A Dual Approach to Valuing $SO_2$ Allowances," Journal of Environmental Economics and Management, 30, 1996, Page 70.

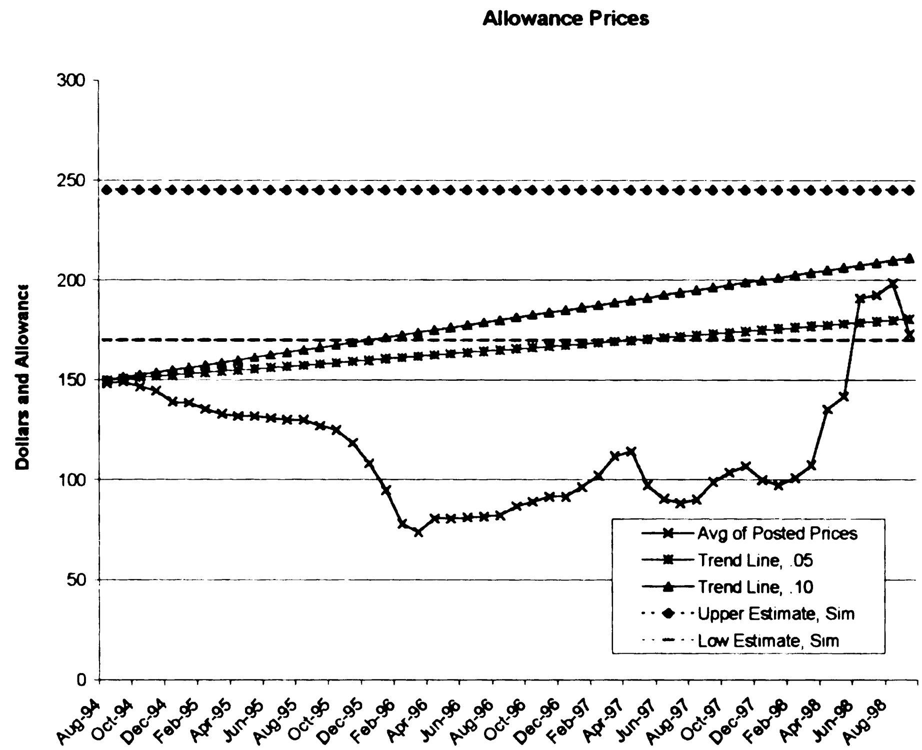


**Diagram 3.6: Allowance Prices over Time**[52]

## B. Comparing Phase I Net Emissions and Total Emissions with Simulation Results for Phase I Units

A study of the current knowledge of what determines the costs of FGD abatement, as presented in Appendix F at the end of this chapter, indicates the role that the average phase I unit can expect to play in the market defined by the Phase II allowance allocations. Phase I units are, on average, dirtier than their yet to be affected phase II counterparts. In general phase I designation was assigned to units based on the fact that they were the dirtiest and biggest emitters of sulfur dioxide, for transitory or real reasons, in the baseline years. As the abatement cost estimates indicate, the dirtier and bigger the plant, the lower the average costs of emission removal on a per ton basis—the basis by market participation is determined.[53] Thus phase I units, given the expected abatement costs, would tend to be suppliers in any market that would be expected to develop under phase II. It should therefore be expected that phase I units will be investing in abatement levels sufficient to guarantee a supplier status in a soon to be developing phase II market. This would cause a large surplus of allowances among phase I units—particularly during the five year period during which only phase I units are involved in the market for allowances.

Table 3.4 shows the activity of phase I designated units in the simulation of the phase II market. Comparing the 1997 actual emissions column to the simulated emission results from phase 1 plants column shows that the market simulation results are very similar to the actual EPA recorded emissions levels in 1997. As predicted, phase I units in the simulation are net suppliers of allowances in the both the Phase I and Phase II allowance market. In the context of a phase II market these results indicate that the phase I boilers are, as predicted, acting as potential suppliers in a future phase II allowance market. That is, they are behaving in a manner consistent with this role.

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[52] Prices are as reported by the Emissions Exchange and Cantor Fitzgerald EBS brokerage firms and the Fieldston Publications' market survey.

[53] As indicated in the previous sections, the average cost of abatement—relative to the price of allowances—determines whether or not a unit invests in abatement capacity. In the case where FGD capacity exists, the decision to run FGD or not is based on the price of allowances relative to the marginal costs of running the FGD capacity.

**Table 3-4** Simulation Results for Phase I Units vs. Actual Phase I Emissions by Region

| | Phase I Unit Actual 1997 Emissions (1000s) | Phase I Units Simulation Emission Results (1000's) | Net Allowances Using Phase I Allocations |
|---|---|---|---|
| NE | 60 | 49 | + |
| MA | 583 | 632 | + |
| ENC | 2593 | 1747 | + |
| WNC | 293 | 548 | + |
| SA | 1101 | 1019 | + |
| PSC | 843 | 713 | + |
| WSC | 0 | 0 | 0 |
| MNT | 0 | 0 | 0 |
| PAC | 0 | 0 | 0 |

## C. Conclusion Regarding Simulation Results and Phase I Behavior

As noted above, current prices and market behavior among phase I units is consistent with predictions made by the simulation used in this paper. Current allowance prices are well within the central estimate of the Phase II simulation, and well within estimated trend lines. The fact that phase I units are exhibiting over-compliance and banking is consistent with the role that phase I units are predicted to have within the context of the simulated, binding Phase II market. The close correlation between the simulation's predictions and the actual market—in terms of price, relative control, and emissions—provides evidence that the model has some amount of predictive power as to the behavior of boilers in the phase II market.

## XII. The effect of title IV on the external costs of emissions

The market for allowances will lower the costs of complying with the emission cap set by title IV. Whether or not the market lowers all the costs associated with achieving the phase II Title IV standards is another matter. The net cost effect of the market under title IV will be dependent on the net welfare effect of the allowance trades. If the exchange of allowances causes, based on location dependant external costs, a decrease in net welfare, the market would prove to be less attractive than the cap as a welfare improving form of emission regulation.

The net external effects of allowance trading are dependent on a number of factors. First and foremost, the net changes in the geographic reallocation of allowances through trading will effect the external costs of the market relative to the external costs of the emission cap.[54,55] The second contributing factor to changes in external costs is how emissions are distributed from their source in terms of directions, range, and rate of deposition. The third factor, how much damage the pollution causes, and the sensitivity of the regions where the emissions falls.

[54] It is the net trade allocation of allowances, rather than any individual trade, which determines the outcome of the market relative to the cap.
[55] Or rather, the net geographic reallocation of emissions due to allowance trades will effect the external costs of the market relative to the external costs of the emission cap. Besides the obvious potential for a reallocation of emissions is the possibility that the

## A. The Emission Model: The Distribution and Transportation of Emissions

### 1. Background

In order to quantify the potential losses from having regions like SA, MA, and NE be net suppliers of allowances under phase II title IV, the relationship between sources of emissions and the locations they affect must be understood. The EPA refers to emission models as a theoretical construct that simulates the deposition and distribution of pollutants from point and/or mobile sources. In the study of the deposition and distribution of acid and sulfur deposition, the EPA has made use of many different emission models. As studies have continued and computer power has increased, these emission models have become more and more sophisticated. For the most part, these very complicated models are based as much on simplifying assumptions and traditional rules of thumb as they are on advances in the scientific understanding of the atmospheric processes involved in transporting and depositing pollutants.

There is a degree of uncertainty regarding any source-receptor relationships[56] in EPA estimates. First of all, sulfur dioxide emissions are not measured directly in any of the studies. Instead, they are estimated, as in this paper, using plant specific operating characteristics.[57] Second, "there is little data on sulfur dry deposition, making analysis of the total deposition difficult."[58] [59] Third, what data is available with regards to other

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market will allow emission totals to increase relative to those possible under the boiler specific caps. This will be demonstrated below.

[56] A source-receptor relationship describes the transportation and deposition process from a source of pollution to any receivers (receptors) of the pollution. Emission model describe source-receptor relationships in mathematical terms.

[57] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 168.

[58] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 168.

[59] Dry deposition is a form of sulfur deposition that appears as particulate matter. It comprises a small proportion of total sulfur emissions and it is almost completely unstudied with regard to source-receptor relationships. It is generally assumed that dry

forms of deposition is based on tracking emissions from only two regions in the U.S.—the Ohio River valley region and a South Atlantic Region.[60] In general, "as a result of many complicating factors, empirical results cannot, by themselves, be used to predict reliably how deposition will change when emissions change."[61]

The most current models make use of Cray super computers in order to encompass a model which estimates probable chemical interactions of over 19 pollutants and weather patterns to predict the transportation and deposition of emissions on an a grid map of 80km by 80km receptor points. The transportation and deposition models are ultimately based on research done by NAPAP. This study attempted to trace emissions from source to receptor from three major emission areas. The end result of this research to date is the RADM emission model that has been used by the EPA to make projections and predictions on sulfur and other pollutant emission depositions. It is interesting to note that the linear-based deposition models used by the EPA have yielded results similar to those of more complicated CRAY resident models.[62] This is important because the model developed here makes use of a linear-based deposition model.

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deposition occurs in close proximity to sources (within 200km or more) but translation to dry sulfates allows transport ranges up to 2000km. The translation feature is partly unknown.

[60] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 168.

[61] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 168.

[62] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 169.

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### 2. Generalized EPA emission model results

The NAPAP research indicates a number of conclusions about sulfur emission deposition in the United States that give reason to be concerned about the net direct of allowance trades. The NAPAP study concluded that 30% of sulfur dioxide emissions are deposited as precipitation, 27% as dry deposition, and 4% as clouds and fog.[63] The remaining 39% of emissions are exported beyond the North American continent.[64] The fact that the greatest sources of emissions are in the mid-west and Great Lakes regions, this indicates a considerable transport range of sulfur dioxide emissions.[65] In addition, it was concluded that, "regions of highest wet sulfate patterns are displaced slightly north and east of regions with the highest emissions."[66] This would indicate that net trades that move allowances from eastern to western regions will work to increase the sulfur deposition that makes landfall in the continental United States.

As far as the extent of emission deposition, the general conclusion of NAPAP is that transport ranges are considerable and dispersal area is wide. The U.S. can, according to the NAPAP models, contribute over 50% of sulfur dioxide deposition in Canada. In fact a significant portion of the emissions falling in any given area are apt to come from significant distances. "The total deposition falling on important receptors areas, such as the Adirondack, Poconos, Central Appalachian, and Southern Blue Ridge is attributed to many widely dispersed sources, in addition to the major source regions."[67]

In addition, the range of emission transport before deposition seems to be dependent on the latitude of the source. "Model calculations indicate that about half of

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[63] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 168.
[64] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 168.
[65] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 169.
[66] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 168.

total sulfur deposition from major source regions in the eastern U.S. occur within 500-700km, except in the South where 50% of emission deposition occurs within 300 to 500km."[68] [69] In general, emission ranges for wet deposition range from local (20 to 200km) to regional (200 to 2000km).[70] Dry deposition of sulfur dioxide tends to be short in range (0 to 200km), but ranges as sulfates can be very long (in excess of 2000km).[71]

### 3. A simplified emission deposition model

As the specific model used by the EPA is beyond the run capacity of all save cray super computers, a simpler more tractable emission model is developed here to attempt to quantify the potential deposition effects caused by net reallocations of allowances through the simulated market trades calculated above. The emission model developed here is based on the EPA's generalized RADM model results. This simple model makes use of generalized results of the RADM and NAPAP reports and the basic assumptions of the EPA's emission model to create a source-receptor relationship for each boiler and plant involved in the simulated phase II market.

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[67] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 169.
[68] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 168.
[69] Noting again that 50% of the 61% of emissions that stay in North America indicates that 31% of total emissions from these sources falls within the proscribed ranges.
[70] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 175.
[71] NAPAP, National Acid Rain Assessment Report (NAPAP), 1990, page 175.

Emission Modeling Process:

1.) Fix the relative geographic location of emission sources (boilers) on a grid map of the United States and Canada.

2.) Set the transport, distribution, and deposition equations to mirror the results and assumptions used and developed in the NAPAP report and the RADM models. In order to account for translation error, sensitivity analysis in the form of varied parameter settings is used.

3.) Feed in the actual 1985 total emissions from each boiler at a number of different parameter settings and record the results. Compare the emission deposition model results for 1985 data with the EPA's actual 1985 emission deposition data using correlation analysis. Change the model, as necessary, to mirror actual published emission/deposition data for 1985.

**Step 1: Spatial Placement**

The first step to the source-receptor process is to determine the location of the sources of emissions being modeled relative to potential receptor sites. Because relative location is important, the NAPAP models fix the location of the emissions sources on a fixed grid that is laid over the map of the United States.. The grid is composed of 150km by 150km receptor areas. Every source of emissions is given a location on the grid in terms of an X and a Y coordinate on the grid based on the plant's city, county, state, and coolant source (in the case of rivers and lakes). This fixes each plant in its relative geographic position to every other phase II plant and the potential receptors that make up the grid-mapped United States and Southern Canada. The basic grid map is given below.

**Table 3-5: Basic Grid Map**

| 0 | 150 | 300 | 450 | 600 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN |
| 300 | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | ME | CAN | CAN |
| 450 | MT | ND | ND | ND | MT | MT | CAN | 0 | 0 | CAN | CAN | CAN | CAN | CAN | CAN | CAN | CAN | ME | CAN | CAN |
| 600 | MT | ND | ND | ND | MT | MT | 0 | MI | 0 | MI | CAN | CAN | CAN | CAN | CAN | CAN | VT | ME | 0 | 0 |
| 750 | MT | SD | SD | SD | MT | MT | WI | WI | MI | 0 | MI | 0 | CAN | CAN | NY | NY | NH | 0 | 0 | 0 |
| 900 | WY | SD | SD | SD | MT | MT | WI | WI | 0 | MI | MI | 0 | CAN | NY | NY | NY | MA | MA | 0 | 0 |
| 1050 | WY | NE | NE | SD | IA | IA | IA | WI | WI | MI | MI | 0 | PA | PA | PA | NJ | NY | 0 | 0 | 0 |
| 1200 | WY | NE | NE | NB | IA | IA | IA | IL | IL | IN | OH | OH | OH | PA | PA | NJ | 0 | 0 | 0 | 0 |
| 1350 | CO | NE | NE | NE | MO | MO | MO | IL | IL | IN | OH | OH | WV | WV | VA | MD | 0 | 0 | 0 | 0 |
| 1500 | CO | KS | KS | KS | KS | MO | MO | IL | IL | IN | KY | KY | WV | VA | VA | VA | 0 | 0 | 0 | 0 |
| 1650 | CO | KS | KS | KS | KS | MO | MO | MO | KY | KY | KY | KY | VA | NC | NC | NC | 0 | 0 | 0 | 0 |
| 1800 | TX | TX | OK | OK | OK | AR | AR | AR | TN | TN | TN | NC | NC | NC | NC | 0 | 0 | 0 | 0 | 0 |
| 1950 | TX | TX | OK | OK | OK | AR | AR | MS | MS | AL | GA | GA | SC | SC | 0 | 0 | 0 | 0 | 0 | 0 |
| 2100 | TX | TX | TX | TX | TX | AR | AR | MS | MS | AL | AL | GA | GA | SC | 0 | 0 | 0 | 0 | 0 | 0 |
| 2250 | TX | TX | TX | TX | TX | LA | LA | MS | MS | AL | AL | GA | GA | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2400 | TX | TX | TX | TX | TX | TX | LA | LA | MS | AL | FL | FL | FL | FL | 0 | 0 | 0 | 0 | 0 | 0 |
| 2550 | MEX | TX | TX | TX | TX | 0 | 0 | LA | 0 | 0 | 0 | 0 | 0 | FL | 0 | 0 | 0 | 0 | 0 | 0 |
| 2700 | MEX | TX | TX | TX | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | FL | FL | 0 | 0 | 0 | 0 | 0 |
| 2850 | MEX | MEX | TX | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | FL | BAH | 0 | 0 | 0 | 0 |
| 3000 | MEX | MEX | MEX | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3150 | MEX | MEX | MEX | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3300 | MEX | MEX | MEX | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3450 | MEX | MEX | MEX | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3600 | MEX | MEX | MEX | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Step 2: Emission density/transport/deposition systems**

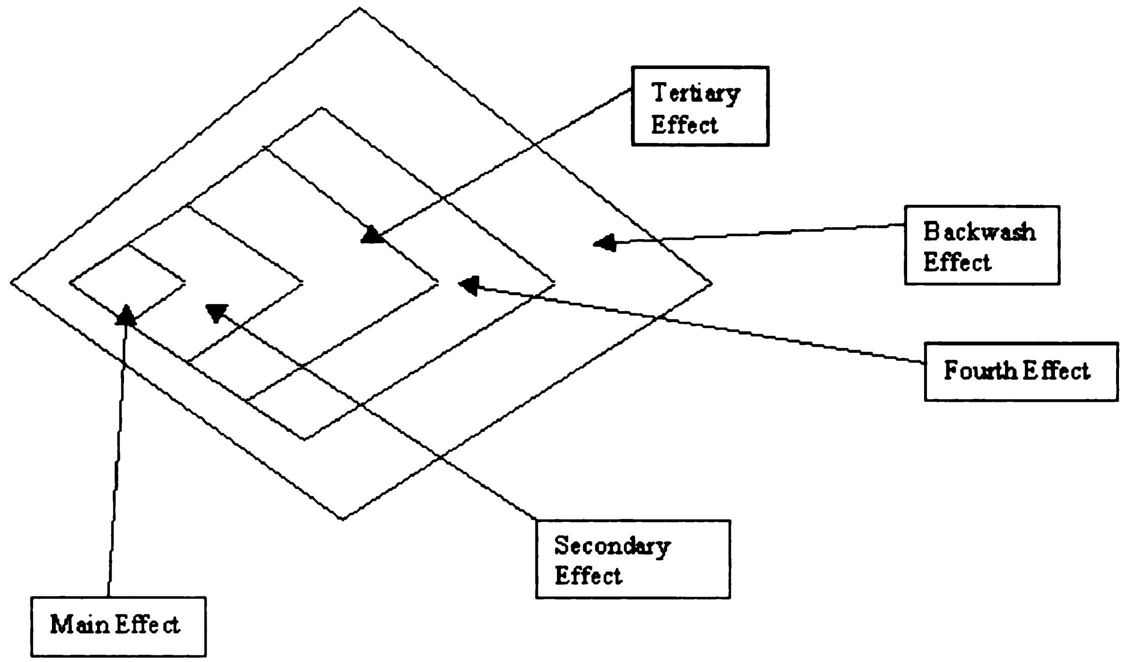
In order to incorporate the assumptions and generalized results of the NAPAP study in terms of source-receptor relationships, a series of emission density/transport/deposition systems had to be set up to run concurrently for each source. The basic structure is split into two emission transport and deposition models—a summer and a winter model. Each model is made up of a deposition tier system of five squares of ever increasing size and ever decreasing emission density to model the area of effect of the sources emissions. These emission squares define the proportion and deposition area of the emissions from each point source according to the guidelines outlined above. Each square represents, in mathematical terms, the short, medium, medium long, and long range transportation and deposition of sulfur emissions from a point source in the United States and Canada.

Diagram 3.7, shown below, presents the basic structure of the emission model for a given point source under the "winter" model. The first square is the Main effect square. This square is the smallest in terms of area, but the highest in terms of emission deposition density to receptors within its area. This receptor square is closest to the source of emissions and will, depending on the offset options chosen in the model, envelope the emission source and the immediate surrounding area. The last square is the largest and is termed the "backwash effect". It is designed to account for the furthest range of the given plants emissions both upwind and downwind of the source of emissions and it has the lowest emission density.[72]

[72] Due to storm patterns and other atmospheric phenomena, transport directions often vary from the typical prevailing wind direction.

**Diagram 3.7: Emission Deposition Diagrams**

**Winter:**




As noted briefly above, there are two sets of transport equations used to define the emission model. The first set of equations represents the cooler temperature, or winter, transport model. The more northerly point sources tend to have a longer transport effect than the more southerly located emitters. Cooler temperatures and lower moisture densities slow the deposition process, allowing emissions to travel and disperse over a larger area than under warmer temperatures. The longer the cold season, the more relevant the northern transport model becomes.

The southern transport model, or summer set of transport equations, is designed to mimic the deposition patterns associated with warmer weather systems. This model assumes more circular[73] weather patterns and faster deposition rates. Thus, relative to the northern model, the southern model makes use of shorter downwind ranges assumptions and a less elongated emission plume from the point source.

The emission model results for each plant are made up of a mixture of the two transport models run simultaneously for each point source. The proportion of annual emissions assigned to each transport model is determined by how far north or south the source is located on the grid. How the proportion changes is discussed in the calibration and estimation setting section below. In general, however, the further south the source the longer the warm transport season and the greater the volume of emissions which was attributed to the "summer" distribution model.

Running the emission model for a given set of parameters settings and emission levels then results in an annual total sulfate concentration/deposition map, measured in terms of $\frac{\mu g}{m^3}$, from emission point sources on grid of the United States and Canada.

The default settings for the winter and summer models are given in the table below. The offset column numbers refers to how far "up-wind" of the source the "rear-most" corner of an emission deposition box is placed for determining deposition locations. The range column indicates the furthest "down-wind" range of the emission deposition box from the offset point. It is therefore not the range from the source. The area column is the assumed area of effect for the effect in question.

The percent of total emissions column indicates the default setting on the percentage of emissions from a source which fall within each box. The emissions in a

[73] Southern state weather patterns tend to be circular in motion, particularly during the warm months, relative to the northern part of the country.

particular box are assumed to be evenly and uniformly distributed within its borders. The last column gives the percent of total emissions from the source that is applied to each square kilometer in the model in terms of annual sulfate concentrations. Note that the "Summer" or southern effect model reflects a more localized deposition system that is found in warmer, wetter weather patterns. A large offset, smaller ranges, and smaller areas for each box characterize the southern emissions transport model.[74]

The main and secondary effect boxes in the summer effect model contain the same percentage of emissions as the main effect of the winter model. In effect the main and secondary effect of the summer model is the equivalent of the main model in the winter model. This was done to present a more sensitive and graduated scale for the main primary deposition area of the southern model that is smaller and more localized than the northern model. As will be discussed in the calibration and estimation setting section, these assumptions allowed a very good match with the actual emission/deposition patterns observed under the EPA studies.

**Table 3-6: Emission Model Default Settings**

**Emission Model Default Settings**

| Winter | Offset Km | Range Km | Area $km^2$ | % of total Emissions | % of emission per square KM |
|---|---|---|---|---|---|
| Main | -50 | 700 | 490000 | 0.4 | 0.0000816% |
| Secondary | -50 | 1200 | 950000 | 0.25 | 0.0000263% |
| Tertiary | -50 | 1800 | 1800000 | 0.15 | 0.0000083% |
| 4th | -50 | 2400 | 2520000 | 0.1 | 0.0000040% |
| Backwash | -100 | 3000 | 6490000 | 0.1 | 0.0000015% |
| **Summer** | Offset Km | Range Km | Area $km^2$ | % of total Emissions | % of emission per square KM |
| Main | -50 | 200 | 20000 | 0.05 | 0.0002500% |
| Secondary | -200 | 400 | 340000 | 0.35 | 0.0001029% |
| Tertiary | -300 | 600 | 375184 | 0.2 | 0.0000533% |
| 4th | -400 | 800 | 571810 | 0.2 | 0.0000350% |
| Backwash | -700 | 1000 | 1258251 | 0.1 | 0.0000079% |

[74] A cyclonic weather system distributes emissions all around the source.

The direction of "downwind" relative to the source is also variable in the model. In general, it is assumed that the prevailing wind pattern is from west to east. But beyond this, two settings are used. Assuming that due east defines the reference ray or direction, the assumed off angles of 45and 0 degrees are used as the average prevailing wind direction when estimating the emission effect totals of the model. To model patterns between these two settings, a series of weights are applied to the 45 and 0 settings to changer the proportion of emissions subject to the 45 or 0 setting. This allows another means of bringing the model's results in line with the EPA's observed data on actual emissions and deposition patterns.

**Step 3. Comparing the actual historic emission deposition grid maps to the Northern-Southern Sulfur Transport Grid Model (Generalized Model).**

The EPA's RADM emission model has been used to map the potential deposition effects of Title IV. The basis of the underlying assumptions used in the EPA's RADM model has been the apparent historic relationship between emission levels and source location and emission deposition. Using deposition measurement stations throughout the United States, and some of Canada, the EPA has collected data on annual sulfate deposition for a number of years. This data was used to develop sulfate deposition gradient maps. Used in conjunction with projected emission levels and the location of the sources of these emissions, the EPA has been able to estimate the basic relationship between emission source, volume, and spatial distribution.

The model created for use with this paper uses a similar method to estimate the relationship between emission and transportation of sulfates in North America. As mentioned above, the model is based on the underlying assumptions used to define the RADM model. Once the model was defined, it was used to predict the deposition of the actual 1985 emissions of the point sources affected by Title IV (the Clean Air Act of 1990). The year 1985 was used for the same reason that the EPA uses this year as its base case for emission distribution models—the EPA has considerable data on emission deposition from that year, and the actual emissions levels of the plants at this time are well documented.[75] The EPA's emission deposition maps were then used to test and set the emission map model used here. By comparing a series of the model's prediction of deposition in 1985 to the actual sulfate concentrations of 1985, the set of parameters that best fit the emission/transportation/deposition relationship can be estimated. The settings that generate the greatest correlation between the actual and predicted 1985 sulfate concentration maps are then used to determine the effects of levels of emission predicted under the simulation of the title IV market and cap—as described above.

The estimation coefficients, emission concentration maps, and the fully estimated emission/deposition model settings are given in Appendix H at the end of this chapter. The estimated model settings are used for the central emission map generation under both the cap and the market for the purposes of this paper. The results of the emission model, as applied to the phase II simulation results, are presented in Appendix I at the end of this chapter.

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[75] The EPA's report, Human Health Benefits From Sulfate Reductions Under Title IV of the Clean Air Act Amendments, is one of many reports where 1985 is used as the base

## B. Estimating the Cost of Emission Deposition: The Potential Effects of Allowance Trading under Title IV.

A large number of studies have been made to examine the effects of acid rain and sulfur dioxide on the materials, ecological systems, and human health. Such studies are plagued by the inability to isolate the cause of a given malady—be it in an ecosystem or a human being—from the possible effect of other factors in the environment. This leads to a great deal of uncertainty in estimating the effects of pollution damage. This is also true in the case of sulfur dioxide emissions. Sulfur dioxide emissions have several avenues by which to affect ecosystems, human health, and materials. The most direct and best-documented health effect is through the direct affect of sulfur dioxide as sulfate aerosols.

### 1. The Damage Function: EPA estimates of the costs of sulfur emissions

The NAPAP study, completed in 1990, states that there are three avenues for potential human health effects from sulfur dioxide emissions. The first are direct health effects from gaseous sulfur dioxide. The second are the direct health effect of acid aerosols in the ambient air. The third comes from indirect health affects of toxic chemicals released into the environment as a result of acid deposition. The damage from all three takes the form of premature death and increased morbidity, with the costs inherent in such effects—economic value of lost life, medical costs, and reduced productivity. Damage to materials and ecosystems are determined by the same three avenues—with effects on crops, buildings, commercial forests, recreation areas, historic monuments, and visibility. Such damage is translated into economic terms as increased

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case in terms of emissions and deposition of sulfates.

maintenance costs, reduced use life of structures, reduced crop yields, stunted tree growth, and reduced fee days.

While NAPAP identified the avenue for effects of acid deposition on human health, it also presented the problems of quantifying the effects of sulfur dioxide from the effects of other environmental factors. There is, for example, a high correlation between the levels of particulate matter in an urban area and the levels of sulfate particles. Sulfate particles, in fact, make up a significant portion of all particulate pollution.[76] It can therefore be difficult to isolate the effects of sulfur dioxide from the effects of other particulate matter on human health. More often than not, there is not enough data to make any assessments of direct effects sulfur dioxide and sulfates. Because of this, actual quantitative figures placed on many aspects of sulfate effects are either absent or based on speculation at this time. This is particularly true in the material and ecosystem effects of sulfates and acid deposition. As the effects are difficult to isolate, the dollar valuation of such effects are equally difficult in many cases. This paper thus does not include material effects in the damage function for sulfate emissions.

