CO_2 TRADING ISSUES

Volume 2: Choosing the Market Level for Trading

Final Report

Prepared by

Anne E. Smith
Anders R. Gjerde
Lynn I. DeLain
Ray R. Zhang

DECISION FOCUS INCORPORATED
1155 Connecticut Avenue NW
Washington, DC 20036

Prepared for

Adaptation Branch, Climate Change Division
Economic Analysis & Research Branch, Economic Analysis & Innovation Division
Office of Policy, Planning and Evaluation
U.S. Environmental Protection Agency
Washington, DC 20460

Contract No. 68-CO-0021

Project Manager
Neil A. Leary

Chief, Adaptation Branch
Joel D. Scheraga

May 1992

PREFACE

There has been increasing concern within the international community about rising concentrations of carbon dioxide (CO_2) and other greenhouse gases in the atmosphere that may contribute to global climate change. The United States and other nations have been, and will continue, grappling with the question of whether or not to constrain the emissions of CO_2. Should a decision be made to constrain greenhouse emissions, there exists a variety of policy tools that could be employed to achieve this objective. Discussions of policy tools have recently focused on approaches that rely upon the creation of market incentives that would induce sources to reduce their emissions. The advantage of these market incentive approaches is that they offer the possibility of controlling emissions at much lower costs than are likely to be achieved through more traditional regulatory approaches.

This three volume report examines one market incentive approach to controlling emissions of CO_2: tradeable permits. There are a number of points in the economy at which a tradeable permit system might be implemented to control CO_2. For example, permits might be required for supplying carbon-based energy. Alternatively, carbon permits might be required of consumers of carbon-based energy. Potential performance of alternative permit market designs and potential implementation problems are investigated in the report. Recommendations are made for market designs that promise to be more cost-effective than other market designs.

Volume 1 of the report examines emissions of CO_2 from industry, the largest source of emissions from energy consumption. Volume 2 examines alternative carbon permit market designs and evaluates the potential performance of the alternatives considered. Volume 3 examines the potential behavior of electric utilities in a carbon permit market and the implications for the functioning of a permit market.

Designing a cost-effective CO_2 trading system that can be readily implemented and enforced is a complex undertaking. This study illuminates these complexities and provides insights useful to policymakers considering such a system.

Neil A. Leary
EPA Project Manager

Joel D. Scheraga
Chief, Adaptation Branch

EXECUTIVE SUMMARY

Tradeable carbon permits and carbon taxes create market incentives for sources to reduce their emissions of carbon dioxide (CO_2). The advantage of abatement policies that rely on market incentives is that they offer the possibility of controlling emissions at much lower costs than are likely to be achieved through more traditional regulatory approaches. There are, however, a variety of ways in which tradeable carbon permits or carbon taxes might be implemented and the choice of implementation can be important to the costs and performance of the policy. This three volume report examines alternative ways of implementing a tradeable carbon permit system for controlling emissions of CO_2.

The focus of the report is limited to the control of CO_2 emissions from fossil energy production and consumption, which accounts for nearly all US CO_2 emissions. The quantity of CO_2 generated by energy production and consumption is largely a function of the carbon content of the fossil energy input to economic activity. Because capture and disposal of generated CO_2 is prohibitively costly, carbon content of fossil energy input also determines the quantity of CO_2 emissions. Thus a system of carbon permits for fossil energy is equivalent to a system of permits for emissions of CO_2 from fossil energy use. This allows a great deal of flexibility for choosing where in the energy system to implement a permit market for the control of CO_2. For example, permits might be required of suppliers for the carbon content of fossil energy supplied to the market. Alternatively, permits might be required of consumers for the carbon content of the fossil energy consumed.

Although these alternative permit systems can be designed to achieve equivalent CO_2 abatement, the costs of the emission reductions and their distribution can vary significantly. This report examines a number of key issues that will influence the costs of CO_2 abatement and their distribution for alternative carbon permit market designs. Volume 1 examines emissions of CO_2 from industry, the largest source of carbon emissions. Volume 2 examines alternative carbon permit market designs and evaluates the potential performance of the alternatives considered. Volume 3 examines the potential behavior of electric utilities in a carbon permit market and the implications for the functioning of a permit market.

The alternative carbon permit market designs evaluated include both supplier and consumer permit systems. There are a number of points in the supply chain at which a carbon permit market might be implemented. Three alternative designs for a supplier permit market are examined: (i) a market that requires primary energy extractors and importers to obtain carbon permits, (ii) a market that requires energy processors to obtain carbon permits for the products that they produce, and (iii) a market that requires energy distributors to obtain carbon permits for the energy that they sell to final consumers. The consumer carbon permit market designs examined include (i) a market that would require all carbon energy consumers to obtain permits, and (ii) a market that would require only major industrial carbon energy consumers to obtain permits.

It is the recommendation of the report that, if a carbon permit market approach is adopted for CO_2 emission control, it should be implemented on the supply side of energy markets. A supplier permit market for carbon is expected to be a more cost-effective CO_2 control policy than a consumer permit market. However, it is not clear which point in the supply chain is the most promising for implementation of a carbon permit market without further study.

A carbon permit market that requires all consumers of carbon energy to obtain permits for the carbon content of the energy that they burn would include millions of participants in the market. The administrative costs of monitoring, operating, and enforcing a permit market with millions of participants is prohibitively high. These costs might be reduced by limiting a consumer permit market to include only relatively large consumers of carbon energy.

One possibility that is examined is to limit coverage to industrial emitters of carbon. Limiting a carbon permit market for consumers to industrial sources would reduce the number of market participants from millions to tens of thousands. Limiting the market further to the six industrial sectors that are the largest sources of CO_2 would reduce the number of market participants to under twenty-thousand and still include 90% of industrial emissions in its coverage.

However, limiting a consumer permit market to only industrial energy consumers would exclude 40% of US CO_2 emissions from control. This eliminates many opportunities for potentially low cost emission reductions from residential, commercial, and transportation sources and promises to raise the control costs per ton of CO_2 abated. The control costs of achieving a chosen CO_2 target might be reduced by complementing a permit market for industrial energy consumers with additional policies that are targeted at other energy consuming sectors. But implementation and operation of two or more separate programs for control of different sources of CO_2 will add to administrative costs.

A further disadvantage of a consumer permit market for carbon are complexities that arise from existing regulations of electric utilities. Rate of return regulations, restrictions on capital gains and losses, and other regulations may lead electric utilities to make inefficient choices. Inefficient behavior by utilities can potentially raise the costs of any CO_2 control policy, but the problem may be particularly severe for a carbon permit market that includes electric utilities as direct market participants.

In contrast, a supplier permit market for carbon energy would achieve almost complete coverage of CO_2 emissions under a single, unified program, while including fewer market participants than would a market for industrial energy consumers. The reduced number of market participants would reduce the administrative costs of a permit market without concentrating the market to a degree that would raise concerns regarding market power. The broad coverage of emissions, the relatively small number of market participants, the lack of significant market power, and the reliance on a single program for all sources suggest that a supplier permit market is likely to be more cost-effective for CO_2 control than a consumer permit market.

Of the various points in the supply chain at which permit trading might be implemented, none emerges as clearly superior. One factor that may influence the cost-effectiveness of CO_2 control is the potential for leakages of emissions that are unconstrained by a permit market. If carbon permits are required at the point of distribution, upstream emissions from energy extraction, refining and processing of energy, and transmission represent potential leakages. These leakages could narrow the range of options for emission reductions and raise costs. In contrast, if carbon permits are required at the point of extraction, these emissions would occur downstream from the permit market and would not represent leakages.

Another factor that may influence the cost of CO_2 control is whether or not the policy imposes constraints that have no emission reduction benefits. Energy used as feedstocks does not contribute to CO_2 emissions and requiring permits for feedstocks would raise costs without providing any emission abatement benefits. If carbon permits are required at the point of extraction, identifying and exempting energy that will ultimately be used as feedstocks may be administratively difficult and costly, while failure to exempt feedstocks will raise control costs. Alternatively, if carbon permits are required at the point of distribution to consumers, identifying and exempting feedstocks may be less costly.

A third factor that may influence the cost of CO_2 control is the ease of monitoring and enforcing compliance with permit requirements. Due to vertical integration of firms that supply energy, monitoring and enforcing compliance may be costly at the levels of extraction and processing. Because there is little vertical integration beyond the point of distribution of energy to energy consumers, monitoring and enforcement costs may be lowest for a carbon permit market at the point of distribution. The net effect of these various factors on the costs of CO_2 reductions for the alternative permit market designs is ambiguous at this time and warrants further study.

The recommendations of the report are based on an evaluation of the cost-effectiveness of alternative permit markets. Another factor that may also guide the selection and design of a CO_2 abatement policy is the distribution of the costs of abatement. The report demonstrates that a carbon permit market for suppliers can yield a very different distribution of costs than would a carbon permit market for consumers. If permits are required of suppliers, the cost of emission reductions may be borne more heavily by energy consumers than by suppliers. If, alternatively, permits are required of consumers, some of these costs may be shifted from energy consumers to energy suppliers. Of course most energy is consumed as an intermediate input by firms, and the ultimate distribution of costs among different portions of the population have not been investigated for this study.

TABLE OF CONTENTS
—Volume 2: Choosing the Market Level for Trading—

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION AND OVERVIEW

The current debate on appropriate methods for controlling emissions of greenhouse gases frequently refers to the use of tradeable emissions permits. In fact, prominent Congressional activity, in the form of the Cooper/Synar Bill, would introduce an offsets program for new sources of CO_2.[1] Despite the attention that emissions trading generates, relatively little has been done to investigate the behavior of trading under different implementation options. This three volume report covers several topics of interest for implementation planning:

Volume 1:	Emissions from Industry
Volume 2:	Choosing the Market Level for Trading
Volume 3:	Effects of Utility Regulation

This volume (Volume 2) looks in some detail at the issue of implementing trading requirements at different levels of the market. The topic is first defined and described, theoretical aspects are summarized, and specific market data are presented in an effort to understand better the relative advantages of the different options posed. Much of the data presented in Volume 1 is also used in the analysis that follows.

SYNOPSIS OF THE ISSUE AND ANALYSIS

The issue of trading at different levels of the market is one that rarely gains attention in the theoretical literature. It arises because many goods go through a series of manufacturing stages before the point of final consumption. Unless these stages are fully integrated vertically, there is a sequence of markets between the initial product development and the final purchase by the consumer. Fossil fuels provide a good example of this type of market sequence. The initial product may be crude oil. This is captured from a well, and may then be sold to a company that will refine it into final consumer products. There may be additional intermediate markets, such as companies that buy crude from small wells, and in turn sell their accumulated crude to refiners. Distributors may purchase refined products from refiners before they reach the point of sale to the final consumer. Vertical integration is present to some extent in these markets, but intermediate markets do exist.

1. Offsets are very closely related to emissions allowances (which are used for SO_2 controls in the 1991 Clean Air Act Amendments). The main differences between the two concepts are: (1) the supply of offsets is created by market forces while allowances are created in a fixed quantity by regulators; and (2) offsets tend to apply only to new sources, while allowances tend to apply to an entire set of sources.

Given that an estimate of the ultimate CO_2 emissions resulting from a product's use can be made at each market stage, it would be possible to impose a CO_2 emissions trading scheme at any of the market levels. For instance, one might require that each oil well have sufficient permits to cover the carbon contained in its total sales of crude. Or, one might instead allow extraction processes to proceed freely, but require that permits be required for each unit of carbon emitted when the petroleum-based fuel is burned. In the first case, the cost of the permits will be passed through the market, ultimately affecting consumer demand. In the second case, the cost of the permits will directly affect demand, which will in turn pass incentives back to the initial producers. However, a variety of reasons may make one system more functional than another. This study evaluates CO_2 permit trading at different market levels subject to three basic criteria listed below. While we believe that each of these criteria should be given considerable attention in evaluating policy options, the list is not intended to be exhaustive. The criteria focused on in the study are:

1. ***Costs of monitoring and administering a trading program.*** This will depend in part on the number of individual companies that make up each of the market levels, which can vary substantially.

2. ***Effectiveness.*** We examine two aspects of market effectiveness: (a) There may be some "leakage" in markets, meaning that some of the ultimate emissions might not be accounted for. Similarly, some economic activities may be penalized at a rate greater than their actual contribution to emissions. The extent of this type of problem will vary at different levels of the market. (b) Market power may exist in either the market for the product, or in the market that will be created for allowances. Such market power could alter the effectiveness of allowance trading at one market level but not at others.

3. ***Distribution.*** The sharing of control costs (i.e., effects on welfare distribution) will vary. This will include geographical as well as sectoral distribution of the regulatory burden. Economic analysis does not itself indicate what distribution is more desirable, but an understanding of distributional implications is also an important element for the policy making process.

In this volume, three generic market levels are considered as options for implementing CO_2 trading:

- Regulation at the level of the primary producer of fossil fuels.
- Regulation of the key industrial points of fossil fuel combustion.
- Regulation of all end users of fossil fuel-based energy services.

There are many possible combinations of these three options that should be kept in mind when devising an implementation plan. However, for purposes of understanding the relative advantages of each, we focus on these three basic underlying options and note obviously advantageous combinations where appropriate.

Initial analyses using EPA's GEMINI model for assessing national impacts of climate change policies have indicated that there may well be some distinct differences in outcomes when trading is implemented at the different market levels. In one example, the model found that the social benefits of trading to reach stabilization were substantially greater when trading occurred among producers of raw fossil fuels, compared to when trading occurred among those who distribute refined fuels to fuel-using customers.[2] GEMINI does not currently take account of all of the issues mentioned above, and the cause of the differences captured by GEMINI appears to be the leakage issue. GEMINI is also a very aggregate model with no detail on numbers of firms in a given market or their locations. More investigation is needed of the nature of these markets to develop an understanding of the best market level to implement trading, should such regulations be desired. This study takes a first step in the direction of collating the relevant information for such an assessment. The rest of this volume is organized to cover the following general questions related to the three evaluation criteria:

- *What would trading requirements consist of at the different market levels? (next part of Section 1)* This is to provide a clear explanation of what is meant by this issue, before moving to a more detailed analysis.

- *What are the welfare distribution impacts from trading at different market levels? (also in Section 1)* Welfare distribution is a theoretical concept used in economics to investigate the relative gains and burdens under different market structures. Investigation of this effect is useful for motivating the point that trading at different market levels can produce situations that will affect various segments of the population quite differently, even if results are equivalent in terms of their overall effectiveness in reducing emissions and cost.

- *How many sources are there in each market level, how are they distributed by size, and where are they geographically located? (Section 2)* Trading will involve a larger or smaller number of affected entities at different market levels. Also, the affected entities may be more or less geographically concentrated under different market level trading schemes. Potential market power problems are also important to identify. All of these concerns are addressed by a better understanding of the number, location and relative sizes of sources at each market level, and are important in drawing conclusions regarding costs, effectiveness, and distributive effects.

2. Scheraga, J. D. and N. Leary, *Improving the Efficiency of Environmental Policy: The Implementation of Strategies to Reduce CO_2 Emissions*, Paper Presented to Stanford University's Energy Modeling Forum #12, Boulder Colorado, August 27-29, 1991, p. 14. Also, "Efficiency of Climate Policy," *Nature*, Vol. 354, November 21, 1991, p. 193.

- *What amount of total emissions would be subject to controls? (Section 3)* Effectiveness of a control program depends on whether a significant fraction of the emissions are covered by the regulation in question. Building on the data developed in Section 2, the relative degree of control at different market levels is discussed, and options for achieving a degree of control are suggested.

- *What are the mechanisms for monitoring and enforcement? (Section 4)* As noted above, the ability to effectively enforce a market is also important in determining the relative desirability of regulating at different market levels. Enforceability may affect the effectiveness of a program, its overall costs, and even public perceptions of fairness.

Section 5 provides a summary and conclusion, centered around Table 1-1. The key conclusion is that the most promising level appears to be the primary producer level. After defining that sector more fully as a series of sub-levels (extraction, refining/processing, and distribution), the distribution sub-level, where fuel distributors sell final fuel products to users of energy services, appears to be the best option, although with qualifications. The other primary producer sub-levels present less enforceability, greater regional concentrations, and issues related to treatment of imports and feedstocks. The distribution level, however, would not account for significant upstream emissions from extraction and refining.