The area with the greatest study in recent years has been the epidemiology of sulfates and sulfur dioxide. The large number of recent studies has illuminated, at least in part, the human health effects of sulfur particulates. The EPA has recently used these studies to estimate the health benefits of the sulfate reductions that will occur under title IV. This study, the Human Health Benefits from Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, is the most recent EPA effort to quantify the effects of sulfur dioxide on human health. It draws on the most recent epidemiology and

[76] All acidic sulfate aerosols are particles rather than a gas. On average sulfate aerosols make up 40% of fine particulate matter in the Eastern U.S., EPA.

field studies to draw conclusions about the effects of sulfate particles on mortality rates and increased morbidity. The EPA makes use of concentration response functions to quantify the relationship between ambient concentration levels of sulfates and the frequency of specific health effects within a given time period. The economic and social costs of sulfur dioxide is then measured using estimates of medical costs, work loss, increased costs for chores and care-giving, and measures of induced restrictions, reduced enjoyment of recreation activities, discomfort, inconvenience, anxiety, and inconvenience.[77]

The EPA tends to be quite conservative when quantifying the effects of pollutants. Whether or not one agrees with the EPA's regulatory response to a perceived problem, the EPA has been careful from the outset to downplay any but the most rigorous studies that quantify the economic and health related effects of various pollutants. The fact the EPA has not been able to quantify the impact of other forms of sulfate, sulfur, and acid deposition—despite millions of dollars spent and hundreds of studies—is a testimony of this conservatism. The EPA appears to have applied the same standards in its efforts to quantify the health and economic effects of sulfates. The EPA made use of a number of outside studies conducted over a number of years to draw together a conservative estimate of the effects of sulfates on human health and activities. There is, therefore a degree of confidence in the damage function estimates for sulfate emissions put forth by the EPA. These relationships represent the best and latest understanding of the relationships between human health and the effects of sulfate emissions. As these

[77] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-2.

relationships are being used by the EPA to determine the potential impact of title IV of the Clean Air Act, it seems appropriate to use the same estimates here.

**2. The concentration response functions**

The EPA makes use of a number of studies when drawing up the concentration response equations. Instead of relying any one range of estimates, the EPA makes use of weighted averages of the results of several studies in each of the identified areas of human health responses—mortality and morbidity.[78] The EPA's concentration response functions all hold one element in common. They are all assume linear relationships between sulfate concentrations and effect:

> "There is considerable uncertainty about whether there is a 'safe' level of sulfate aerosol exposure that does not cause any harmful health effects. There is no definitive quantitative evidence that such a threshold exists, but neither is there proof tat nay amount of sulfate aerosol exposure causes some harmful effect in at least some people."[79]

Thus in the EPA study, any change in concentrations was assumed to cause some effect on human health in the affected region, lacking significant counter evidence of such effects.

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[78] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, Chapter 4.
[79] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-7.

### 3. Mortality Response Functions

The concentration response equations for mortality are derived from studies by Pope (1995), Dockery (1993), Ozkaynak and Thurston (1987), Evans (1984), Chappie and Lave (1982), and Plagiannakos and Parker (1988). These studies made use of prospective cohort and cross-sectional studies on the relationship between SO4 and changes in mortality. It was found that the age of the individual at risk of premature mortality has an effect on the concentration response function for mortality. The EPA makes use of "a range of four estimates to reflect the range of results obtained in the mortality studies."[80] The EPA makes use of the total population in the affected area, the effects of age on sensitivity[81], and the sulfur induced mortality rate as a percentage of the average annual mortality rate when drawing up its range of concentration response functions.[82] The equations and weights are given in the table 3-7 below.

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[80] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, Page 4-23.

[81] Base on the work of Swartz and Dockery (1992), it is assumed that 85% of the deaths associated with sulfates exposures are 65 years or older. EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-23.

[82] "The selected percentage changes in mortality must be multiplied by average annual mortality to calculate the change in annual premature deaths per change in annual average sulfate concentrations....the average U.S. non-accidental mortality rate of about 8,000 per million population per year (Census, 1994)." EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 4-24.

### 4. Morbidity: chronic respiratory disease and acute morbidity

The morbidity response functions are broken down into a number of effects. Concentration responses are given for respiratory hospital admissions (RHA), for cardiac hospital admissions (CHA), aggravated asthma symptoms (ASD), restricted activity days (RAD), acute lower respiratory symptoms (LRS) and chronic bronchitis cases (CB).[83] As in the mortality response equations, the proportion of the sensitive population is used, where appropriate, to adjust the equations. As before, the EPA made use of a range of response equations. The response equations for each effect and their weights are given in the table 3-7 below.

Each category in the table has a low estimate (L), a central estimate ( C ) and, and high end (H) estimate for the concentration response equation. The EPA develops the central estimate as follows: "The central estimate is typically selected from the middle range reported in the study, or a group of studies, that has been selected as providing the most reliable results for that health effect based on the study selection criteria."[84] The low and high estimates "are not intended to reflect absolute upper and lower bounds, but rather they are ranges of estimates that are reasonably likely to be correct, given available epidemiology and economics study results."[85] In the probability weight column is the weight each concentration response estimate is given in estimating the most probable effect of changes in sulfate concentrations. Any variance in how the coefficients are applied to the population of a given area is noted in the note column of the table.

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[83] The chronic bronchitis equation is for estimating the effect of sulfates on the number of people who acquire the disease in a given population in a given year.
[84] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 2-7.

**Table 3-7**
Selected Coefficients for Human Health Effects Associated with Sulfate Concentrations Changes
Source: EPA, 1995

| Health Effect Category | Selected Concentration-Response Function | | Notes | Probability Weights | |
|---|---|---|---|---|---|
| Annual mortality risk for 1 ug/m$^3$ in annual average sulfate concentrations | L | 0.000008 | | 25 | |
| | L-C | 0.000024 | | 25 | |
| | H-C | 0.000056 | | 25 | |
| | H | 0.000112 | | 25 | |
| Chronic bronchitis (CB) annual risk per ug/m3 change in annual average sulfate Concentrations | L | 0.00005 | 1 | 25 | |
| | C | 0.00011 | 1 | 50 | |
| | H | 0.0002 | 1 | 25 | |
| Respiratory hospital admissions (RHA) annual risk factors per 1 ug.m3 change in annual average sulfate concentrations | L | 0.000013 | | 25 | |
| | C | 0.000016 | | 50 | |
| | H | 0.000018 | | 25 | |
| Cardiac hospital admissions (CHA) annual risk per 1 ug/m3 change in annual sulfate concentrations | L | 0.00001 | | 25 | |
| | C | 0.000013 | | 50 | |
| | H | 0.000017 | | 25 | |
| Asthma symptom day (ASD) annual risk factors a 1 ug.m3 change in annual Average sulfate concentrations | L | 0.01551 | 2 | 33 | |
| | C | 0.03149 | 2 | 34 | |
| | H | 0.04653 | 2 | 33 | |
| Restricted activity day(RAD) annual risk factors given a 1 ug/m3 change in annual Average sulfate concentrations | L | 0.047 | 3 | 33 | |
| | C | 0.093 | 3 | 34 | |
| | H | 0.146 | 3 | 33 | |
| Day with lower respiratory symptom (LRS) annual risk factors per 1 ug.m3 change in Average sulfate concentrations | L | 0.066 | 3 | 25 | |
| | C | 0.164 | 3 | 50 | |
| | H | 0.23 | 3 | 25 | |

Notes: 1. For populations 25 years and older. 3. Adjustment for proportion of population with asthma (4.7%) already factored in. 3. For population aged 18 and older.

As there may be some overlap between the "broad categories of acute morbidity health effects, such as restricted activity days or days with respiratory symptoms, may include days on which effects measured in anther function occur" the EPA makes use of some adjustments to the response equations.[86] The EPA takes additional steps to compensate for the fact that the population of people most prone to each of the effects

[85] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-2.
[86] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-2, Chapter 4.

differs with the effect in question.[87] That is, some health effects of sulfates are a concern to the population as a whole, while others only affect adults. This last adjustment is made using the assumption that 83 percent of the U.S. population is 18 and older. This paper makes use of the same adjustments and assumptions used by the EPA in its damage function formation. Thus, for the purposes of the study, all respiratory hospital admissions (RHA) cases last an average of 6.8 days.[88] And all cardiac hospital admissions (CHA) last an average of 6.9 days.[89],[90] The adjustment to the morbidity equations is made prior to estimating the economic costs of the effects. The EPA's adjustment equations are as follows:

Net RADs=total RADS-(0.83 x 6.8 x RHAs) – (0.83 x 6.9 x CHAs) – (0.83 x ASDs)

Net LSRs=LRSs – (0.28 x total RADs)

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[87] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-2.
[88] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 4-34.
[89] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 4-28.

### 5. Application to the emission model results

The EPA then applies its projected emissions results from the RADM model onto a population density map based on census data. The average population density for each 80 by 80 km square is drawn from the density of the relevant region or state. In this paper, the net concentration response equations are similarly applied to an estimated population density measure in the emission deposition grid maps generated by the emission model from the section above. Each 150 by 150 receptor square has an estimated population per square kilometer from U.S. census for 1996 which, multiplied by the number of square km in a the receptor square, is used as the population number in each areas concentration response equations.[91] This along with the emission concentration results from the emission model give the total applicable incidences of each mortality and morbidity effect from the EPA study. This procedure assumes, as the EPA does, that there is no safe level of sulfate exposure and that the relationships are linear over their entire range. Thus the number of cases from each effect represents the total number of utility specific sulfur dependent cases in a given area for a given year given the emission deposition concentrations and eligible population in that receptor area.

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[90] The length of stay or duration of every effect is important in determining the cost of each effect.

[91] The average population density of the relevant state is used for each grid. Where the grid encompasses a city, a weighted average between the city's average density and the state's is used. Where the grid overlaps two or more states, a weighted average of each

### 6. The Human Health Costs of Sulfur Deposition

The economic and social costs of sulfur dioxide are measured using estimates of medical costs, work loss, increased costs for chores and care-giving, and measures of induced restrictions, reduced enjoyment of recreation activities, discomfort, inconvenience, anxiety, and inconvenience.

The cost of illness (COI) estimates used by the EPA includes both the medical costs and the work loss caused by emissions. They do not, however, "reflect the total welfare impact of adverse health effect."[92] "The full costs of an adverse health effect include financial losses such as medical expenses and lost income, plus less tangible costs such as pain and discomfort, restrictions on non-work activities and inconvenience to others."[93] To capture the full economic costs of emission effects the EPA makes use of willingness to pay measures (WTP). The WTP studies used by the EPA estimate what individuals would be willing to pay to for small changes in the risks of death. [94]

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states density is used. The relative area taken by each state in the relevant grid is used to weight the calculations. The population map is listed in Appendix H.

[92] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-2.

[93] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-2.

[94] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-2.

## 7. Monetary Valuation Estimates for Premature Mortality Risks

The EPA makes use of several studies to generate a range of WTP estimates.[95] Using the recommended ranges of VSL (morbidity) estimates, the EPA generate a range of WTP for avoided mortality estimates, modified by age. This range is given in Table 3-8.

| Table 3-8: Summary of Selected Monetary Values for Mortality Effects[96] | | | |
|---|---|---|---|
| Population Group | VSL Estimate (1994 dollars) | | |
| | Low | Central | High |
| >65 years | $1.9 million | $3.4 million | $6.8 million |
| <65 years | $2.5 million | $4.5 million | $9.0 million |
| Age Weighted Average | $2.0 million | $3.5 million | $7.1 million |
| Selected Probability Weights | 33% | 50% | 17% |

[95] A. Fisher, L.G. Chestnut, and D.M. Violette, "The Value of Reducing Risks of Death: A Note On New Evidence," Journal of Policy Analysis and Management 8(1):88-100, 1989; T.R. Miller, "Willingness to Pay Comes of Age: Will the System Survive?," Northwestern University Law Review 83, 1989, 876-907; M.L. Cropper and A.M. Freeman III, "Environmental Health Effects," Measuring the Demand for Environmental Quality," J.B. Braden and C.D. Kolstad, North-Holland, New York, 1991; W.K. Viscusi, "Fatal Tradeoffs: Public and Private Responsibilities for Risk," Oxford University Press, New York, 1992.

**8. Monetary valuation estimates for morbidity**

Where possible, the EPA made use of WTP estimates for the non-fatal health effects of sulfates identified earlier. When these estimates were not available, modified Cost of Illness (COI) estimates were used instead. These modified were adjusted to reflect WTP estimates.[97] The reason being that the COI estimates only capture medical costs and lost productivity. In the base COI estimates, the average daily wage was used as a measure of lost productivity due to illness. The number of days lost includes time "spent in hospitals, once day for each emergency room visit, and days spent in bed because of illness."[98] For the estimate of the average daily wage, the EPA made use of the 1994 median daily wage for full-time salaried workers in the United States.[99] This was determined to be around $93 a day.[100]

This wage was assumed to be "the average opportunity cost of time for employed and not-employed individuals, on the presumption that those who are not employed value their leisure or household services at a level equal to the wage they forgo in choosing not to pursue paid employment."[101] While this may overstate the earning potential of the unemployed, The EPA was of the opinion that there are offsetting factors. Since this

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[96] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-16.

[97] For the methodology see Human Health Benefits from Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, EPA, Nov 10, 1995, Chapter 5.

[98] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-17.

[99] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-18.

[100] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-16..

[101] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-18.

measure "does not reflect any productivity losses beyond the average work-day hours, (and assuming that not-employed individual who perform household, child-care, and community services beyond the usual work day hours), it was felt that the bias was reduced.[102]

The summary of selected monetary values is provided in the table 3-9 below. Note again, that each value estimation has a low (L), a central (C), and a high (H) value with selected probability weights. All values are in 1994 dollars.

**Table 3-9: Summary of Selected Monetary Values for Morbidity Effects[103]**

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |
| | Estimate per incident (1994) | | | | Type of |
| Morbidity Effect | Low | Central | High | Primary Source | Estimate[104] |
| Adult Chronic | $ 140,000 | $ 240,000 | $ 380,000 | Viscusi et al. (1991) | WTP |
| Bronchitis | | | | Krupnick and Cropper | |
| | | | | (1992) | |
| Respiratory Hospital | $ 7,000 | $ 14,000 | $ 21,000 | Graves (1994) | Adjusted |
| Admission | | | | | COI |
| Cardiac Hospital | $ 7,000 | $ 14,000 | $ 21,000 | Graves (1994) | Adjusted |
| Admission | | | | | COI |
| Restricted Activity | $ 30 | $ 60 | $ 90 | Loehman et al. (1979) | WTP & |
| Day | | | | | Adj. COI |
| Asthma Symptom | $ 13 | $ 36 | $ 58 | Rowe and Chestnut | WTP |
| Day | | | | (1986) | |
| Lower Respiratory | $ 6 | $ 11 | $ 17 | Loehman et al. (1979) | WTP |
| Symptom Day | | | | Tolley et al. (1986) | |
| Selected probability | 33% | 34% | 33% | | |
| Weights for all effects | | | | | |

[102] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-18.
[103] EPA, Human Health Benefits From Sulfate Reductions Under Title IV of the 1990 Clean Air Act Amendments, October 1997, page 5-24.
[104] WTP=Contigent valuation WTP estimate. Adjusted COI=COI x 2 to approximate WTP.

### 9. Non-health related damage equations

There is evidence that sulfur emissions, and its various products, have a detrimental economic effects besides those directly related to human health. However, the actual relationships as far as concentration effect equations have yet to be determined. The NAPAP report of 1990 list a number of effects of acidic deposition and sulfur emissions on crops, forests, lakes, streams, visibility, and wildlife. But as the relationship between sulfur emissions and effects have yet to be modeled within any level of reasonable confidence[105], the EPA and the NAPAP reports have not estimated the potential economic effects of non-health related impacts. For these reasons the issue of non-health related effects and the issue of indirect health effects are ignored in this paper. Any attempts to estimate these costs would be based solely on conjecture. There is, however, more confidence in the response relationships between health and sulfates—as noted above.

## C. Application of the EPA Concentration Effect Equations and Economic Impact per Case Estimates

The complete set of EPA concentration effect equations and costs estimates is applied to the results of the emission deposition model developed earlier in this paper. The model calculates the annual sulfate concentration levels for every 150 km by 150 km receptor on the model's grid. Each grid, depending on the region it represents, is assigned a total population depending on the population density provided by the 1996 census. From these two pieces of information the total economic impact of the sulfur's health effects on that receptor are estimated using the EPA's Concentration Effect

Equations and Economic Impact per Case Estimates. The total costs of emission from the fully estimated emission model are then summed for both the market and the cap. Note again that the estimation results are given in Appendix H. The sulfate concentration maps that form the 95% confidence interval of emission concentrations for the phase II simulation are given in Appendix I.

The range of emission concentrations which make up the 95% confidence interval of emission are run through the EPA's range of equations for Concentration Effects and economic impacts. In the table below, the Lowest effect Lowest cost (LOW) estimate is generated by using the lowest coefficients in terms of both effect and costs from the EPA's numbers.[106] The Low coefficients were designed by the EPA to predict the lower 20th percentile of health costs from sulfate emissions. The Fully Weighted (Full Weight) estimate makes use of all of the equations with their EPA assigned weights, to achieve the mid-range estimate. This range of equations—with assigned weights—is used by the EPA to estimate the middle of its estimated 60% confidence interval of the benefits of Title IV.[107] The Highest Effect and Highest Cost (High) estimate uses the highest effect and cost coefficients. In the EPA's estimates these coefficients are used to determine the

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[105] NAPAP, National Acid Rain Assessment Report (NAPAP), 1991, page 168.
[106] In other words, the LOW estimate for each concentration map provides the lowest estimated external cost associated with sulfate concentrations. This estimate uses the lowest estimate of effect in terms of who is impacted by the damage and the lowest estimate in terms of actual damage to the affected population.
[107] The EPA did not use a market in making it estimates. Instead the equations were used to estimate the benefits of reducing emissions at each plant according to title IV (as in the cap model developed here) and compared the health effects obtained against the projected emissions that would occur in the absence of Title IV. The EPA found the mid-range estimate to be around $40 billion in savings a year.

80th percentile of costs.[108] That is, there is a projected 80% probability that the economic health affects of sulfates will at or below the High cost estimate.

## XIII. The Results

### A. Net External Cost Effect of Phase II Market Relative to Phase II as a Cap

The following table present the results of the applying the results of the estimated emission/sulfate concentration model to the EPA's external damage function for sulfate concentrations. The results of the model and estimation procedure are not unexpected given the predicted movement of net allowance trades and underlying assumptions regarding weather patterns and sulfate deposition rates in North America. The model demonstrates that, given FGD is the primary long-term phase II compliance option, the net movement of allowances will cause an increase in external costs associated with sulfate concentrations relative to a situation where Title IV emission goals were applied as a cap on emissions. This result is consistent over the entire 95% confidence range of the sulfate concentration results provided by the emission model for every set of EPA external cost estimation equations.

Table 3-10 presents the central results from the mid-range concentration (the center range estimate of the concentration model) map applied to the EPA's concentration effect equations. The results of the upper and lower concentrations are given in Appendix I. In all cases the net trades of the allowance market cause a substantial net increase in external costs relative to external costs where phase II emissions goals (indicated by total annual allowance allocations) are applied as a cap.

[108] That is to say, the EPA estimates that 80% of the economic costs from sulfate

**Table 3-10: Central Estimate Concentration Level (mid-range of 95% confidence interval)**
Damage Function Estimates for Sulfate Concentration Levels at Ground Level
Using EPA's Human Health Benefits From Sulfate Reductions Under Title IV
Of the Clean Air Act Amendments Report, Nov 10, 1995

| EPA Equations Used | Total External Cost Estimate MKT ($millions) | Total External Cost Estimate CAP ($millions) | Total External Cost Estimate Difference ($millions) |
|---|---|---|---|
| LOW | $40,993 | $38,965 | $2,027 |
| Full Weight | $371,387 | $353,019 | $18,368 |
| HIGH | $1,528,184 | $1,452,605 | $75,579 |

In all cases, the effect of using the market instead of the cap causes an increase in external costs due to sulfate concentrations. These increases in costs are significant--ranging from around $2 billion to around $75.5 billion in annual costs. As can be seen in the table, the cause for the range in values for cost estimates is the wide range of coefficients used by the EPA in setting ups its concentration effect equations. The wide range of effects at the 60% confidence interval used by the EPA in setting up the concentration effect numbers is some indication of the uncertainty involved in measuring the health and mortality effects of pollutants. The sulfate concentration results themselves are, however, quite tight over the 95% confidence interval due to the high level of correlation between the estimated emission deposition model and actual historic emission patterns.[109]

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emission are below the amount estimated by the HH coefficients.

[109] As noted earlier in this chapter, Appendix H presents the correlation results model's parameter settings. Appendix I shows the results from the upper and lower bound emission deposition estimates.

As noted the net effects of the simulated phase II allowance market are not a surprise given the model's estimates of net allowance sales in the various regions in the sections above. The net pattern, regardless of interest rate or elasticity assumption, shows that, on average, the NE, MA, and SA regions along the eastern half of the United States are potential suppliers of allowances in a Phase II market. As suggested in Chapter 1, such a market induced movement of allowances is expected to cause the external costs of a pollution to increase, relative to the results of a cap with a similar emission goal. While the effects of the market on total external costs are clear and consistent, it still remains to be seen if the total net cost effect of the market under Phase II is negative. Whether or the trades made possible by the market cause a net loss is dependent on how big the negative impact of the trades are relative to the cost savings afforded by the market relative to the cap, which will be examined in the next section.

**B. Net Effect of Trades on Total Costs of the Market Relative to the Cap**

In order to measure the net welfare effect of the market versus the cap, it is necessary to compare the net difference in social costs associated with both the cap and the market. As outlined in chapter 1, where there are locationally dependent external costs, there is the possibility that a market for allowances can cause a net loss in welfare relative to a cap with the same total emission goal. While a functioning market for allowances will lower the costs of abatement, it may actually cause a welfare loss. This loss would occur if the allowance trades were such that the external costs of emissions increased more than the market saved in abatement costs over an equivalent cap.[110] The

[110] Equivalent in terms of the total emission goal under Phase II of Title IV of the Clean Air Act of 1990.

cost savings of using a market over the cap are potentially very large, as discussed earlier in this chapter. Based on EPA Estimates, abatement cost savings can vary anywhere from \$360 million to \$1.6 billion a year. The central estimate of this model ranges from \$936 million to \$1.16 billion in annual savings from using the market instead of the cap to reach Title IV phase II emission goals. The range of cost savings in summarized again in table 3-11 below.

**Table 3-11**

| Simulation Cost Savings of the Allowance Market for Various Costs of Capital | |
|---|---|
| Cost of Capital | e=.03 (millions) |
| 0.16 | \$1,600 |
| 0.12 | \$1,144 |
| 0.11 | \$1,030 |
| 0.1 | \$917 |
| 0.05 | \$350 |

While the predicted annual abatement cost savings are substantial, the potential economic losses from changes in external costs are substantial as well. These losses were outlined in the previous section for the 95% confidence interval for sulfate concentrations and the EPA's 60% confidence interval on external costs. The following table (3-12) tabulates the net cost effect of the market for allowances versus the equivalent cap,[111] where the net effect is defined as the abatement cost savings of the market plus the net external effect of a switch from a cap to the market. The predicted direction of net trades and the east-west transmission of emission has an negative impact on the projected cost saving benefits of the Title IV market. Even in the best case scenario, the results shows a serious reduction in the net cost savings of the market over the cap—so much so that the net effect of the market is an annual loss of $427 million. In the worst case, the use of a market causes a dramatic net loss from using the market due to external costs of trades heavily outweighing the cost savings benefits of same—with net losses reaching 73.9 billion a year.

**Table 3-12**
**Cost Savings Due to Trades Net of Central Emission Estimate's Net External Costs**

| Cost Of Capital | EPA's External Cost | e=.03 (millions) |
|---|---|---|
| 0.16 | HIGH | ($73,979) |
| | Full Weight | ($16,768) |
| | LOW | ($427) |
| 0.11 | HIGH | ($74,549) |
| | Full Weight | ($17,338) |
| | LOW | ($997) |
| 0.05 | HIGH | ($75,229) |
| | Full Weight | ($18,018) |
| | LOW | ($1,677) |

The central estimate of net costs of the market in Table (3-12) is given by the cost of capital setting of .11. At this setting, the EPA's 60% confidence interval for external costs estimate an annual net loss of $997 million to $74.5 billion. The fully weighted external cost estimate[112] (denoted by the Full Weight row) indicates a net loss from using the market averaging $17 billion in annual losses. Therefore, even in the best case scenario (least effect caused by sulfates and the greatest cost savings predicted in the model), the use of a market to achieve Title IV's phase II emission goals are very likely to cause a net loss relative to using a cap.

The results of the model do indicate that the effect of Title IV will tend towards being absolutely negative relative to a cap with the same emission goal. Even in the best

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[111] Again, the cap and the market are equivalent in emission goals.
[112] As noted earlier in this chapter, the EPA's full weight equations represent the central best estimate of the concentration response functions.

case scenario, the model indicates that there is a significant potential for the Title IV market to cause significant net welfare loss. The model shows that there may be some need to be concerned about the directions of allowance trades under Title IV. At every parameter setting used in the model, a significant portion of the predicted external losses due to trade exceeds the costs savings predicted by the model. The table above is an illustration of this fact. In addition, the upper end losses due to trade are much larger than the potential gains of cost savings predicted by the model. The best case scenario (assuming the highest cost savings and the lower 60% bound loss estimate) has net loss of $427 million a year. The worst case scenario (assuming the lowest cost savings from trade and the highest 60% bound loss estimate) has a net welfare loss of $75 billion a year.

## XIV. Conclusion

The results of this study underscore the potential problems with using a market for emission allowances where external costs are location dependent. As outlined in chapter 1, the cost savings which attract the policy maker to the use of a market may be overwhelmed by increases in external costs caused by the allowances trades. This is the potential case with the Title IV market. The model indicates a strong possibility, based on the EPA's estimates of abatement and external costs, that the use of a market—rather than a cap—will cause a loss of net welfare. This is not to say that markets for emission rights are not useful tools in effectively and efficiently combating pollution. Nor does it say that Title IV will definitely cause a net welfare loss. There is the possibility that the net effect will be a wash—with little actual change in net welfare. However, the potential losses are very substantial. If the direction of net trades proves to reduce external costs under title IV, the market will prove to have a very positive effect on net welfare relative to a cap.[113] Not only would the market reduced the costs of abatement, as it does in the scenarios investigated here, but it would have resulted in a net welfare gain in terms of reduced external costs as well. However, it is clear that caution is required in setting up such markets where the pollutants in question have localized or location dependent—as opposed to ambient—effects.

Where effects are dependent on location of sources, it should prove beneficial to reduce the size of the market area, to eliminate large shifts in emission locations—at least until the likely direction of trades can determined. If, for example, Illinois and Indiana were defined as a market for allowances, and no trades could occur outside of this area, the emissions coming from the two states would be reduced to the level set by the cap. Yet some abatement costs savings would be gained from trades within the two-state market. And by limiting the market, policy makers would be assured that states to the east of Indiana and Illinois would be no worse off under the market than they are under the cap.[114] Another option would be to limit the direction of trades. If allowances could only be sold to the east[115] of a controlling source, any trade would make the market as a whole at least as well off as the situation before the trade.

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[113] This is outlined in chapter 1.

[114] Of course, if Indiana proved to be the net seller, and Illinois, the net buyer in such a market, there could be some loss in the reduced market from the trade. The net effect on the rest of the eastern United States would, however, be reduced relative to a larger market where both Indiana and Illinois are net buyers of allowances.

[115] Allowing only easterly sales moves allowances downwind of the original sources. The further east the allowances when used, the less emissions make landfall (assuming easterly winds).

In addition, some pollutants are better suited for use in large markets. The less location-dependent the external costs associated with a pollutant are, the more suitable they would be for a market for emission allowances as a means of achieving emission goals. Greenhouse gases and CFC are a good example of emissions without localized effects. Presumably both of these agents effects are based on the ambient levels in the atmosphere. Thus, thus the location of reductions is not as important as the level of reductions on a world-wide scale. Under such a situation, the potential benefits of using market for emissions to achieve an emission goal are very large in terms of abatement costs savings and the potential loss in changes in external costs either negligible or non-existent. Again, the more localized the effect, the more the market needs to be scrutinized for welfare effects.