Table 1-1
EVALUATION OF CO_2 ALLOWANCE TRADING AT DIFFERENT MARKET LEVELS

	# Involved	Market Dysfunction Potential	Degree of Geographical Concentration	Enforce-ability	Emissions Coverage	Import Issues?
Extraction	1,000s	None	High	Moderate	High	Yes
Refining	1,000s	None	High	Moderate	High	Yes
Distribution to Users	1,000s	None	Low	High	High	No
Industries	10,000s	Electric utility rates regulations	Moderate	High	Low	No
All End-Users	100,000,000s	None	Low	Low	High	No
Hybrid (Equipment Manufacturers & Industry)	10,000s	Electric utility rates regulations	Moderate	High	Moderate	Yes

The industry level provides less coverage of emissions than either other level, and is faced with an important problem area in the case of utility incentives. As Volume 3 of this report explains in detail, utilities may fail to participate fully in an emissions trading market except with very careful design of the implementation. Even with such care, the areas of jurisdiction over utility decisions are so complex that the problem may not be easily circumvented. Because utilities would be such a large fraction of any industrially-based CO_2 emissions market, the potential for disruption is a serious concern.

The end-user level is too cumbersome to administer and enforce for the entire population of end-users. An hybrid approach that expands an industrial-based system to try to capture most other end-user emissions is a promising idea, but in our judgment appears have less potential effectiveness than the fuels distribution level, with no offsetting advantages other than a possible one of social welfare distribution. The latter issue is described at the end of this section.

The industry data collected for this study come from standard sources such as the Energy Information Agency, the Census of Manufacturers, and industry statistical reports. The data from these sources can be disaggregated geographically only to the state level, making it difficult to obtain reliable estimates of the size distribution of individual facilities. The only direct information on size distributions is for companies, which may comprise many individual facilities in many parts of the country. These caveats should be kept in mind in interpreting some of the specific numbers presented in this report.

This report considers the case of CO_2 emissions trading only, rather than all greenhouse gases. This is in part because manmade CO_2 emissions come almost entirely from combustion of fossil fuels. (Cement production is the key exception, as described in Volume 1.) Comparison of market levels is made more clear when limited to the fossil fuels. Further, many of the other greenhouse gases are not as clearly tied to specific markets. For example, methane emissions are largely by-products of a large variety of activities such as agriculture, landfilling, and mining. In each case, the level of activity (e.g., the number of acres cultivated with rice or the tons of rice sold) is less important in determining the emissions level than the nature of the activity (e.g., the method of fertilization, tillage, or irrigation). While CFCs do have very clear markets, they are of less interest in discussions of trading because they are being phased out of existence. Options for including all greenhouse gas emissions in a trading scheme could be considered after a system has been designed to address CO_2 only. Doing the analysis in this order does not mean that regulations should be phased in this order.

For this analysis, fossil fuels considered include natural gas, coal, and petroleum-based fuels (fuel oil, gasoline, etc.). Markets for wood and other biomass fuels are not analyzed because they pose a question of how significantly they create *net* emissions, if at all. Similarly, use of waste methane, such as that captured from landfills or farming, is also not considered because of complications in determining whether its use adds to emissions, or whether it in fact reduces total greenhouse forcing. This could happen because (1) the methane that is captured is itself a powerful if short-lived greenhouse gas, and (2) its use as a new fuel source could displace more carbon-intensive coal or oil, thus reducing net carbon emissions per energy unit. Both of these energy sources require further analysis to determine whether they would be considered fuels that require allowances, or whether use of them would be a basis for the award of additional allowances.

WHAT WOULD TRADING REQUIREMENTS CONSIST OF AT THE DIFFERENT MARKET LEVELS?

The following subsections describe how trading at each level would be implemented. In addition to the mechanical details of implementation, we also note what the resulting system might "look like" to the public. Such perceptions do not provide any economic basis for selecting among the options. They are included to help the reader visualize trading at each market level. They are also useful to understand when ultimately preparing an implementation plan that is acceptable within a broader framework than the purely economic comparison that is the purpose of this study.

Regulation of the Primary Producers

Primary producers are most typically thought of as those that are involved in the extraction of oil, gas, and coal. As noted in Table 1-1, and as will be discussed in detail in Section 2, this is an overly simplistic definition. In fact, primary production might also be expanded to include refiners or fuels distributors. Regardless of this distinction at the primary level, one could require permits according to the amount of carbon in fuel extracted, without consideration of its end-user destination. Regulation is feasible at this level of the economic chain because the carbon emissions of the ultimate products can be anticipated quite accurately in terms of the carbon content of the extracted primary material. This level of the market may not be as easily incorporated into other pollution-control regulations because emissions are usually dependent on processes and control technologies used, and not on the properties of the raw materials alone. For fossil fuels, however, carbon emissions are very closely tied to initial carbon in the extracted raw material.

The way emissions trading would work at the primary producer level would be that each primary producer would be required to have a sufficient number of units of allowances for carbon extracted and sold. Allocating allowances to the agents in the market might seem at first as if producers were being told that there was to be a specific reduction in the historical extraction rate. This is because there is no alternative for fossil fuel extraction enterprises as a group to reduce carbon sold than to simply extract less. Because allowances would be tradeable, however, market forces would result in the lower cost producers being able to buy out the marginal producers. Thus trading would allow the final form of the extraction reductions to occur in the most cost-effective manner from society's point of view, and some producers may be able to actually expand extraction (for example, of natural gas) while others would reduce production even more than their allotted allowances would require (for example, coal). Thus the ultimate effect of tradeable carbon permits would be a shift away from carbon-intensive fuels, and there would be no actual limitation of supplies of individual fuels, nor of the total supply of energy services.

The cost of the allowances would be passed on to purchasers, ultimately to those who burn the fuels, thereby providing an economic incentive to energy consumers to reduce their use of energy, and to switch to less polluting fuels. Even though the incentives for pollution reduction would be passed on to the ultimate polluters, this type of implementation could potentially be perceived as much as an intervention in energy markets as a controlling of pollution levels. As will be discussed below, there are also distributional effects that could have implications for this approach, regardless of its cost-effectiveness: producers may gain more than consumers.

Regulation of Industrial Sources of CO_2

Tradeable allowances could also be required at the industrial combustion point. In this case, allowances could be tracked in terms of measured carbon emissions, giving the impression of a more direct link to the control of pollution. The system would work by allotting, or requiring purchase of, allowances for each unit of carbon emissions from fossil fuels. Companies that currently burn fossil fuels would have incentives to switch to low- or no-carbon energy, and to conserve energy, exactly as in the case of trading at the primary production level. These reactions would feed back to the fossil fuels market in the form of a shift in output to relatively more low- and no-carbon energy sources.

Controls on industrial sources of pollution have a strong political heritage. Yet, as Volume 1 of this report discusses, there are many more important sources of CO_2 than industry alone. In particular, transportation is equally as important as electric utilities, or as all other industry put together. Unfortunately, with millions of vehicles, transportation amounts to an area source created by the independent decisions of millions of citizens. Unless the options of individual citizens are also included in the trading scheme, direct control of CO_2 emissions will be less effective than their indirect control via requiring allowances per unit of fossil fuel extracted. Similarly, consumers of electricity (i.e., virtually every household as well as industrial and commercial users) can affect the effectiveness of emissions control in the electric sector. However, without changes in the current system of rate setting, there are incomplete incentives for such consumers to take actions that would be socially cost-effective.

Regulation of All End-Users of Fuel Services

A third level of the market in which emissions allowance trading might be required: all end-users of energy services. In such a scheme, allowances would be required of consumers as a function of energy used in a number of daily activities. These could be required (1) at the time of purchase of the fuel or electricity, or (2) they could be estimated from records of annual mileage or kWh consumption.

In the first case, the permits requirement could be more precise: annual transportation usage would not have to be estimated, and in the case of electricity, time of day information could allow the type of generating equipment being dispatched to be included in the emissions estimate. However, the actual accounting of permits might be cumbersome on an as-used basis. Consumers would have to have a continual supply of permits in small denominations, almost like carrying around a second currency, or a second type of checking account. It is possible that the providers of the energy sources could start buying up allowances themselves, and then sell them to consumers with the fuel or electricity. This would appear as a surcharge on fuel pump prices, or on the electricity bill. Consumers might welcome the service of not having to obtain their own allowances, but also might perceive the system as a large energy tax rather than a market in which they actively participate.

In the second case, there would be problems of agreeing on a fair basis for estimating total annual emissions, especially for the use of equipment such as automobiles where the fuel usage rates can vary dramatically according to personal driving styles, even for a given brand and model of equipment. Further, waiting until the end of a year before taking an accounting may be more problematic at the individual citizen level than at the corporate level. Some form of permits withholding might be necessary throughout the year, with the resulting system being as cumbersome as a second income tax scheme, replete with forms and filing requirements.

WHAT ARE THE WELFARE DISTRIBUTION IMPACTS FROM TRADING AT DIFFERENT MARKET LEVELS?

The previous discussion indicated how trading might proceed on different bases depending on the market level at which it could be implemented. Before moving to a comparison based on the cost-effectiveness criteria, it is useful to review welfare distributional considerations that may enter into the debate, at least implicitly. These are considerations of how the total social welfare would be shared by the market participants, depending on which market level is required to have allowances for its economic activities. Section 2 then also provides some information on the distributional impacts across regions of the country.

Total surplus is a term used in economics to describe how well off society is under specific market conditions. It is used by economists primarily for comparing among market options, rather than to determine if a specific market outcome is acceptable in some absolute sense. Total surplus in a market has two components: *consumer surplus* and *producer surplus*. These concepts indicate the benefits captured by producers and consumers from market transactions. They are always greater than or equal to zero for both sides of the market, or else the market would cease to exist.

A regulatory action will often reduce the total surplus in the market for a good that is responsible for some externality, such as pollution. This is accepted as part of the decision to regulate because surplus is believed to be increased elsewhere in the economy, such as through enhanced environmental quality, and such increase is judged to outweigh the loss in surplus in the regulated market. However, regulatory actions can also change the relative shares of total surplus among economic sectors or regions. That is, the burden of meeting the regulation may fall more on one party than another. Although these concepts come from the economics literature, they have nothing to do with the economic optimality of an outcome. Instead, decisions among these effects can only be decided on the basis of concepts of fairness, which is inherently a political issue.

Consumer surplus is defined as the excess that consumers would be willing to pay for the commodity over that which they have to pay as the market price. Producer surplus is the excess over costs that producers can earn, given the market price they obtain for their product. (Producer surplus is synonymous with economic profits.) These are best displayed graphically, as in Figure 1-1. The market price is the point where the demand and supply curves intersect. Since the demand curve traces out the marginal willingnesses of consumers to pay, each consumer's individual marginal surplus is the difference between the market price and that consumer's position on the demand curve. The total consumer surplus is thus the area labelled CS. Since the supply curve traces out the marginal costs of producers, each producer's marginal surplus is the difference between the supply curve and the market price, and total producer surplus is the area labelled PS.

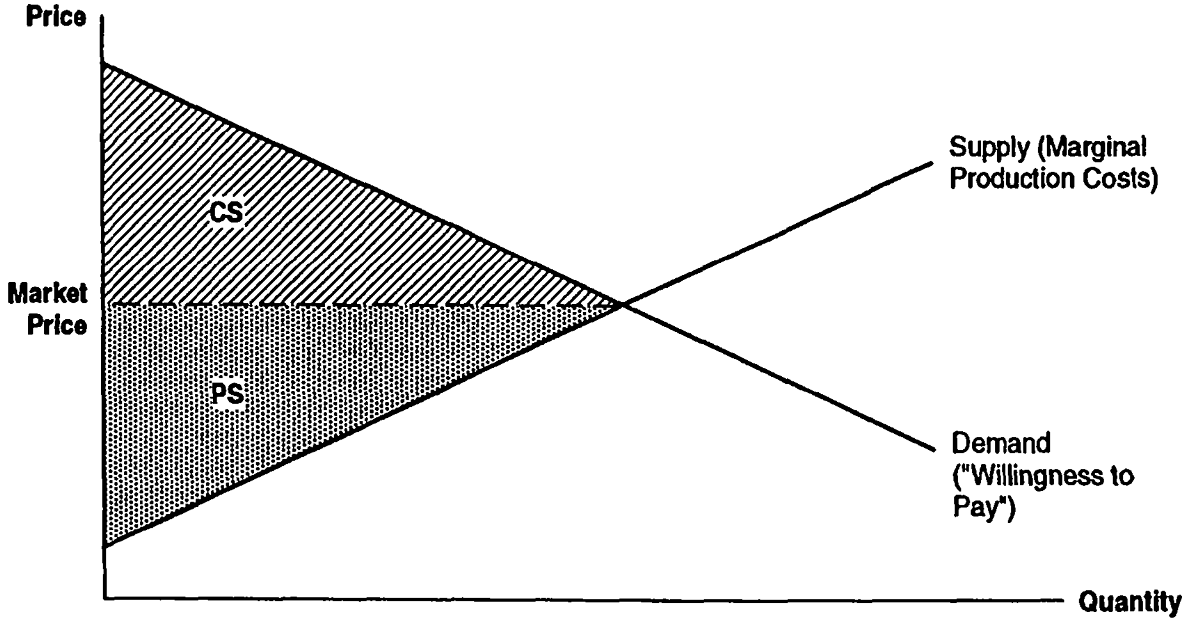


Figure 1-1. Illustration of Components of Market Surplus Concept

An Hypothetical Example

To compare the surplus outcomes of different trading schemes, a simple hypothetical market case is presented. In this, there are only two market levels: the primary producer and the consumer levels. The primary producers are represented by two oil extraction enterprises. They sell fuel to a set of six industrial customers, which represent the consumer level of the market. Hypothetical market information is presented to provide easily verified surplus calculations, so that the example can concentrate on the comparative nature of market outcomes under trading of permits instituted at each level of this market.

The two oil extraction enterprises have different costs of production: $10/barrel for producer X and $100 for producer Y. Clearly producer X would always take the market from Y, but cannot take the entire oil market because he cannot extract more than 6 barrels of oil per year. Producer Y can extract much larger amounts of oil. The market supply curve for oil under these conditions is illustrated in Figure 1-2, labelled S.

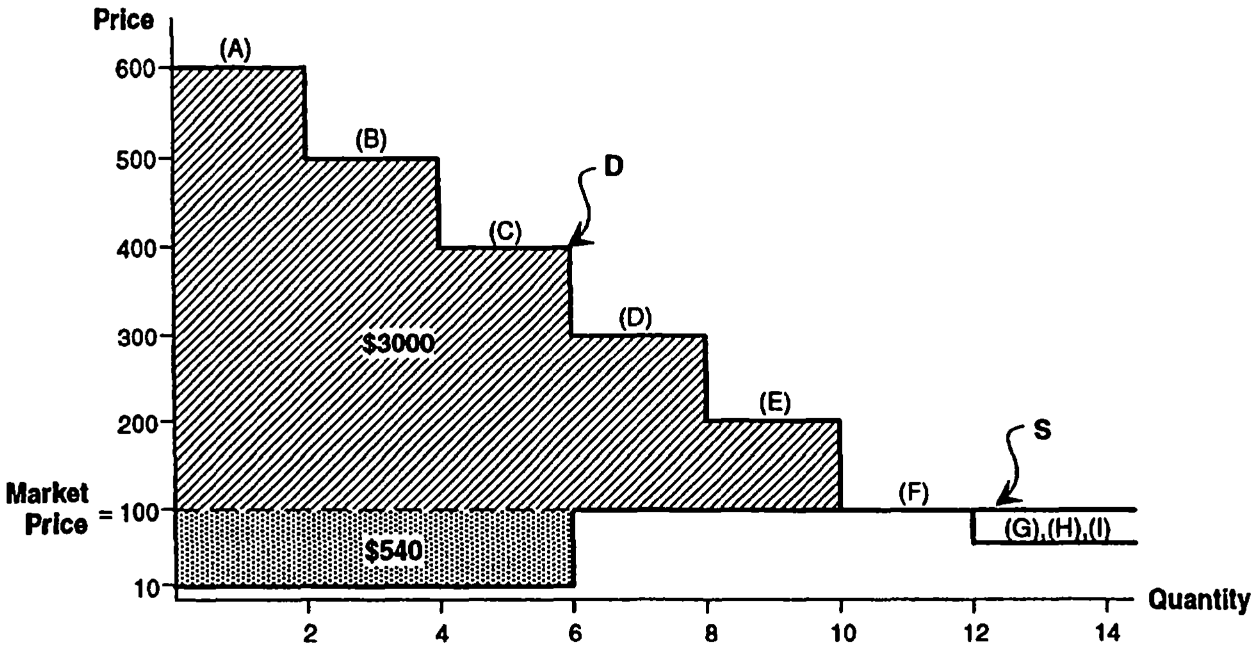


Figure 1-2. Hypothetical Market for Oil Products

Demand for oil comes from six different industries, A through F. Other potential demand for oil comes from industries G, H, and I, but these do not participate in the market because their willingness to pay for the oil is less than current market prices. Industry A has the highest willingness to pay, $600/barrel, for the oil, and wants 2 barrels/year at any price under that value. This very high willingness to pay is because industry A depends on oil very strongly and has few options for either substituting to other fuel sources or for conserving fuel consumption in its production process. Other industries have more options, and thus lower willingnesses to pay, as traced out by the declining demand curve, D.

Given these market assumptions, the market price for oil is $100. Producer X sells as much as he can at that price, and producer Y produces the remaining 6 barrels/year. The total surplus in this market of 12 barrels/year is $3540. Only $540 of that is producer surplus (note that it goes entirely to producer X), and the remaining $3000 is "profit" to the six consuming industries. This is the initial, pre-regulatory situation against which different trading schemes are now to be compared. Regulations are suddenly implemented to cut CO_2 emissions from oil by 50%. This means that consumption of oil must be cut by 50%, to six barrels/year.

Regulations Implemented at the Primary Producer Level. In the first trading scheme, assume that the permits are assigned to the primary producer level. Producers X and Y each get 3 permits. If they are not allowed to trade these permits, each will continue to produce at the maximum rate possible. The supply curve shifts to that labelled S1 in Figure 1-3(A). Because there is excess demand at the initial price, prices may rise to as high as $400/barrel, which is the value above which there is still sufficient willingness to pay for up to the six barrels/year now permitted. Under these new market conditions, total surplus has declined to $2670, but producer surplus has actually risen to $2070 and both producers are now making larger profits.

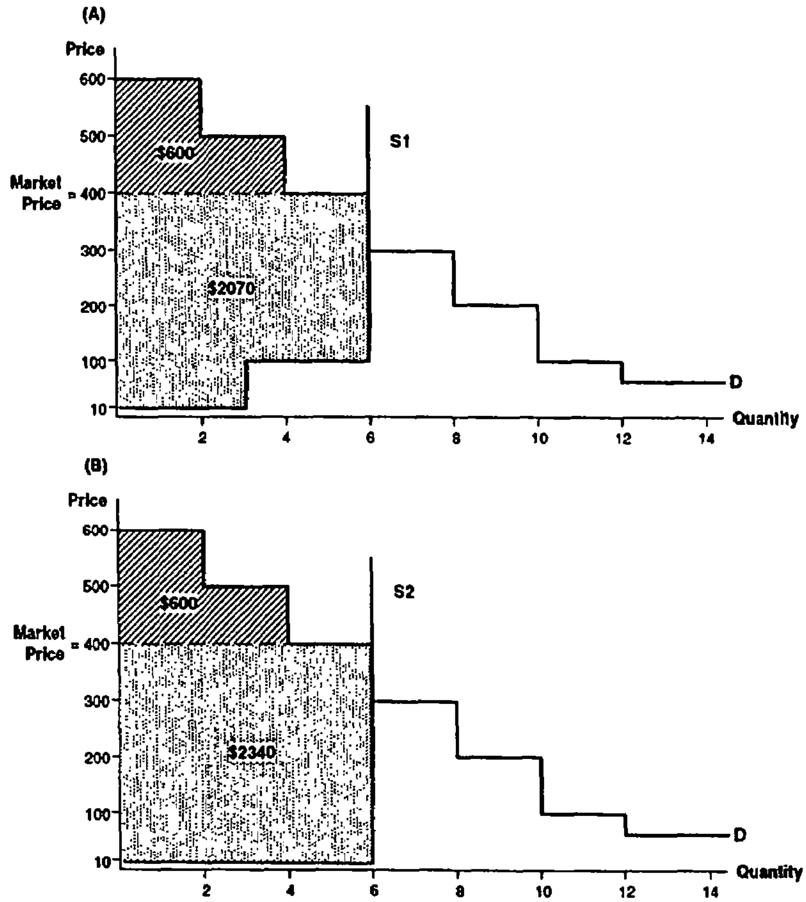


Figure 1-3. Market Conditions After Permits Allocated to Primary Producers: (A) No Permit Trading Is Allowed; (B) Permit Trading Is Allowed

If the two producers are allowed to trade allowances, producer X will have an incentive to buy out producer Y at any price less than $390 (400-10). Producer Y may be making a profit of $300/barrel now, but will sell out at any price above $300/permit. Thus the two can be mutually happier by a trade of permits somewhere in the price range of $300 to $390. If we assume that they roughly split the difference at a price of $350/barrel, producer X can now sell at his full capacity, producer Y leaves the market a richer person, and society benefits from lower costs of meeting the regulation (Figure 1-3(B)). That is, the total surplus increases from $2670 to $2940. This is not as high as the pre-regulation surplus in the oil market, but the rise in total surplus represents a cheaper regulation for society as a whole than if permit trading were not allowed. The trading of permits reallocates the burden of emissions reductions so as to minimize losses of consumer plus producer surplus. In this example, the increase in surplus goes entirely to the producers, while consumers take on the costs of the regulatory burden: their surplus falls from $3000 pre-regulation to $600.

Figure 1-3 illustrates potential distributional impacts of a producer permit system. However, the reader should be aware that the rise in producer surplus in the example due to a permit system is the result of the assumed price elasticities of demand and supply. If demand were more price elastic and supply were less price elastic, price would rise less and costs would fall less when output is constrained by an emission allowance system. The net result could be a fall in producer surplus as well as in consumer surplus. Estimates for fossil fuel price elasticities of demand (Table 1-2) show them to be relatively price inelastic in the short-run, and mostly borderline elastic in the long run. Elasticities of supply for fossil fuels have been observed to be relatively more elastic, with substantial increases and declines in reserves following historical price fluctuations. Thus, our expectation is that a producer permit system for carbon content of fuels would be likely to raise producer surplus. Over time we would expect the positive impact on producer surplus to diminish due to the fact that long-run price elasticities of demand are greater than short-run elasticities.

This example is specific to emissions permits that affect only a single commodity that has no substitutes that would also compete for the same permits. For instance, the example is constructed so that only oil is required to have permits. In reality, for CO_2 controls, coal and natural gas would also have to have permits, all drawn from the same pool of *carbon* permits. These fuels are also substitutes in consumption. If we extend the example to account for *carbon* permits, rather than *oil* permits, then the reduction in consumer surplus for oil may not be as large as it appears in Figure 1-3(B). Oil producers might buy carbon allowances from coal producers, which is a more carbon-intensive fuel, and increase oil supply above 6 units. The price of oil would fall below $400 and consumer surplus would rise above $600 as a result of extending the allowance trading to all fossil fuels. In turn, coal consumers would suffer a loss as the market reallocates permits away from coal production, causing coal supply to decrease further than under the original allocation of allowances and causing the price of coal to rise. The net effect for total surplus (consumer plus producer) across all energy markets will be positive as the market reallocates carbon emission allowances among energy resources of different carbon intensities. Consumers as well as producers would share in the improvement from the position of Figure 1-3(A). However, when comparing a no regulation case (Figure 1-2), and a carbon permits market case (Figure 1-3(B)), consumers of fossil fuels, as a group, still would bear more of the total impact of the regulation than would fossil fuel producers, as a group, when the permits market is implemented at the producer level of the market.

The reason the hypothetical example where permits can only be traded among oil producers causes consumers not to benefit from trading of producer permits is because a fixed quantity of emission allowances also fixes the quantity of oil supplied. When extended to include all carbon-based fuels, then a fixed supply of emission allowances does not fix the quantity of any energy type, nor the aggregate quantity of energy services. Consumers also stand to gain from trading in cases where emissions control technologies exist because, again, a fixed supply of emission allowances does not fix the quantity of the commodity that can be supplied. However, this extension of the illustrative example does not apply to a carbon permits market: reduction of carbon emissions can only be attained by reducing use of fuels.

Table 1-2
SAMPLE OF PRICE ELASTICITIES OF DEMAND FOR FOSSIL FUELS

	Short-run	Long-run
Industrial, heavy oil [1]	N/A	-0.30 to -1.17
Industrial, natural gas [1,3]	-0.07 to -0.63	-0.12 to -2.53
Industrial, coal [1]	N/A	-1.00 to -1.12
Commercial/Residential, heating oil [1]	N/A	-1.10 to -1.38
Commercial/Residential, natural gas [1,3]	-0.05 to -0.68	-0.39 to -4.60
Commercial/Residential, coal [1]	N/A	-1.29 to -2.24
Electricity [4]	-0.16 to -0.29	-0.17 to -0.63
Transportation, gasoline [1,2]	-0.13 to -0.29	-0.60 to -1.77
Transportation, diesel [1]	N/A	-0.61 to -1.10

(**Sources**: [1] Al-Sahlawi, M.A., "The Demand for Natural Gas: A Survey of Price and Income Elasticities," *The Energy Journal*, Vol. 10, No. 1, January 1989, p. 77-90. [2] Moss, M. F., and J. L. Small, "Deriving Electricity Demand Elasticities from a Simulation Model," *The Energy Model*, Vol. 10, No. 3, July 1989, p. 51-76. [3] Jacoby, Henry D., and J. L. Paddock, "World Oil Prices and Economic Growth in the 1980s," *The Energy Journal*, Vol. 4, No. 2, April 1983, p. 31-47. [4] Dahl, Carol A., "Gasoline Demand Survey," *The Energy Journal*, Vol. 7, No. 1, January 1986, p. 67-82.

Taking the multi-fuels market extensions into account, we can summarize the general effects of a market of producer emission allowances for carbon:

- Supplies of fossil energy will decrease.
- Marginal (e.g., high cost) carbon-intensive fuel producers will leave the market with the benefit of a large "bribe."[3]
- Prices of fossil energy will rise.
- Economic profits in the energy supply industry will rise (given relatively inelastic demands for fossil energy).
- Consumers of energy services will lose.
- Overall, there will be a fall in total social welfare related to fossil fuel markets.

3. This "bribe" is the amount the marginal producer could obtain by selling his permits and leaving the business. This transfer of wealth would not occur if permits were auctioned rather than allocated to the existing producers in a market. However, the ability to give out such wealth is an inducement that makes tradeable permits appear politically advantageous over taxes, which leave no such winners in the regulated community.

The last point should be qualified to acknowledge that we have focused solely on effects in the energy sector, and have not attempted to account for environmental benefits associated with these costs. The losses in social welfare in the energy sector are the costs of obtaining environmental gains. Whether or not the environmental gains are sufficiently large to justify the costs of carbon emission reductions is beyond the scope of this study.

Note that our discussion assumes that producers do not pay for the emission allowances allocated to them. If producers were required to pay for the allowances, producer surplus would decline correspondingly and be transferred to the authority collecting the payments.

Controls Implemented at the Consumer Level. What happens to the surplus if instead the oil consumers are required to have permits to buy oil? In this case, assume that each of the six industries are allocated 1 permit for each unit of carbon emissions, rather than the 2 units that they are currently producing (assuming that 1 barrel of oil burned produces 1 unit of carbon emissions). In this case, the effect is to shift the demand curve rather than the supply curve, as depicted in Figure 1-4(A). Without trading, all six consumers remain in the market, but the market is halved. The reduction in oil consumption by half for each oil consumer reduces consumer surplus from \$3000 to \$1500. Total surplus is reduced from \$3540 to \$2040. (Oil prices may fall if a lower cost set of producers can now meet the full demand. In this example, the price remains at \$100, but this is an anomalous outcome specific to this special case.)[4]

If trading of emission allowances among primary energy consumers is permitted, allowances will be sold by consumers who place relatively low value on carbon-based energy to consumers who place a high value on carbon-based energy. These trades reallocate allowances so that carbon energy goes to the uses for which it has the highest market value. In the example, industries A, B, and C would buy allowances from industries D, E, and F.[5] As permits are transferred to industries that are willing to pay the most for oil, the demand curve shifts out to the right as depicted in Figure 1-4(B). The result is to raise consumer surplus from \$1500 to \$2400, substantially reducing the costs to consumers of emission reductions. The total surplus rises from \$2040 to \$2940.

In the example provided, producers do not benefit from trading of allowances among consumers (i.e., in the comparison of Figures 1-4(A) and 1-4(B)) because the trades do not alter

4. The lack of change in price is an artifact of the problem construction, where the oil market is split 50-50 between producers X and Y, and the regulation cuts demand exactly in half. If demand were cut more, prices for oil could drop, particularly if the example were more realistic, to include more than just two producers.

5. Industries D, E, and F would not necessarily go out of business, but would likely turn to other sources of energy services that may be available to them at lower cost than the alternatives for A, B, and C.

ERROR: ioerror
OFFENDING COMMAND: imagemask

STACK:

-dictionary-
-mark-
-savelevel-

Regional Strategy Implementation Work Plan

Engage in Programmatic Outreach and Communication

- Beyond supporting program travel to the annual User's conference, Network governance could develop materials for Regional staff to use in marketing and advocating the Network customers and programmatic counterparts.
    - Leads: NOB/NPRG
- Conference calls could be scheduled, perhaps 4 per year, with Network governance and EPA Regional program staff to discuss outreach and communication, programmatic updates, and future Network focus areas.
    - Leads: Maryane Tremaine and Mitch West

Convene Network Partners

- Network governance could gather information on all the relevant meetings convened by EPA Regional offices and identify opportunities where Exchange Network content can be "piggybacked."
    - Lead: Mitch West with NPRG

Leverage the Unique Role of OEI Lead Region ENLC Delegate

- Network governance could create training or marketing information about the Exchange Network to familiarize lead regional coordinators with the Network and enable them to fulfill their role. The Network User's Guides are an excellent example of the type of material that could be developed to disseminate Network use and functionality.
    - Lead: NPRG

Continue Supporting Exchange Network Grant Administration and Leverage the Network for Other EPA Grant Programs

- EPA Regional staff can consult with the Exchange Network Grant Program and the Network governance to develop a tool that tracks how an Exchange Network was used and the resulting product. EPA Grant Program could also require exit interviews with grant recipients to identify observations, reflections, and challenges encountered by grantees. Further, Network governance could assemble this information into a database that could be used to inform future grant proposals and disseminating ideas more broadly to the Network community.
    - Lead: Andy Battin

Establish Regions as Centers of Leadership

- Network governance and EPA Regional staff will work together to identify, coordinate, and establish Centers of Leadership.
    - Leads: Bill Rice and Maryane Tremaine

- At the National User's meeting or other relevant conferences, Network governance can give targeted presentations to the Center of Leadership on tools and resources that could be implemented to develop solutions. For example, a presentation could be given on how to adapt the HERE Tool to other regions. The States of Nebraska, Kansas, Iowa and Missouri could also share their experiences using the Tool.