Nitrous Oxide emissions are an example of a pollutant with a very localized effect. Nitrous oxide emissions are not only a precursor of acid rain, but also a major component of ozone pollution at ground level.[116] As such, ozone is not a good candidate for regional emission allowance markets. Local markets may work, but anything larger in scope risks the welfare losses seen in this study with regards to Title IV.

The use of markets for emission allowances is a potentially powerful policy tool for achieving emission goals. But as with any policy tool, the decision of when and how to use it determines its effectiveness in achieving the goals of a policy. If the goal is to reduce the external costs of a pollutant in a more cost-effective manner than a cap, the market will prove useful where the effect of the pollutant is based on ambient, rather than

[116] Ozone at ground level is a pollutant. Ozone is a very reactive gas with effects that have been compared to Mustard Gas as far as effects on lung tissue. The conversion of nitrous oxides and other volatile organic compounds into ozone tends to be a very localized phenomena downwind of emission sources.

localized effects. In cases where external costs are based on the location of sources, care must be used in defining and managing the market to insure that the goal of improving welfare is not lost.

## CHAPTER 4

## THE POTENTIAL WELFARE EFFECT OF USING REGIONAL, RATHER THAN A NATIONAL, ALLOWANCE MARKET FOR TITLE IV IN THE CONTEXT OF LOCATION-SOURCE DEPENDENT DAMAGE FUNCTIONS FOR SO2 EMISSIONS

### I. Introduction

The focus of chapter 4 is the examination of the possibility that a set of regional allowance markets could be used to improve the net cost effect of the national allowance market as set up under phase II of the clean air act of 1990. The theoretical basis for this possibility is seen in the general theory discussion that occurs in chapter 1. Breaking a larger market up into smaller markets based on relative external costs can reduce the size of the externality effect of allowance relocations in a market. This would be done to reduce the disparity in marginal external costs among the participants in a given allowance market. Therefore any trade in a given market would have minimal impact on total external costs. Of course, reduced trade opportunities would also tend to reduce the abatement cost savings of a market for allowances if abatement costs are also somewhat dependent on location, so there are tradeoffs that need to be measured.

This paper will examine the potential abatement and external cost effect of using more region-specific binding allowances markets as a potential fix to the welfare losses estimated by the simulation in chapter 3. It is expected that a number of smaller geographically compact regional markets will improve the net results of the Title IV emission target relative to the results of the simulated national market system of chapter 3.

## II. Methodology and Outline of the Body of Chapter 4

Part V outlines the national and the proposed regional allowance markets to be faced by the each utility boiler in the simulation model described in chapter 3. As in chapter 3, the units participate in two markets—an allowance market and an output market. However, each economic agent will be restricted, by location of the agent, in potential allowance trading partners.

Part VI presents the results from each binding Phase II regional market simulation using the model and real world data described in section V of Chapter 3. The model's set of calculated equilibrium prices for a number of demand elasticity and interest rate settings are presented, along with the after-market-trades allocation of allowances. In addition, the compliance cost savings allowed with trades for each regional market are also presented. These results are compared to the national market simulation results from chapter 3 in terms of market prices and re-allocation of allowances.

Part VII applies the emission results to the emission deposition model and EPA sulfate concentration equations defined in chapter 3. Part VII presents estimates of the total external costs found under the regional market and compares them to the results from the national market outlined in chapter 3. Part VII then presents the potential net cost estimates of the regional markets for phase II allowances relative to the national market results presented in chapter 3. The net cost of the regionally defined phase II markets relative to phase II as a cap is presented for a range of assumptions regarding the emission and economic model.

Part VIII presents the summary of the paper and the policy implications of using regional markets rather than a national market for emission allowances where external costs of emissions are dependent on the relative location of the sources of emissions.

## III. Defining the National and Regional Markets

### A. The National Market

The national market is defined by all the title IV affected boilers, as identified by the EPA. All potential trades from all plants and their boilers are allowed within the lower 48 states. This is the market defined and used in the simulation described in chapter 3 of this paper.

### B. The Regional Markets

The purpose of chapter 3 is to study the potential net welfare effect of a number of regional allowance markets rather than a national market under title IV. To this end, a number of regional markets are set up to compare with the national market described above. Each proposed regional market is defined roughly by grouping states by geographic proximity and association with the specific geographic regions described in chapter 3.[1] As such, the regional markets are set up arbitrarily with the intent of reducing the negative impact of emission source relocation through allowance trades—as

[1] The geographic regions used in Chapter 3, and as the bases for regional markets in this chapter, are those used by the EPA.

demonstrated in chapter 3. These are not the only possible market designations, nor does this paper propose that the markets defined here are the best. However, it is expected that the groupings will improve the net cost of the market relative to the national market as set up under title IV. The source of this improvement in net costs is expected to come from reduced external costs associated with trades relative to potential trades in the national market set up by title IV. Cost savings from using the market rather than a cap are expected to decrease, but not by enough to offset the benefits gained in external cost reductions.

The North Atlantic Market (NAM) is defined as the states which make up the North East (NE) and Mid-Atlantic (MA) regions used in chapter 3: Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, New Jersey, and Pennsylvania. These north and easternmost states that are included in NAM represents were identified as potential suppliers of allowances in chapter 3 in the national allowances market simulation.[2] Grouping these states into a single market is expected to reduce the negative impact of allowance trades due to the fact that the regions to the west and south of the North Atlantic Market were identified as potential net buyers of allowances in a national market.[3] Equilibrium allowance prices are expected to be lower in this region than the average due to the lower than average FGD costs predicted in this area.

The South Atlantic Market (SAM) is defined as the states which make up the South Atlantic (SA) region from chapter 3: Delaware, Maryland, DC, Virginia, West

[2] These states were potential suppliers of allowances in a national allowance market because the estimated relative abatement costs in these states was lower than the average of the nation as a whole.

Virginia, North Carolina, South Carolina, Georgia, and Florida. The South Atlantic Market is the southeastern most market and another potential net supplier of allowances in a national market, as indicated in chapter 3. As in the North Atlantic Market (NAM), the restriction of allowance trades to within the market is expected to improve net external costs relative to the national market results by reducing net allowance trades to the west of the SA region. As in NAM, equilibrium allowance prices are expected to be lower in this region than the average due to the lower than average FGD costs predicted in this area.

The Central Market (CM) is defined by the states in the Eastern North Central (ENC) and Pocohonos South Central (PSC) regions from Chapter 3: Ohio, Indiana, Illinois, Michigan, Wisconsin, Kentucky, Tennessee, Alabama, and Mississippi. This region sits just west of the region defined as NAM and along the northern portion of SAM. The ENC region was a potential supplier of allowances, though a relatively small source given the volume of allowances assigned to the region, in the national market predicted by chapter 3. The PSC region was identified as a relatively small net buyer of allowances in chapter 3. Combining these two regions into a single market is expected to have a small impact on total net costs relative to the national market prediction. While the volume of allowances assigned to these regions is substantial, the net trading activity predicted in the ENC and PSC region indicates only a small net external cost effects from the regrouping. Average abatement costs in this market, and thus the expected equilibrium allowance price in the market, should be around the average generated by this regional market system.

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[3] As noted in chapter 3, prevalent weather patterns are assumed to move emissions in a north easterly direction from point sources.

The West Central Market (WSM) is defined by the West North Central (WNC) and West South Central (WSC) regions defined in chapter 3: Minnesota, Iowa, Missouri, North Dakota, South Dakota, Nebraska, Kansas, Arkansas, Louisiana, Oklahoma, and Texas. This market is made up of a strip of states to the west of CM and SAM. It is a large market, geographically—though not the largest in assigned allowance volume. WSM is made up of two regions identified as potential buyers of allowances. This is because the states in these regions are low-sulfur states. This means that FGD technology will be less efficient, on a ton per ton removal basis, than where higher sulfur is in use. Thus, on average, these regions will have abatement costs higher than the national average. As this market is to the west of potential sellers, the isolation of this region into a single market is expected to reduce potential external costs relative to national market as defined under Title IV. At the same time, the costs of compliance with title IV are expected to rise relative to the national market equilibrium. Thus, the equilibrium market price for allowances in WSM are expected to be higher than the national average.

The net cost effect of the use of WSM relative to a national market is assumed to be positive given the volume of buying predicted in the national market—despite the projected costs increases in achieving Title IV emission requirements under the regional market setting.

The Western Market (WM) is made up of the Mountain (MNT) and Pacific (PAC) regions defined in chapter 3: Montana, Idaho, Wyoming, Colorado, New Mexico, Arizona, Utah, Nevada, Washington, Oregon, and California.[4] The Mountain region was

[4] Alaska and Hawaii, both exclusively natural gas and oil burning states, are not included in the markets.

identified as a potential buyer for allowances under a national market. The Pacific region, on the other hand was predicted to be a net supplier of allowances under a national market due to its early reductions in emission levels. Both regions are relatively low sulfur states relative to the national average. The potential supply offered by the Pacific region should offset the demand of the Mountain region in the WM and keep prices around the new average for regional markets. Due to the potential national market behavior of the utilities in the region, the limiting of trades in this region is expected to cancel each other out fairly effectively in terms of net external costs relative to the national market model results from chapter 3.

## IV. Effect of Regional Markets on Allowance Prices, Allowance Allocation, and Compliance Costs Relative to the National Market

### A. Price

The equilibrium price results of the national allowance market simulations from chapter 3 is given again in Table 4-1 below for comparison to the results of the regional market simulation. Table 4-2 shows the model's estimates of the each regional market's equilibrium allowance price.

**Table 4-1**

Simulation Equilibrium Prices for Allowances for Various Output Demand Elasticities and Cost of Capital

| R | e=.01 | E=.03 | E=.06 | e=.09 |
|---|---|---|---|---|
| 0.16 | 276 | 276 | 276 | 277 |
| .14 | 245 | 245 | 245 | 245 |
| 0.12 | 220 | 221 | 221 | 221 |
| 0.11 | 207 | 207 | 207 | 207 |
| 0.1 | 194 | 194 | 194 | 194 |
| .08 | 170 | 170 | 170 | 170 |
| 0.05 | 125 | 125 | 125 | 125 |

The effects of regional markets on regional equilibrium allowance prices also match expectations in direction and magnitude, as expressed in the sections above. Table 4-5 shows that the shift to the suggested regional market structure would cause prices to vary with the region in question, but prices—on average—would increase. Given that both NE and MA are predicted to be suppliers in the national market simulation, it was expected that the North Atlantic Market (made up of both regions) would have lower than the new market average prices. As indicated in table 4-5 above, it does. Not only are the prices lower than the new market average, they are lower than the equilibrium prices found in the national market equilibrium for corresponding elasticities and interest rates on capital investment.

The South Atlantic Market generates equilibrium prices a little below the average found in the national market, which is not unexpected given the prediction that it was a potential supplier in the national model results. The Central market, made up of ENC and PSC regions, generates a set of equilibrium prices that are higher than the equilibrium prices found in the national market. This too is expected given the potential net demand demonstrated by the PSC region in the national market model—which is only offset a little by the ENC slight net supplier status in the national market simulation.

| Table 4-2: Equilibrium Prices Estimates in Regional Allowance Market Given Phase II Allowances Allocations | | |
|---|---|---|
| Regional Market | Interest Rate | Elasticity 0.03 |
| North Atlantic Market | 0.16 | 203 |
| | 0.12 | 171 |
| | 0.11 | 163 |
| | 0.1 | 155 |
| | 0.05 | 102 |
| South Atlantic Market | 0.16 | 235 |
| | 0.12 | 191 |
| | 0.11 | 180 |
| | 0.1 | 169 |
| | 0.05 | 114 |
| Central Market | 0.16 | 302 |
| | 0.12 | 240 |
| | 0.11 | 225 |
| | 0.1 | 210 |
| | 0.05 | 136 |
| West Central Market | 0.16 | 365 |
| | 0.12 | 286 |
| | 0.11 | 266 |
| | 0.1 | 246 |
| | 0.05 | 147 |
| Western Market | 0.16 | 251 |
| | 0.12 | 212 |
| | 0.11 | 200 |
| | 0.1 | 187 |
| | 0.05 | 122 |

The West Central Market (WNC and WSC) generates equilibrium market prices much higher than those predicted in the national allowance market simulation. Given the strong potential for both regions to be net demanders of allowances in the national market, this is not surprising. The Western Market (MNT and Pacific) generates equilibrium prices right around those predicted in the national market simulation, as expected.

**B. Allowance Allocations**

Table 4-3 shows the regional allocations of allowances under the cap and under the market given the regional markets for allowances as defined above. Note that the table lists emissions by their sub-regions, as defined in chapter 3. Table 4-3 shows the central estimate of the model. There is limited sensitivity to interest rates in allowance distribution. A full set of tables is given in the Appendix K.

Table 4-3
Phase II Regional Market and Cap Emission Totals by Sub-Region
Central Estimate, Regional Markets for Allowances
Emission results given in 1000's of tons

| | e=.03 Emissions CAP | Emissions MKT | Emissions Difference |
|---|---|---|---|
| NE | 263 | 226 | 36 |
| MA | 883 | 930 | -47 |
| ENC | 2,158 | 2,016 | 142 |
| WNC | 781 | 758 | 23 |
| SA | 2,003 | 2,057 | -55 |
| PSC | 1,016 | 1,073 | -56 |
| WSC | 787 | 933 | -146 |
| Mountain | 548 | 627 | -80 |
| Pacific | 46 | 20 | 25 |
| | 8,484 | 8,641 | -158 |

The effect of the proposed regional markets on total and regional emissions, relative to the national market, is not surprising either. Total emissions under all the regional markets are lower than under the national market structure due to reduced trading opportunities. Note that in all three sets of results, the difference between the emissions under the cap and under the market have been reduced relative to the differences seen in the national market results shown in Chapter 3, tables 3-2, 3-3, and 3-4. The reason for this is straight forward—the regionally defined markets reduce the trading opportunities available to the economic agents relative to the national market for allowances. Trading within a geographic market will also allow differences in net allowances within the regions that make up a given market. The overall effect is, however, a reduction in total emissions relative to the national markets equilibrium results.

As evidenced in the chapter 3 results, some regions will see higher emissions under the market rather than the cap. This is due to the fact that units, which have already reduced their emissions prior to 1990, can sell their excess allowances on the market—thus increasing total emissions relative to the case where the agents are forced to treat the allowances as non-marketable permits (a cap). The use of regionally defined markets limits this effect, however. What is more, net long-distance trades are eliminated except with defined regional markets. The net impact of these effects are examined in the few sections.

## C. Compliance Costs

The effect of the use of regional, rather than a national market, on estimated abatement costs is not insubstantial. The compliance cost savings summary is given in table 4-4 below. Cost savings range from $318 million to $1.53 billion a year. Compared with the potential range of cost savings predicted in the national market—from $345 million to over $1.64 billion a year—the regional markets reduce the potential costs savings of the market over the cap. The use of regional markets reduces the high end of cost savings by an estimated $95 million a year. At the lower range of cost savings estimates the use of regional markets reduces compliance cost savings by $27 million a year. The difference in cost savings between the regional markets model and the national market for allowance simulation is given in table 4-5 below.

| Table 4-4 | |
|---|---|
| Regional Market Simulation Cost Savings of the Regional Allowance Market for Various Costs of Capital | |
| Cost of Capital | e=.03 (millions) |
| 0.16 | $1,505 |
| 0.12 | $1,083 |
| 0.11 | $974 |
| 0.1 | $865 |
| 0.05 | $323 |

| Table 4-5 | |
|---|---|
| Effect of Using the Regional Allowance Markets On Compliance Costs Relative to the Compliance Costs Under the National Market Simulation (Brackets denote negative numbers) | |
| Cost of Capital | e=.03 (millions) |
| 0.16 | ($95) |
| 0.12 | ($61) |
| 0.11 | ($56) |
| 0.1 | ($52) |
| 0.05 | ($27) |

## V. Net Cost Effect of the Market Versus the Cap: Comparing the Regional to the National Market for Allowances

Using the emission deposition model developed in chapter 3 and the EPA's official estimates of external cost functions for sulfates, this section presents the estimates of the net effects of using the market for allowances, rather than a cap, in the case of the regionally limited market system defined above.

### A. The Net External Cost Effects of the Regional Allowance Markets Relative to the Cap

Table 4-6 shows the central estimate results of the regional market simulation model applied to the emission-deposition and concentration models outlined above. The upper and lower bound estimate are given in the Appendix K.

As in the national market model results, the regional markets shows the strong probability that allowance trades within the markets cause external costs to increase relative to initial allowance allocations. As noted earlier, the relative costs of emissions, given each regions plant characteristics, seem to indicate that abatement cost saving trades will cause some movement from west to east[5] within a national market. In the regional model, this effect is muted, relative to the national market, but some movement still occurs, though within a smaller geographic space. In addition, the fact that allowances can be traded from already clean plants[6] to dirty plants within the same region can cause total emissions to increase. This results in the possibility of some loss, even in

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[6] Plants which have received bonus allowances, for example.

the regional market setting, though such losses are smaller than those found under the national market at every setting.

| **Table 4-6** | | | | | | |
|---|---|---|---|---|---|---|
| Damage Function Estimates for Sulfate Concentration Levels at Ground Level Using EPA's Human Health Benefits From Sulfate Reductions Under Title IV Of the Clean Air Act Amendments Report, Nov 10, 1995 Mid-Range Sulfate Deposition Concentration (Mid-Range of 95% confidence interval) | | | | | | |
| EPA Equations Used | Total External Cost Estimate MKT ($millions) | | Total External Cost Estimate CAP ($millions) | | Total External Cost Estimate Difference ($millions) | |
| Low Effect Equations | $ | 40,347 | $ | 38,965 | $ | 1,382 |
| Fully Weighted Effect Equations | $ | 365,537 | $ | 353,019 | $ | 12,518 |
| High Effect Equations | $ | 1,504,113 | $ | 1,452,605 | $ | 51,508 |

The regional market simulation predicts an increase in external costs from allowance trades to range from $1.4 to $51.5 billion a year relative to the allowance allocations applied as a cap. The mid-run, fully weighted estimate indicates a loss of around $12.5 billion a year—assuming all trade possibilities within each region are taken advantage of. While substantial, these increases in external costs are significantly lower than the external cost effects predicted by the national simulation model in chapter 3. The national market model estimated an increase in external costs ranging from $2 to $75.6 billion a year relative to title IV applied as a cap. The national market's mid-range external cost estimates indicated an annual loss of $18.3 billion a year. A summary of the differences in the external costs estimates of the national and regional allowance market models is given in Table 4-7 below.

| Table 4-7 | |
|---|---|
| External Costs Effect Of Regional Markets Relative to the National Market Model | |
| EPA<br>Sulfate Concentration<br>Equations | Reduction in<br>Annual<br>External Costs<br>in Millions |
| Low Effect<br>Equations | $ 645 |
| Fully Weighted Effect<br>Effect Equations | $ 5,850 |
| High Effect<br>Equations | $ 24,071 |

## B. Net Cost Effect of the Regional Market Relative to the Cap

The net cost effect (abatement cost and external cost effect) of the regional market for allowances relative to a cap is given in table 4-8 below. This table was created by adding the compliance cost savings of the regional market to the net external cost of using the regional market rather than the cap. The regional allowance market simulation estimates net costs ranging from a loss of $51.1 billion a year to a gain of $148 million a year in net cost savings.

While trade opportunities are reduced, the negative impact of many trades is abated by an even greater amount relative to the national market simulation results seen in chapter 3. The net result is an improvement in potential net cost results from the regional rather than the national market—as predicted. The mid-range estimate of annual losses is around $11.5 billion a year compared to the $17 billion a year estimated under the national allowance market simulation. It is assumed that other regional designation of markets, or limitations of the physical directions of trades, could improve on the gains of the regional market idea relative to the national market for allowances.

| Table 4-8 | | |
|---|---|---|
| Simulation's Estimated Net Cost Effect of Proposed Regional Market Vs. The Cap: Cost Savings Due to Trades Net of Net External Costs | | |
| Cost Of Capital | EPA's External Cost | e=.03 millions |
| 0.16 | High | ($50,003) |
| | Full Weight | ($11,013) |
| | Low | $123 |
| 0.11 | High | ($50,534) |
| | Full Weight | ($11,544) |
| | Low | ($408) |
| 0.05 | High | ($51,186) |
| | Full Weight | ($12,196) |
| | Low | ($1,059) |

Table 4-9 below shows the direct comparison of the regional and the national market results. Note that at every setting of the simulation models in terms of interest rates and output demand elasticities, the regional market provides a greater net cost benefit than the national market for allowances where all possible trades are made. The potential net cost benefits of the regional allowance markets over the national allowance market ranges from $550 million to $24 billion a year in the simulation results. The mid-range estimates indicates that the proposed regional market could improve on the title IV national market around $5.7 to $5.8 billion a year in net cost savings.

| Table 4-9 | | |
|---|---|---|
| Simulated Net Gains for the Use of the Regional Rather than the National Allowance Market Structure | | |
| Cost Of Capital | EPA's External Cost | e=.03 Millions |
| 0.16 | High | $23,976 |
| | Full Weight | $5,755 |
| | Low | $550 |
| 0.11 | High | $24,015 |
| | Full Weight | $5,794 |
| | Low | $589 |
| 0.05 | High | $24,043 |
| | Full Weight | $5,822 |
| | Low | $618 |

## VI. Conclusion: Defining Regional Allowance Markets Can Reduce the External Cost Effect of Title IV Relative to a National Sulfur Dioxide Allowance Market, Assuming Location Dependent External Costs of Sulfur Dioxide Emissions

Chapter 3 indicates the possibility that the binding Phase II national allowance market may decrease total welfare relative to a Phase II compliant cap. The source of this loss is the potential external cost affect of allowance trades under a binding phase II market. From chapter 1, this indicates that there is a disparity in the external cost among the units involved in the Phase II allowance market which is greater than the disparity in abatement costs. Under this circumstance, the external cost effects of trades can be larger than the abatement cost effect of a given set of trades—even if total emissions remains the same before and after trades.

As indicated in chapter 1, the less disparity among the external costs of units, the smaller the external cost effect of any allowance trades among the units. This suggests a possible efficiency improving measure to use when the external cost effect of an allowance market threaten to neutralize or overwhelm the abatement cost effect of allowance trades. If the disparities in the external cost among the units allowed to trade in a market are reduced, the external cost effect of trades in the market will also be reduced.

There are two means of reducing the disparity in external costs among trading units in a given market that come immediately to mind. The first method, forbidding allowance trades to the west (upwind) of the supplying unit, is one that has already been proposed by several state environmental protection agencies, notably the New York EPA.

Units would only be able to trade allowances along the same or east of their own longitude. In some areas—but not all—this requirement would reduce the external cost effect of emissions. Along the East Cost, this requirement would reduce the external cost of allowance trades since trading east causes more emissions to hit the ocean and have minimal measurable effect. This same requirement among western and mid-western states may not reduce external cost effects, however. A California unit that sold allowances to a Ohio unit would still increase external costs due to the fact that the Ohio unit's emissions affect the east cost, which has higher population concentrations than the western states within reach of California emissions.

The second, and perhaps more practical, method of reducing the disparity among the external costs of trading firms, is to reduce the distance or the region within which a unit can trade allowances. Properly defined, regional markets would only allow trades among unit with similar external cost of sulfur dioxide emissions. A market limited to the state of Ohio, for example, would only allow Ohio units to trade allowances. Given the range of emissions and weather patterns, emissions from all Ohio units are more similar in external cost impact than units in Maine. Given the concepts outlined in chapter 1, trades within the Ohio market would have a smaller external cost impact than any trades that may involve Ohio buying allowances from a state to the East (where the external cost of a unit is lower due to a significant portion of emissions hitting the ocean instead of population centers).

This paper explores the possibility that by breaking the national sulfur dioxide allowance market into a number of geographically compact markets will reduce the disparity in external costs among units in each market and thereby reduce the external cost effects of allowance trades relative to the national market simulation. As this paper's results indicate, such a reorganization of the allowance market will indeed reduce the possible external costs effects of the units that participate in a given market, thereby reducing the net external cost impact of any sum of trades. The cause of this effect is the location dependence of external costs associated with sulfur dioxide emissions.

In the case where the market are defined such that the external cost of emissions are identical among participating units, there would be nothing but benefits from reducing the costs of compliance. The external cost effect would be strictly equal to zero and the abatement cost affect, if any, would cause the market to improve welfare relative to a cap. Where the potential external cost effects are positive (if, for example, allowance trades went west to east, instead of east to west), the use of the market is even more pareto improving relative to the cap. In the case demonstrated here, however, market restrictions of some kind may be in order reduce the negative external cost effects of allowance trades in the national allowance market.

# CHAPTER 5

## CONCLUSION AND POLICY IMPLICATIONS OF LOCATION AND SOURCE DEPENDENT EXTERNAL COSTS

Chapter 1 identified two effects a market for allowances has on welfare relative to a single emission rule cap in achieving the same emission goal—the abatement cost effect and the external cost effect. The existence of both effects indicates that the net welfare effect of using a market rather than a cap on emissions is not strictly pareto improving nor can the benefits be measured strictly in terms of abatement cost savings. Unfortunately, in the public policy arena it has been the promise of substantial abatement cost savings which has been the central, if not only, focus of promoting marketable permit systems as an alternative to traditional command and control emission caps as a means of pollution regulatory policy. Due to this, a market for sulfur dioxide emissions under Title IV was approved in 1990, and markets for emissions have been proposed with regard to ground-level ozone precursors ($NO_x$), green house gases (CFCs and $CO_2$), and ozone layer reactants (CFCs).

Title IV of the 1990 Clean Air Act, for example, sets up the sulfur dioxide allowance market among electric power producers. The benefits of this market have consistently been portrayed in terms of abatement cost savings relative to the emission restrictions applied as a cap. However, as examined in chapter 3, the external costs generated by sulfur dioxide emissions are affected by the location of the units that generate them. This is because external costs are based on the relative locations of the sources of emissions relative to receptor areas. Given the predicted reallocation of allowances which increases sulfur dioxide levels in populated areas, the external cost effect of the future binding allowance market may cause a net welfare loss relative to the initial allowance allocations of the Title IV emission standards.

While Chapter 3's results are not definitive proof that the Title IV market will cause a net loss in terms of averted costs relative to a cap, they do indicate some causes for concern. The possibility that the external effects of sulfur dioxide allowance trades in a national allowance market can offset, or even overwhelm, the cost savings provided by the market should be accounted for when calculating the total benefits of using a market rather than a cap to achieve an emission goal. Any such benefit calculations must include an external cost effect in addition to the abatement cost affect typically focused on when discussing the benefits of incentive based emission regulation. Where this external cost affect in non-zero, it needs to be included in any benefit measure.

The results of this study underscore the potential problems with using a market for emission allowances where external costs are location dependent. This is not to say that markets for emission rights are not useful tools in effectively and efficiently combating pollution. Nor does it say that Title IV will definitely cause a net welfare loss. There is the possibility that the net effect will be a wash—with little actual change in net welfare. However, the potential losses are very substantial and it is clear that caution is required in setting up such markets where the pollutants in question have localized or location dependent—as opposed to ambient—effects.

Chapter 1 indicates that it is the differences in firm-specific external cost that drives the magnitude of the external cost effects of allowance reallocations under a market. The greater the difference between the external cost effects, the greater the external cost effect of trades—either positive or negative. This indicates that reducing the disparity in external cost among participants in an allowance market will reduce the external cost effect of trades in a market. Where effects are dependent on location of sources, it therefore should prove beneficial to reduce the size of the market area, to eliminate large shifts in emission locations—at least until the likely direction of trades can determined. This possibility is explored in chapter 4 with regard to the Title IV market for sulfur dioxide emission allowances. In that chapter, the national market for allowances in broken up into a number of smaller, geographically compact market. The idea being to group market participants more closely in terms of external costs effects than occurs under the national allowance market. The ad hoc market assignments reduced the east-to-west mobility of allowances in the simulation and reduced the disparity in external costs of emissions among each market's participants. The result of the Chapter 4 market assignment was substantial reduction in the external cost effect of the Title IV allowance system relative to the national allowance market.

The dependence of the external cost effect on the disparity of external costs indicates that some pollutants are better suited for the use of large allowance markets than others. The less location-dependent the external costs associated with a pollutant are, the more suitable they would be for a market for emission allowances as a means of achieving emission goals. Greenhouse gases (carbon dioxide and CFC) and ozone layer depleters (CFCs) are good examples of emissions without localized effects. Presumably both of these agents effects are based on the ambient levels in the atmosphere—the external costs generated by every unit of emissions is therefore equal across all sources. The location of reductions is therefore not as important as the level of reductions on a world-wide scale. Under such a situation, the potential benefits of using market for emissions to achieve an emission goal are very large in terms of abatement costs savings and the potential loss in changes in external costs either negligible or non-existent. Again, the more localized the effect, the more the market needs to be scrutinized for welfare effects. The less localized the effect, the less concern needs to be attached to the external cost affects of allowance reallocations under a market.

Nitrous Oxide emissions are an example of a pollutant with a very localized effect. Nitrous oxide emissions are not only a precursor of acid rain, but a major component of ozone pollution at ground level.[1] As such, ozone is not a good candidate for regional emission allowance markets. Local markets may work, but anything larger in scope risks the welfare losses seen in chapter 3 and 4 with regards to Title IV.

The use of markets for emission allowances is a potentially powerful policy tool for achieving emission goals. But as with any policy tool, the decision of when and how to use it determines its effectiveness in achieving the goals of a policy. If the goal is to reduce the external costs of a pollutant in a more cost effective manner than a cap, the market will prove useful where the effect of the pollutant is based on ambient, rather than

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[1] Ozone at ground level is a pollutant. Ozone is a very reactive gas with effects that have been compared to Mustard Gas as far as effects on lung tissue. The conversion of nitrous oxides and other volatile organic compounds into ozone tends to be very localized phenomena downwind of emission sources.

localized effects. In cases where external costs are based on the location of sources, care must be used in defining and managing the market to insure that the goal of improving welfare is not lost.

## Glossary

| | |
|---|---|
| 1.95 | The chemical conversion factor from sulfur to so2 in terms of mass. |
| A | Intercept of the linear demand curve for annual kWh |
| B | Slope of the linear demand curve for annual kWh |
| Abate | Dummy variable, Abate=1 if utility chooses to invest in FGD, 0 otherwise. |
| $\alpha 1$ | Percent of btu's attributable to coal |
| $\alpha 2$ | Percent of btu's attributable to oil |
| Barrel | A volumetric unit of measure for crude oil and petroleum products equivalent to 42 U.S. gallons. |
| Baseload | The minimum amount of electricity power delivered or required over a given period of time at a steady rate. |
| Baseload Capacity | The generating equipment normally operated to serve loads on an around-the-clock basis. |
| Bcf | 1 billion cubic feet |
| Boiler | A structure for generating steam to provide mechanical energy. |
| Btgaoi | Btu per gallon of oil |
| Btlbco | Btu per pound of coal |
| Btu | British Thermal Unit, the heat energy required to raise the temperature of one pound of water by one degree F. |
| CAC | Command and Control Regulation |
| Capacity | Full-load continuous power rating of a generator |
| COBTUYR | Total btu's used in a year by the boiler |
| DispP | The cost of removing 1 ton of so2 in terms of limestone, adipic acid, and waste disposal |
| DSM | Demand Side Management |
| Em | The uncontrolled emissions per kWh generated by the boiler |
| Em | So2 emissions boiler produces per unit of kWh, prior to abatement |
| EPA | Environmental Protection Agency. Alternatively, in chapter 1, the Environmental Planning Agent. |
| FERC | Federal Energy Regulatory Commission |
| FGD | Fluidized Gas Desulfurization |
| FSR | Firm Specific Regulator |
| H | The heat rate of the boiler, that is the number of mmbtu needed to generate a kWh of power |
| IB | Incentive Based Regulation |
| IPP | Independent Power Producer |
| KapA | portion of capital abatement that is dependent on the level of abatement used |
| KapB | portion of abatement capital that is independent of the level of abatement capital used |
| KWh | Annual output of boiler in kilowatt hours. Takes the form of Q in chapter 1. |
| KWH | Electric power needed to operate FGD in a year |
| $\Lambda$ | The annual allotment of allowances |
| LBSSO2RE | Pounds of so2 removed in a year at the boiler |
| LIMETONS | Tons of limestone used to remove so2 in a year |
| MD | Marginal damage of emissions which make landfall. |
| NUG | Non-Utility Generator |
| $P_A$ | Price of allowances |
| Padipic | The price of adipic acid, per ton |
| $P_{alw}$ | Price of materials and services needed to remove each ton of emissions |
| $P_f$ | Price of fuel per mmbtu |
| $P_{kh}$ | Price per kilowatt hour generated to run abatement hardware in terms of kWh and water |

| | |
|---|---|
| $P_{kWh}$ | Price per kilowatt hour |
| $P_L$ | Non-fuel variable portion of generation costs of kWh, per kWh |
| $P_{lmstn}$ | The price of limestone, per ton |
| $P_{waste}$ | The cost of disposing 1 ton of waste |
| RE | The removal efficiency of the abatement capital, range from 0 to 90 |
| S | The amount of adipic acid, in tons, needed to remove 1 ton of so2 from emissions |
| So2coal | Sulfur as a percent of mass |
| So2hr | Max sulfur dioxide output of a boiler per hour |
| So2oil | Sulfur as a percent of mass |
| T | Waste tonnage from FGD operation generated by each ton of so2 removed from emissions |
| U | The amount of limestone, in tons, needed to remove 1 ton of so2 from emissions |
| WASTONS | Tons of waste generated by FGD process in a year |
| WATER | Thousands of gallons of water used by FGD in a year |
| Wghtga | The weight of a gallon of oil, in lbs. |
| Z | Fixed costs of the boiler in question |

# Appendices

## Appendix A:

## Distortionary Effects of Assuming Constant Heat Rates (H) across boilers at a given plant and Distortionary Effects of Assuming Constant Variable Costs Across Boilers from Given Plant

### A-I: Distortionary Effects of Assuming Constant Heat Rates (H) across boilers at a given plant

The assumptions that each boiler uses the same fuel mix and has the plants average heat rate (H) leads to the result, given the information available, that the marginal cost of kWh in terms of fuel is constant for each boiler. Where the boilers at a plant are the same size and type these assumptions will have only limited distortionary effects on the cost function. Over the capacity and use ranges examined most of the plants are well below their engineering capacity and should experience little variation in heat rate of fuel mix for relevant output ranges. Table A-1 below shows the percentage of annual capacity used at the power plants in the study. If the heat rate and fuel mix do vary with the size of the boiler at a plant (or from boiler to boiler), some distortion in the kWh produced by boiler may be possible. Given the information available at this time there is little that can be done to correct for this. However, some examination of the problem is in order.

Table A-1: Percent of Annual Capacity Used

| All Plants Percent of Annual Capacity Used | Percentage of Plants |
|---|---|
| 88 to 80 | 2.36% |
| 79 to 70 | 7.33% |
| 69 to 60 | 12.77% |
| 59 to 50 | 33.33% |
| 49 to 40 | 12.29% |
| 39 to 30 | 13.71% |
| 29 to 20 | 9.22% |
| 19 to 10 | 4.96% |
| 9 to 0 | 4.02% |

In general, the amount of distortion that occurs from assuming a constant marginal cost is how increases or decreases in kWh demand affects the load demand of the plant over the course of a year and how this affects the plant's marginal cost of production. In cases where there are prime and secondary boilers used for the main and peak demand, respectively, it is common wisdom that the peak generators tend to have a higher marginal cost of operation. These generators tend to be smaller, need a shorter start-up time (making them good for load on demand runs), but tend to have a higher cost to operate on a per kWh basis. If such a plant experiences an increase/decrease in demand, it is possible that the increase/decrease could occur either during a peak or an off-peak time. If it occurs during an off-peak time and it does not change the peak/off-peak status of the plant it is assumed that the marginal fuel costs do not change, the plant is under normal load. If the change occurs during a peak time, it could adjust the load to off-peak, or increase the size or duration of the peak load, of the plant. Either of these effects may impact the annual heat rate (H) or fuel mix (the alphas) of the plants and boilers[1]. Either of these effects would affect the marginal fuel cost of the annual production of kWh for the plant and boilers. The magnitude of this effect on annual marginal cost would depend on the effect of this demand shift has on the proportion of the peak boiler's share of total annual mmbtu relative to the total annual mmbtu of the boiler.

But as seen in table A-2, the share of mmbtu's provided by non-coal fuel at plant's which burn coal is very small in the majority of plants. In fact, 87.2% of the coal

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[1] As a general rule, peak-load generators tend to be oil or natural gas burners due to the characteristics needed by peak-load generators. These tend to be smaller units with higher marginal costs than the much larger coal burning units which serve as the majority of the prime movers in the data set (95%).

burning plants have 98% or more of their total annual mmbtus supplied by coal in a given year. If the remainder the mmbtu were assumed to be used by peak-load generators at the plants in question, any given change in demand may or may not change the .2% load carried peak generators. It is more likely that the increase or decrease in demand will, over the coarse of the year, be distributed proportionally between the peak and off-peak hours. If this is true, the annual H average for the year and the average fuel mix of each plant will remain relatively unchanged with the change in annual demand. While, on a day to day basis, the change in demand may affect one portion of demand more than another, over the course of the year it seems reasonable to assume that these effects would fall within the normal distribution of mmbtu between the boilers at a plant. Any distortion in estimates caused by the assumption of constant marginal costs is thus assumed to be limited under conditions where the boiler's at a plant represent peak and off-peak units.

In general, however, the vast majority of the coal burning plants in the data set are made up of two or more boilers of equal size, heat rate, and fuel mix.[2] The use of oil or gas is used in addition to coal at some of these plants to provide the mmbtu needed to generate kWh. The issue of changing marginal costs over changing loads is thus limited to the question of whether or not the heat rate for the boilers is affected by varying loads on the plant. It is the assumption of this study that, except in extreme load changes, the average annual heat rate and fuel mix of the boilers at a plant do not change with load changes. While this assumption is neither supported or challenged by the data available at the time, it is a convention forced by the limits of the data used in the data set. Interviews with personal from Niagara Mohawk and engineers with the New York State Energy Regulatory Commission have supported this premise. Large coal firing units tend to experience a flat marginal cost in fuel once running and under load when within their design parameters and after being properly warmed.

Table A-2: Coal's Share of total Annual BTU's Burned at Plant

| Coal's Share of total Annual BTU's Burned at Plant | % of coal plants |
|---|---|
| 100% | 22.02% |
| 99% | 61.31% |
| 98% | 3.87% |
| 97 to 90% | 4.46% |
| 89 to 80% | 2.38% |
| 79 to 70% | 1.49% |
| 69 to 60% | 2.08% |
| 59 to 50% | 1.49% |
| 49 to 10% | 0.89% |

**A-II. Distortionary Effects of Assuming Constant Variable Costs Across Boilers from Given Plant**

While the effects of changing demand on the heat rate and fuel mix seem limited[3], it is not clear that the same can be said for all of the cost components captured under the L variable used in the model. While the same arguments from appendix A can apply to the coolants used by the plant, it is not clear that the limited labor costs directly

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[2] Peak load generators tend to be located at other plants owned by the same company. The location of plants tends to determined by the access to gas lines, trains, and shipping lanes.

[3] And thus, the effects of changing demand are assumed to have a negligible effect on the marginal cost of production in terms of fuel usage (see section A-I above).

associated with generation vary as directly with changes in kWh produced. Thus, the marginal costs of kWh may vary with respect to the need to adjust such labor in a linear fashion. However, the data prevents divining the actual relationship between this category of costs and the production of kWh. The data includes these costs as a generation costs and this model has done the same. While this may cause some measurement error in the model, these costs are a small portion of the marginal cost associated with kWh production by the plant. The average marginal fuel cost per kWh in the data set is around .12 per kWh. The average price of the entire L component per unit, on the other hand, is .00183 per kWh. Of this, around 15% are actually made up of a labor component. In the worst case scenario then, 1.5% of the MC of kWh production may have a non-constant, non-linear component. At best .023% of the marginal costs of kWh production is truly questionable under the assumption of constant marginal costs. This will still have some impact on the results of the model, however it is assumed that some variability in these costs is consistent with reality (operating personnel are not needed when the plant is shut down, etc.). In any event, the distortions are of small magnitude in the contexts of both total and marginal costs.

## APPENDIX B:

### The Shawnee Model: The Black Box behind the Data Set

The most comprehensive source of abatement costs estimates data comes from the "integrated air pollution control system" program published by the Air and Energy Engineering Research Laboratory of the EPA. The program was made available to the public in December of 1990 and was the basis for the costs estimates used in the Clean Air Act's summary reports.

There are several limitations of the model used by the EPA. The biggest limitation is that the model estimates the costs of FGD based technology that is relatively out of date. "From 1968 to 1980, EPA sponsored research on the development of lime/limestone slurry FGD technology at the Alkali Scrubbing Test Facility located at TVA's Shawnee Steam Plant…the experimental test data collected during these tests were used to develop a computer model to simulate conceptual designs and estimate costs for lime/limestone slurry processes." [4]

The Shawnee model, a revision started in 1974 based on information from the Shawnee test bed,[5] saw numerous revisions over the next ten years to reflect improvements in technology and changing cost structures in the market. The model received a major overhaul in 1980. The most recent version of the model, the one used in the 1990 release, is based on "The Shawnee Flue Gas Desulfurization Computer Model"

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[4] T. Emmel and M. Maibodi, "Retrofit Costs for $SO_2$ and $NO_x$ Control Options at 200 Coal-Fired Plants," EPA contract No. 68-02-4286; National Acid Rain Precipitation Assessment Program, 1990 Integrated Assessment Report, pages 408-433; M. Maibodi and Blackard, Integrated Air Pollution Control System version 4.0 Volume 2 technical documentation manual, December 1990, and Pages 4-39.

[5] M. Maibodi and Blackard, Integrated Air Pollution Control System version 4.0 Volume 2 technical documentation manual , December 1990, and Pages 4-39.

which was completed in 1984 and released in March of 1985.[6] This model, as advertised, "is capable of simulating a complete conceptual design for lime/limestone slurry FGD processes utilizing different absorber towers, with and without chemical additives, with any of five sludge disposal options." [7] The model's actual cost functions, were, however, unavailable. The one published equation on costs is "a simple curvefit equation to predict direct capital cost versus boiler size (MW) was performed on IAPCS model as follows: Direct Capital cost ($)=763,900*boiler size^0.69." [8] This covers the direct capital cost in 1988 dollars for lime FGD, with the following qualifications:
"for lime FGD with 1 percent sulfur, 10 percent ash, 4 percent moisture, and adipic acid as an additive (liquid to gas ratio of 65)."[9] For any variation on that theme it is necessary to run the Shawnee program which is sold to utilities so that they may estimated their costs of complying with Title IV.

In order to gather the necessary data to estimate the costs of any affected utility boiler it was necessary to construct a data set using the model. This data was then checked against information provided by the New York State Utility Commission and in phone interviews with Norman Kaplan, the Integrated Air Pollution Control System project officer. For more information about the Shawnee model derived data set and the cost curves derived from it, see appendix G.

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[6] Sudhoff, F.A., and R.L. Torstrick. Shawnee Flue Gas Desulfurization Computer Model Users Manual, U.S. EPA. Research Triangle Park, NC. EPA-600/8-85-006, March 1985.
[7] M. Maibodi and Blackard, Integrated Air Pollution Control System version 4.0 Volume 2 technical documentation manual , December 1990, and Pages 4-39.
[8] M. Maibodi and Blackard, Integrated Air Pollution Control System version 4.0 Volume 2 technical documentation manual , December 1990, and Pages 4-39.
[9] M. Maibodi and Blackard, Integrated Air Pollution Control System version 4.0 Volume 2 technical documentation manual , December 1990, and Pages 4-39.

## APPENDIX C:

### Definitions and Terms Used in Text and In the Appendices

This appendix has terms divided into four parts. Part C-1 describes the terms used in the body of chapter 3 in regard to the development of the economic model. Part C-2 describes the variables used in the in the regressions with regard to abatement costs, as found in appendix F. Part C-3 defines the technical relationships behind a number of the variables in C-1 and C-2.

**Part C-1: Definitions and Terms of Chapter 3**

| Definition List from Equations | |
|---|---|
| KWh | Annual output of boiler in kilowatt hours |
| $P_{kWh}$ | Price per kilowatt hour |
| $P_F$ | Price of fuel per mmbtu |
| $P_L$ | Non-fuel variable portion of generation costs of kWh, per kWh |
| $P_{alw}$ | Price of materials and services needed to remove each ton of emissions |
| $P_A$ | Price of allowances |
| $P_{kh}$ | Price per kilowatt hour generated to run abatement hardware in terms of kWh and water |
| Z | Fixed costs of the boiler in question |
| H | The heat rate of the boiler, that is the number of mmbtu needed to generate a kWh of power |
| KapA | portion of capital abatement that is dependent on the level of abatement used |
| KapB | portion of abatement capital that is independent of the level of abatement capital used |
| Em | The uncontrolled emissions per kWh generated by the boiler |
| RE | The removal efficiency of the abatement captial installed. |
| a | Intercept of the linear demand curve for annual kWh |
| b | Slope of the linear demand curve for annual kWh |
| $\Lambda$ | The annual allotment of allowances |

## C-2: Engineering Definitions and Terms Used in Appendix G

### Variable Names and Definitions for Appendix G Regressions

| Name | Definition |
|---|---|
| LBSSO2RE | Pounds of so2 removed in a year at the boiler |
| WASTONS | Tons of waste generated by FGD process in a year |
| LIMETONS | Tons of limestone used to remove so2 in a year |
| WATER | Thousands of gallons of water used by FGD in a year |
| KWH | Electric power needed to operate FGD in a year |
| COBTUYR | Total btu's used in a year by the boiler |

**Names and Definitions for Appendix G Regressions**

| Name | Definition |
|---|---|
| 1.95 | The chemical conversion factor from sulfur to so2 in terms of mass. |
| Abate | Dummy variable, Abate=1 if utility chooses to invest in FGD, 0 otherwise. |
| alpha 1 | Percent of btu's attributable to coal |
| alpha 2 | Percent of btu's attributable to oil |
| btgaoi | Btu per gallon of oil |
| btlbco | Btu per pound of coal |
| dispP | The cost of removing 1 ton of so2 in terms of limestone, adipic acid, and waste disposal |
| Em | So2 emissions boiler produces per unit of kWh, prior to abatement |
| H | Heat rate of boiler |
| kWh | Annual kWh of boiler |
| padipic | The price of adipic acid, per ton |
| plmstn | The price of limestone, per ton |
| pwaste | The cost of disposing 1 ton of waste |
| RE | Abatement efficiency, range from 0 to 90 |
| S | The amount of adipic acid, in tons, needed to remove 1 ton of so2 from emissions |
| so2coal | Sulfur as a percent of mass |
| so2hr | Max sulfur dioxide output of a boiler per hour |
| so2oil | Sulfur as a percent of mass |
| T | Waste tonnage from FGD operation generated by each ton of so2 removed from emissions |
| U | The amount of limestone, in tons, needed to remove 1 ton of so2 from emissions |
| wghtga | The weight of a gallon of oil, in lbs. |

## C-3: Technical Relationships and Definitions

### So2hr:

This measure has two components, the so2 from coal (so2hrco) and the so2 from oil (so2hroi)-- $so2hr := so2hrco + so2hroi$.

Where

$$so2hrco := \left(\frac{H \cdot MW \cdot \alpha 1}{btlbco}\right) \cdot \frac{1}{2} \cdot \frac{so2coal}{100} \cdot 1.95 \cdot 2000$$

And

$$so2hroi := \left(\frac{H \cdot MW \cdot \alpha 2}{\frac{btgaoi}{wghtga}}\right) \cdot \frac{1}{2} \cdot \frac{so2oil}{100} \cdot 1.95 \cdot 2000$$

### Em: Emissions per kWh.

$$Em_i = \left[\frac{\alpha 1_i \cdot \left(1 + W \cdot Abate_{ik}\right)}{btlbco_i} \cdot \frac{so2coal_i}{100} \cdot \frac{H_i}{1000} \cdot 1.95 + \frac{\alpha 2_i \cdot \left(1 + W \cdot Abate_{ik}\right)}{\left(\frac{btgaoi_i}{wghtga_i}\right)} \cdot \frac{so2oil_i}{100} \cdot \frac{H_i}{1000} \cdot 1.95\right]$$

### COALHR: Max coal that a boiler can handle in an hour.

$$COALHR = \frac{H \cdot MW \cdot \alpha 1}{btlbco} \cdot \frac{1}{2}$$

## APPENDIX D:

### Allowance Allocation Formulas for Phase II of Title IV—Before New Allocation Rules

The basic idea behind the allowance formulas is the reduction of emissions below the 1.2 lbs. per mmbtu level. Based on the baseline[10] average so2 lbs per mmbtu of each boiler, each boiler is assigned a number of allowances according to a predetermined set of formulas. For large emitters (those with more than 1.2 per mmbtu), allowances are granted according to the following formula:

$$\text{If } \frac{1.2\text{lbs}}{\text{mmbtu}} \le \frac{\text{so2lbs}_{ik}}{\text{mmbtu}_{ik}} \text{ then } A1_{ik} = \frac{1.2 \cdot \text{mmbtu}_{ik}}{1000}$$

This insures that the boiler must achieve the 1.2 lbs per mmbtu standard set by title IV (assuming no trade).

If cleaner than 1.2 lb per mmbtu in the baseline, the plant is given a number of allowance sufficient to keep it at that baseline emission level:

$$\text{If } \frac{1.2\text{lbs}}{\text{mmbtu}} > \frac{\text{so2lbs}_{ik}}{\text{mmbtu}_{ik}} > \frac{.6\text{lbs}}{\text{mmbtu}} \text{ then } A1_{ik} = \frac{\dfrac{\frac{\text{so2}_{ik}}{\text{mmbtu}_{ik}}}{1.2} \cdot \text{mmbtu}_{ik} \cdot 1.2}{1000}$$

If the plant is considered a clean coal power plant, that is with .6 lbs. Per mmbtu or less in the baseline, then the plant is granted allowances according to the following formula:

If $\frac{.6\text{lbs}}{\text{mmbtu}} \geq \frac{\text{so2lbs}_{ik}}{\text{mmbtu}_{ik}}$ then $\Lambda 1_{ik} = \frac{.6\text{lbs} \cdot \text{mmbtu}_{ik}}{1000}$

Note that the "clean" power plant may be granted allowances in excess of its actual baseline. If the unit's baseline is less than .6 lbs per mmbtu, the allowances will still be assigned at the .6 lbs per mmbtu rate—meaning allowances>baseline emissions.

For each mmbtu of oil burned allowances ($\Lambda 2_{ik}$), the formulas are identical. Summing the allowances ($\Lambda_{ik} = \Lambda 1_{ik} + \Lambda 2_{ik}$) provides the total number of allowances granted to the boiler in question for a given year.

[10] As discussed earlier, the baseline for a plant refers to the average mmbtu and so2 per mmbtu of the plant over the 1984 through 1986 time period.

## APPENDIX E:

### The Mechanism of Banking of Allowances under Title IV

Banked allowances can be used to cover emission requirements of the holder in any year following the year they are banked (not used). Or banked allowances can be sold to another economic unit in a future year. Banked allowances are always worth one ton of emissions regardless of when they are used, for all intents and purposes; the banking of allowances is nearly cost-less to the holding agent.[11] There are several potential reasons for banking—the failure to find buyers at asked or market price, holding allowances against growing future needs (due to growth in the output market), holding allowances in anticipation of higher allowance prices in the future, and uncertainty.

The failure to find buyers, and some portion of allowances banked by uncertainty, constitute unplanned inventory building or banking of allowances—just as unplanned inventory occurs in other industries. Given the fact that there is substantial punishment to failing to meet emissions limits, there is uncertainty in any developing market regarding supply, and the fact that the electric industry has experienced a steady increase in annual demand; it seems likely that utilities will err on the side of over compliance in their abatement decision making. This should lead to the existence of over-compliance in the allowance market, all else held equal. Once the decision to abate has been made, the capital costs become fixed and the supply of allowances becomes fixed at too high a level. The result of this would be equilibrium allowance prices settling at levels below that which would otherwise be expected in the market. Over time, the over supply of allowances would deteriorate as demand for electricity continues to grow and new boilers—which are not assigned allowances under title IV—need to buy allowances to cover their emissions. It seems reasonable that growth in the electric industry demand would slowly erode oversupply and cause prices to increase in the market for allowances.

This growth in demand relative to supply is also built into the system in the implementation of a two-phase plan where the standards tighten and the population of affected plants increases. Phase I plants tend to be the dirtier plants and they are granted allowances using allowance assigning rules which are less stringent than the phase II rules. Phase I designated plants were required to have emission levels that matched their allowance holdings starting in 1995. By 2005, however, the plants understood that they would be subject to more stringent phase II allowance rules—thus just meeting phase I emission rules was not a good long-term strategy. This is particularly true given the fact that phase I plants, for the most part, should have the lowest average costs of sulfur dioxide removal of the all the plants that will be affected by the phase II rules.[12] Thus phase I plants could, and do, anticipate being suppliers of allowances in the market that includes phase II affected boilers. In the addition, the number of affected phase II boilers includes any new sulfur emitting boilers of over 50MW in capacity that come into service after 1986. Unlike other phase II affected units, units that come on line after 1986 are not

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[11] This allowance banking is unlike the inventories that build up in other industries such as automobiles and computers where inventories cost are caused by storage costs and depreciation of the stock.

[12] A study of the abatement cost curves will show that the average cost of removing a ton of so2 falls as sulfur content of coal increases, the amount of abatement (RE) increases for a given sulfur content, and as the MW of the plant to be "controlled" increases. Phase 1 plants tend to be the largest, dirtiest plants—thus the greater the level of RE, the better off the plant in terms of the average costs of so2 removal.

assigned allowances. All of these new phase II units must purchase all of their allowance needs from the market or from the EPA's run auction. While newer plants will tend to be cleaner and have lower abatement costs than retrofit plants, or use non-sulfur-generating fuels[13], demand for allowance is expected to grow, not diminish in the future. This expectation of future demand has lead to the expectation of higher prices for allowances under a phase II affected market as well. This expectation may provide some incentives for phase I plants to bank allowance today in anticipation of higher allowance prices in the future under phase II.

[13] Natural gas is a becoming a very viable, low cost fuel source for generators. New technology in the area of natural gas generators has made them some of the lowest cost sources of electricity. In fact, the advent of the inexpensive natural gas generator has been a significant force in pushing deregulation of the electric industry.

## APPENDIX F:

## FGD Abatement Cost Curve Estimates based on Data from the Shawnee Computer Model

There are several components to the costs associated with FGD according to the research performed at the Shawnee plant. As described in chapter 1, each increase in RE (abatement or removal efficiency) takes a fixed ratio of both the capital (k) and consumable component (L). The minimum of either component used will determine the level of abatement (RE) achieved.

**Variable costs in the form of consumables (L)**

According to the Shawnee model[14], the variable component of abatement for a given plant and fuel mix will vary with the amount of fuel burned and the percentage of sulfur dioxide removed from the emission stream. The regression analysis of the Shawnee synthetic data indicates that the EPA assumes a very linear relationship between the amount of emissions removed and the variable costs associated with removal. Each ton of so2 removed from the emission stream takes a certain amount of adipic acid[15], limestone, water, etc. The relationship between output (kWh), abatement effort (RE), and the amount of sulfur in the fuels (so2coal, so2oil), is broken down into two main components. The first is based on the amount of emissions removed from the flue gas. The second is dependent on a rough measure of the total volume of the material entering the boiler system.

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[14] Appendix B introduces the Shawnee model as the source of data on FGD costs.

**The Data Set**

As mentioned above, this paper makes used of a synthetic data set derived from the Shawnee FGD "black box" computer model developed by the EPA to estimate the costs of abatement.[16] The EPA's computer model was used to generate a data set regarding the estimated costs of emission controls. The model was used to estimate the costs of FGD for 190 cases which covered a range of boilers of 100MW, 200MW, 300MW, 400MW, and 500MW in size—with a variety of coal types, heat rates, capacity factors, and removal efficiencies run at each MW setting. This data was then used to estimate the cost curves of FGD abatement. The Shawnee FGD model provides estimates at each setting for the amount of materials needed to remove each ton of sulfur dioxide from the flue gases and the capital equipment needed to achieve each removal efficiency setting. Table F-1 below lists the variables used in estimating the variable costs of FGD. A more thorough explanation of the definitions is given in Appendix C. Table F-2 shows the results of the regressions using the data set developed using the EPA's back box computer model on each of the variable components of FGD.