- Lead: Kurt Rakouskas

Coordinate with Tribes and Engage Network Tribal Participation

- Network governance or EPA Regional Offices could convene a semiannual conference calls for Regional Tribal Coordinators, Regional staff, and Network governance to discuss tribal outreach and identify opportunities for Network participation. The conference calls would also provide an opportunity for Regional Tribal Coordinators and Regional staff to share what is going on in the ROC meetings and ensure that the flow of communication between tribes and Network governance is further enhanced.
  - Lead: Mitch West and Robert Holden

Work with Network Governance to Implement the Regional Strategy

- Network governance should convene data stewards for an annual "State of the Flow" meeting. Not only will this keep the community of interest informed but it also representing a prime marketing opportunity for the Network and individual flows.
  - Lead: NOB

- The Network governance will work in conjunction with the Regions to identify, recruit, and educate Program staff in each Region and in as many Programs as possible to be voluntary Network advocates.
  - Leads: Bill Rice (ENLC Regional Representative) with ENLC Co-Chairs, and Mitch West

- The NOB and Network Coordinator will work with the Regional Network advocates to develop plans for engaging potential and existing Network customers on how the Exchange Network might be leveraged to meet programmatic business needs and priorities.
  - Leads: Mitch West, Andy Battin, and Nancie Imler

- The Network Coordinator and NPRG will continue to track national programmatic meetings, and will also track significant Regional meetings, like Program Director Meetings, and identify how to capitalize on those opportunities for outreach.
  - Leads: Mitch West, Chris Simmers, Doreen Sterling

- The ENLC will work with the Network Coordinator in determining how Network Governance wants to manage its relationships with the EPA Regional staff working on Network business.
  - Lead: Mitch West

- The Exchange Network Governance support will include preparation of materials that outline where there are areas of convergence between EPA Grants and potential uses of the Network.
  - Lead: Andy Battin

- The ENLC will discuss whether to recommend to the EPA that EPA Regions be given sections in Appendix B of the Grants Guidance to identify projects of Regional importance, or the ENLC could identify this information and make it available on the Network website.
  - Lead: Mitch West

- The ENLC will work with the Network Coordinator in identifying how best define an explicit role for the Regions in the Network financial strategy, especially in regards to grant alignment. The ENLC will also collaborate with Regions in defining this role.
    - Leads: Mitch West with ENLC Co-Chairs

- The ENLC (or via the Network Coordinator) will send an email to EPA Regional Office Partners encouraging them to attend the Network User's conference.
    - Leads: ENLC Co-Chairs

- The ENLC will identify which sessions at the User's Meeting they would like the data stewards to run and contact them to do so.
    - Lead: Mitch West

- The ENLC will consider adding Regional Program representatives to the Network Governance groups.
    - Leads: ENLC Co-Chairs

Regional Strategy Implementation Work Plan

Engage in Programmatic Outreach and Communication

- Beyond supporting program travel to the annual User's conference, Network governance could develop materials for Regional staff to use in marketing and advocating the Network customers and programmatic counterparts.
    - Leads: NOB/NPRG
- Conference calls could be scheduled, perhaps 4 per year, with Network governance and EPA Regional program staff to discuss outreach and communication, programmatic updates, and future Network focus areas.
    - Leads: Maryane Tremaine and Mitch West

Convene Network Partners

- Network governance could gather information on all the relevant meetings convened by EPA Regional offices and identify opportunities where Exchange Network content can be "piggybacked."
    - Lead: Mitch West with NPRG

Leverage the Unique Role of OEI Lead Region ENLC Delegate

- Network governance could create training or marketing information about the Exchange Network to familiarize lead regional coordinators with the Network and enable them to fulfill their role. The Network User's Guides are an excellent example of the type of material that could be developed to disseminate Network use and functionality.
    - Lead: NPRG

Continue Supporting Exchange Network Grant Administration and Leverage the Network for Other EPA Grant Programs

- EPA Regional staff can consult with the Exchange Network Grant Program and the Network governance to develop a tool that tracks how an Exchange Network was used and the resulting product. EPA Grant Program could also require exit interviews with grant recipients to identify observations, reflections, and challenges encountered by grantees. Further, Network governance could assemble this information into a database that could be used to inform future grant proposals and disseminating ideas more broadly to the Network community.
    - Lead: Andy Battin

Establish Regions as Centers of Leadership

- Network governance and EPA Regional staff will work together to identify, coordinate, and establish Centers of Leadership.
    - Leads: Bill Rice and Maryane Tremaine

- At the National User's meeting or other relevant conferences, Network governance can give targeted presentations to the Center of Leadership on tools and resources that could be implemented to develop solutions. For example, a presentation could be given on how to adapt the HERE Tool to other regions. The States of Nebraska, Kansas, Iowa and Missouri could also share their experiences using the Tool.

- Lead: Kurt Rakouskas

Coordinate with Tribes and Engage Network Tribal Participation

- Network governance or EPA Regional Offices could convene a semiannual conference calls for Regional Tribal Coordinators, Regional staff, and Network governance to discuss tribal outreach and identify opportunities for Network participation. The conference calls would also provide an opportunity for Regional Tribal Coordinators and Regional staff to share what is going on in the ROC meetings and ensure that the flow of communication between tribes and Network governance is further enhanced.
    - Lead: Mitch West and Robert Holden

Work with Network Governance to Implement the Regional Strategy

- Network governance should convene data stewards for an annual "State of the Flow" meeting. Not only will this keep the community of interest informed but it also representing a prime marketing opportunity for the Network and individual flows.
    - Lead: NOB

- The Network governance will work in conjunction with the Regions to identify, recruit, and educate Program staff in each Region and in as many Programs as possible to be voluntary Network advocates.
    - Leads: Bill Rice (ENLC Regional Representative) with ENLC Co-Chairs, and Mitch West

- The NOB and Network Coordinator will work with the Regional Network advocates to develop plans for engaging potential and existing Network customers on how the Exchange Network might be leveraged to meet programmatic business needs and priorities.
    - Leads: Mitch West, Andy Battin, and Nancie Imler

- The Network Coordinator and NPRG will continue to track national programmatic meetings, and will also track significant Regional meetings, like Program Director Meetings, and identify how to capitalize on those opportunities for outreach.
    - Leads: Mitch West, Chris Simmers, Doreen Sterling

- The ENLC will work with the Network Coordinator in determining how Network Governance wants to manage its relationships with the EPA Regional staff working on Network business.
    - Lead: Mitch West

- The Exchange Network Governance support will include preparation of materials that outline where there are areas of convergence between EPA Grants and potential uses of the Network.
    - Lead: Andy Battin

- The ENLC will discuss whether to recommend to the EPA that EPA Regions be given sections in Appendix B of the Grants Guidance to identify projects of Regional importance, or the ENLC could identify this information and make it available on the Network website.
    - Lead: Mitch West

- The ENLC will work with the Network Coordinator in identifying how best define an explicit role for the Regions in the Network financial strategy, especially in regards to grant alignment. The ENLC will also collaborate with Regions in defining this role.
    - Leads: Mitch West with ENLC Co-Chairs

- The ENLC (or via the Network Coordinator) will send an email to EPA Regional Office Partners encouraging them to attend the Network User's conference.
    - Leads: ENLC Co-Chairs

- The ENLC will identify which sessions at the User's Meeting they would like the data stewards to run and contact them to do so.
    - Lead: Mitch West

- The ENLC will consider adding Regional Program representatives to the Network Governance groups.
    - Leads: ENLC Co-Chairs

CO_2 TRADING ISSUES

Volume 2: Choosing the Market Level for Trading

Final Report

Prepared by

Anne E. Smith
Anders R. Gjerde
Lynn I. DeLain
Ray R. Zhang

DECISION FOCUS INCORPORATED
1155 Connecticut Avenue NW
Washington, DC 20036

Prepared for

Adaptation Branch, Climate Change Division
Economic Analysis & Research Branch, Economic Analysis & Innovation Division
Office of Policy, Planning and Evaluation
U.S. Environmental Protection Agency
Washington, DC 20460

Contract No. 68-CO-0021

Project Manager
Neil A. Leary

Chief, Adaptation Branch
Joel D. Scheraga

May 1992

PREFACE

There has been increasing concern within the international community about rising concentrations of carbon dioxide (CO_2) and other greenhouse gases in the atmosphere that may contribute to global climate change. The United States and other nations have been, and will continue, grappling with the question of whether or not to constrain the emissions of CO_2. Should a decision be made to constrain greenhouse emissions, there exists a variety of policy tools that could be employed to achieve this objective. Discussions of policy tools have recently focused on approaches that rely upon the creation of market incentives that would induce sources to reduce their emissions. The advantage of these market incentive approaches is that they offer the possibility of controlling emissions at much lower costs than are likely to be achieved through more traditional regulatory approaches.

This three volume report examines one market incentive approach to controlling emissions of CO_2: tradeable permits. There are a number of points in the economy at which a tradeable permit system might be implemented to control CO_2. For example, permits might be required for supplying carbon-based energy. Alternatively, carbon permits might be required of consumers of carbon-based energy. Potential performance of alternative permit market designs and potential implementation problems are investigated in the report. Recommendations are made for market designs that promise to be more cost-effective than other market designs.

Volume 1 of the report examines emissions of CO_2 from industry, the largest source of emissions from energy consumption. Volume 2 examines alternative carbon permit market designs and evaluates the potential performance of the alternatives considered. Volume 3 examines the potential behavior of electric utilities in a carbon permit market and the implications for the functioning of a permit market.

Designing a cost-effective CO_2 trading system that can be readily implemented and enforced is a complex undertaking. This study illuminates these complexities and provides insights useful to policymakers considering such a system.

Neil A. Leary
EPA Project Manager

Joel D. Scheraga
Chief, Adaptation Branch

EXECUTIVE SUMMARY

Tradeable carbon permits and carbon taxes create market incentives for sources to reduce their emissions of carbon dioxide (CO_2). The advantage of abatement policies that rely on market incentives is that they offer the possibility of controlling emissions at much lower costs than are likely to be achieved through more traditional regulatory approaches. There are, however, a variety of ways in which tradeable carbon permits or carbon taxes might be implemented and the choice of implementation can be important to the costs and performance of the policy. This three volume report examines alternative ways of implementing a tradeable carbon permit system for controlling emissions of CO_2.

The focus of the report is limited to the control of CO_2 emissions from fossil energy production and consumption, which accounts for nearly all US CO_2 emissions. The quantity of CO_2 generated by energy production and consumption is largely a function of the carbon content of the fossil energy input to economic activity. Because capture and disposal of generated CO_2 is prohibitively costly, carbon content of fossil energy input also determines the quantity of CO_2 emissions. Thus a system of carbon permits for fossil energy is equivalent to a system of permits for emissions of CO_2 from fossil energy use. This allows a great deal of flexibility for choosing where in the energy system to implement a permit market for the control of CO_2. For example, permits might be required of suppliers for the carbon content of fossil energy supplied to the market. Alternatively, permits might be required of consumers for the carbon content of the fossil energy consumed.

Although these alternative permit systems can be designed to achieve equivalent CO_2 abatement, the costs of the emission reductions and their distribution can vary significantly. This report examines a number of key issues that will influence the costs of CO_2 abatement and their distribution for alternative carbon permit market designs. Volume 1 examines emissions of CO_2 from industry, the largest source of carbon emissions. Volume 2 examines alternative carbon permit market designs and evaluates the potential performance of the alternatives considered. Volume 3 examines the potential behavior of electric utilities in a carbon permit market and the implications for the functioning of a permit market.

The alternative carbon permit market designs evaluated include both supplier and consumer permit systems. There are a number of points in the supply chain at which a carbon permit market might be implemented. Three alternative designs for a supplier permit market are examined: (i) a market that requires primary energy extractors and importers to obtain carbon permits, (ii) a market that requires energy processors to obtain carbon permits for the products that they produce, and (iii) a market that requires energy distributors to obtain carbon permits for the energy that they sell to final consumers. The consumer carbon permit market designs examined include (i) a market that would require all carbon energy consumers to obtain permits, and (ii) a market that would require only major industrial carbon energy consumers to obtain permits.

It is the recommendation of the report that, if a carbon permit market approach is adopted for CO_2 emission control, it should be implemented on the supply side of energy markets. A supplier permit market for carbon is expected to be a more cost-effective CO_2 control policy than a consumer permit market. However, it is not clear which point in the supply chain is the most promising for implementation of a carbon permit market without further study.

A carbon permit market that requires all consumers of carbon energy to obtain permits for the carbon content of the energy that they burn would include millions of participants in the market. The administrative costs of monitoring, operating, and enforcing a permit market with millions of participants is prohibitively high. These costs might be reduced by limiting a consumer permit market to include only relatively large consumers of carbon energy.

One possibility that is examined is to limit coverage to industrial emitters of carbon. Limiting a carbon permit market for consumers to industrial sources would reduce the number of market participants from millions to tens of thousands. Limiting the market further to the six industrial sectors that are the largest sources of CO_2 would reduce the number of market participants to under twenty-thousand and still include 90% of industrial emissions in its coverage.

However, limiting a consumer permit market to only industrial energy consumers would exclude 40% of US CO_2 emissions from control. This eliminates many opportunities for potentially low cost emission reductions from residential, commercial, and transportation sources and promises to raise the control costs per ton of CO_2 abated. The control costs of achieving a chosen CO_2 target might be reduced by complementing a permit market for industrial energy consumers with additional policies that are targeted at other energy consuming sectors. But implementation and operation of two or more separate programs for control of different sources of CO_2 will add to administrative costs.

A further disadvantage of a consumer permit market for carbon are complexities that arise from existing regulations of electric utilities. Rate of return regulations, restrictions on capital gains and losses, and other regulations may lead electric utilities to make inefficient choices. Inefficient behavior by utilities can potentially raise the costs of any CO_2 control policy, but the problem may be particularly severe for a carbon permit market that includes electric utilities as direct market participants.

In contrast, a supplier permit market for carbon energy would achieve almost complete coverage of CO_2 emissions under a single, unified program, while including fewer market participants than would a market for industrial energy consumers. The reduced number of market participants would reduce the administrative costs of a permit market without concentrating the market to a degree that would raise concerns regarding market power. The broad coverage of emissions, the relatively small number of market participants, the lack of significant market power, and the reliance on a single program for all sources suggest that a supplier permit market is likely to be more cost-effective for CO_2 control than a consumer permit market.

Of the various points in the supply chain at which permit trading might be implemented, none emerges as clearly superior. One factor that may influence the cost-effectiveness of CO_2 control is the potential for leakages of emissions that are unconstrained by a permit market. If carbon permits are required at the point of distribution, upstream emissions from energy extraction, refining and processing of energy, and transmission represent potential leakages. These leakages could narrow the range of options for emission reductions and raise costs. In contrast, if carbon permits are required at the point of extraction, these emissions would occur downstream from the permit market and would not represent leakages.

Another factor that may influence the cost of CO_2 control is whether or not the policy imposes constraints that have no emission reduction benefits. Energy used as feedstocks does not contribute to CO_2 emissions and requiring permits for feedstocks would raise costs without providing any emission abatement benefits. If carbon permits are required at the point of extraction, identifying and exempting energy that will ultimately be used as feedstocks may be administratively difficult and costly, while failure to exempt feedstocks will raise control costs. Alternatively, if carbon permits are required at the point of distribution to consumers, identifying and exempting feedstocks may be less costly.

A third factor that may influence the cost of CO_2 control is the ease of monitoring and enforcing compliance with permit requirements. Due to vertical integration of firms that supply energy, monitoring and enforcing compliance may be costly at the levels of extraction and processing. Because there is little vertical integration beyond the point of distribution of energy to energy consumers, monitoring and enforcement costs may be lowest for a carbon permit market at the point of distribution. The net effect of these various factors on the costs of CO_2 reductions for the alternative permit market designs is ambiguous at this time and warrants further study.

The recommendations of the report are based on an evaluation of the cost-effectiveness of alternative permit markets. Another factor that may also guide the selection and design of a CO_2 abatement policy is the distribution of the costs of abatement. The report demonstrates that a carbon permit market for suppliers can yield a very different distribution of costs than would a carbon permit market for consumers. If permits are required of suppliers, the cost of emission reductions may be borne more heavily by energy consumers than by suppliers. If, alternatively, permits are required of consumers, some of these costs may be shifted from energy consumers to energy suppliers. Of course most energy is consumed as an intermediate input by firms, and the ultimate distribution of costs among different portions of the population have not been investigated for this study.

TABLE OF CONTENTS
—Volume 2: Choosing the Market Level for Trading—

TABLE OF CONTENTS (continued)

LIST OF FIGURES

LIST OF TABLES

1

INTRODUCTION AND OVERVIEW

The current debate on appropriate methods for controlling emissions of greenhouse gases frequently refers to the use of tradeable emissions permits. In fact, prominent Congressional activity, in the form of the Cooper/Synar Bill, would introduce an offsets program for new sources of CO_2.[1] Despite the attention that emissions trading generates, relatively little has been done to investigate the behavior of trading under different implementation options. This three volume report covers several topics of interest for implementation planning:

Volume 1:	Emissions from Industry
Volume 2:	Choosing the Market Level for Trading
Volume 3:	Effects of Utility Regulation

This volume (Volume 2) looks in some detail at the issue of implementing trading requirements at different levels of the market. The topic is first defined and described, theoretical aspects are summarized, and specific market data are presented in an effort to understand better the relative advantages of the different options posed. Much of the data presented in Volume 1 is also used in the analysis that follows.