**Table F-1: Variable Names and Definitions**

| Name | Definition |
|---|---|
| LBSSO2RE | Pounds of so2 removed in a year at the boiler |
| WASTONS | Tons of waste generated by FGD process in a year |
| LIMETONS | Tons of limestone used to remove so2 in a year |
| WATER | Thousands of gallons of water used by FGD in a year |
| KWH | Electric power needed to operate FGD in a year |
| COBTUYR | Total btu's used in a year by the boiler |

[15] Adipic acid is an agent used to prevent scaling in the scrubber mechanisms.
[16] See Appendix B for more information on the Shawnee model.

**Table F-2: FGD Variable Cost Regression Results**

| | | Coefficient | Starndard | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Dependent | Variable | Value | Error | Independent | | sig. | Multiple | | Adjusted | Standard |
| Variable | Name | B | SE B | Variable | T | T | R | $R^2$ | $R^2$ | Error |
| Adipic | s | 1.1856E-06 | 1.47E-09 | LBSSO2RE | 807.395 | 0 | 0.9999 | 0.99971 | 0.9997 | 1.42928 |
| Tnswaste | t | 0.001756 | 1.78E-06 | LBSSO2RE | 988.291 | 0 | 0.9999 | 0.99981 | 0.9998 | 1729.495 |
| Tnslmstn | u | 0.00096052 | 1.36E-06 | LBSSO2RE | 704.979 | 0 | 0.9981 | 0.99962 | 0.9996 | 1326.12 |
| Water | v | 7.3747E-09 | 4.98E-11 | COBTUYR | 148.132 | 0 | 0.9957 | 0.99151 | 0.9915 | 13650.35 |
| Kwh | w | 1.5167E-06 | 1.04E-08 | COBTUYR | 145.191 | 0 | 0.9956 | 0.99116 | 0.9911 | 2864142 |

**Table F-2** (Continued): **FGD Variable Cost Regression Results**

Analysis of Variance

| Dependent | Regression | | | Residual | | | | Signi- | |
|---|---|---|---|---|---|---|---|---|---|
| Variable | | Sum of | Mean | | Sum of | Mean | | Ficant | |
| Name | DF | Squares | Square | DF | Squares | Square | F | F | |
| Adipic | 1 | 1331695.92 | 1331695.92 | 189 | 386.09593 | 2.04284 | 651885.9873 | 0 | |
| Tnswaste | 1 | 2.92152E+12 | 2.92152E+12 | 189 | 565327608 | 2991151.366 | 976719.4597 | 0 | |
| Tnslmstn | 1 | 8.74013E+11 | 8.74013E+11 | 189 | 332374488 | 1758595.175 | 496995.2745 | 0 | |
| Water, | 1 | 4.08872E+12 | 4.08872E+12 | 188 | 3.503E+10 | 186331990.6 | 21943.22073 | 0 | |
| Kwh | 1 | 1.7293E+17 | 1.7293E+17 | 188 | 1.542E+15 | 8.20331E+12 | 21080.48023 | 0 | |

Given the synthetic engineering and chemical rule basis for the data set, the R squared and T-scores of the regressions are not surprising. In each case, the R squared score indicates that a .99 or better correlation between the variations found in the dependent variable and independent variable chosen. These regressions only serve to uncover the relationships assumed by the EPA in its computer cost models, as described in the appendix.

As noted in the regression table above, the annual amount of adipic acid and limestone used, and the annual amount of waste generated, by FGD at a boiler is dependent on the amount of $SO_2$ removed from the flue gases in a given year (**LBSSO2RE**). The regressions on adipic acid and limestone use are nothing more than the expression of the chemical process by which sulfur is removed from the emissions of the boiler given sufficient capital applicators. That is, each ton of sulfur removed from the flue gas needs a given amount of adipic acid and limestone to combine and react with to remove it from the emission stream. The amount of $SO_2$ removed by the abatement equipment is a function of the total $SO_2$ flow per kWh—**(Em)**[17]—in tons, the total number of kWh in a given year **(kWh)**[18], and the removal efficiency of the abatement equipment installed (RE)[19]. The amount of emission flow per kWh **(Em)** is dependent on the sulfur weight of the oil and coal burned at the plant **(so2coal** and **so2oil**, respectively), the weight of the oil **(wghtga)**, and the Btu content of a unit of oil and the coal (**btugaoi** and **btulbco**, respectively). Thus, the $SO_2$ tonnage removed from a given boiler is equal to LBSSO2RE= $Em_i \cdot kw_{ik} \cdot \frac{RE_{ik}}{100}$. Table F-3 presents a list of variable names and definitions used here.

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[17] See appendix C for further explanation of the definition given below:

$$Em_i = \left[ \frac{\alpha 1_i \cdot \left(1 + W \cdot Abate_{ik}\right)}{btlbco_i} \cdot \frac{so2coal_i}{100} \cdot \frac{H_i}{1000} \cdot 1.95 + \frac{\alpha 2_i \cdot \left(1 + W \cdot Abate_{ik}\right)}{\left(\frac{btgaoi_i}{wghtga_i}\right)} \cdot \frac{so2oil_i}{100} \cdot \frac{H_i}{1000} \cdot 1.95 \right]$$

[18] Where the total kw includes the power required to run the abatement equipment. The kw cost of abatement is denoted by W, which is defined in table 1.

[19] As noted, the abatement technology is assumed to have a leontif styled costs function. It is therefore assumed that the abatement technology is run at capacity. Thus equipment designed to run at 90% removal efficiency will be run at full capacity when determining actual running costs.

| Table F-3 Variable Names and Definitions | |
|---|---|
| Name | Definition |
| 1.95 | the conversion factor from sulfur to so2. |
| Abate | Dummy variable, Abate=1 if utility chooses to invest in FGD, 0 otherwise. |
| alpha 1 | percent of btu's attributable to coal |
| alpha 2 | percent of btu's attributable to oil |
| Btgaoi | btu per gallon of oil |
| Btlbco | btu per pound of coal |
| DispP | The cost of removing 1 ton of so2 in terms of limestone, adipic acid, and waste disposal |
| Em | so2 emissions boiler produces per unit of kWh, prior to abatement |
| H | Heat rate of boiler |
| KWh | annual kWh of boiler |
| Padipic | The price of adipic acid, per ton |
| Plmstn | The price of limestone, per ton |
| Pwaste | The cost of disposing 1 ton of waste |
| RE | abatement efficiency, range from 0 to 90 |
| S | The amount of adipic acid, in tons, needed to remove 1 ton of so2 from emissions |
| so2coal | sulfur as a percent of mass |
| so2hr | max sulfur dioxide output of a boiler per hour |
| so2oil | sulfur as a percent of mass |
| T | Waste tonnage from FGD operation generated by each ton of so2 removed from emissions |
| U | The amount of limestone, in tons, needed to remove 1 ton of so2 from emissions |
| Wghtga | the weight of a gallon of oil, in lbs. |

Each ton of $SO_2$ removed requires a given volume of adipic acid (**S*LBSSO2RE**), limestone (**U*LBSSO2RE**), and disposal space (**T* LBSSO2RE**).[20] Given the price for adipic ($\mathbf{P_a}$), limestone ($\mathbf{P_l}$), and disposal ($\mathbf{P_w}$), the annual cost of removing $SO_2$ at a plant in terms of limestone, adipic acid and waste disposal is equal to the following:

**(F.1)** $\mathbf{P_a * (S * LBSSO2RE) + P_l * (U * LBSSO2RE) + P_w * (T * LBSSO2RE).}$

Re-arranging F.1:

**(F.10)** $\mathbf{(P_a * S + P_l * U + P_w * T) * LBSSO2RE.}$

[20] The values of S, U, and T are given in table F-2.

Setting $\mathbf{P_{alw}}$=**($\mathbf{P_a}$*S+ $\mathbf{P_l}$*U+ $\mathbf{P_w}$*T)** simplifies F.10 to:

**(F.11) $\mathbf{P_{alw}}$* LBSSO2RE.**

Noting from above that **LBSSO2RE=** $Em_i \cdot kw_{ik} \cdot \frac{RE_{ik}}{100}$, total annual cost of removing a given amount of $SO_2$ **(LBSSO2RE)** in terms of limestone, adipic acid, and disposal is equal to

**(F.12) $\mathbf{P_{alw}}$*** $Em_i \cdot kw_{ik} \cdot \frac{RE_{ik}}{100}$ for a given **RE**[21], **kWh**, and **Em** from the boiler in question.

The amount of water and electricity needed to run the FGD system is not directly related to the amount of $SO_2$ removed, as indicated in the regression results presented in Table F-1. The annual FGD consumption of water **(V*COBTUYR)** and electricity **(W*COBTUYR)** is instead dependent on the annual volume of btu's burned at the plant **(COBTUYR)**.

Using an average market price for electricity **($\mathbf{P_{kw}}$)** the total cost of abatement in terms of electricity is

(F.13) **$\mathbf{P_{kw}}$* W*COBTUYR.**

It is assumed that this FGD derived electricity demand is supplied by the boiler itself. The cost of this self-supplied power is accounted at the boiler's resident state's average price for the electricity.

Since FGD uses electricity, this adds to the total annual btu burned by the plant to meet its output demand (kWh). This, in turns, affects the amount of water needed to run the FGD unit. The new btu total is **(1+W)*COBTUYR**. Using a plant specific price for

[21] Abatement effort, RE, is converted to a percentage of emissions removed by dividing by 100. Thus an RE of 90 means that .9 of emissions will be removed.

water $(\mathbf{P_{h20}})$[22] the total cost of FGD related water consumption is equal to $\mathbf{P_{h20}* V*(1+W)*COBTUYR}$.

Adding the total annual FGD related cost of electricity and the total FGD related cost of water results in:

(F.13) $\mathbf{(P_{h20}* V*(1+W)+ P_{kw}* W)*COBTUYR}$

Noting again that the total annual btus burned at a plant is function of the annual kWh supplied by the plant **(COBTUYR=H*kWh)**, F.13 can be rewritten as:

(F.14) $\mathbf{(P_{h20}* V*(1+W)+ P_{kw}* W)*H*kWh.}$

Defining $\mathbf{P_{kh_i} =(P_{h20_i}* V*(1+W)+ P_{kw_i}* W)*H_i}$ sets a per kWh price for active FGD.

Using

$\mathbf{P_{kh}}$, the total annual cost of FGD related electricity and water consumption **(F.14)** can be rewritten as:

(F.15) $\mathbf{P_{kh_i}*kWh_{ik}}$

Thus equation F.12 and F.15 combined give the total[23] boiler-specific annual consumables-based cost of FGD for given level of abatement (RE), emissions per kWh (Em) and annual output demand (kWh):

(F.16) **FGD Total Consumables Cost =** $\mathbf{P_{alw}} * Em_i \cdot kw_{ik} \cdot \frac{RE_{ik}}{100} + \mathbf{P_{kh_i}*kWh_{ik}}$

[22] The price of water faced by a given plant is based on a base price modified by the existence of local, free water sources such as lakes, rivers, or reservoirs.

## FGD Capital Cost

According to the EPA model, there are six components to the direct capital costs associated with FGD. There is the solid preparation equipment, gas treatment capital, the scrubbers, material handling equipment, fans, and feed equipment. Each component has its own cost structure and was modeled independently in the Shawnee program. Capital equipment costs are largely dependent on the maximum amount of sulfur dioxide that can flow through the system over a given amount of time. That is, the costs are dependent on the maximum $SO_2$ volume for a set time period. The basic volume/time unit used in the model developed by the EPA is a measure of the maximum sulfur dioxide volume possible in a given hour for the boiler in question (so2hr).[24] [25] This flow rate is measured in tons an hour at maximum output.

Another measure used is coal tons an hour (COALHR)[26], which gives an idea of the total solid mass being forced into the boiler system every hour at maximum load. Table F-4 below lists the variable names and definitions used in these regressions.

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[23] Note that where RE=0, WE=0, as the costs of abatement only occur if abatement technology is used.
[24] See the variable definition table above.
[25] See Appendix C for derivation of so2hr and other synthetic engineering relationships.

| Table F-4 Dependent Variable Names | |
|---|---|
| **Dependent Variable Names** | **Definitions** |
| GAS | Gas treatment capital |
| SO2SCRUB | Flue Gas Scrubber Equipment (Nozzles, etc) |
| MH | Material Handling Equipment |
| FANS | Blowers |
| FEED | Feed Equipment Capital |
| SOLIDPREP | Solid Preparation Capital |
| **Independent Variable Names** | **Definitions** |
| SO2HRSO2 | Sulfur dioxide per hour/sulfur content[27] of fuel $=\frac{so2hr}{so2}$ |
| RESSOVHR | RE * SO2HRSO2 = $RE \cdot \frac{so2hr}{so2}$ |
| TH2REHR | dummy, =1 if RESSOVHR>2,000,000: $RE \cdot \frac{so2hr}{so2} > 2,000,000$ |
| COALHR | Maximum Burn Rate of Coal per Hour in Tons |
| RESTH160 | dummy, =1 if RESSOVHR>160,000: $RE \cdot \frac{so2hr}{so2} > 160,000$ |
| SQRSO2HR | Square root of SO2HRSO2 = $\left(\frac{so2hr}{so2}\right)^{.5}$ |

[26] See appendix C for derivation of so2hr and other synthetic engineering relationships.
[27] See appendix C for derivation of so2hr and other synthetic engineering relationships.

The same data set used to determine the relationship between consumables and FGD effort is used here to estimate the capital components of the FGD process. Table F-5 through F-10 below presents results of these reverse engineering efforts. Each table is followed by the relationship between the dependent and independent variables expressed as an equation.

### Table F-5: Sold Preparation Component

| Table F-5 | B | Coefficient | Standard | Independent | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dependent | Variable | Value | Error | Variable | | sig. | Multiple | | Adjusted | Standard | | Sign. |
| Variable | Name | B | SE B | | T | T | R | $R^2$ | $R^2$ | Error | F | F |
| SOLIDPREP | A | 1154658.251 | 13143.54 | (Constant) | 87.85 | 0 | 0.99307 | 0.98619 | 0.9861 | 84706.15 | | |
| | B | 9039.979919 | 76.79479 | SQRSO2HR | 117.716 | 0 | | | | | | |
| | | | | | | 0 | | | | | 13857.1 | 0 |

F.17 $Solidprep := A + B \cdot so2hr^{.5}$

### Table F-6: Gas Treatment

| Table F-6 | B | Coefficient | Standard | Independent | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dependent | Variable | Value | Error | Variable | | sig. | Multiple | | Adjusted | Standard | | Sign. |
| Variable | Name | B | SE B | | T | T | R | $R^2$ | $R^2$ | Error | F | F |
| GAS | C | 1247809.424 | 22890.47 | (Constant) | 54.512 | 0 | 0.99675 | 0.99352 | 0.9935 | 0.34843 | | |
| | D | 533.869887 | 3.789318 | SO2HRSO2 | 140.888 | 0 | | | | | | |
| | E | 0.110465 | 0.011717 | RESSOVHR | 9.427 | 0 | | | | | 14250.8 | 0 |

F.18 $Gas := C + D \cdot \frac{so2hr}{so2} + E \cdot RE \cdot \frac{so2hr}{so2}$

### Table F-7: Scrubbers

| Table F-7 | B | Coefficient | Standard | Independent | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Dependent | Variable | Value | Error | Variable | | sig. | Multiple | | Adjusted | Standard | | Sign. |
| Variable | Name | B | SE B | | T | T | R | $R^2$ | $R^2$ | Error | F | F |
| SO2SCRUB | F | 5737840.583 | 106005.8 | (Constant) | 54.128 | 0 | 0.99447 | 0.98896 | 0.9888 | 0.31331 | | |
| | G | 1911.959168 | 17.54834 | SO2HRSO2 | 108.954 | 0 | | | | | | |
| | h | 0.268811 | 0.054263 | RESSOVHR | 4.954 | 0 | | | | | 8331.79 | 0 |

F.19 $SO2SCRUB := F + G \cdot \frac{so2hr}{so2} + h \cdot RE \cdot \frac{so2hr}{so2}$

## Table F-8: Material Handling Equipment

| Table F-8 Dependent Variable | B Variable Name | Coefficient Value B | Standard Error SE B | Independent Variable | T | sig. T | Multiple R | $R^2$ | Adjusted $R^2$ | Standard Error | F | Sign. F |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| MH | I | 1155700.689 | 14072.37 | (Constant) | 82.126 | 0 | 0.98233 | 0.96498 | 0.9646 | 0.4418 | | |
| | K | 1283306.181 | 43063.47 | TH2REHR | 29.8 | 0 | | | | | | |
| | J | 0.240438 | 0.016396 | RESSOVHR | 14.664 | 0 | | | | | 2658.75 | 0 |

F.20 $MH = I + J \cdot RE\frac{so2hr}{so2} + K \cdot THREST160$

## Table F-9: Fans

| Table F-9 Dependent Variable | B Variable Name | Coefficient Value B | Standard Error SE B | Independent Variable | T | sig. T | Multiple R | $R^2$ | Adjusted $R^2$ | Standard Error | F | Sign. F |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FANS | L | 1030777.94 | 44808.79 | (Constant) | 23.004 | 0 | 0.99068 | 0.98144 | 98135 | 0.00797 | | |
| | M | 25280.40182 | 249.5635 | COALHR | 101.298 | 0 | | | | | | |
| | | | | | | | | | | | 10261.4 | 0 |

F.21 $FANS = L + M \cdot COALHR$

## Table F-10: Feed Equipment

| Table F-10 Dependent Variable | B Variable Name | Coefficient Value B | Standard Error SE B | Independent Variable | T | sig. T | Multiple R | $R^2$ | Adjusted $R^2$ | Standard Error | F | Sign. F |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| FEED | N | 1836178.334 | 30774.19 | (Constant) | 59.666 | 0 | 0.98697 | 0.97411 | 0.9738 | 176547 | | |
| | p | 668178 | 37014.5 | RESTH160 | 18.052 | 0 | | | | | | |
| | O | 1.046014 | 0.015302 | RESSOVHR | 68.359 | 0 | | | | | 3630.82 | 0 |

F.22 $FEED = N + O \cdot RE\frac{so2hr}{so2} + RESTH160p$

Again, the data set's basis on a synthetic cost model used by the EPA results in very high correlation between the dependent and independent terms in the regressions above. The regressions and econometric effort presented hear represents attempts to reverse engineer the EPA synthetic engineering model which underpins the all of the EPA's cost estimates for pollution control.

The regressions indicate that some of the costs are dependent on the level of abatement chosen by the boiler in question. The remaining costs are based on the boilers characteristics in terms of fuel quality, heat rate, size, and other factors.[28] Referring to the portion of capital costs which is dependent on the level of removal efficiency (RE) as $KapA_{ik}$, and the remainder as $KapB_{ik}$, total capital costs ($KAP_{ik}$) are written as equation F.3[29]:

F.23 $KAP_{ik} = \left(KapA_{ik} \cdot RE_{ik} + KapB_{ik}\right)$

Equation F.23 represents the total direct capital price tag of the abatement equipment, as such it does not reflect the annual cost of the equipment to the utility. This figure does not include any arbitrary secondary capital costs based on the difficulty in installing FGD equipment, nor does it include any of the EPA's proportionally assigned secondary capital costs as found in the Shawnee model.[30] The annual, cost (price) of each unit abatement equipment is given by r.[31]

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[28] See Appendix C for the underlying equations that provide so2hr and other terms used here.

[29] This is a limiting assumption, but given the data available to the EPA prior to the enactment of the law, a defendable one. Coal switching was assumed to be limited option due to difficulties in changing ash/water contents in the fuel mix which could cause fouling of feeding system. Switching to low sulfur coal was assumed to entail some major retrofit of burners to handle the new compositions. In addition lower sulfur coals tend to be harder than high sulfur coals. This would require new grinders or more frequent maintenance on existing equipment. Estimates of both forms of cost, though based purely on conjecture at the time, were quite high. In addition many utilities had long term contracts with their suppliers, limiting fuel switching as an option. For a more thorough discussion of coal switching costs see the Integrated Air Pollution Control System Technical Documentation Manuals, volumes 2 and 3.

[30] The EPA has indicated that some existing power plants would require more or less capital, depending on space available and other factors. Since no way of predicating these costs was forwarded in any of the studies available, this arbitrary component of capital costs was dropped as being speculative and impossible to model at best. In

**Total Abatement Cost ($A_{ik}(RE_{ik}, kw_{ik})$)**

Thus the total abatement costs for a given boiler is as follows:

F.27 $A_{ik}(RE_{ik}, kWh_{ik}) = r \cdot (KapA_{ik} \cdot RE_{ik} + KapB_{ik}) + P_{alw} \cdot (Em_i \cdot kWh_{ik} \cdot RE_{ik}) + P_{kh_i} \cdot kWh_{ik}$

addition, the EPA model allowed the calculation of indirect capital cost based on a user set proportion of the direct capital costs. The EPA default on this measure was around 30%. This indirect cost measure was dropped from the model as well as conversations indicated that this was highly speculative and based on the prototype development costs associated with the Shawnee FGD equipment.

[31] See appendix G for a more thorough discussion of the annualized capital cost determination of scrubbers.

## APPENDIX G:

**Coal Switching vs. FGD: Assessments as a long-term Compliance Strategies and Expected Effects in a Phase II Market Simulation**

There are two basic means of reducing emissions—fuel switching and scrubbing (via Fluidized Gas Desulfurization—FGD). Fuel switching involves substituting lower sulfur fuel sources for the current fuels being burned. Options range from to switching to a lower sulfur coal to introducing a coal blend of the old fuel and the lower sulfur fuel. Scrubber technologies involve removing sulfur emissions from boiler waste gases. Scrubber technologies vary as well, but the most promising and popular scrubber technology is FGD.

This simulation model assumes that Fluidized Gas Desulfurization (FGD) is the only emission reducing technology available to the economic agents. That is, the use of FGD is internally modeled as a decision parameter. Coal switching is not internally modeled in the simulation. Instead of choosing the sulfur content of fuel, each unit's 1990 emission rate, the year the law was enacted, is assumed to be the initial emission rate. This is a limiting assumption, in some respects, but not a crippling one to the analysis. There are a number of reasons for this. First of all, there is not enough data at present to model the decision process until after a switch is made. Second, coal switching, as an industry-wide compliance strategy, will not be sufficient to satisfy the stricter Phase II rules which take effect in 2000. Only FGD allows sufficient reductions to meet phase II standards in the long run and only FGD will allow continued growth in fossil fuel use as a means of generating electricity.[32]

The decision to not use coal switching as an internally determined part of the simulation model is based on the fact that there is clear way to identify the best candidates for the switch prior to the switch occurring. Nor is there clear data on what is involved in coal switching—very unlike the use of FGD technology. What information is available indicates that the costs of coal switching are unit specific. Costs vary across units based on existing take-or-pay contracts, shipping costs, the delivered cost of the lower sulfur coal relative to initial fuel source on a mmbtu level, and any capital investments necessary to handle differences in ash content and burn temperature. Unlike FGD, there is no readily available data that clearly identifies the best candidates for coal switching prior to the signing of a new contract. Nor is it clear how much a given plant can reduce its emissions through coal switching. Again this seems to be based on plant location, design, and existing contracts.

There is a great deal of confusion regarding coal switching as a means of abatement. Initial estimates of the costs of coal switching were very high in terms of capital costs and in terms of increased fuel costs when the clean air act was written in 1990. Coal switching was assumed to be limited option due to difficulties in changing ash/water contents in the fuel mix which could cause fouling of feeding system. Switching to low sulfur coal was assumed to entail some major retrofit of burners to handle the new compositions. Estimates of the retrofit cost, though based purely on conjecture at the time, were quite high. In addition many utilities had long term contracts

[32] New power plants (built after 1990) are not granted allowances. Any allowances needed to cover emissions must be purchased from the market. In any event, New power

with their suppliers, limiting fuel switching as an option.[33] In addition, it had been common wisdom that switching to lower cost coal would increase costs per mmbtu used at a boiler. And it was expected that the push to use low sulfur coal after the Clean Air Act of 1990 was passed would make low sulfur coal even more expensive—with increased demand driving low sulfur coal prices even higher.

Recent data refutes these earlier beliefs. Switching to lower sulfur coals, or introducing lower sulfur coal into a fuel blend, was found to be much easier than initially thought. In fact, coal switching so far has involved little or no capital costs.[34] This may be selection bias at work here—with boilers with no retrofit expense taking advantage of lower sulfur coal, while other plants that would incur such costs are looking at other options. Another interesting outcome is the fact, in many cases, low sulfur coal is cheaper than it was in 1990 and much cheaper than projections were saying in the early 1990's. There are two components to low sulfur coal being cheaper than initial projections. First of all, as Schmalensee points out, transportation costs via rail have dropped since 1990. This has been due to a consolidation of ownership of the rail lines that service the Powder Basin coal mines.[35] Equally important is the fact that the price of lower sulfur coal has not risen with increased demand. This anomaly has been made possible by the fact that western open-pit mines have been able to greatly increase their productivity per man-hour in the face of promises of growing demand under Phase II.

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plants face stricter standards under codes pre-dating the 1990 Clean Air Act.

[33] For a more thorough discussion of coal switching costs see the Integrated Air Pollution Control System Technical Documentation Manuals, volumes 2 and 3.

[34] Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey; "An interim Evaluation of Sulfur Dioxide Emission Trading", Journal f Economic Perspectives, Vol 12, Number 3—summer 1998, Page 55.

[35] Every time cargo had to shift lines there is a cost involved. Consolidating the lines along a route thus lowers the costs of transport.

It is common wisdom that both of these cost changes were products of the increased demand for western coal under Title IV. In some cases the price of the western coal is actually lower than the higher sulfur coal used in many plants that switched to the powder basin coal. This leads to an interesting circumstance. Given the current pricing, units able to make use of the western coal would do so even without title IV requirements.

The end result of all this discrepancy between expectations and the reality, is that there is a great deal of uncertainty involved in the mechanics and costs of coal switching. This uncertainty is seen in the actions taken by many utilities during the short time that Phase I has been in effect. Schmalensee points to a number of utilities that signed long term contracts for low-sulfur coal prior to 1993 and have found themselves paying excessive prices relative to the current market for western coal. In areas where western coal has not been an option, lower sulfur coals have been added to the fuel mix—but at a cost in the form of higher price per mmbtu. And these costs—and the level of emission reduction realized—vary by unit, by utility, and by state. There is, in fact, no clear relationship between the differences in the delivered prices paid for coal and differences in the coal's sulfur content.

The inability to model coal switching as a decision is mitigated, somewhat, by the fact that coal switching has relative little importance as an effective means of meeting the long term compliance requirements for Title IV. Schmalensee made a rough estimate of emission reductions due to Title IV via coal switching and scrubbing. Schmalensee uses a measurement called a "counterfactual emissions" to estimate what so2 emissions would have been in a given period without title IV. The counterfactual emission level is found by multiplying a unit's 1993 emission rate by its actual heat input for the year in question. Comparing this measure to the unit's actual emissions gives Schmalensee a measure of how much reduction have occurred due to title IV. Using this method, Schmalensee determined that 55% of emission reductions from 1993 to 1995 and 1996 were attributable to fuel switching—including the use of lower sulfur coal. [36] [37] However, only 13 percent of the difference between actual and counterfactual emissions at Phase I units were due to true low sulfur coal (from the Powder River Basin, for example).[38] The rest of the fuel switching was to lower sulfur coals from eastern or mid-western mines or to other fuels such as natural gas. [39] However, of the mandated and voluntary phase I units which had emission rates in excess of 1.2 lbs per mmbtu[40] in 1985, only 13% reduced emission rates via coal switching alone to a level sufficient to guarantee compliance under Phase II rules.[41] [42] The 87% of phase I plants will have to either find access to even lower sulfur fuel mixtures or make the move to FGD.

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[36] Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey; "An interim Evaluation of Sulfur Dioxide Emission Trading", <u>Journal f Economic Perspectives</u>, Vol 12, Number 3—summer 1998, Page 54.

[37] In 1997 roughly 80% of the phase I affected units (including substitution units) total emission reductions are attributable to reducing the rate of emission per mmbtu from 1985 levels—that is due to coal switching and scrubbing. The other 20% of reductions can be traced to reduced utilization of the boilers in question relative to 1985 utilization rates.