SYNOPSIS OF THE ISSUE AND ANALYSIS

The issue of trading at different levels of the market is one that rarely gains attention in the theoretical literature. It arises because many goods go through a series of manufacturing stages before the point of final consumption. Unless these stages are fully integrated vertically, there is a sequence of markets between the initial product development and the final purchase by the consumer. Fossil fuels provide a good example of this type of market sequence. The initial product may be crude oil. This is captured from a well, and may then be sold to a company that will refine it into final consumer products. There may be additional intermediate markets, such as companies that buy crude from small wells, and in turn sell their accumulated crude to refiners. Distributors may purchase refined products from refiners before they reach the point of sale to the final consumer. Vertical integration is present to some extent in these markets, but intermediate markets do exist.

1. Offsets are very closely related to emissions allowances (which are used for SO_2 controls in the 1991 Clean Air Act Amendments). The main differences between the two concepts are: (1) the supply of offsets is created by market forces while allowances are created in a fixed quantity by regulators; and (2) offsets tend to apply only to new sources, while allowances tend to apply to an entire set of sources.

Given that an estimate of the ultimate CO_2 emissions resulting from a product's use can be made at each market stage, it would be possible to impose a CO_2 emissions trading scheme at any of the market levels. For instance, one might require that each oil well have sufficient permits to cover the carbon contained in its total sales of crude. Or, one might instead allow extraction processes to proceed freely, but require that permits be required for each unit of carbon emitted when the petroleum-based fuel is burned. In the first case, the cost of the permits will be passed through the market, ultimately affecting consumer demand. In the second case, the cost of the permits will directly affect demand, which will in turn pass incentives back to the initial producers. However, a variety of reasons may make one system more functional than another. This study evaluates CO_2 permit trading at different market levels subject to three basic criteria listed below. While we believe that each of these criteria should be given considerable attention in evaluating policy options, the list is not intended to be exhaustive. The criteria focused on in the study are:

1. ***Costs of monitoring and administering a trading program.*** This will depend in part on the number of individual companies that make up each of the market levels, which can vary substantially.

2. ***Effectiveness.*** We examine two aspects of market effectiveness: (a) There may be some "leakage" in markets, meaning that some of the ultimate emissions might not be accounted for. Similarly, some economic activities may be penalized at a rate greater than their actual contribution to emissions. The extent of this type of problem will vary at different levels of the market. (b) Market power may exist in either the market for the product, or in the market that will be created for allowances. Such market power could alter the effectiveness of allowance trading at one market level but not at others.

3. ***Distribution.*** The sharing of control costs (i.e., effects on welfare distribution) will vary. This will include geographical as well as sectoral distribution of the regulatory burden. Economic analysis does not itself indicate what distribution is more desirable, but an understanding of distributional implications is also an important element for the policy making process.

In this volume, three generic market levels are considered as options for implementing CO_2 trading:

- Regulation at the level of the primary producer of fossil fuels.
- Regulation of the key industrial points of fossil fuel combustion.
- Regulation of all end users of fossil fuel-based energy services.

There are many possible combinations of these three options that should be kept in mind when devising an implementation plan. However, for purposes of understanding the relative advantages of each, we focus on these three basic underlying options and note obviously advantageous combinations where appropriate.

Initial analyses using EPA's GEMINI model for assessing national impacts of climate change policies have indicated that there may well be some distinct differences in outcomes when trading is implemented at the different market levels. In one example, the model found that the social benefits of trading to reach stabilization were substantially greater when trading occurred among producers of raw fossil fuels, compared to when trading occurred among those who distribute refined fuels to fuel-using customers.[2] GEMINI does not currently take account of all of the issues mentioned above, and the cause of the differences captured by GEMINI appears to be the leakage issue. GEMINI is also a very aggregate model with no detail on numbers of firms in a given market or their locations. More investigation is needed of the nature of these markets to develop an understanding of the best market level to implement trading, should such regulations be desired. This study takes a first step in the direction of collating the relevant information for such an assessment. The rest of this volume is organized to cover the following general questions related to the three evaluation criteria:

- *What would trading requirements consist of at the different market levels? (next part of Section 1)* This is to provide a clear explanation of what is meant by this issue, before moving to a more detailed analysis.

- *What are the welfare distribution impacts from trading at different market levels? (also in Section 1)* Welfare distribution is a theoretical concept used in economics to investigate the relative gains and burdens under different market structures. Investigation of this effect is useful for motivating the point that trading at different market levels can produce situations that will affect various segments of the population quite differently, even if results are equivalent in terms of their overall effectiveness in reducing emissions and cost.

- *How many sources are there in each market level, how are they distributed by size, and where are they geographically located? (Section 2)* Trading will involve a larger or smaller number of affected entities at different market levels. Also, the affected entities may be more or less geographically concentrated under different market level trading schemes. Potential market power problems are also important to identify. All of these concerns are addressed by a better understanding of the number, location and relative sizes of sources at each market level, and are important in drawing conclusions regarding costs, effectiveness, and distributive effects.

2. Scheraga, J. D. and N. Leary, *Improving the Efficiency of Environmental Policy: The Implementation of Strategies to Reduce CO_2 Emissions*, Paper Presented to Stanford University's Energy Modeling Forum #12, Boulder Colorado, August 27-29, 1991, p. 14. Also, "Efficiency of Climate Policy," *Nature*, Vol. 354, November 21, 1991, p. 193.

- *What amount of total emissions would be subject to controls? (Section 3)* Effectiveness of a control program depends on whether a significant fraction of the emissions are covered by the regulation in question. Building on the data developed in Section 2, the relative degree of control at different market levels is discussed, and options for achieving a degree of control are suggested.

- *What are the mechanisms for monitoring and enforcement? (Section 4)* As noted above, the ability to effectively enforce a market is also important in determining the relative desirability of regulating at different market levels. Enforceability may affect the effectiveness of a program, its overall costs, and even public perceptions of fairness.

Section 5 provides a summary and conclusion, centered around Table 1-1. The key conclusion is that the most promising level appears to be the primary producer level. After defining that sector more fully as a series of sub-levels (extraction, refining/processing, and distribution), the distribution sub-level, where fuel distributors sell final fuel products to users of energy services, appears to be the best option, although with qualifications. The other primary producer sub-levels present less enforceability, greater regional concentrations, and issues related to treatment of imports and feedstocks. The distribution level, however, would not account for significant upstream emissions from extraction and refining.

Table 1-1
EVALUATION OF CO_2 ALLOWANCE TRADING AT DIFFERENT MARKET LEVELS

	# Involved	Market Dysfunction Potential	Degree of Geographical Concentration	Enforce-ability	Emissions Coverage	Import Issues?
Extraction	1,000s	None	High	Moderate	High	Yes
Refining	1,000s	None	High	Moderate	High	Yes
Distribution to Users	1,000s	None	Low	High	High	No
Industries	10,000s	Electric utility rates regulations	Moderate	High	Low	No
All End-Users	100,000,000s	None	Low	Low	High	No
Hybrid (Equipment Manufacturers & Industry)	10,000s	Electric utility rates regulations	Moderate	High	Moderate	Yes

The industry level provides less coverage of emissions than either other level, and is faced with an important problem area in the case of utility incentives. As Volume 3 of this report explains in detail, utilities may fail to participate fully in an emissions trading market except with very careful design of the implementation. Even with such care, the areas of jurisdiction over utility decisions are so complex that the problem may not be easily circumvented. Because utilities would be such a large fraction of any industrially-based CO_2 emissions market, the potential for disruption is a serious concern.

The end-user level is too cumbersome to administer and enforce for the entire population of end-users. An hybrid approach that expands an industrial-based system to try to capture most other end-user emissions is a promising idea, but in our judgment appears have less potential effectiveness than the fuels distribution level, with no offsetting advantages other than a possible one of social welfare distribution. The latter issue is described at the end of this section.

The industry data collected for this study come from standard sources such as the Energy Information Agency, the Census of Manufacturers, and industry statistical reports. The data from these sources can be disaggregated geographically only to the state level, making it difficult to obtain reliable estimates of the size distribution of individual facilities. The only direct information on size distributions is for companies, which may comprise many individual facilities in many parts of the country. These caveats should be kept in mind in interpreting some of the specific numbers presented in this report.

This report considers the case of CO_2 emissions trading only, rather than all greenhouse gases. This is in part because manmade CO_2 emissions come almost entirely from combustion of fossil fuels. (Cement production is the key exception, as described in Volume 1.) Comparison of market levels is made more clear when limited to the fossil fuels. Further, many of the other greenhouse gases are not as clearly tied to specific markets. For example, methane emissions are largely by-products of a large variety of activities such as agriculture, landfilling, and mining. In each case, the level of activity (e.g., the number of acres cultivated with rice or the tons of rice sold) is less important in determining the emissions level than the nature of the activity (e.g., the method of fertilization, tillage, or irrigation). While CFCs do have very clear markets, they are of less interest in discussions of trading because they are being phased out of existence. Options for including all greenhouse gas emissions in a trading scheme could be considered after a system has been designed to address CO_2 only. Doing the analysis in this order does not mean that regulations should be phased in this order.

For this analysis, fossil fuels considered include natural gas, coal, and petroleum-based fuels (fuel oil, gasoline, etc.). Markets for wood and other biomass fuels are not analyzed because they pose a question of how significantly they create *net* emissions, if at all. Similarly, use of waste methane, such as that captured from landfills or farming, is also not considered because of complications in determining whether its use adds to emissions, or whether it in fact reduces total greenhouse forcing. This could happen because (1) the methane that is captured is itself a powerful if short-lived greenhouse gas, and (2) its use as a new fuel source could displace more carbon-intensive coal or oil, thus reducing net carbon emissions per energy unit. Both of these energy sources require further analysis to determine whether they would be considered fuels that require allowances, or whether use of them would be a basis for the award of additional allowances.

WHAT WOULD TRADING REQUIREMENTS CONSIST OF AT THE DIFFERENT MARKET LEVELS?

The following subsections describe how trading at each level would be implemented. In addition to the mechanical details of implementation, we also note what the resulting system might "look like" to the public. Such perceptions do not provide any economic basis for selecting among the options. They are included to help the reader visualize trading at each market level. They are also useful to understand when ultimately preparing an implementation plan that is acceptable within a broader framework than the purely economic comparison that is the purpose of this study.

Regulation of the Primary Producers

Primary producers are most typically thought of as those that are involved in the extraction of oil, gas, and coal. As noted in Table 1-1, and as will be discussed in detail in Section 2, this is an overly simplistic definition. In fact, primary production might also be expanded to include refiners or fuels distributors. Regardless of this distinction at the primary level, one could require permits according to the amount of carbon in fuel extracted, without consideration of its end-user destination. Regulation is feasible at this level of the economic chain because the carbon emissions of the ultimate products can be anticipated quite accurately in terms of the carbon content of the extracted primary material. This level of the market may not be as easily incorporated into other pollution-control regulations because emissions are usually dependent on processes and control technologies used, and not on the properties of the raw materials alone. For fossil fuels, however, carbon emissions are very closely tied to initial carbon in the extracted raw material.

The way emissions trading would work at the primary producer level would be that each primary producer would be required to have a sufficient number of units of allowances for carbon extracted and sold. Allocating allowances to the agents in the market might seem at first as if producers were being told that there was to be a specific reduction in the historical extraction rate. This is because there is no alternative for fossil fuel extraction enterprises as a group to reduce carbon sold than to simply extract less. Because allowances would be tradeable, however, market forces would result in the lower cost producers being able to buy out the marginal producers. Thus trading would allow the final form of the extraction reductions to occur in the most cost-effective manner from society's point of view, and some producers may be able to actually expand extraction (for example, of natural gas) while others would reduce production even more than their allotted allowances would require (for example, coal). Thus the ultimate effect of tradeable carbon permits would be a shift away from carbon-intensive fuels, and there would be no actual limitation of supplies of individual fuels, nor of the total supply of energy services.

The cost of the allowances would be passed on to purchasers, ultimately to those who burn the fuels, thereby providing an economic incentive to energy consumers to reduce their use of energy, and to switch to less polluting fuels. Even though the incentives for pollution reduction would be passed on to the ultimate polluters, this type of implementation could potentially be perceived as much as an intervention in energy markets as a controlling of pollution levels. As will be discussed below, there are also distributional effects that could have implications for this approach, regardless of its cost-effectiveness: producers may gain more than consumers.

Regulation of Industrial Sources of CO_2

Tradeable allowances could also be required at the industrial combustion point. In this case, allowances could be tracked in terms of measured carbon emissions, giving the impression of a more direct link to the control of pollution. The system would work by allotting, or requiring purchase of, allowances for each unit of carbon emissions from fossil fuels. Companies that currently burn fossil fuels would have incentives to switch to low- or no-carbon energy, and to conserve energy, exactly as in the case of trading at the primary production level. These reactions would feed back to the fossil fuels market in the form of a shift in output to relatively more low- and no-carbon energy sources.

Controls on industrial sources of pollution have a strong political heritage. Yet, as Volume 1 of this report discusses, there are many more important sources of CO_2 than industry alone. In particular, transportation is equally as important as electric utilities, or as all other industry put together. Unfortunately, with millions of vehicles, transportation amounts to an area source created by the independent decisions of millions of citizens. Unless the options of individual citizens are also included in the trading scheme, direct control of CO_2 emissions will be less effective than their indirect control via requiring allowances per unit of fossil fuel extracted. Similarly, consumers of electricity (i.e., virtually every household as well as industrial and commercial users) can affect the effectiveness of emissions control in the electric sector. However, without changes in the current system of rate setting, there are incomplete incentives for such consumers to take actions that would be socially cost-effective.

Regulation of All End-Users of Fuel Services

A third level of the market in which emissions allowance trading might be required: all end-users of energy services. In such a scheme, allowances would be required of consumers as a function of energy used in a number of daily activities. These could be required (1) at the time of purchase of the fuel or electricity, or (2) they could be estimated from records of annual mileage or kWh consumption.

In the first case, the permits requirement could be more precise: annual transportation usage would not have to be estimated, and in the case of electricity, time of day information could allow the type of generating equipment being dispatched to be included in the emissions estimate. However, the actual accounting of permits might be cumbersome on an as-used basis. Consumers would have to have a continual supply of permits in small denominations, almost like carrying around a second currency, or a second type of checking account. It is possible that the providers of the energy sources could start buying up allowances themselves, and then sell them to consumers with the fuel or electricity. This would appear as a surcharge on fuel pump prices, or on the electricity bill. Consumers might welcome the service of not having to obtain their own allowances, but also might perceive the system as a large energy tax rather than a market in which they actively participate.

In the second case, there would be problems of agreeing on a fair basis for estimating total annual emissions, especially for the use of equipment such as automobiles where the fuel usage rates can vary dramatically according to personal driving styles, even for a given brand and model of equipment. Further, waiting until the end of a year before taking an accounting may be more problematic at the individual citizen level than at the corporate level. Some form of permits withholding might be necessary throughout the year, with the resulting system being as cumbersome as a second income tax scheme, replete with forms and filing requirements.

WHAT ARE THE WELFARE DISTRIBUTION IMPACTS FROM TRADING AT DIFFERENT MARKET LEVELS?

The previous discussion indicated how trading might proceed on different bases depending on the market level at which it could be implemented. Before moving to a comparison based on the cost-effectiveness criteria, it is useful to review welfare distributional considerations that may enter into the debate, at least implicitly. These are considerations of how the total social welfare would be shared by the market participants, depending on which market level is required to have allowances for its economic activities. Section 2 then also provides some information on the distributional impacts across regions of the country.

Total surplus is a term used in economics to describe how well off society is under specific market conditions. It is used by economists primarily for comparing among market options, rather than to determine if a specific market outcome is acceptable in some absolute sense. Total surplus in a market has two components: *consumer surplus* and *producer surplus*. These concepts indicate the benefits captured by producers and consumers from market transactions. They are always greater than or equal to zero for both sides of the market, or else the market would cease to exist.