[38] Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey; "An interim Evaluation of Sulfur Dioxide Emission Trading", <u>Journal f Economic Perspectives</u>, Vol 12, Number 3—summer 1998, Page 59.

[39] Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey; "An interim Evaluation of Sulfur Dioxide Emission Trading", <u>Journal f Economic Perspectives</u>, Vol 12, Number 3—summer 1998, Page 59.

[40] 1.2 pounds of so2 per mmbtu burned in 1985 is the basic emission rule under Title IV.

[41] Data from EPA's compliance reports for 1995, 1996, and 1997.

[42] Assuming utilization rates (mmbtu annual burn totals) consistent with levels evidenced from 1985 to 1990 generation levels.

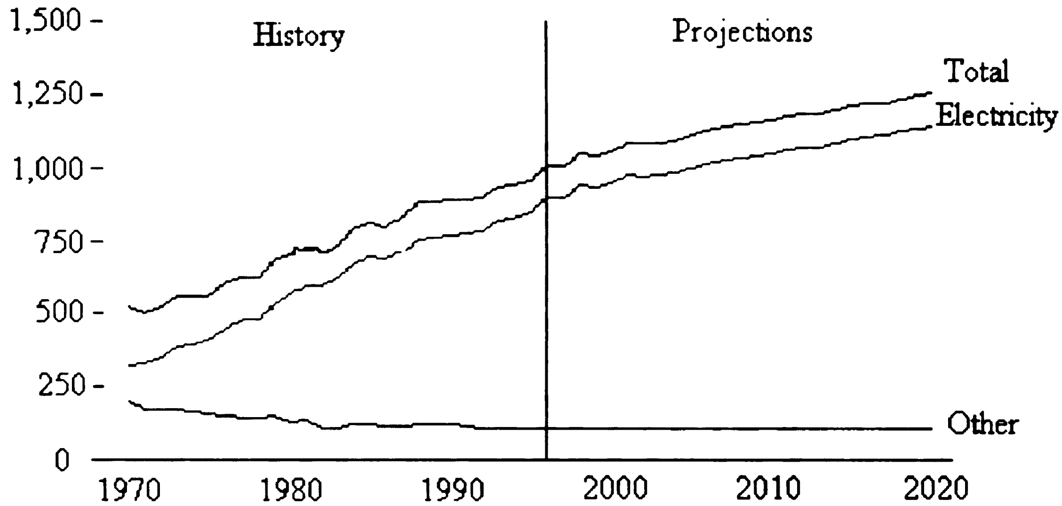


**Diagram G-1: Total Consumption of Coal by Use.**[43]

The prospect of using more low sulfur coal for compliance seems unlikely at best—given that current projections indicate that high sulfur coal consumption is expected to at least hold steady over the next decade. As seen in diagram G-1, coal use as a means of generating electricity has been on a steady increase for the last several decades. More importantly, this trend is expected to continue at a steady rate well into the next century. Since all coal contains some sulfur, the continued growth of coal use guarantees that even with the use of western coal, the utility industry will exceed the Phase II total annual allowance cap. This fact is more readably apparent when looking the present and projected composition of total coal consumption over the same time frame.

[43] DOE. Annual Energy Outlook 1998—Market Trends—Coal.
[Online] Available

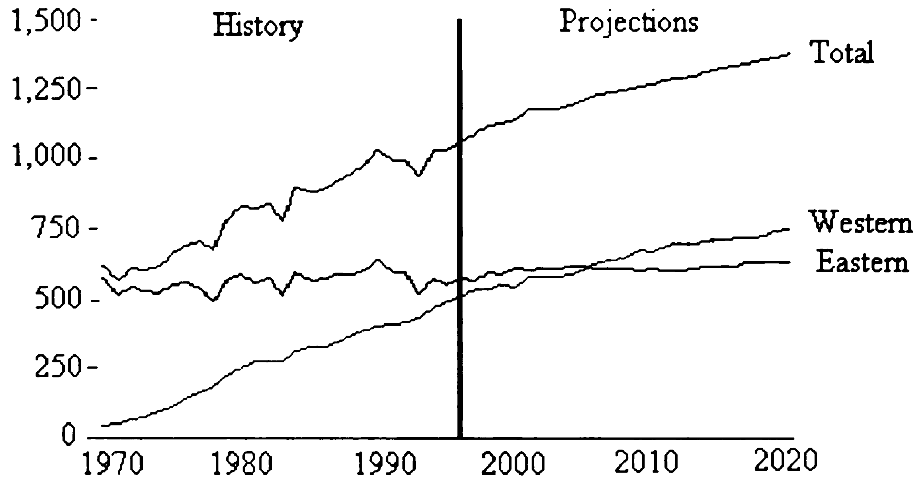


**Diagram G-2: Total Consumption of Coal by Source (Type)**[44]

Diagram G-2 shows the trend line of the change in total composition of coal consumption in terms of western and eastern coal. As can be seen, western coal use has been increasing since the 1970 (with the passage of the first Clean Air Act). Eastern coal has been increasing as well, but at a much slower rate. Even if Eastern coal consumption plateaus completely in the next century, FGD will be required to reduced emissions to within compliance with Phase II of Title IV. At current consumption levels of both coal types, and without the use of FGD, the industry will not meet Phase II requirements. Holding eastern coal consumption constant under phase II still causes emissions to increase as total coal consumption increases—thus the problem of matching total emissions with total allowances only grows with time under coal switching. This

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http://www/eia.doe.gov/oiaf/aeo98/fig102.html, January, February 1999.
[44] DOE. Annual Energy Outlook 1998—Market Trends—Coal.
[Online] Available
http://www/eia.doe.gov/oiaf/aeo98/fig95.html, January, February 1999.

problem is compounded by the fact that high sulfur coal consumption levels are actually expected to rise with time. Diagram G-3 shows the actual and projected break down of coal consumption as high sulfur, medium sulfur (lower sulfur eastern coal), and low sulfur (western coal) for the years 1996, 2000, and 2020. The graph indicates a growth of not only low sulfur coal, but of the higher sulfur grades as well.[45]

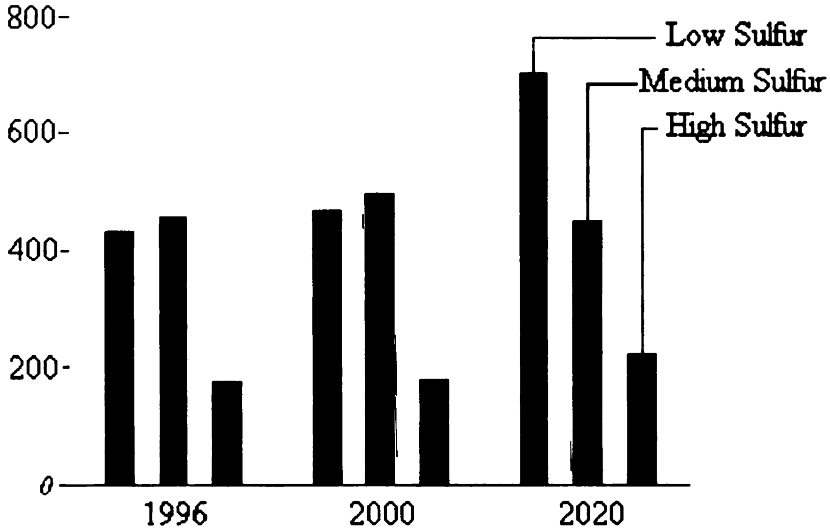


**Diagram G-3: Composition of Coal Consumption**[46]

Coal switching, though wide spread among Phase I units so far, has proven to be of little use in preparing for the long-term compliance requirements of Phase II. And it will prove to be inadequate as an industry-wide phase II compliance strategy.

FGD, on the other hand, is a far more effective long term strategy in terms of a means of meeting and exceeding Phase II requirements. And if there is to be continued

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[45] In the end, the increase in consumption of high sulfur coal may occur due to the fact that a high sulfur content is associated with lower average and marginal costs of emission removal under FGD systems—as will explained in the next section of the paper.
[46] DOE. Annual Energy Outlook 1998—Market Trends—Coal.
[Online] Available
http://www/eia.doe.gov/oiaf/aeo98/fig105.html, January, February 1999

growth in coal consumption as a means of generating electricity, exceeding requirements will be a necessity to free up allowances for new units and greater generation at older units. While Schmalensee found that fuel switching of some sort was responsible for a significant decrease in emissions from 1993 to 1995 and 1996, in terms of effectiveness on a per unit scale, coal switching has had a limited impact relative to the use of scrubbers. Schmalensee found that the "27 'table A' units that began operating scrubbers in 1995 or 1996 accounted for about 45 percent of the total reduction in emissions—(with) almost two-thirds of the reduction from due to scrubbing in 1995 and 1996…contributed by seven units at three large plants." [47] All of these units will be well within Phase II compliance with FGD—along with the other 30 or so phase II affected units with FGD capacity installed.

This is not to say that coal switching will not play a role in the Phase II market. Coal switching will find a use among those plants which, at the long-term equilibrium market price for allowances, will choose to buy rather than sell allowances. To a prospective buyer of allowances, the use of coal switching will be a low cost way to reduce the number of allowances needed to cover their compliance needs. For plants with scrubbers (i.e., units that will be in a position to sell allowances), the use of higher sulfur coal will actually lower both the marginal and average cost of emission reduction—allowing for the economic use of greater amounts of high sulfur coal.[48] The effect of coal switching on the long-term market would thus be expected to decrease the demand and lower the price for allowances relative to a situation where no coal switching

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[47] Schmalensee, Richard, Paul L. Joskow, A. Denny Ellerman, Juan Pablo Montero, and Elizabeth M. Bailey; "An interim Evaluation of Sulfur Dioxide Emission Trading", Journal f Economic Perspectives, Vol 12, Number 3—summer 1998, Page 59.

occurred. This does not change the fact that the prime mover technology in this future market will be FGD. The expected end result of the failure to include coal switching in the decision tree of the simulation is that estimated costs of compliance will be higher than the situation where coal switching is included, but only where the cost of coal switching is less than the price of allowances. At present allowance prices, this is a limited segment of the current phase I market—the 13% of phase I units able to make use of Powder Basin coal.

[48] This is discussed in the next section of the paper regarding the costs of FGD abatement technology.

# APPENDIX H:

## The Calibration of the Emission Transportation and Deposition Model Relative to Historic Source/Receptor Relationships

This appendix to presents the calibration analysis results between the actual 1985 emission/deposition data available and the results of the best fit emission model developed for this paper. It will also present the parameter setting which make up the best fit model and both the actual 1985 sulfate concentration maps and the concentration maps generated by the model for the 1985 emission data.

### Section 1. Actual 1985 Sulfate Concentration Levels in the United States and Canada

Table H-1 below shows the actual ground-level sulfate concentration levels recorded by the EPA in 1985, as fitted to the 150 by 150km grid map used by this paper's emission model. These concentration levels are drawn from the data collected at a number of collection stations operated by the EPA during this time. All concentration data is in terms of u/m3. Note that concentration figures are not available over bodies of water.

**Table H-1: Actual 1985 Sulfate Concentrations**

| 0 | 150 | 300 | 450 | 600 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | 0.51 | 0.51 | 0.51 | 0.84 | 0.84 | 1.76 | 1.76 | 2.87 | 3.31 | 3.31 | 3.31 | 3.53 | 3.53 | 3.97 | 3.97 | 3.97 | 4.41 | 3.31 | 2.65 | 2.43 |
| 300 | 0.51 | 0.51 | 0.66 | 0.84 | 1.32 | 1.76 | 1.76 | 2.87 | 3.53 | 3.53 | 3.53 | 3.75 | 0.00 | 4.63 | 4.41 | 4.41 | 4.63 | 2.78 | 2.91 | 2.65 |
| 450 | 0.52 | 0.82 | 0.75 | 0.84 | 2.08 | 1.81 | 1.87 | 0.00 | 0.00 | 3.53 | 3.75 | 3.97 | 5.29 | 5.73 | 4.63 | 4.63 | 4.86 | 3.50 | 2.98 | 2.21 |
| 600 | 0.55 | 0.51 | 1.03 | 0.92 | 1.43 | 1.98 | 2.43 | 3.47 | 0.00 | 3.74 | 4.41 | 4.41 | 6.62 | 8.38 | 7.72 | 4.86 | 4.37 | 4.45 | 0.00 | 0.00 |
| 750 | 0.54 | 0.53 | 0.99 | 1.10 | 1.76 | 2.76 | 2.79 | 4.04 | 4.63 | 0.00 | 4.71 | 0.00 | 7.72 | 8.96 | 8.54 | 4.30 | 3.98 | 0.00 | 0.00 | 0.00 |
| 900 | 0.25 | 0.62 | 1.04 | 1.32 | 2.06 | 2.87 | 2.87 | 3.38 | 0.00 | 7.28 | 5.07 | 0.00 | 7.06 | 7.72 | 7.72 | 6.07 | 6.59 | 5.74 | 0.00 | 0.00 |
| 1050 | 0.69 | 0.68 | 1.07 | 1.65 | 2.21 | 3.09 | 3.31 | 3.42 | 4.34 | 6.17 | 6.17 | 0.00 | 7.28 | 6.06 | 6.67 | 5.49 | 5.81 | 0.00 | 0.00 | 0.00 |
| 1200 | 0.57 | 0.71 | 1.10 | 2.01 | 2.21 | 3.22 | 3.97 | 4.41 | 5.98 | 5.46 | 5.83 | 7.72 | 6.58 | 6.41 | 6.84 | 5.73 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1350 | 0.71 | 0.88 | 0.88 | 2.43 | 2.87 | 3.53 | 5.07 | 5.35 | 6.97 | 7.20 | 6.24 | 7.43 | 10.50 | 8.82 | 6.73 | 4.30 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1500 | 0.81 | 0.86 | 0.92 | 2.84 | 3.09 | 4.41 | 4.87 | 6.75 | 7.59 | 7.28 | 5.25 | 5.41 | 7.72 | 5.51 | 5.07 | 4.91 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1650 | 0.77 | 0.82 | 1.15 | 2.07 | 4.72 | 4.74 | 4.34 | 5.51 | 6.07 | 5.65 | 5.51 | 5.51 | 5.51 | 4.02 | 3.16 | 3.64 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1800 | 0.68 | 0.95 | 1.26 | 1.92 | 3.97 | 3.49 | 3.97 | 4.19 | 2.86 | 4.04 | 6.44 | 5.51 | 5.12 | 3.22 | 3.05 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1950 | 0.55 | 0.66 | 1.32 | 3.71 | 3.70 | 3.27 | 3.53 | 3.31 | 3.30 | 4.19 | 5.57 | 5.73 | 6.18 | 3.53 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2100 | 0.48 | 0.66 | 1.10 | 1.98 | 3.81 | 3.53 | 3.61 | 3.53 | 3.31 | 3.75 | 3.97 | 3.53 | 2.87 | 3.62 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2250 | 0.71 | 0.66 | 1.32 | 2.21 | 3.53 | 3.13 | 3.13 | 3.11 | 3.81 | 3.31 | 2.82 | 2.40 | 3.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2400 | 0.82 | 0.81 | 0.88 | 2.65 | 2.87 | 2.87 | 3.09 | 3.48 | 3.64 | 3.31 | 2.65 | 2.35 | 3.97 | 3.24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2550 | 0.84 | 0.84 | 1.10 | 2.65 | 2.45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 3.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2700 | 0.68 | 0.99 | 2.01 | 2.43 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 2.46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2850 | 0.60 | 0.66 | 1.98 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 2.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3000 | 0.55 | 0.55 | 1.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Actual emission per plant in 1985 were also available from a number of sources—such as the EPA emission compliance reports and from the Electric Monthly. This data was used in this paper's emission model to generate a number of sulfate concentration maps based on the basic parameters used in the NAPAP RADM emission models. Using data, the individual emission plume from each individual source was modeled under a winter and a summer model (as explained in the body of chapter 3) for a number of wind directions. The results of all of the emission model runs were collected in a data set according to location on the grid map seen above. Thus providing 151 concentration grid maps for each assumed weather system and each assumed prevailing wind pattern—with each individual grid map representing the emissions from all the sources from within a given 150X150 km grid location.

Four basic systems were assumed for each point source. Two systems represent the range of prevailing wind directions under the warm climate distribution system (the summer model) and two systems represent the range of prevailing wind directions under the cold climate distribution system (the winter model). Again the concept of a cold and warm distribution system is discussed in the text of chapter 2. Assuming that due east is represented by an angle of 0 degrees, each system was run at two prevailing wind directions—0 and 45 degrees from due east (east and north east of the point source). Thus four sets of 151 data maps were collected (thus a total of 604 maps)—each with 480 data points representing the ground level sulfate concentrations generated all the sources within a given 150 X 150 km area.

Each of the four data maps for each of the 480 source locations represents the range of possible transportation, distribution, and deposition of emissions from that source location given the underlying assumptions used to design the EPA's RADM model. Percentage weights (which sum to 1) assigned to each concentration result map for each source location and region crossed by the plume provides a composite map of the emissions from each source location. Changing the weights changes the prevailing wind and weather pattern—and thus the distribution of emissions from the source location to the 480 receptor areas on the grid. A given set of weights on the concentration maps of a given source location represents the parameters of the emission transport and deposition model for that point source. Each source location's parameters are set individually based on its location and regions that the plume covers on the grid. A program was then set up to determine the sum of all concentration maps for the all the sources from each 150X150 source area given location specific "weather" parameter weights on each source locations 4 emission maps. Each set of parameters thus generated a sulfate concentration map of 480 data points based on actual 1985 source specific emission data. A series of weights was applied, starting with weights that represented the common wisdom about weather patterns, until the correlation coefficient between the actual 480 1985 sulfate concentration map location-specific data points and the model's 480 sulfate concentration location-specific data points peaks.

The parameter set that peaks the correlation between the actual 1985 data set and the model's map is given in table H-2 below.

**Table H-2: Emission Model Parameter Set**

| X | Y | SUM | Ratio of Summer To Winter By receptor X coord | Ratio of 0 to 45 Degree Wind |
|---|---|---|---|---|
| -1500 | 1350 | 541.1133 | NA | 1 |
| -1500 | 1500 | 632.4738 | NA | 1 |
| -1500 | 1650 | 1235.369 | NA | 1 |
| -1350 | 1350 | 234.8656 | NA | 1 |
| -1350 | 1800 | 260.317 | NA | 1 |
| -1200 | 450 | 68803.2 | NA | 1 |
| -1200 | 1800 | 1124.161 | NA | 1 |
| -1200 | 1950 | 398.7498 | NA | 1 |
| -900 | 1650 | 40602.48 | NA | 1 |
| -750 | 1950 | 7274.609 | NA | 1 |
| -600 | 1200 | 5327.684 | NA | 1 |
| -600 | 1350 | 17972.58 | NA | 1 |
| -600 | 1650 | 79202.91 | NA | 1 |
| -600 | 2100 | 15208.4 | NA | 1 |
| -450 | 1050 | 18596.23 | NA | 1 |
| -450 | 1800 | 10739.99 | NA | 1 |
| -450 | 2100 | 47180.42 | NA | 1 |
| -300 | 750 | 14506.54 | NA | 1 |
| -300 | 1200 | 71004.93 | NA | 1 |
| -300 | 1350 | 1365.223 | NA | 1 |
| -150 | 450 | 1652.679 | NA | 1 |
| -150 | 1050 | 27244.3 | NA | 1 |
| -150 | 1650 | 26630.79 | NA | 1 |
| -0 | 900 | 20639.08 | NA | 1 |
| -0 | 1350 | 71100.97 | NA | 1 |
| -0 | 1500 | 9680.383 | NA | 1 |
| 150 | 900 | 2646.688 | 0.9 | 0.045455 |
| 150 | 1200 | 2.55668 | 0.9 | 0.045455 |

**Table H-2 (Continued)**

| | | | | |
|---|---|---|---|---|
| 150 | 2250 | 81.02479 | 0.9 | 0.045455 |
| 300 | 600 | 144826.8 | 0.9 | 0.090909 |
| 300 | 1200 | 44349.91 | 0.9 | 0.090909 |
| 300 | 2250 | 455.7831 | 0.9 | 0.090909 |
| 300 | 2400 | 4.70486 | 0.9 | 0.090909 |
| 450 | 2550 | 84738.17 | 0.7 | 0.136364 |
| 600 | 750 | 31067.46 | 0.8 | 0.181818 |
| 600 | 1500 | 82626.42 | 0.8 | 0.181818 |
| 600 | 1650 | 41582.12 | 0.8 | 0.181818 |
| 600 | 1950 | 19905.5 | 0.8 | 0.181818 |
| 600 | 2100 | 4415.946 | 0.8 | 0.181818 |
| 600 | 2250 | 172725.8 | 0.8 | 0.181818 |
| 600 | 2400 | 13309.3 | 0.8 | 0.181818 |
| 600 | 2550 | 5691.012 | 0.8 | 0.181818 |
| 600 | 2700 | 23915.57 | 0.8 | 0.181818 |
| 750 | 600 | 28139.99 | 0.8 | 0.227273 |
| 750 | 900 | 22.14028 | 0.8 | 0.227273 |
| 750 | 1050 | 51560.53 | 0.8 | 0.227273 |
| 750 | 1200 | 71184.75 | 0.8 | 0.227273 |
| 750 | 1350 | 3583.845 | 0.8 | 0.227273 |
| 750 | 1500 | 105760.9 | 0.8 | 0.227273 |
| 750 | 1800 | 71059.66 | 0.8 | 0.227273 |
| 750 | 2100 | 107647.5 | 0.8 | 0.227273 |
| 750 | 2550 | 146122.1 | 0.8 | 0.227273 |
| 900 | 900 | 4168.333 | 0.8 | 0.272727 |
| 900 | 1050 | 60325.9 | 0.8 | 0.272727 |
| 900 | 1200 | 33939.77 | 0.8 | 0.272727 |
| 900 | 1500 | 349947.2 | 0.8 | 0.272727 |
| 900 | 2550 | 11835.21 | 0.8 | 0.272727 |
| 1050 | 600 | 41871.95 | 0.8 | 0.318182 |
| 1050 | 900 | 29199.28 | 0.8 | 0.318182 |
| 1050 | 1200 | 101901.4 | 0.8 | 0.318182 |
| 1050 | 1500 | 204148.3 | 0.8 | 0.318182 |
| 1050 | 2100 | 34209.68 | 0.8 | 0.318182 |
| 1050 | 2400 | 30597.68 | 0.8 | 0.318182 |
| 1050 | 2550 | 30456.64 | 0.8 | 0.318182 |
| 1200 | 750 | 73175.98 | 0.8 | 0.363636 |
| 1200 | 1050 | 127255 | 0.8 | 0.363636 |
| 1200 | 1200 | 144459.8 | 0.8 | 0.363636 |
| 1200 | 1350 | 107272.3 | 0.8 | 0.363636 |
| 1200 | 1500 | 401736.3 | 0.8 | 0.363636 |
| 1200 | 1650 | 193324.9 | 0.8 | 0.363636 |
| 1200 | 1950 | 54557.72 | 0.8 | 0.363636 |
| 1200 | 2100 | 17938.16 | 0.8 | 0.363636 |
| 1200 | 2250 | 9.345033 | 0.8 | 0.363636 |
| 1200 | 2400 | 3.110654 | 0.8 | 0.363636 |
| 1200 | 2550 | 33.47846 | 0.8 | 0.363636 |
| 1350 | 600 | 25693.13 | 0.6 | 0.409091 |

**Table H-2 (Continued)**

| | | | | |
|---|---|---|---|---|
| 1350 | 1050 | 187133.7 | 0.6 | 0.409091 |
| 1350 | 1200 | 348019.6 | 0.6 | 0.409091 |
| 1350 | 1350 | 181975.1 | 0.6 | 0.409091 |
| 1350 | 1500 | 340462.6 | 0.6 | 0.409091 |
| 1350 | 1650 | 167059.6 | 0.6 | 0.409091 |
| 1350 | 2250 | 109077.4 | 0.6 | 0.409091 |
| 1350 | 2400 | 84130.75 | 0.6 | 0.409091 |
| 1350 | 2550 | 18055 | 0.6 | 0.409091 |
| 1500 | 1050 | 127558.3 | 0.5 | 0.454545 |
| 1500 | 1200 | 41605.77 | 0.5 | 0.454545 |
| 1500 | 1350 | 255965.2 | 0.5 | 0.454545 |
| 1500 | 1500 | 309230.4 | 0.5 | 0.454545 |
| 1500 | 1650 | 185388.2 | 0.5 | 0.454545 |
| 1500 | 1800 | 595779.2 | 0.5 | 0.454545 |
| 1500 | 1950 | 133052.2 | 0.5 | 0.454545 |
| 1500 | 2100 | 188395.7 | 0.5 | 0.454545 |
| 1500 | 2400 | 151224.4 | 0.5 | 0.454545 |
| 1650 | 900 | 39125.07 | 0.3 | 0.5 |
| 1650 | 1050 | 153070.6 | 0.3 | 0.5 |
| 1650 | 1350 | 570897.1 | 0.3 | 0.5 |
| 1650 | 1500 | 602511.5 | 0.3 | 0.5 |
| 1650 | 1650 | 20822.05 | 0.3 | 0.5 |
| 1650 | 2250 | 181382.9 | 0.3 | 0.5 |
| 1650 | 2400 | 13908.86 | 0.3 | 0.5 |
| 1800 | 1050 | 330616.3 | 0.3 | 0.545455 |
| 1800 | 1200 | 73024.9 | 0.3 | 0.545455 |
| 1800 | 1350 | 242825.4 | 0.3 | 0.545455 |
| 1800 | 1500 | 419251.9 | 0.3 | 0.545455 |
| 1800 | 1650 | 81801.85 | 0.3 | 0.545455 |
| 1800 | 1800 | 103847 | 0.3 | 0.545455 |
| 1800 | 1950 | 308191.9 | 0.3 | 0.545455 |
| 1800 | 2400 | 7296.567 | 0.3 | 0.545455 |
| 1950 | 900 | 32698.54 | 0.3 | 0.590909 |
| 1950 | 1050 | 54224.26 | 0.3 | 0.590909 |
| 1950 | 1200 | 731175.2 | 0.3 | 0.590909 |
| 1950 | 1350 | 825526.7 | 0.3 | 0.590909 |
| 1950 | 1500 | 237062.6 | 0.3 | 0.590909 |
| 1950 | 1650 | 27880.62 | 0.3 | 0.590909 |
| 1950 | 1800 | 31980.81 | 0.3 | 0.590909 |
| 1950 | 1950 | 15803.79 | 0.3 | 0.590909 |
| 1950 | 2100 | 391101.1 | 0.3 | 0.590909 |
| 1950 | 2550 | 9689.13 | 0.3 | 0.590909 |
| 1950 | 2700 | 170751.5 | 0.3 | 0.590909 |
| 2100 | 900 | 67761.1 | 0.1 | 0.636364 |
| 2100 | 1050 | 46476.15 | 0.1 | 0.636364 |
| 2100 | 1200 | 518931.9 | 0.1 | 0.636364 |
| 2100 | 1350 | 220120.2 | 0.1 | 0.636364 |
| 2100 | 1650 | 85422.83 | 0.1 | 0.636364 |
| 2100 | 1800 | 93181.79 | 0.1 | 0.636364 |
| 2100 | 1950 | 85067.36 | 0.1 | 0.636364 |

**Table H-2 (Continued)**

| | | | | |
|---|---|---|---|---|
| 2100 | 2550 | 143381.3 | 0.1 | 0.636364 |
| 2100 | 2700 | 71129.68 | 0.1 | 0.636364 |
| 2250 | 900 | 57542.67 | 0 | 0.681818 |
| 2250 | 1050 | 5183.236 | 0 | 0.681818 |
| 2250 | 1200 | 149598.4 | 0 | 0.681818 |
| 2250 | 1350 | 202992.9 | 0 | 0.681818 |
| 2250 | 1650 | 136812.7 | 0 | 0.681818 |
| 2250 | 1800 | 9439.59 | 0 | 0.681818 |
| 2250 | 1950 | 36162.14 | 0 | 0.681818 |
| 2250 | 2550 | 7278.475 | 0 | 0.681818 |
| 2250 | 2700 | 15150.65 | 0 | 0.681818 |
| 2250 | 2850 | 45861.29 | 0 | 0.681818 |
| 2400 | 900 | 61869.62 | 0 | 0.727273 |
| 2400 | 1050 | 99358.01 | 0 | 0.727273 |
| 2400 | 1200 | 174487.8 | 0 | 0.727273 |
| 2400 | 1350 | 123021.3 | 0 | 0.727273 |
| 2400 | 1500 | 61989.34 | 0 | 0.727273 |
| 2550 | 750 | 75886.42 | 0 | 0.772727 |
| 2550 | 900 | 75358.57 | 0 | 0.772727 |
| 2550 | 1050 | 214237.3 | 0 | 0.772727 |
| 2550 | 1200 | 65807.97 | 0 | 0.772727 |
| 2700 | 600 | 249.2271 | 0.1 | 0.818182 |
| 2700 | 750 | 10016.99 | 0.1 | 0.818182 |
| 2700 | 900 | 170293 | 0.1 | 0.818182 |
| 2700 | 2100 | 118055.8 | 0.1 | 0.818182 |

The parameter set results in the concentration emission map depicted in Table H-3 below.

**Table H-3 Adjusted Emission Map**

Model Total Sulfate Concentration--Mid Range Estimate

| 0 | 150 | 300 | 450 | 600 | 750 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | 0.30 | 0.32 | 0.46 | 0.43 | 0.55 | 0.68 | 0.79 | 1.03 | 0.97 | 1.25 | 1.35 | 1.47 | 1.62 | 1.85 | 2.07 | 2.42 | 2.46 | 2.88 | 3.02 | 3.15 | 2.45 |
| 300 | 0.53 | 0.56 | 0.64 | 0.77 | 0.90 | 1.15 | 1.38 | 1.85 | 1.88 | 2.09 | 1.89 | 2.31 | 0.00 | 2.66 | 2.64 | 3.35 | 3.76 | 3.80 | 3.89 | 3.95 | 3.05 |
| 450 | 0.67 | 0.68 | 0.80 | 0.99 | 1.25 | 1.45 | 2.06 | 0.00 | 0.00 | 2.95 | 2.75 | 3.43 | 3.73 | 3.65 | 3.89 | 4.41 | 4.66 | 4.73 | 4.56 | 4.55 | 3.29 |
| 600 | 0.73 | 1.23 | 0.84 | 1.15 | 1.50 | 2.02 | 3.16 | 3.55 | 0.00 | 4.48 | 4.53 | 5.24 | 5.53 | 4.30 | 5.44 | 7.01 | 5.89 | 5.17 | 0.00 | 0.00 | 0.00 |
| 750 | 0.87 | 0.92 | 0.99 | 1.48 | 1.65 | 2.43 | 3.85 | 5.08 | 5.51 | 0.00 | 6.61 | 0.00 | 7.67 | 8.59 | 9.13 | 8.85 | 8.08 | 0.00 | 0.00 | 0.00 | 0.00 |
| 900 | 0.92 | 0.92 | 0.90 | 1.48 | 1.97 | 3.06 | 4.58 | 5.85 | 0.00 | 7.56 | 8.19 | 0.00 | 10.39 | 11.23 | 11.24 | 9.63 | 8.41 | 6.11 | 0.00 | 0.00 | 0.00 |
| 1050 | 1.01 | 1.00 | 0.92 | 1.46 | 2.21 | 3.37 | 4.92 | 6.75 | 7.67 | 8.43 | 9.18 | 0.00 | 11.58 | 11.33 | 10.99 | 9.39 | 7.69 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1200 | 0.85 | 1.00 | 1.05 | 1.76 | 2.74 | 3.93 | 5.79 | 7.77 | 8.71 | 9.49 | 9.49 | 11.57 | 12.95 | 12.47 | 10.92 | 8.31 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1350 | 0.86 | 1.01 | 1.04 | 1.79 | 2.52 | 3.84 | 5.56 | 7.97 | 8.50 | 9.80 | 9.91 | 10.83 | 12.56 | 10.10 | 8.26 | 5.87 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1500 | 0.92 | 0.97 | 0.94 | 1.81 | 2.60 | 4.23 | 5.31 | 7.80 | 8.38 | 9.61 | 8.76 | 9.34 | 9.65 | 7.04 | 6.44 | 4.90 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1650 | 0.85 | 0.84 | 0.93 | 1.78 | 2.34 | 3.28 | 4.47 | 6.56 | 6.74 | 7.84 | 6.47 | 7.66 | 7.83 | 6.57 | 5.42 | 4.77 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1800 | 0.79 | 0.79 | 1.02 | 1.38 | 1.97 | 2.23 | 3.20 | 4.42 | 5.06 | 6.14 | 4.99 | 6.37 | 6.17 | 5.62 | 4.24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1950 | 0.58 | 0.64 | 1.02 | 1.40 | 1.50 | 1.81 | 2.03 | 3.17 | 3.77 | 4.22 | 3.91 | 4.67 | 4.61 | 4.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2100 | 0.47 | 0.54 | 0.82 | 1.27 | 1.59 | 1.79 | 2.06 | 2.33 | 2.96 | 3.42 | 3.45 | 3.45 | 3.88 | 3.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2250 | 0.40 | 0.53 | 0.82 | 1.57 | 1.53 | 1.41 | 1.60 | 1.86 | 2.41 | 2.11 | 2.49 | 2.85 | 2.67 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2400 | 0.37 | 0.48 | 0.90 | 1.18 | 1.24 | 1.45 | 1.27 | 1.44 | 1.80 | 1.84 | 1.76 | 2.22 | 2.11 | 1.84 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2550 | 0.30 | 0.44 | 0.83 | 0.96 | 1.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.25 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2700 | 0.15 | 0.40 | 0.63 | 0.76 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.80 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2850 | 0.11 | 0.16 | 0.45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3000 | 0.09 | 0.11 | 0.10 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3150 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3300 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3450 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3600 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

The results of running an OLS analysis on H-1 relative to H-3 results in a correlation coefficient of 0.913299 between the model's estimate of sulfate concentration levels for 1985 emission levels and the actual sulfate concentration levels in 1985. The statistics of the analysis is given in table H-4 below:

| Table H-4: Correlation Analysis Between Model Projections And Actual Sulfate Concentration Levels | |
|---|---|
| a= | 0.4650 |
| b= | 0.7108 |
| | |
| Standard error | 0.0094 |
| Correlation | 0.9133 |
| R square | 0.8341 |

Both map H-1 and map H-3 were transformed into vectors of concentration levels arranged first by its X coordinate and then in terms of its Y coordinate (each X coordinate and all of its attached Y data points are taken as a vector and the vectors are arranged into a single column). The two vectors were then mapped against each other—this forms a scatter diagram of the concentration levels of both maps for common receptor points on the map. This scatter diagram shows a close correlation between the concentration levels of the model under the given parameters and the actual observed 1985 sulfate concentration levels.

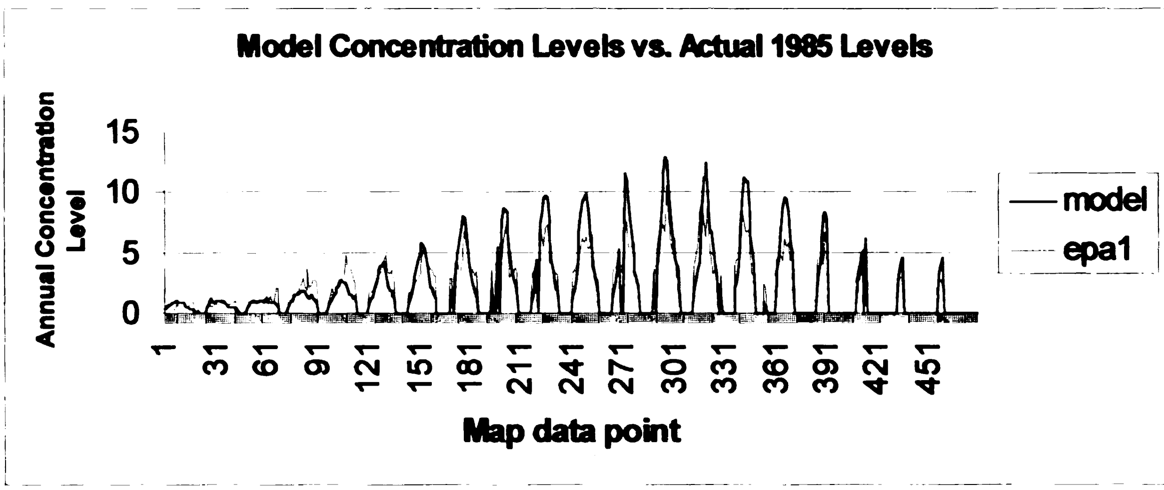


**Diagram H-1: Model Concentration Levels vs. Actual 1985 Levels**

## APPENDIX I:

### 95% Confidence Interval of the Projected Sulfate Concentration Grid Maps for the Phase II Emission Goal as an Allowance or a Cap, Including External Cost Effects

The maps given hear represent the 95% confidence interval of sulfate concentration levels at ground level given the parameter settings and correlation statistics discussed in Appendix J. The first set of maps represents the upper (Table I-1), lower (Table I-2), and mid-range (Table I-3) ground level concentration levels for the 95% confidence interval for emission levels where phase II is applied as a cap. The second set of maps represents the upper (Table I-4), lower (Table I-5), and mid-range (Table I-6) ground level concentration levels for the 95% confidence interval for emission levels where phase II is applied via marketable allowances. All values are in u/m3 in annual concentration levels.

External cost effects of the upper and lower emission concentration levels are given in Table I-7 and Table I-8, respectively.

## Table I-1 Upper Bound of 95% Confidence Interval For Emission Levels under Phase II as a Cap

| 0 | 150 | 300 | 450 | 600 | 750 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | 0.09 | 0.10 | 0.11 | 0.11 | 0.14 | 0.14 | 0.15 | 0.16 | 0.20 | 0.22 | 0.26 | 0.27 | 0.29 | 0.31 | 0.33 | 0.37 | 0.39 | 0.40 | 0.39 | 0.39 | 0.37 |
| 300 | 0.12 | 0.15 | 0.17 | 0.18 | 0.19 | 0.20 | 0.21 | 0.25 | 0.30 | 0.33 | 0.36 | 0.43 | 0.00 | 0.54 | 0.55 | 0.61 | 0.61 | 0.67 | 0.68 | 0.64 | 0.54 |
| 450 | 0.19 | 0.23 | 0.24 | 0.23 | 0.27 | 0.28 | 0.33 | 0.00 | 0.00 | 0.51 | 0.58 | 0.68 | 0.81 | 0.86 | 0.90 | 0.98 | 1.00 | 0.97 | 0.95 | 0.89 | 0.74 |
| 600 | 0.26 | 0.29 | 0.33 | 0.30 | 0.36 | 0.39 | 0.49 | 0.55 | 0.00 | 0.77 | 0.91 | 1.08 | 1.17 | 1.30 | 1.42 | 1.54 | 1.54 | 1.47 | 0.00 | 0.00 | 0.00 |
| 750 | 0.30 | 0.33 | 0.36 | 0.38 | 0.43 | 0.49 | 0.63 | 0.79 | 1.00 | 0.00 | 1.35 | 0.00 | 1.79 | 2.03 | 2.03 | 2.10 | 2.16 | 0.00 | 0.00 | 0.00 | 0.00 |
| 900 | 0.38 | 0.39 | 0.39 | 0.46 | 0.52 | 0.65 | 0.88 | 1.12 | 0.00 | 1.69 | 1.99 | 0.00 | 2.68 | 2.73 | 2.80 | 2.71 | 2.77 | 2.83 | 0.00 | 0.00 | 0.00 |
| 1050 | 0.47 | 0.44 | 0.43 | 0.49 | 0.64 | 0.79 | 1.07 | 1.43 | 1.95 | 2.36 | 2.99 | 0.00 | 3.58 | 3.41 | 3.31 | 3.40 | 3.38 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1200 | 0.47 | 0.53 | 0.55 | 0.55 | 0.64 | 1.06 | 1.48 | 1.90 | 2.38 | 2.99 | 3.63 | 4.17 | 4.57 | 5.07 | 4.62 | 4.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1350 | 0.60 | 0.51 | 0.65 | 0.72 | 0.94 | 1.18 | 1.76 | 2.14 | 2.75 | 3.49 | 4.17 | 4.62 | 5.20 | 5.39 | 5.27 | 5.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1500 | 0.56 | 0.61 | 0.66 | 0.85 | 1.07 | 1.45 | 2.07 | 2.40 | 3.13 | 3.79 | 4.30 | 5.01 | 5.09 | 5.27 | 5.11 | 4.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1650 | 0.66 | 0.71 | 0.68 | 0.90 | 1.09 | 1.38 | 1.90 | 2.41 | 2.95 | 3.64 | 4.09 | 4.48 | 4.81 | 4.91 | 4.88 | 4.39 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1800 | 0.65 | 0.60 | 0.69 | 0.79 | 1.20 | 1.46 | 1.80 | 2.21 | 2.72 | 3.42 | 4.02 | 4.25 | 4.36 | 4.64 | 4.47 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1950 | 0.56 | 0.56 | 0.69 | 0.94 | 1.24 | 1.42 | 1.64 | 2.05 | 2.52 | 3.03 | 3.51 | 3.95 | 3.85 | 3.64 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2100 | 0.48 | 0.51 | 0.68 | 1.00 | 1.34 | 1.54 | 1.67 | 1.84 | 2.17 | 2.81 | 3.17 | 3.13 | 3.50 | 3.52 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2250 | 0.40 | 0.46 | 0.71 | 1.27 | 1.47 | 1.34 | 1.54 | 1.65 | 2.09 | 2.35 | 2.61 | 2.74 | 2.91 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2400 | 0.34 | 0.43 | 0.69 | 1.02 | 1.21 | 1.34 | 1.46 | 1.56 | 1.76 | 2.09 | 2.12 | 2.33 | 2.28 | 2.46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2550 | 0.31 | 0.42 | 0.74 | 0.96 | 1.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 2.11 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2700 | 0.25 | 0.34 | 0.50 | 0.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.57 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2850 | 0.20 | 0.23 | 0.41 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3000 | 0.10 | 0.20 | 0.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3150 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3300 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3450 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3600 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## Table I-2: Lower Bound of 95% Confidence Interval For Emission Levels under Phase II as a Cap

| 0 | 150 | 300 | 450 | 600 | 750 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | 0.04 | 0.04 | 0.05 | 0.06 | 0.08 | 0.09 | 0.09 | 0.11 | 0.14 | 0.17 | 0.20 | 0.21 | 0.24 | 0.25 | 0.27 | 0.31 | 0.33 | 0.34 | 0.33 | 0.33 | 0.31 |
| 300 | 0.06 | 0.10 | 0.11 | 0.12 | 0.13 | 0.14 | 0.15 | 0.19 | 0.24 | 0.27 | 0.30 | 0.37 | 0.00 | 0.48 | 0.50 | 0.55 | 0.55 | 0.61 | 0.62 | 0.58 | 0.49 |
| 450 | 0.14 | 0.17 | 0.18 | 0.17 | 0.21 | 0.22 | 0.28 | 0.00 | 0.00 | 0.45 | 0.52 | 0.62 | 0.75 | 0.80 | 0.84 | 0.92 | 0.95 | 0.91 | 0.89 | 0.83 | 0.68 |
| 600 | 0.20 | 0.23 | 0.27 | 0.24 | 0.31 | 0.33 | 0.44 | 0.49 | 0.00 | 0.71 | 0.85 | 1.03 | 1.12 | 1.24 | 1.36 | 1.48 | 1.49 | 1.41 | 0.00 | 0.00 | 0.00 |
| 750 | 0.24 | 0.27 | 0.30 | 0.32 | 0.37 | 0.43 | 0.57 | 0.73 | 0.94 | 0.00 | 1.29 | 0.00 | 1.74 | 1.97 | 1.97 | 2.04 | 2.10 | 0.00 | 0.00 | 0.00 | 0.00 |
| 900 | 0.33 | 0.33 | 0.33 | 0.40 | 0.46 | 0.60 | 0.83 | 1.06 | 0.00 | 1.64 | 1.93 | 0.00 | 2.63 | 2.67 | 2.74 | 2.65 | 2.71 | 2.77 | 0.00 | 0.00 | 0.00 |
| 1050 | 0.42 | 0.38 | 0.38 | 0.43 | 0.59 | 0.73 | 1.02 | 1.38 | 1.90 | 2.30 | 2.94 | 0.00 | 3.53 | 3.35 | 3.25 | 3.34 | 3.33 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1200 | 0.41 | 0.48 | 0.49 | 0.49 | 0.78 | 1.00 | 1.42 | 1.84 | 2.32 | 2.93 | 3.57 | 4.11 | 4.51 | 5.01 | 4.56 | 4.22 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1350 | 0.54 | 0.45 | 0.59 | 0.66 | 0.88 | 1.12 | 1.70 | 2.08 | 2.69 | 3.43 | 4.11 | 4.56 | 5.15 | 5.33 | 5.21 | 4.96 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1500 | 0.51 | 0.56 | 0.60 | 0.80 | 1.02 | 1.39 | 2.01 | 2.35 | 3.07 | 3.74 | 4.25 | 4.95 | 5.03 | 5.22 | 5.05 | 4.85 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1650 | 0.60 | 0.65 | 0.63 | 0.84 | 1.04 | 1.32 | 1.84 | 2.35 | 2.89 | 3.58 | 4.03 | 4.43 | 4.75 | 4.85 | 4.82 | 4.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1800 | 0.60 | 0.55 | 0.64 | 0.73 | 1.14 | 1.41 | 1.74 | 2.15 | 2.67 | 3.36 | 3.96 | 4.19 | 4.30 | 4.59 | 4.41 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1950 | 0.50 | 0.50 | 0.63 | 0.88 | 1.18 | 1.37 | 1.59 | 2.00 | 2.46 | 2.97 | 3.45 | 3.89 | 3.80 | 3.58 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2100 | 0.42 | 0.45 | 0.62 | 0.94 | 1.28 | 1.48 | 1.61 | 1.78 | 2.12 | 2.75 | 3.12 | 3.08 | 3.44 | 3.46 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2250 | 0.34 | 0.40 | 0.65 | 1.21 | 1.41 | 1.28 | 1.49 | 1.59 | 2.03 | 2.29 | 2.56 | 2.68 | 2.86 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2400 | 0.29 | 0.37 | 0.63 | 0.96 | 1.15 | 1.28 | 1.41 | 1.50 | 1.70 | 2.03 | 2.06 | 2.28 | 2.23 | 2.40 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2550 | 0.25 | 0.36 | 0.68 | 0.90 | 1.24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 2.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2700 | 0.19 | 0.28 | 0.44 | 0.65 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.51 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2850 | 0.15 | 0.18 | 0.35 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.21 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3000 | 0.05 | 0.15 | 0.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3150 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3300 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3450 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3600 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

# Table I-3: Mid-range of 95% Confidence Interval For Emission Levels under Phase II as a Cap

| 0 | 150 | 300 | 450 | 600 | 750 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | 0.06 | 0.07 | 0.08 | 0.08 | 0.11 | 0.11 | 0.12 | 0.14 | 0.17 | 0.20 | 0.23 | 0.24 | 0.27 | 0.28 | 0.30 | 0.34 | 0.36 | 0.37 | 0.36 | 0.36 | 0.34 |
| 300 | 0.09 | 0.12 | 0.14 | 0.15 | 0.16 | 0.17 | 0.18 | 0.22 | 0.27 | 0.30 | 0.33 | 0.40 | 0.00 | 0.51 | 0.53 | 0.58 | 0.58 | 0.64 | 0.65 | 0.61 | 0.52 |
| 450 | 0.17 | 0.20 | 0.21 | 0.20 | 0.24 | 0.25 | 0.31 | 0.00 | 0.00 | 0.48 | 0.55 | 0.65 | 0.78 | 0.83 | 0.87 | 0.95 | 0.97 | 0.94 | 0.92 | 0.86 | 0.71 |
| 600 | 0.23 | 0.26 | 0.30 | 0.27 | 0.33 | 0.36 | 0.46 | 0.52 | 0.00 | 0.74 | 0.88 | 1.05 | 1.14 | 1.27 | 1.39 | 1.51 | 1.51 | 1.44 | 0.00 | 0.00 | 0.00 |
| 750 | 0.27 | 0.30 | 0.33 | 0.35 | 0.40 | 0.46 | 0.60 | 0.76 | 0.97 | 0.00 | 1.32 | 0.00 | 1.77 | 2.00 | 2.00 | 2.07 | 2.13 | 0.00 | 0.00 | 0.00 | 0.00 |
| 900 | 0.36 | 0.36 | 0.36 | 0.43 | 0.49 | 0.62 | 0.85 | 1.09 | 0.00 | 1.66 | 1.96 | 0.00 | 2.65 | 2.70 | 2.77 | 2.68 | 2.74 | 2.80 | 0.00 | 0.00 | 0.00 |
| 1050 | 0.44 | 0.41 | 0.41 | 0.46 | 0.62 | 0.76 | 1.04 | 1.41 | 1.92 | 2.33 | 2.97 | 0.00 | 3.56 | 3.38 | 3.28 | 3.37 | 3.35 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1200 | 0.44 | 0.50 | 0.52 | 0.52 | 0.81 | 1.03 | 1.45 | 1.87 | 2.35 | 2.96 | 3.60 | 4.14 | 4.54 | 5.04 | 4.59 | 4.25 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1350 | 0.57 | 0.48 | 0.62 | 0.69 | 0.91 | 1.15 | 1.73 | 2.11 | 2.72 | 3.46 | 4.14 | 4.59 | 5.18 | 5.36 | 5.24 | 4.99 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1500 | 0.54 | 0.58 | 0.63 | 0.83 | 1.04 | 1.42 | 2.04 | 2.37 | 3.10 | 3.76 | 4.28 | 4.98 | 5.06 | 5.24 | 5.08 | 4.88 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1650 | 0.63 | 0.68 | 0.65 | 0.87 | 1.06 | 1.35 | 1.87 | 2.38 | 2.92 | 3.61 | 4.06 | 4.45 | 4.78 | 4.88 | 4.85 | 4.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1800 | 0.62 | 0.57 | 0.66 | 0.76 | 1.17 | 1.44 | 1.77 | 2.18 | 2.70 | 3.39 | 3.99 | 4.22 | 4.33 | 4.61 | 4.44 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1950 | 0.53 | 0.53 | 0.66 | 0.91 | 1.21 | 1.39 | 1.62 | 2.03 | 2.49 | 3.00 | 3.48 | 3.92 | 3.83 | 3.61 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2100 | 0.45 | 0.48 | 0.65 | 0.97 | 1.31 | 1.51 | 1.64 | 1.81 | 2.15 | 2.78 | 3.14 | 3.10 | 3.47 | 3.49 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2250 | 0.37 | 0.43 | 0.68 | 1.24 | 1.44 | 1.31 | 1.52 | 1.62 | 2.06 | 2.32 | 2.59 | 2.71 | 2.89 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2400 | 0.32 | 0.40 | 0.66 | 0.99 | 1.18 | 1.31 | 1.44 | 1.53 | 1.73 | 2.06 | 2.09 | 2.31 | 2.25 | 2.43 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2550 | 0.28 | 0.39 | 0.71 | 0.93 | 1.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 2.08 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2700 | 0.22 | 0.31 | 0.47 | 0.68 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.54 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2850 | 0.18 | 0.20 | 0.38 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3000 | 0.07 | 0.17 | 0.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3150 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3300 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3450 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3600 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## Table I-5: Upper Bound of 95% Confidence Interval For Emission Levels under Phase II as a Market

| 0 | 150 | 300 | 450 | 600 | 750 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | 0.11 | 0.12 | 0.12 | 0.13 | 0.16 | 0.17 | 0.20 | 0.22 | 0.29 | 0.32 | 0.34 | 0.33 | 0.36 | 0.36 | 0.36 | 0.39 | 0.40 | 0.39 | 0.38 | 0.37 | 0.36 |
| 300 | 0.15 | 0.19 | 0.20 | 0.21 | 0.24 | 0.26 | 0.31 | 0.35 | 0.43 | 0.45 | 0.48 | 0.54 | 0.00 | 0.58 | 0.57 | 0.62 | 0.59 | 0.64 | 0.63 | 0.60 | 0.51 |
| 450 | 0.25 | 0.29 | 0.28 | 0.28 | 0.33 | 0.37 | 0.47 | 0.00 | 0.00 | 0.70 | 0.75 | 0.80 | 0.84 | 0.85 | 0.90 | 0.92 | 0.94 | 0.91 | 0.89 | 0.81 | 0.71 |
| 600 | 0.34 | 0.35 | 0.38 | 0.38 | 0.51 | 0.57 | 0.73 | 0.77 | 0.00 | 0.99 | 1.11 | 1.19 | 1.20 | 1.28 | 1.34 | 1.44 | 1.45 | 1.39 | 0.00 | 0.00 | 0.00 |
| 750 | 0.38 | 0.41 | 0.47 | 0.51 | 0.59 | 0.72 | 0.91 | 1.15 | 1.36 | 0.00 | 1.52 | 0.00 | 1.76 | 1.93 | 1.85 | 1.94 | 2.03 | 0.00 | 0.00 | 0.00 | 0.00 |
| 900 | 0.46 | 0.49 | 0.51 | 0.62 | 0.75 | 0.96 | 1.28 | 1.53 | 0.00 | 2.01 | 2.31 | 0.00 | 2.64 | 2.57 | 2.59 | 2.49 | 2.57 | 2.69 | 0.00 | 0.00 | 0.00 |
| 1050 | 0.58 | 0.54 | 0.59 | 0.68 | 0.94 | 1.13 | 1.49 | 2.02 | 2.57 | 2.83 | 3.22 | 0.00 | 3.55 | 3.26 | 3.15 | 3.24 | 3.24 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1200 | 0.56 | 0.68 | 0.73 | 0.76 | 1.18 | 1.51 | 2.09 | 2.52 | 3.03 | 3.43 | 3.98 | 4.30 | 4.57 | 4.75 | 4.12 | 4.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1350 | 0.74 | 0.62 | 0.85 | 1.01 | 1.32 | 1.69 | 2.35 | 2.84 | 3.53 | 4.12 | 4.56 | 4.67 | 5.07 | 5.07 | 5.17 | 4.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1500 | 0.64 | 0.77 | 0.86 | 1.13 | 1.54 | 2.10 | 2.79 | 3.11 | 3.84 | 4.39 | 4.70 | 5.15 | 5.07 | 5.11 | 4.67 | 4.48 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1650 | 0.78 | 0.89 | 0.95 | 1.33 | 1.61 | 2.01 | 2.68 | 3.28 | 3.76 | 4.42 | 4.57 | 4.78 | 4.89 | 4.76 | 4.58 | 4.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1800 | 0.80 | 0.83 | 1.02 | 1.15 | 1.82 | 2.22 | 2.81 | 3.21 | 3.59 | 3.91 | 4.24 | 4.63 | 4.61 | 4.58 | 4.15 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1950 | 0.74 | 0.77 | 0.99 | 1.43 | 1.95 | 2.24 | 2.63 | 3.16 | 3.42 | 3.73 | 3.93 | 3.94 | 3.88 | 3.76 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2100 | 0.65 | 0.72 | 0.99 | 1.47 | 2.01 | 2.47 | 2.84 | 3.05 | 3.11 | 3.28 | 3.52 | 3.35 | 3.38 | 3.36 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2250 | 0.57 | 0.68 | 1.10 | 1.94 | 2.29 | 2.21 | 2.55 | 2.68 | 3.10 | 3.16 | 3.00 | 2.88 | 2.76 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2400 | 0.52 | 0.71 | 1.11 | 1.59 | 1.89 | 2.15 | 2.47 | 2.57 | 2.65 | 2.75 | 2.56 | 2.47 | 2.23 | 2.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2550 | 0.48 | 0.70 | 1.28 | 1.71 | 2.20 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.79 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2700 | 0.37 | 0.56 | 0.82 | 1.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2850 | 0.32 | 0.33 | 0.63 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.06 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3000 | 0.17 | 0.31 | 0.32 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3150 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3300 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3450 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3600 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Table I-5: Lower Bound of 95% Confidence Interval For Emission Levels under Phase II as a Mkt