A regulatory action will often reduce the total surplus in the market for a good that is responsible for some externality, such as pollution. This is accepted as part of the decision to regulate because surplus is believed to be increased elsewhere in the economy, such as through enhanced environmental quality, and such increase is judged to outweigh the loss in surplus in the regulated market. However, regulatory actions can also change the relative shares of total surplus among economic sectors or regions. That is, the burden of meeting the regulation may fall more on one party than another. Although these concepts come from the economics literature, they have nothing to do with the economic optimality of an outcome. Instead, decisions among these effects can only be decided on the basis of concepts of fairness, which is inherently a political issue.

Consumer surplus is defined as the excess that consumers would be willing to pay for the commodity over that which they have to pay as the market price. Producer surplus is the excess over costs that producers can earn, given the market price they obtain for their product. (Producer surplus is synonymous with economic profits.) These are best displayed graphically, as in Figure 1-1. The market price is the point where the demand and supply curves intersect. Since the demand curve traces out the marginal willingnesses of consumers to pay, each consumer's individual marginal surplus is the difference between the market price and that consumer's position on the demand curve. The total consumer surplus is thus the area labelled CS. Since the supply curve traces out the marginal costs of producers, each producer's marginal surplus is the difference between the supply curve and the market price, and total producer surplus is the area labelled PS.

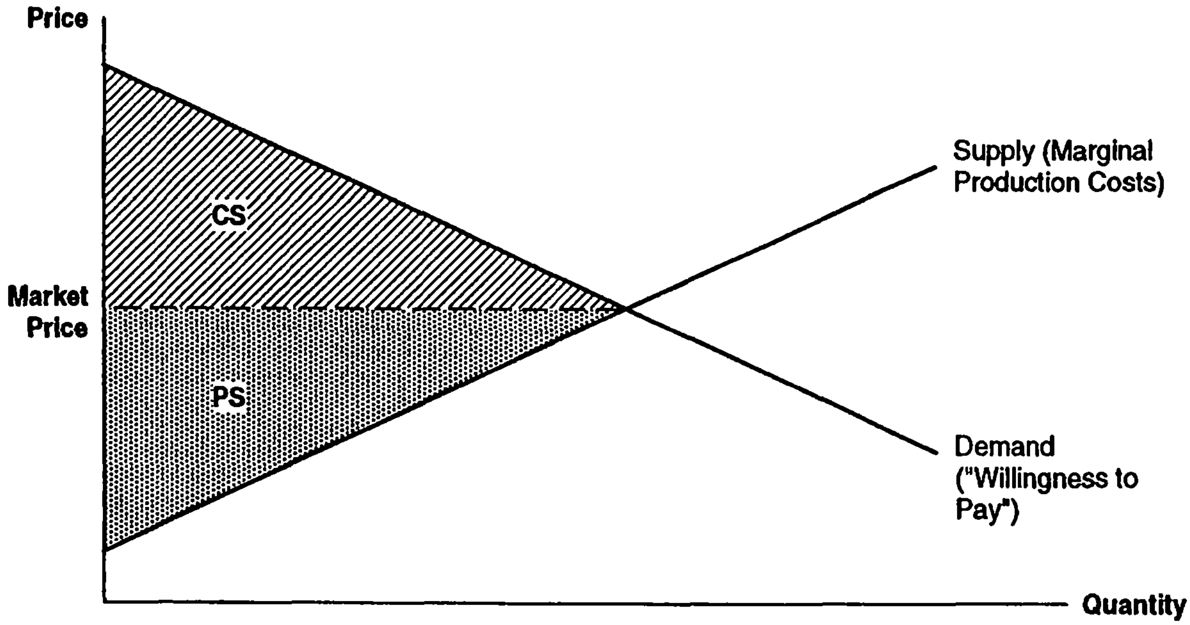


Figure 1-1. Illustration of Components of Market Surplus Concept

An Hypothetical Example

To compare the surplus outcomes of different trading schemes, a simple hypothetical market case is presented. In this, there are only two market levels: the primary producer and the consumer levels. The primary producers are represented by two oil extraction enterprises. They sell fuel to a set of six industrial customers, which represent the consumer level of the market. Hypothetical market information is presented to provide easily verified surplus calculations, so that the example can concentrate on the comparative nature of market outcomes under trading of permits instituted at each level of this market.

The two oil extraction enterprises have different costs of production: \$10/barrel for producer X and \$100 for producer Y. Clearly producer X would always take the market from Y, but cannot take the entire oil market because he cannot extract more than 6 barrels of oil per year. Producer Y can extract much larger amounts of oil. The market supply curve for oil under these conditions is illustrated in Figure 1-2, labelled S.

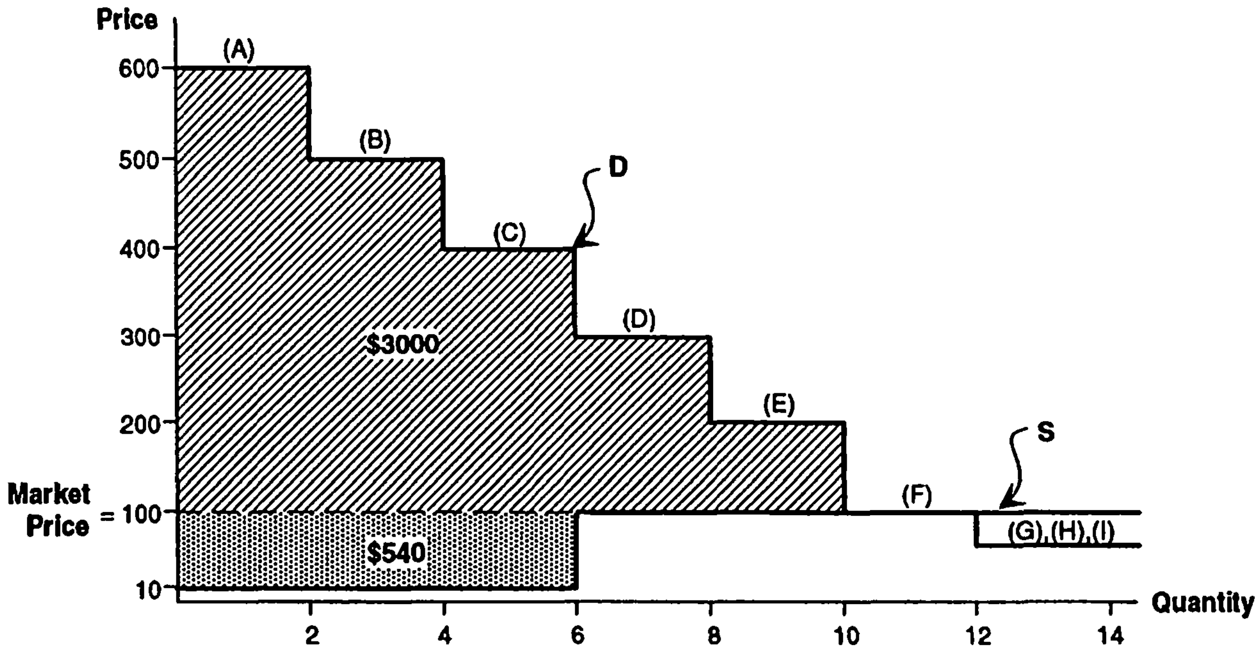


Figure 1-2. Hypothetical Market for Oil Products

Demand for oil comes from six different industries, A through F. Other potential demand for oil comes from industries G, H, and I, but these do not participate in the market because their willingness to pay for the oil is less than current market prices. Industry A has the highest willingness to pay, $600/barrel, for the oil, and wants 2 barrels/year at any price under that value. This very high willingness to pay is because industry A depends on oil very strongly and has few options for either substituting to other fuel sources or for conserving fuel consumption in its production process. Other industries have more options, and thus lower willingnesses to pay, as traced out by the declining demand curve, D.

Given these market assumptions, the market price for oil is $100. Producer X sells as much as he can at that price, and producer Y produces the remaining 6 barrels/year. The total surplus in this market of 12 barrels/year is $3540. Only $540 of that is producer surplus (note that it goes entirely to producer X), and the remaining $3000 is "profit" to the six consuming industries. This is the initial, pre-regulatory situation against which different trading schemes are now to be compared. Regulations are suddenly implemented to cut CO_2 emissions from oil by 50%. This means that consumption of oil must be cut by 50%, to six barrels/year.

Regulations Implemented at the Primary Producer Level. In the first trading scheme, assume that the permits are assigned to the primary producer level. Producers X and Y each get 3 permits. If they are not allowed to trade these permits, each will continue to produce at the maximum rate possible. The supply curve shifts to that labelled S1 in Figure 1-3(A). Because there is excess demand at the initial price, prices may rise to as high as $400/barrel, which is the value above which there is still sufficient willingness to pay for up to the six barrels/year now permitted. Under these new market conditions, total surplus has declined to $2670, but producer surplus has actually risen to $2070 and both producers are now making larger profits.

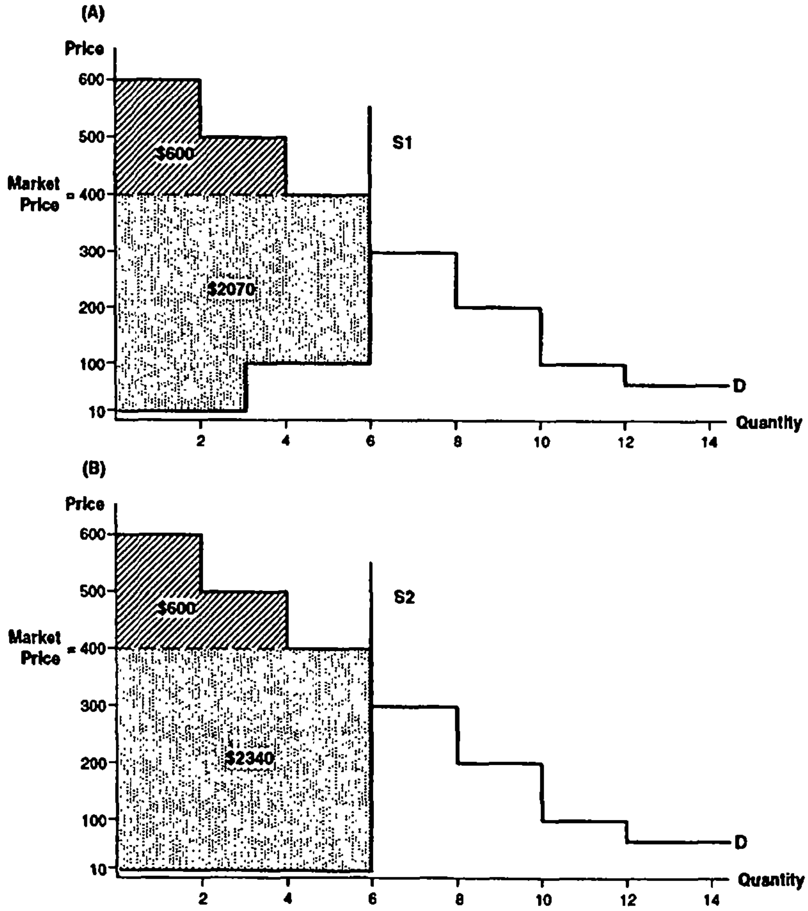


Figure 1-3. Market Conditions After Permits Allocated to Primary Producers: (A) No Permit Trading Is Allowed; (B) Permit Trading Is Allowed

If the two producers are allowed to trade allowances, producer X will have an incentive to buy out producer Y at any price less than $390 (400-10). Producer Y may be making a profit of $300/barrel now, but will sell out at any price above $300/permit. Thus the two can be mutually happier by a trade of permits somewhere in the price range of $300 to $390. If we assume that they roughly split the difference at a price of $350/barrel, producer X can now sell at his full capacity, producer Y leaves the market a richer person, and society benefits from lower costs of meeting the regulation (Figure 1-3(B)). That is, the total surplus increases from $2670 to $2940. This is not as high as the pre-regulation surplus in the oil market, but the rise in total surplus represents a cheaper regulation for society as a whole than if permit trading were not allowed. The trading of permits reallocates the burden of emissions reductions so as to minimize losses of consumer plus producer surplus. In this example, the increase in surplus goes entirely to the producers, while consumers take on the costs of the regulatory burden: their surplus falls from $3000 pre-regulation to $600.

Figure 1-3 illustrates potential distributional impacts of a producer permit system. However, the reader should be aware that the rise in producer surplus in the example due to a permit system is the result of the assumed price elasticities of demand and supply. If demand were more price elastic and supply were less price elastic, price would rise less and costs would fall less when output is constrained by an emission allowance system. The net result could be a fall in producer surplus as well as in consumer surplus. Estimates for fossil fuel price elasticities of demand (Table 1-2) show them to be relatively price inelastic in the short-run, and mostly borderline elastic in the long run. Elasticities of supply for fossil fuels have been observed to be relatively more elastic, with substantial increases and declines in reserves following historical price fluctuations. Thus, our expectation is that a producer permit system for carbon content of fuels would be likely to raise producer surplus. Over time we would expect the positive impact on producer surplus to diminish due to the fact that long-run price elasticities of demand are greater than short-run elasticities.

This example is specific to emissions permits that affect only a single commodity that has no substitutes that would also compete for the same permits. For instance, the example is constructed so that only oil is required to have permits. In reality, for CO_2 controls, coal and natural gas would also have to have permits, all drawn from the same pool of *carbon* permits. These fuels are also substitutes in consumption. If we extend the example to account for *carbon* permits, rather than *oil* permits, then the reduction in consumer surplus for oil may not be as large as it appears in Figure 1-3(B). Oil producers might buy carbon allowances from coal producers, which is a more carbon-intensive fuel, and increase oil supply above 6 units. The price of oil would fall below $400 and consumer surplus would rise above $600 as a result of extending the allowance trading to all fossil fuels. In turn, coal consumers would suffer a loss as the market reallocates permits away from coal production, causing coal supply to decrease further than under the original allocation of allowances and causing the price of coal to rise. The net effect for total surplus (consumer plus producer) across all energy markets will be positive as the market reallocates carbon emission allowances among energy resources of different carbon intensities. Consumers as well as producers would share in the improvement from the position of Figure 1-3(A). However, when comparing a no regulation case (Figure 1-2), and a carbon permits market case (Figure 1-3(B)), consumers of fossil fuels, as a group, still would bear more of the total impact of the regulation than would fossil fuel producers, as a group, when the permits market is implemented at the producer level of the market.

The reason the hypothetical example where permits can only be traded among oil producers causes consumers not to benefit from trading of producer permits is because a fixed quantity of emission allowances also fixes the quantity of oil supplied. When extended to include all carbon-based fuels, then a fixed supply of emission allowances does not fix the quantity of any energy type, nor the aggregate quantity of energy services. Consumers also stand to gain from trading in cases where emissions control technologies exist because, again, a fixed supply of emission allowances does not fix the quantity of the commodity that can be supplied. However, this extension of the illustrative example does not apply to a carbon permits market: reduction of carbon emissions can only be attained by reducing use of fuels.

Table 1-2
SAMPLE OF PRICE ELASTICITIES OF DEMAND FOR FOSSIL FUELS

	Short-run	Long-run
Industrial, heavy oil [1]	N/A	-0.30 to -1.17
Industrial, natural gas [1,3]	-0.07 to -0.63	-0.12 to -2.53
Industrial, coal [1]	N/A	-1.00 to -1.12
Commercial/Residential, heating oil [1]	N/A	-1.10 to -1.38
Commercial/Residential, natural gas [1,3]	-0.05 to -0.68	-0.39 to -4.60
Commercial/Residential, coal [1]	N/A	-1.29 to -2.24
Electricity [4]	-0.16 to -0.29	-0.17 to -0.63
Transportation, gasoline [1,2]	-0.13 to -0.29	-0.60 to -1.77
Transportation, diesel [1]	N/A	-0.61 to -1.10

(**Sources**: [1] Al-Sahlawi, M.A., "The Demand for Natural Gas: A Survey of Price and Income Elasticities," *The Energy Journal*, Vol. 10, No. 1, January 1989, p. 77-90. [2] Moss, M. F., and J. L. Small, "Deriving Electricity Demand Elasticities from a Simulation Model," *The Energy Model*, Vol. 10, No. 3, July 1989, p. 51-76. [3] Jacoby, Henry D., and J. L. Paddock, "World Oil Prices and Economic Growth in the 1980s," *The Energy Journal*, Vol. 4, No. 2, April 1983, p. 31-47. [4] Dahl, Carol A., "Gasoline Demand Survey," *The Energy Journal*, Vol. 7, No. 1, January 1986, p. 67-82.