| 0 | 150 | 300 | 450 | 600 | 750 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | 0.05 | 0.06 | 0.06 | 0.07 | 0.11 | 0.11 | 0.15 | 0.17 | 0.23 | 0.26 | 0.29 | 0.27 | 0.30 | 0.30 | 0.30 | 0.33 | 0.34 | 0.33 | 0.32 | 0.31 | 0.30 |
| 300 | 0.09 | 0.13 | 0.15 | 0.15 | 0.18 | 0.20 | 0.25 | 0.30 | 0.37 | 0.39 | 0.42 | 0.48 | 0.00 | 0.52 | 0.51 | 0.56 | 0.53 | 0.59 | 0.57 | 0.54 | 0.45 |
| 450 | 0.19 | 0.24 | 0.22 | 0.23 | 0.27 | 0.31 | 0.41 | 0.00 | 0.00 | 0.64 | 0.69 | 0.74 | 0.78 | 0.80 | 0.84 | 0.86 | 0.89 | 0.86 | 0.83 | 0.76 | 0.65 |
| 600 | 0.28 | 0.29 | 0.33 | 0.32 | 0.45 | 0.51 | 0.67 | 0.72 | 0.00 | 0.93 | 1.05 | 1.13 | 1.14 | 1.22 | 1.28 | 1.38 | 1.39 | 1.33 | 0.00 | 0.00 | 0.00 |
| 750 | 0.33 | 0.35 | 0.41 | 0.45 | 0.53 | 0.66 | 0.85 | 1.09 | 1.30 | 0.00 | 1.47 | 0.00 | 1.70 | 1.88 | 1.80 | 1.88 | 1.97 | 0.00 | 0.00 | 0.00 | 0.00 |
| 900 | 0.41 | 0.43 | 0.45 | 0.56 | 0.69 | 0.91 | 1.23 | 1.47 | 0.00 | 1.95 | 2.25 | 0.00 | 2.58 | 2.51 | 2.53 | 2.44 | 2.51 | 2.63 | 0.00 | 0.00 | 0.00 |
| 1050 | 0.53 | 0.48 | 0.53 | 0.63 | 0.89 | 1.07 | 1.44 | 1.96 | 2.52 | 2.77 | 3.16 | 0.00 | 3.49 | 3.21 | 3.09 | 3.19 | 3.18 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1200 | 0.51 | 0.62 | 0.68 | 0.71 | 1.12 | 1.45 | 2.03 | 2.46 | 2.97 | 3.37 | 3.93 | 4.24 | 4.51 | 4.70 | 4.07 | 4.01 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1350 | 0.68 | 0.57 | 0.79 | 0.96 | 1.26 | 1.63 | 2.30 | 2.78 | 3.47 | 4.06 | 4.51 | 4.61 | 5.01 | 5.01 | 5.11 | 4.64 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1500 | 0.58 | 0.72 | 0.81 | 1.08 | 1.48 | 2.04 | 2.73 | 3.05 | 3.78 | 4.33 | 4.64 | 5.09 | 5.01 | 5.05 | 4.61 | 4.42 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1650 | 0.72 | 0.83 | 0.90 | 1.27 | 1.56 | 1.95 | 2.63 | 3.22 | 3.71 | 4.36 | 4.52 | 4.72 | 4.83 | 4.70 | 4.52 | 3.94 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1800 | 0.75 | 0.77 | 0.96 | 1.09 | 1.77 | 2.16 | 2.76 | 3.16 | 3.53 | 3.85 | 4.18 | 4.57 | 4.55 | 4.53 | 4.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1950 | 0.68 | 0.72 | 0.94 | 1.38 | 1.89 | 2.18 | 2.57 | 3.11 | 3.37 | 3.67 | 3.87 | 3.88 | 3.82 | 3.70 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2100 | 0.59 | 0.66 | 0.93 | 1.42 | 1.96 | 2.41 | 2.78 | 2.99 | 3.05 | 3.22 | 3.46 | 3.29 | 3.32 | 3.30 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2250 | 0.52 | 0.62 | 1.04 | 1.89 | 2.23 | 2.15 | 2.49 | 2.62 | 3.04 | 3.11 | 2.94 | 2.82 | 2.71 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2400 | 0.46 | 0.65 | 1.05 | 1.53 | 1.84 | 2.10 | 2.41 | 2.51 | 2.59 | 2.70 | 2.50 | 2.41 | 2.17 | 2.24 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2550 | 0.43 | 0.64 | 1.23 | 1.66 | 2.14 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.74 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2700 | 0.32 | 0.50 | 0.77 | 1.07 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2850 | 0.26 | 0.28 | 0.57 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3000 | 0.11 | 0.25 | 0.26 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3150 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3300 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3450 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3600 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

## Table I-6: Mid-range of 95% Confidence Interval For Emission Levels under Phase II as a Mkt

| 0 | 150 | 300 | 450 | 600 | 750 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | 0.08 | 0.09 | 0.09 | 0.10 | 0.13 | 0.14 | 0.17 | 0.20 | 0.26 | 0.29 | 0.32 | 0.30 | 0.33 | 0.33 | 0.33 | 0.36 | 0.37 | 0.36 | 0.35 | 0.34 | 0.33 |
| 300 | 0.12 | 0.16 | 0.17 | 0.18 | 0.21 | 0.23 | 0.28 | 0.33 | 0.40 | 0.42 | 0.45 | 0.51 | 0.00 | 0.55 | 0.54 | 0.59 | 0.56 | 0.61 | 0.60 | 0.57 | 0.48 |
| 450 | 0.22 | 0.26 | 0.25 | 0.26 | 0.30 | 0.34 | 0.44 | 0.00 | 0.00 | 0.67 | 0.72 | 0.77 | 0.81 | 0.83 | 0.87 | 0.89 | 0.92 | 0.88 | 0.86 | 0.78 | 0.68 |
| 600 | 0.31 | 0.32 | 0.36 | 0.35 | 0.48 | 0.54 | 0.70 | 0.74 | 0.00 | 0.96 | 1.08 | 1.16 | 1.17 | 1.25 | 1.31 | 1.41 | 1.42 | 1.36 | 0.00 | 0.00 | 0.00 |
| 750 | 0.35 | 0.38 | 0.44 | 0.48 | 0.56 | 0.69 | 0.88 | 1.12 | 1.33 | 0.00 | 1.50 | 0.00 | 1.73 | 1.91 | 1.83 | 1.91 | 2.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 900 | 0.43 | 0.46 | 0.48 | 0.59 | 0.72 | 0.93 | 1.25 | 1.50 | 0.00 | 1.98 | 2.28 | 0.00 | 2.61 | 2.54 | 2.56 | 2.46 | 2.54 | 2.66 | 0.00 | 0.00 | 0.00 |
| 1050 | 0.55 | 0.51 | 0.56 | 0.65 | 0.91 | 1.10 | 1.47 | 1.99 | 2.54 | 2.80 | 3.19 | 0.00 | 3.52 | 3.23 | 3.12 | 3.22 | 3.21 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1200 | 0.54 | 0.65 | 0.70 | 0.74 | 1.15 | 1.48 | 2.06 | 2.49 | 3.00 | 3.40 | 3.95 | 4.27 | 4.54 | 4.73 | 4.09 | 4.04 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1350 | 0.71 | 0.60 | 0.82 | 0.98 | 1.29 | 1.66 | 2.33 | 2.81 | 3.50 | 4.09 | 4.54 | 4.64 | 5.04 | 5.04 | 5.14 | 4.67 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1500 | 0.61 | 0.74 | 0.84 | 1.10 | 1.51 | 2.07 | 2.76 | 3.08 | 3.81 | 4.36 | 4.67 | 5.12 | 5.04 | 5.08 | 4.64 | 4.45 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1650 | 0.75 | 0.86 | 0.92 | 1.30 | 1.59 | 1.98 | 2.66 | 3.25 | 3.73 | 4.39 | 4.54 | 4.75 | 4.86 | 4.73 | 4.55 | 3.97 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1800 | 0.78 | 0.80 | 0.99 | 1.12 | 1.80 | 2.19 | 2.79 | 3.19 | 3.56 | 3.88 | 4.21 | 4.60 | 4.58 | 4.55 | 4.12 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1950 | 0.71 | 0.74 | 0.97 | 1.40 | 1.92 | 2.21 | 2.60 | 3.13 | 3.40 | 3.70 | 3.90 | 3.91 | 3.85 | 3.73 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2100 | 0.62 | 0.69 | 0.96 | 1.45 | 1.98 | 2.44 | 2.81 | 3.02 | 3.08 | 3.25 | 3.49 | 3.32 | 3.35 | 3.33 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2250 | 0.54 | 0.65 | 1.07 | 1.92 | 2.26 | 2.18 | 2.52 | 2.65 | 3.07 | 3.13 | 2.97 | 2.85 | 2.74 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2400 | 0.49 | 0.68 | 1.08 | 1.56 | 1.86 | 2.12 | 2.44 | 2.54 | 2.62 | 2.73 | 2.53 | 2.44 | 2.20 | 2.27 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2550 | 0.45 | 0.67 | 1.25 | 1.69 | 2.17 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.77 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2700 | 0.35 | 0.53 | 0.79 | 1.09 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 2850 | 0.29 | 0.30 | 0.60 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 1.03 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3000 | 0.14 | 0.28 | 0.29 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3150 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3300 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3450 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 3600 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

**Table I-7: High Concentration Level (upper-bound of 95% confidence interval)**

Damage Function Estimates for Sulfate Concentration Levels at Ground Level Using EPA's Human Health Benefits From Sulfate Reductions under Title IV of the Clean Air Act Amendments Report, Nov 10, 1995

| EPA Equations Used | Total External Cost Estimate MKT ($millions) | Total External Cost Estimate CAP ($millions) | Total External Cost Estimate Difference ($millions) |
|---|---|---|---|
| LOW | $41,460 | $39,433 | $2,027 |
| Full Weight | $375,622 | $357,255 | $18,368 |
| HIGH | $1,545,611 | $1,470,032 | $75,579 |

**Table I-8: Low Concentration Level (lower-bound of 95% confidence interval)**

Damage Function Estimates for Sulfate Concentration Levels at Ground Level Using EPA's Human Health Benefits From Sulfate Reductions under Title IV of the Clean Air Act Amendments Report, Nov 10, 1995

| EPA Equations Used | Total External Cost Estimate MKT ($millions) | Total External Cost Estimate CAP ($millions) | Total External Cost Estimate Difference ($millions) |
|---|---|---|---|
| LOW | $40,525 | $38,498 | $2,027 |
| Full Weight | $367,152 | $348,784 | $18,368 |
| HIGH | $1,510,757 | $1,435,178 | $75,579 |

## Appendix J: The population grid maps used in conjunction with the emission response functions

## The population grid maps.

## Table J-1: State by state population per square mile from 1996 data base, no city adjustments, rough guideline

| 0 | 150 | 300 | 450 | 600 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | C | C | C | C | C | C | C | C | C | C | C | C | C | C | C | C | C | C | C | C |
| 300 | C | C | C | C | C | C | C | C | C | C | C | C | C | C | C | C | C | 99.9 | C | C |
| 450 | 6 | 9.3 | 9.3 | 9.3 | 6 | 6 | C | 0 | 0 | C | C | C | C | C | C | C | C | 99.9 | C | C |
| 600 | 6 | 9.3 | 9.3 | 9.3 | 6 | 6 | 0 | 168.9 | 0 | 168.9 | C | C | C | C | C | C | 63.6 | 99.9 | 0 | 0 |
| 750 | 6 | 9.7 | 9.7 | 9.7 | 6 | 6 | 95 | 95 | 168.9 | 0 | 168.9 | 0 | C | C | 385.1 | 385.1 | 129.6 | 0 | 0 | 0 |
| 900 | 5 | 9.7 | 9.7 | 9.7 | 6 | 6 | 95 | 95 | 0 | 168.9 | 168.9 | 0 | C | 385.1 | 385.1 | 385.1 | 99.9 | 99.9 | 0 | 0 |
| 1050 | 5 | 21.5 | 21.5 | 9.7 | 51 | 51 | 51 | 95 | 95 | 168.9 | 168.9 | 0 | 269 | 269 | 269 | 1076.7 | 385.1 | 0 | 0 | 0 |
| 1200 | 5 | 21.5 | 21.5 | 21.5 | 51 | 51 | 51 | 213.1 | 213.1 | 162.8 | 272.8 | 272.8 | 272.8 | 269 | 269 | 1076.7 | 0 | 0 | 0 | 0 |
| 1350 | 36.9 | 21.5 | 21.5 | 21.5 | 77.8 | 77.8 | 77.8 | 213.1 | 213.1 | 162.8 | 272.8 | 272.8 | 75.8 | 75.8 | 168.6 | 99.9 | 0 | 0 | 0 | 0 |
| 1500 | 36.9 | 31.4 | 31.4 | 31.4 | 31.4 | 77.8 | 77.8 | 213.1 | 213.1 | 162.8 | 97.7 | 97.7 | 75.8 | 168.6 | 168.6 | 168.6 | 0 | 0 | 0 | 0 |
| 1650 | 36.9 | 31.4 | 31.4 | 31.4 | 31.4 | 77.8 | 77.8 | 77.8 | 97.7 | 97.7 | 97.7 | 97.7 | 168.6 | 150.3 | 150.3 | 150.3 | 0 | 0 | 0 | 0 |
| 1800 | 73 | 73 | 48.1 | 48.1 | 48.1 | 48.2 | 48.2 | 48.2 | 129.1 | 129.1 | 129.1 | 150.3 | 150.3 | 150.3 | 150.3 | 0 | 0 | 0 | 0 | 0 |
| 1950 | 73 | 73 | 48.1 | 48.1 | 48.1 | 48.2 | 48.2 | 57.9 | 57.9 | 84.2 | 127 | 127 | 122.8 | 122.8 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2100 | 73 | 73 | 73 | 73 | 73 | 48.2 | 48.2 | 57.9 | 57.9 | 84.2 | 84.2 | 127 | 127 | 122.8 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2250 | 73 | 73 | 73 | 73 | 73 | 99.9 | 99.9 | 57.9 | 57.9 | 84.2 | 84.2 | 127 | 127 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2400 | 73 | 73 | 73 | 73 | 73 | 73 | 99.9 | 99.9 | 57.9 | 84.2 | 266.7 | 266.7 | 266.7 | 266.7 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2550 | M | 73 | 73 | 73 | 73 | 0 | 0 | 99.9 | 0 | 0 | 0 | 0 | 0 | 266.7 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2700 | M | 73 | 73 | 73 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 266.7 | 266.7 | 0 | 0 | 0 | 0 | 0 |
| 2850 | M | M | 73 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 266.7 | 39 | 0 | 0 | 0 | 0 |
| 3000 | M | M | M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3150 | M | M | M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3300 | M | M | M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3450 | M | M | M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3600 | M | M | M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## Table J-2: State by state population per square mile with minor adjustments for city population, Canada, and Mexico

| 0 | 150 | 300 | 450 | 600 | 750 | 900 | 1050 | 1200 | 1350 | 1500 | 1650 | 1800 | 1950 | 2100 | 2250 | 2400 | 2550 | 2700 | 2850 | 3000 | 3150 | 3300 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 150 | 6 | 6 | 9.3 | 9.3 | 6 | 6 | 95 | 95 | 95 | 95 | 66 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 66 | 30 | 0 |
| 300 | 10 | 6 | 9.3 | 9.3 | 6 | 6 | 95 | 95 | 95 | 95 | 66 | 40 | 40 | 40 | 40 | 40 | 40 | 40.3 | 40 | 66 | 30 | 30 |
| 450 | 10 | 9.3 | 9.3 | 9.3 | 25 | 35 | 95 | 0 | 0 | 95 | 168 | 40 | 40 | 40 | 100 | 200 | 60 | 40.3 | 40 | 66 | 30 | 30 |
| 600 | 10 | 9.3 | 9.3 | 9.3 | 35 | 35 | 0 | 168.9 | 0 | 168.9 | 168 | 40 | 200 | 200 | 269 | 269 | 120 | 40.3 | 0 | 0 | 0 | 0 |
| 750 | 50 | 9.7 | 9.7 | 9.7 | 35 | 35 | 95 | 95 | 168.9 | 0 | 168.9 | 0 | 269 | 385 | 385.1 | 385.1 | 129.6 | 0 | 0 | 0 | 0 | 0 |
| 900 | 75.8 | 9.7 | 9.7 | 9.7 | 50 | 50 | 95 | 95 | 0 | 168.9 | 168.9 | 0 | 269 | 385.1 | 385.1 | 385.1 | 777.3 | 777.3 | 0 | 0 | 0 | 0 |
| 1050 | 75.8 | 21.5 | 21.5 | 9.7 | 51 | 51 | 51 | 95 | 95 | 168.9 | 168.9 | 0 | 269 | 269 | 269 | 1076.7 | 500 | 0 | 0 | 0 | 0 | 0 |
| 1200 | 75.8 | 21.5 | 21.5 | 21.5 | 51 | 51 | 51 | 213.1 | 213.1 | 162.8 | 272.8 | 272.8 | 272.8 | 269 | 269 | 1076.7 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1350 | 36.9 | 21.5 | 21.5 | 21.5 | 77.8 | 77.8 | 77.8 | 213.1 | 213.1 | 162.8 | 300 | 272.8 | 75.8 | 75.8 | 168.6 | 518.8 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1500 | 36.9 | 31.4 | 31.4 | 31.4 | 31.4 | 77.8 | 77.8 | 213.1 | 213.1 | 162.8 | 97.7 | 97.7 | 75.8 | 168.6 | 168.6 | 168.6 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1650 | 36.9 | 31.4 | 31.4 | 31.4 | 31.4 | 77.8 | 77.8 | 77.8 | 97.7 | 97.7 | 97.7 | 97.7 | 168.6 | 150.3 | 150.3 | 150.3 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1800 | 73 | 73 | 48.1 | 48.1 | 48.1 | 48.2 | 48.2 | 48.2 | 129.1 | 129.1 | 129.1 | 150.3 | 150.3 | 150.3 | 150.3 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1950 | 73 | 73 | 48.1 | 48.1 | 48.1 | 48.2 | 48.2 | 57.9 | 57.9 | 84.2 | 127 | 127 | 122.8 | 122.8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2100 | 73 | 73 | 73 | 73 | 73 | 48.2 | 48.2 | 57.9 | 57.9 | 84.2 | 84.2 | 127 | 127 | 122.8 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | 73 | 73 | 73 | 73 | 73 | 99.9 | 99.9 | 57.9 | 57.9 | 84.2 | 84.2 | 127 | 127 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2400 | 73 | 73 | 73 | 73 | 73 | 73 | 99.9 | 99.9 | 57.9 | 84.2 | 266.7 | 266.7 | 266.7 | 266.7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2550 | 73 | 73 | 73 | 73 | 73 | 0 | 0 | 99.9 | 0 | 0 | 0 | 0 | 0 | 266.7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2700 | 73 | 73 | 73 | 73 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 266.7 | 300 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2850 | 73 | 73 | 73 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 266.7 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3000 | 73 | 73 | 73 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3150 | 73 | 73 | 73 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3300 | 73 | 73 | 73 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3450 | 73 | 73 | 73 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3600 | 73 | 73 | 73 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## APPENDIX K:

## Upper and Lower Range Estimate Tables

This appendix presents the upper and lower estimates of the simulation model. Table K-1 presents the emission distribution for the upper bound of the abatement cost estimates using the highest return of capital seen in the energy industry over the last 15 years. Table K-2 presents the same information for the lower bound of abatement costs using the lowest return on capital seen in the energy industry over the last 15 years. Table K-3 and K-4 show the upper and lower bound estimates of the emission distribution model applied to external costs equations developed in chapter 3.

Table K-1:
Phase II Regional Market Emission Totals by Sub-Region under both the Cap and the Market for Allowances R=.16

Emission results given in 1000's of tons

| | e=.01 | | | e=.03 | | |
|---|---|---|---|---|---|---|
| Region | Emissions CAP | Emissions MKT | Emissions Difference | Emissions CAP | Emissions MKT | Emissions Difference |
| NE | 263 | 226 | 36 | 263 | 226 | 36 |
| MA | 888 | 922 | (35) | 883 | 930 | (47) |
| ENC | 2,157 | 2,031 | 126 | 2,157 | 2,014 | 144 |
| WNC | 782 | 767 | 15 | 781 | 757 | 24 |
| SA | 2,003 | 2,062 | (60) | 2,003 | 2,056 | (54) |
| PSC | 1,017 | 1,067 | (50) | 1,016 | 1,082 | (66) |
| WSC | 787 | 932 | (145) | 787 | 933 | (146) |
| Mountain | 548 | 628 | (80) | 548 | 627 | (80) |
| Pacific | 46 | 20 | 26 | 46 | 20 | 25 |
| | 8,489 | 8,656 | (167) | 8,483 | 8,646 | (163) |

| | e=.06 | | | e=.09 | | |
|---|---|---|---|---|---|---|
| Region | Emissions CAP | Emissions MKT | Emissions Difference | Emissions CAP | Emissions MKT | Emissions Difference |
| NE | 263 | 226 | 36 | 263 | 226 | 37 |
| MA | 887 | 935 | (48) | 858 | 914 | (56) |
| ENC | 2,157 | 2,018 | 139 | 2,155 | 2,018 | 137 |
| WNC | 779 | 757 | 21 | 774 | 749 | 25 |
| SA | 2,003 | 2,044 | (41) | 2,003 | 2,054 | (51) |
| PSC | 1,015 | 1,073 | (58) | 1,014 | 1,077 | (63) |
| WSC | 788 | 955 | (167) | 788 | 998 | (210) |
| Mountain | 548 | 623 | (75) | 547 | 622 | (75) |
| Pacific | 46 | 20 | 25 | 46 | 21 | 25 |
| | 8,485 | 8,652 | (168) | 8,448 | 8,678 | (230) |

Table K-2:
**Phase II Regional Market Emission Totals by Sub-Region under both the Cap and the Market for Allowances r=.05**

Emission results given in 1000's of tons

| | e=.01 Emissions CAP | Emissions MKT | Emissions Difference | e=.03 Emissions CAP | Emissions MKT | Emissions Difference |
|---|---|---|---|---|---|---|
| NE | 263 | 226 | 36 | 263 | 226 | 36 |
| MA | 888 | 942 | (54) | 887 | 946 | (59) |
| ENC | 2,158 | 1,978 | 180 | 2,159 | 1,973 | 186 |
| WNC | 782 | 738 | 44 | 781 | 727 | 54 |
| SA | 2,003 | 2,025 | (23) | 2,003 | 2,022 | (19) |
| PSC | 1,017 | 1,124 | (107) | 1,017 | 1,079 | (62) |
| WSC | 787 | 992 | (206) | 787 | 994 | (207) |
| Mountain | 548 | 628 | (80) | 548 | 628 | (80) |
| Pacific | 46 | 20 | 26 | 46 | 20 | 25 |
| | 8,490 | 8,673 | (183) | 8,489 | 8,616 | (126) |

| Region | e=.06 Emissions CAP | Emissions MKT | Emissions Difference | e=.09 Emissions CAP | Emissions MKT | Emissions Difference |
|---|---|---|---|---|---|---|
| NE | 263 | 226 | 36 | 263 | 227 | 36 |
| MA | 887 | 938 | (51) | 860 | 918 | (59) |
| ENC | 2,161 | 1,992 | 168 | 2,158 | 2,005 | 153 |
| WNC | 779 | 730 | 49 | 775 | 724 | 51 |
| SA | 2,003 | 2,014 | (11) | 2,004 | 2,008 | (4) |
| PSC | 1,016 | 1,074 | (57) | 1,016 | 1,062 | (47) |
| WSC | 788 | 997 | (210) | 788 | 1,000 | (212) |
| Mountain | 548 | 624 | (76) | 547 | 623 | (76) |
| Pacific | 46 | 21 | 25 | 46 | 21 | 25 |
| | 8,490 | 8,616 | (126) | 8,456 | 8,587 | (131) |

Table K-3:
Damage Function Estimates for Sulfate Concentration Levels at Ground Level
Using EPA's Human Health Benefits From Sulfate Reductions under Title IV
of the Clean Air Act Amendments Report, Nov 10, 1995

High Sulfate Deposition Concentration (upper-bound of 95% confidence interval)

| EPA Equations Used | Total External Cost Estimate MKT ($millions) | Total External Cost Estimate CAP ($millions) | Total External Cost Estimate Difference ($millions) |
|---|---|---|---|
| Low Effect Equations | $40,815 | $39,433 | $1,382 |
| Fully Weighted Effect Effect Equations | $369,773 | $357,255 | $12,518 |
| High Effect Equations | $1,521,540 | $1,470,032 | $51,508 |

Table K-4
Damage Function Estimates for Sulfate Concentration Levels at Ground Level
Using EPA's Human Health Benefits From Sulfate Reductions under Title IV
of the Clean Air Act Amendments Report, Nov 10, 1995
Lower-Bound Sulfate Deposition Concentration (Lower-Bound Range of 95% confidence interval)

| EPA Equations Used | Total External Cost Estimate MKT ($millions) | Total External Cost Estimate CAP ($millions) | Total External Cost Estimate Difference ($millions) |
|---|---|---|---|
| Low Effect Equations | $39,880 | $38,498 | $1,382 |
| Fully Weighted Effect Effect Equations | $361,302 | $348,784 | $12,518 |
| High Effect Equations | $1,486,686 | $1,435,178 | $51,508 |

## APPENDIX L:

**Second Order Conditions for Optimization Problems in Chapters 1 and 3 (Where Not Given in the Text.**

1.) From optimization problem seen in 1.4 (Chapter 1)

$$\frac{d}{d\lambda 1_i}\frac{d}{dQ_i}\zeta(Q_i,\lambda 1_i)<0$$

$$\frac{d^2}{dQ_i^2}\zeta(Q_i,\lambda 1_i)<0$$

$$\begin{vmatrix} 0 & \frac{d}{d\lambda 1_i}\frac{d}{dQ_i}\zeta(Q_i,\lambda 1_i) \\ \frac{d}{d\lambda 1_i}\frac{d}{dQ_i}\zeta(Q_i,\lambda 1_i) & \frac{d^2}{dQ_i^2}\zeta(Q_i,\lambda 1_i) \end{vmatrix}<0$$

2.) From the optimization problem seen in 1.9 (Chapter 1), the bordered Hessian (an $|H_2|$) must be positive definite (whether or not the emission constraint is binding):

$$\begin{vmatrix} 0 & \frac{d}{d\lambda 1_i}\frac{d}{dRE_i}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d}{d\lambda 1_i}\frac{d}{dQ_i}\xi(Q_i,RE_i,\lambda 1_i) \\ \frac{d}{d\lambda 1_i}\frac{d}{dRE_i}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d^2}{dRE_i^2}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d}{dRE_i}\frac{d}{dQ_i}\xi(Q_i,RE_i,\lambda 1_i) \\ \frac{d}{d\lambda 1_i}\frac{d}{dQ_i}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d}{dRE_i}\frac{d}{dQ_i}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d^2}{dQ_i^2}\xi(Q_i,RE_i,\lambda 1_i) \end{vmatrix}>0$$

3.) From the optimization problem seen in 1.25 (Chapter 1)

$$\begin{bmatrix} 0 & \frac{d}{d\lambda 1_i}\frac{d}{dRE_i}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d}{d\lambda 1_i}\frac{d}{dQ_i}\xi(Q_i,RE_i,\lambda 1_i) \\ \frac{d}{d\lambda 1_i}\frac{d}{dRE_i}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d^2}{dRE_i^2}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d}{dRE_i}\frac{d}{dQ_i}\xi(Q_i,RE_i,\lambda 1_i) \\ \frac{d}{d\lambda 1_i}\frac{d}{dQ_i}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d}{dRE_i}\frac{d}{dQ_i}\xi(Q_i,RE_i,\lambda 1_i) & \frac{d^2}{dQ_i^2}\xi(Q_i,RE_i,\lambda 1_i) \end{bmatrix} > 0$$

4.) From the optimization problem seen in 3.21 (Chapter 3)

$$\left(\frac{d}{d\lambda_1}\frac{d}{dkWh}\zeta(kWh,\lambda_1)\right) < 0$$

$$\frac{d^2}{dkWh^2}\zeta(kWh,\lambda_1) < 0$$

$$\begin{bmatrix} 0 & \frac{d}{d\lambda_1}\frac{d}{dkWh}\zeta(kWh,\lambda_1) \\ \frac{d}{d\lambda_1}\frac{d}{dkWh}\zeta(kWh,\lambda 1_i) & \frac{d^2}{dkWh^2}\zeta(kWh_i,\lambda_1) \end{bmatrix} < 0$$

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