Taking the multi-fuels market extensions into account, we can summarize the general effects of a market of producer emission allowances for carbon:

- Supplies of fossil energy will decrease.
- Marginal (e.g., high cost) carbon-intensive fuel producers will leave the market with the benefit of a large "bribe."[3]
- Prices of fossil energy will rise.
- Economic profits in the energy supply industry will rise (given relatively inelastic demands for fossil energy).
- Consumers of energy services will lose.
- Overall, there will be a fall in total social welfare related to fossil fuel markets.

3. This "bribe" is the amount the marginal producer could obtain by selling his permits and leaving the business. This transfer of wealth would not occur if permits were auctioned rather than allocated to the existing producers in a market. However, the ability to give out such wealth is an inducement that makes tradeable permits appear politically advantageous over taxes, which leave no such winners in the regulated community.

The last point should be qualified to acknowledge that we have focused solely on effects in the energy sector, and have not attempted to account for environmental benefits associated with these costs. The losses in social welfare in the energy sector are the costs of obtaining environmental gains. Whether or not the environmental gains are sufficiently large to justify the costs of carbon emission reductions is beyond the scope of this study.

Note that our discussion assumes that producers do not pay for the emission allowances allocated to them. If producers were required to pay for the allowances, producer surplus would decline correspondingly and be transferred to the authority collecting the payments.

Controls Implemented at the Consumer Level. What happens to the surplus if instead the oil consumers are required to have permits to buy oil? In this case, assume that each of the six industries are allocated 1 permit for each unit of carbon emissions, rather than the 2 units that they are currently producing (assuming that 1 barrel of oil burned produces 1 unit of carbon emissions). In this case, the effect is to shift the demand curve rather than the supply curve, as depicted in Figure 1-4(A). Without trading, all six consumers remain in the market, but the market is halved. The reduction in oil consumption by half for each oil consumer reduces consumer surplus from $3000 to $1500. Total surplus is reduced from $3540 to $2040. (Oil prices may fall if a lower cost set of producers can now meet the full demand. In this example, the price remains at $100, but this is an anomalous outcome specific to this special case.)[4]

If trading of emission allowances among primary energy consumers is permitted, allowances will be sold by consumers who place relatively low value on carbon-based energy to consumers who place a high value on carbon-based energy. These trades reallocate allowances so that carbon energy goes to the uses for which it has the highest market value. In the example, industries A, B, and C would buy allowances from industries D, E, and F.[5] As permits are transferred to industries that are willing to pay the most for oil, the demand curve shifts out to the right as depicted in Figure 1-4(B). The result is to raise consumer surplus from $1500 to $2400, substantially reducing the costs to consumers of emission reductions. The total surplus rises from $2040 to $2940.

In the example provided, producers do not benefit from trading of allowances among consumers (i.e., in the comparison of Figures 1-4(A) and 1-4(B)) because the trades do not alter

4. The lack of change in price is an artifact of the problem construction, where the oil market is split 50-50 between producers X and Y, and the regulation cuts demand exactly in half. If demand were cut more, prices for oil could drop, particularly if the example were more realistic, to include more than just two producers.

5. Industries D, E, and F would not necessarily go out of business, but would likely turn to other sources of energy services that may be available to them at lower cost than the alternatives for A, B, and C.

the price of oil nor the quantity of oil traded in the market.[6] This is because a fixed quantity of emission allowances for consumers also fixes the quantity of oil demanded in the example. Just as in the case of producer permits, if a carbon permit system for consumers includes all carbon-based fuels and not just oil, then a fixed quantity of carbon emission allowances does not fix the quantity of energy demanded for any fuel type, nor does it fix the aggregate quantity of energy demanded. In the example, oil consumers might buy allowances from coal consumers and increase the quantity of oil demanded beyond 6 units. The price of oil received by suppliers would rise above $100 and producer surplus of oil suppliers would rise as a result of allowance trading among consumers. The net effect on producer surplus is ambiguous for the general case.

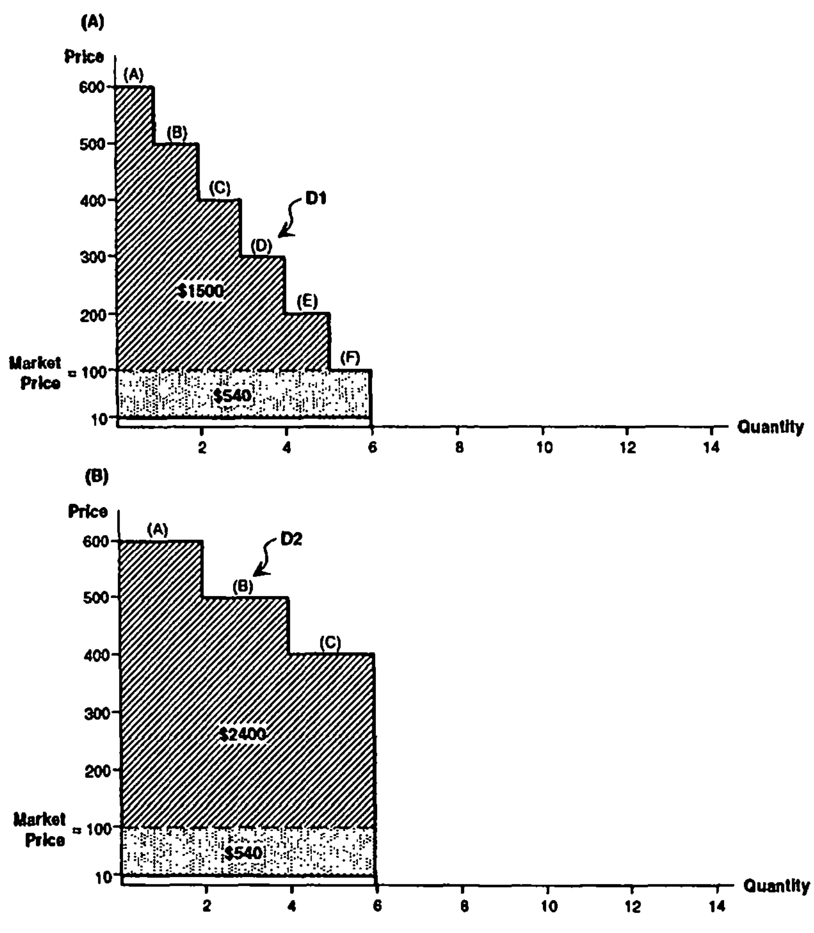


Figure 1-4. Market Conditions After Permits Allocated to Consumer Level: (A) No Permit Trading Is Allowed; (B) Permit Trading Is Allowed

6. This is a different point from the special-case result discussed in Footnote 4, that the producers in the example suffer no loss when a regulation is implemented putting constraints on consumers. That unusual result is because of the simplistic supply function assumed in the example. Under more general assumptions for the supply of oil, a reduction in the demand for oil would reduce producer surplus as well as consumer surplus.

In the case of a producer permit system we saw that producers could benefit from a policy that restricts the supply of oil. Symmetrically, consumers could benefit from a consumer permit system that restricts the quantity of oil demanded. Although consumer surplus is decreased in the example presented, an emission permit system for consumers could increase consumer surplus under specific elasticity conditions. An emission permit market for consumers reduces the price and quantity of energy. The reduced quantity reduces consumer surplus because consumers consume less energy. The reduced price raises consumer surplus because consumers pay less for what they do consume. Whether the net change in consumer surplus from these two opposing effects is positive or negative will depend upon the price elasticities of demand and supply. The more elastic is demand, and the less elastic is supply, the more likely is it that consumer surplus will increase. However, because energy demand appears to be relatively price inelastic, and aggregate energy supply appears to be relatively price elastic, we expect that a carbon emission allowance system for fossil fuel consumers would decrease consumer surplus and producer surplus relative to a case of no regulation (i.e, when comparing Figures 1-2 and 1-4(B)).

In summary, the effects of an emission allowance trading system implemented at the consumer level of the market are:

- Demand for primary energy will decrease in aggregate and demand will shift away from carbon-intensive energy to low- or no-carbon energy.
- Marginal carbon-intensive fossil fuel producers will leave the industry without large personal gains.
- Prices of fossil energy will fall.
- Economic profits in the energy supply industry will fall.
- It is ambiguous whether consumers of energy are likely to lose or win.
- Total social welfare will fall in the fossil fuels market (as before, presumably offset by social welfare gains from environmental improvements).

In well-functioning markets, trading of emission permits will yield identical results in terms of the quantities of each energy type produced and consumed, the allocation of production among producers, and the allocation of consumption among consumers, regardless of whether the trading is implemented at the producer or consumer level. Both systems achieve emission reductions at the same total cost. This can be seen in the above examples by noting that for both allowance trading systems, total surplus is reduced $590, from $3540 to $2950. In the example, this is the lowest possible cost for a 50% reduction of emissions.

Although the total cost of emission reductions is the same for the two systems, the burden may be distributed very differently between producers and consumers. In a producer allowance system, consumer surplus unambiguously decreases, while producer surplus is likely to increase due to a transfer from consumers. In our example, a permit market for oil producers reduces consumer surplus from $3000 to $600 and raises producer surplus from $540 to $2340. In comparison, a permit market for oil consumers that yields an identical reduction in oil consumption and carbon emissions reduces consumer surplus from $3000 to $2400. Producer surplus is unchanged. The costs of emission reductions paid by consumers in our examples are much lower in a consumer permit market than in a producer permit market. Producers fare better, and even benefit, in a producer permit market. More generally, in a producer allowance system, producer surplus unambiguously decreases, while consumer surplus may increase or decrease. Even if consumer surplus decreases, the fact that prices fall makes them unambiguously better off with trading at the consumer level than with trading at the producer level.

We have demonstrated that there is a clear difference in which parties bear the burden of a regulation depending on the market level at which it is implemented. However, it is important to recognize that the specific conclusions about which parties are better off come from assuming the permits are allocated at no cost to market participants according to their historical market activities. While this is a plausible scenario, results can be quite different if other ways of distributing permits are applied. By auctioning allowances or charging fees for allowances, it would be possible to alter the distribution of the burden of reducing emissions under a chosen allowance market structure. If one allowance system was thought to yield an undesirable distribution of costs, payments for the allowances could be used to improve upon the allocation of costs. In any case, the analysis of consumer and producer surplus changes makes it clear that alternative systems for allowance trading can yield very different distributions of costs. The distribution of costs will be an important criterion by which competing CO_2 policy options will be judged by the various constituencies that will influence climate policy.

On the other hand, there are only about 200 refineries,[11] owned by the 2,000 companies mentioned above, and 3,600 coal blending/cleaning facilities (roughly one per coal mine) in the U.S. However, implementing permit trading at this level would require special consideration for natural gas, since this energy type usually is transferred directly to a distributor or the final user without further processing. For gas, permit trading could be implemented at the transportation level to reduce the number of source units. There are 133 gas pipeline companies in the U.S.[12]

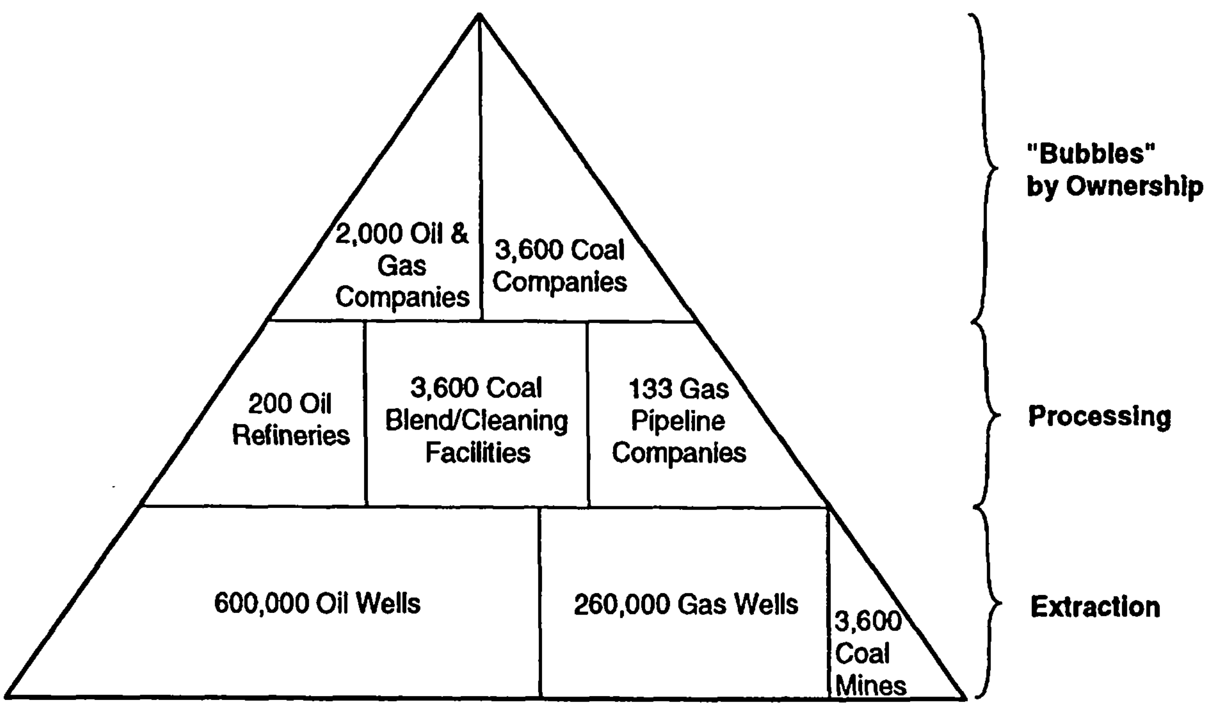


Figure 2-2. Number of Sources at Primary Production Level

Because there is a high degree of vertical integration in the oil, gas, and coal industries (discussed separately below), it would be possible to impose a permit trading market at any primary production sub-level outlined in Figure 2-1, and treat oil and coal companies as "bubbles", i.e., multi-source units where only total production by company would face the scrutiny of the regulators. This would probably be more workable than requiring permits at each point of extraction.

11. U.S. Department of Commerce, Bureau of the Census, *1987 Census of Manufacturers. Industry Series*, Washington, D.C., 1989, Table 2.

12. Oil & Gas Journal Special, *Pipeline Economics*, Tulsa, Oklahoma, November 27, 1989, p. 64-66.

Size and Regional Distribution

Fossil fuels are produced in regional production centers around the country. Figure 2-3 provides an overview of major production regions in the U.S. Appendix A provides a detailed breakdown of oil, gas, and coal production by state, with extraction volumes reported in physical units; barrels of oil, cubic feet of natural gas, and short tons of coal. By converting these units to energy equivalents (i.e., Btu), we are able to compare total U.S. energy extraction across the three sectors. While coal production accounts for about 40% of total U.S. fossil energy extraction, coal mines account for only about 0.5% of the extraction sources. Oil and gas each account for approximately 30% of energy extraction, and about 69% and 30% of total source units, respectively. Thus, an average coal mine produces about 200 times more energy than an oil well, and about 100 times more than a gas well.

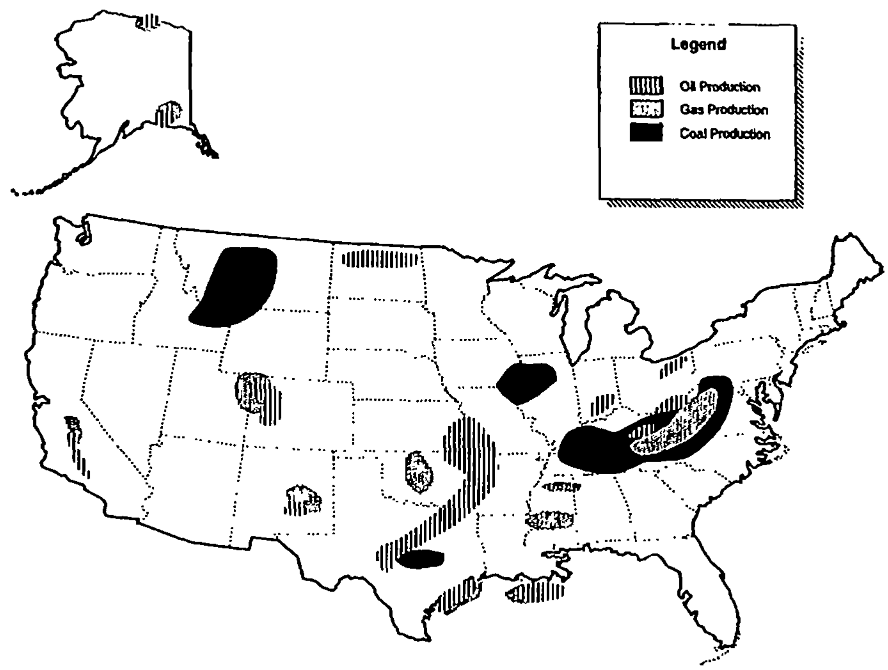


Figure 2-3. Major Fossil Fuel Extraction Regions in the U.S.

These data also can be combined into a measure of total carbon extracted in each state by weighting each fossil fuel unit by its carbon content. The result provides a regional distribution on the sources of carbon at the primary producer level. Figure 2-4 illustrates this distribution in a histogram. Note how skewed the distribution is, with the majority of emissions in a few states, and over half of the states being accountable for negligible amounts of the carbon. Over 50 percent of the carbon comes from only four states (Texas, Wyoming, Louisiana, and Kentucky). Not surprisingly, the key carbon extraction states correspond to the major fossil fuel extraction regions of Figure 2-3: the Gulf states, Ohio River Valley states, and North Central states. If a trading scheme were instituted at the primary producer level, transfers of wealth among producers would be concentrated in these regions.

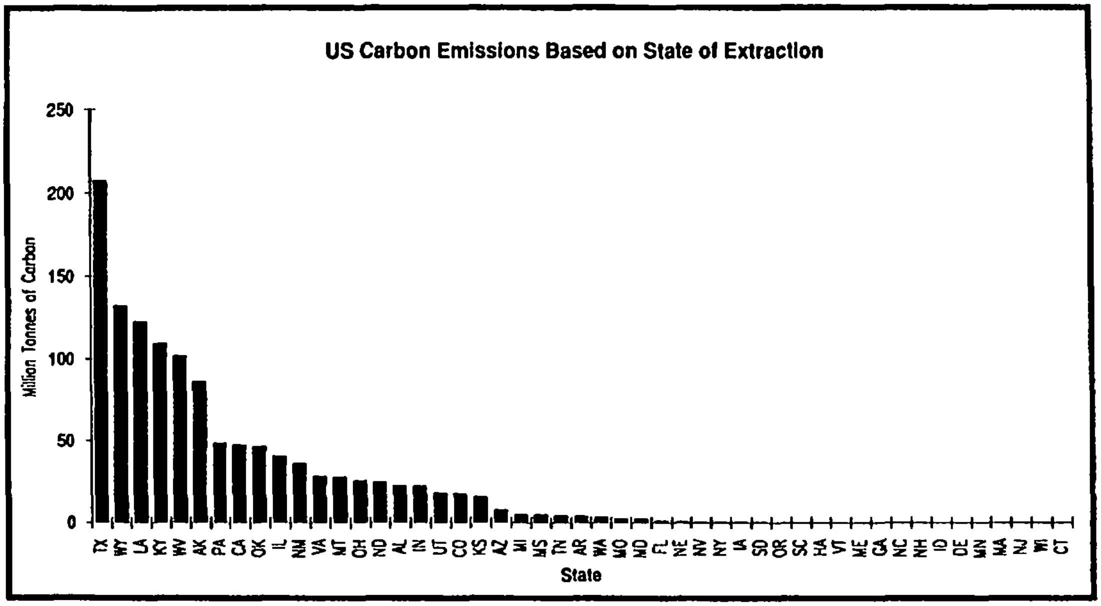


Figure 2-4. Histogram of Carbon Extracted, by State

Market Concentration

Market concentration is an important factor in determining the possibilities for market power within an industry or a market. However, a permit trading market will typically cut across different industries/markets, and this will reduce the risk of any one participant gaining significant market power. For example, if a refinery wanted to gain market power in a CO_2 permit market, it would face not only other refineries but also all coal and gas producers.

Table 2-1 provides information about concentration of output markets for different sub-levels of oil production, gas production, and coal production. Market concentration is typically measured by large producers' market share. The ten largest producers cover between 33% and 60% of their output markets. In no instance does the market share of the largest firm exceed 11% of its output market. In comparison with concentration ratios for the major carbon-emitting industries (see Volume 1), the concentration of energy producers in their individual markets is moderate. The ten largest producers are, on the average, between three and five times the size of the next ten producers. A list of the top 20 producers is provided in Appendix B.

2

HOW MANY SOURCES ARE THERE AND WHERE?

Comparing some of the cost-effectiveness and distributional consequences of different implementations of a permit trading market requires knowledge about the major emitters, and the structure of the markets in which they will interact. Administration and monitoring depend on the numbers of agents that might be regulated at each level. Total emissions from each market level are important for the effectiveness criterion. The potential for market power to arise in the permits market is also relevant to an assessment of effectiveness. The overall structure and interrelationships in output markets may affect the feasibility of instituting and monitoring a permits market at specific levels of the economy.

In this section we summarize the market locations and other features, addressing each of the three market levels under consideration separately. The facts presented do not enable us to make rigorous predictions about the workings of a dynamic permit trading market. However, they provide a good basis for identifying problem areas and key relationships in designing a CO_2 trading scheme, and will serve well as a starting point for more structured modeling of market behavior.

INDUSTRY STRUCTURE AT THE FOSSIL FUEL PRIMARY PRODUCTION LEVEL

Extraction (oil and gas wells and coal mines) is most commonly thought of as the primary production of fossil fuels. However, fossil fuels typically proceed through a number of transportation, storage, and processing links in order to get to the final consumer. For example, once crude oil has been extracted from the well, it is transported to the refinery through pipelines, or by tanker, barge, or truck. Sometimes a different company performs the transport than performs the extraction. In the refinery, the oil is processed into multiple products. Marketers sometimes buy the refined products and sell them to distributors or large single customers.[7] Natural gas, on the other hand, is typically transported directly from the well via pipeline to distributors or large consumers, without intermediate processing. Coal can either go through a blending/cleaning process at the extraction site, or it can be shipped in its extracted form to the final consumer. Either way, modes of transportation for coal include rail, conveyer, barge, truck, or ship.

7. This latter step of distribution is not formally part of *primary* production, and is sometimes called a *secondary* energy market.

Figure 2-1 illustrates the different transition points for oil, natural gas, and coal. While the wellhead or minehead may be the immediate concept of where the "primary production level" is, there are in fact several sub-levels before the products reach industrial and other consumers. It would be possible to implement permit trading at any of these sub-levels. It may be desirable to keep such options in mind, in addition to the standard "point of extraction" concept, as the number and location of market agents ("sources") varies dramatically at different sub-levels.

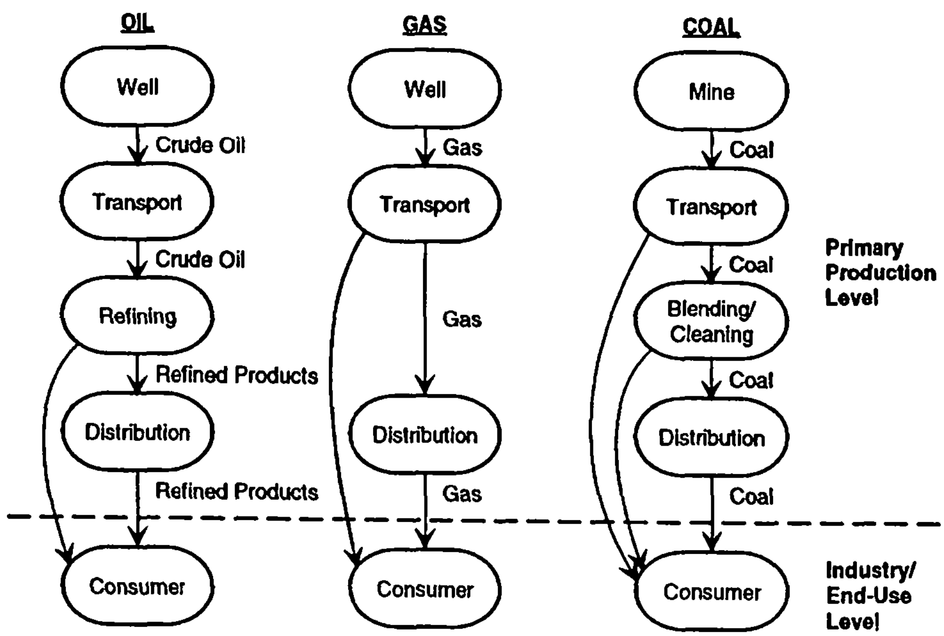


Figure 2-1. Fossil Fuel Pathways to the End-User

Number of Sources

Figure 2-2 shows the number of sources at different sub-levels of the primary production sector for oil, natural gas, and coal. Permit trading at the extraction level would imply more than 863,000 source units, with oil and gas wells accounting for more than 99% of these units. There are only about 3,600 coal mines in the U.S.[8] Although there are very many individual source units for oil, most are owned by large integrated oil and gas companies. There are approximately 2,000 oil companies[9] and 3,600 coal companies[10] in the U.S.

8. American Petroleum Institute, *Basic Petroleum Data Book. Petroleum Industry Statistics*, Vol. XI, No. 1, Washington, D.C., 1991; and Energy Information Administration, *Coal Production 1989*, DOE/EIA-0118(89), Washington, D.C., 1989, Table 28.

9. U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States 1988*, Washington, D.C., 1988, Table 1153.

10. Energy Information Administration, *Coal Production 1989*, Table 28.

Table 2-1
MARKET CONCENTRATION AT PRIMARY PRODUCTION LEVEL, 1989

	Market share of largest company	Market share of 10 largest	Market share of 20 largest
Oil extraction	9%	50%	60%
Oil refineries *	11%	58%	78%
Gasoline marketers **	8%	60%	75%
Gas producers	5%	33%	44%
Gas pipeline companies	11%	45%	69%
Coal producers	11%	44%	55%

* Measured as capacity for crude oil input.
** 1973 data

(**Sources**: American Petroleum Institute (1991), Tables IV:7c, VIII:11c, and XIII:12b; E. J. Mitchell (1976), Table 7; Energy Information Administration (DOE/EIA-0130(91/03), Table FE2; Oil and Gas Journal Special (November 27, 1989), p.66; and EIA *Coal Production 1989*, Table 28.)

Because an allowance market for carbon content of primary energy would include coal, oil, and gas producers as a single group, concentration in the allowance market would be less than in the individual fuel markets. The ten largest extractors of fossil carbon account for 34% of total carbon extracted in the U.S. The twenty largest account for 46% of domestic carbon extracted.[13] The ten largest domestic extractors of carbon include two coal companies, seven companies that extract oil and natural gas, and one that extracts only oil. The largest source is a coal company, which accounts for 4% of domestic carbon extraction.

The above figures for concentration of an allowance market at the primary producer corporate level are based on quantities of energy extracted in 1989, and the concentration will change once allowance trading occurs. If the emission reduction target is aggressive, requiring significant reduction in the production of fossil fuels, it is possible that the allowance market, and energy markets, will become more concentrated.

The analysis suggests that a carbon allowance market for primary energy producers and importers would not be heavily concentrated and that market power would not be a severe problem. However, it is possible that the larger producers would have some degree of market power that could lead to some losses of efficiency in an allowance market.

If permit trading was implemented at the energy extraction level, we would also be interested in the size distribution of wells and mines. Information on this distribution was not directly available. To obtain an estimate, we divided the total production in each state by the

13. It is unclear whether the carbon market concentration would increase or decrease if imports could be included in these estimates.

number of wells or mines in that state. (Details are provided in Appendix A.) Although this gives only a crude estimate of the average size, some interesting patterns emerged for comparisons across fuel types and across geographical regions. Long established extraction areas, such as oil and gas extraction in the Gulf and Appalachian regions, have more wells than relatively new production areas, such as Alaska. In the Appalachian region, production units are generally small, but elsewhere oil and gas wells vary widely in typical size.[14]

Interrelationships Among the Sub-levels

If a specific sub-level is selected for implementing trading at the primary producer level, a full evaluation of its effectiveness will require understanding the degree of economic interrelationships among the agents in each sub-level. For example, if the sub-levels are fully integrated vertically, then there should be little difference in regulatory outcomes, regardless of which sub-level were regulated. If vertical integration is high, regulators may be able to take advantage of this by designing regulations at the most easily monitored sub-level. Complex and strongly tied interrelationships among sub-levels may provide insights about an emissions market from a couple of perspectives:

- They are likely to affect a company's motivation to switch fuels; the more integrated, the more the commitment to a given fuel type within the industry.

- They might make monitoring of a permit trading market more difficult. An integrated oil/coal company may not publicly report internal product flows, making some levels of the market less easily implemented if they include companies of differing degrees of integration.

Following is a discussion about market relationships in the oil, gas, and coal sectors, structured around the fossil fuel pathways illustrated in Figure 2-1. A summary is provided in Table 2-2, from which one can see that a substantial amount of ties exist, but the sub-levels are not fully integrated.

Oil and Gas. Most oil and gas production is carried out by conglomerate oil companies. Crude oil is generally transported directly from wells to refineries. Approximately 60% of the oil flowing through refineries has been transported through pipelines, 38% has been transported

14. The greatest size variability is noted in the Gulf region. This may in part be explained by the region's substantial offshore production. Due to the large capital investments connected to offshore drilling, offshore wells tend to be much larger than onshore wells: offshore oil wells account for only 5% of total oil wells in the Gulf region, but they produce approximately 25% of the region's oil; offshore gas wells are about 18% of total gas wells, and 40% of production. This means that offshore wells in the region are about 6 and 3 times the magnitude of the average onshore oil and gas well, respectively. This information is derived from American Petroleum Institute's *Basic Petroleum Data Book* (1991).

by barge or tanker (most of which is imported crude oil), and 2% by truck.[15] Oil companies own about one-third of private tanker capacity. Pipelines are owned directly by large oil companies, or by joint ventures of oil companies.

Table 2-2
INTERRELATIONSHIPS AMONG FOSSIL FUEL MARKETS

Holding Company	Activity	Degree of Involvement
Oil Company	Drilling	Base Activity
	Pipeline Transportation	Substantial
	Tanker Transportation	Some
	Refining	Substantial
	Marketing	Substantial
	Distribution	Substantial
	Chemicals Industry	Substantial
Gas Company	Drilling	Base Activity
	Transport	Substantial
	Distribution	Some
Coal Company	Mining	Base Activity
	Transport	Some
	Cleaning/Blending	Substantial
	Distribution	Substantial
	Electric Utilities	Some
	Steel Industry	Some

The top 20 refining companies in the U.S. have 78% of total U.S. refining capacity,[16] and have about 50% of the total U.S. plant units (over 90 plants).[17] Of the top 20 refining companies, 13 (with more than 90% of the top-20 production) are integrated oil companies with crude oil extraction in the U.S. Three leading companies are foreign oil companies without substantial drilling in the U.S.[18]

15. U.S. Department of Commerce, Bureau of the Census, op. cit., Table 1166, 1986 data.

16. American Petroleum Institute, op. cit., Section VIII, Table 11c.

17. Oil & Gas Journal, *Annual Refining Report*, Tulsa, Oklahoma, March 18, 1991, p. 59.

18. American Petroleum Institute, op. cit., Section VIII, Table 11c.

Marketing of refined petroleum products is carried out by marketers ("jobbers") who purchase refined oil products and supply retail dealers. Marketers can be independent of refiners and retailers, but are often affiliated with one or both of them. Of the top 20 marketers, at least 19 were extensions of large refineries (99% of top-25 capacity) in the 1970s.[19]

Most large oil companies are also suppliers of natural gas, and several are substantial participants in the coal industry.[20] Most natural gas is sold at the wellhead to large natural gas pipeline companies. Pipelines require large capital investments, and there are substantial economies of scale to their operation. The pipeline companies are mostly joint ventures between producers and/or marketers, and some are owned by single large oil companies. From them, the gas is sold directly to gas distribution companies or large end-users. The top 20 pipeline companies had about 70% of the market in 1988.[21]

Most large oil companies also are heavily involved in various chemical industries through domestic and foreign subsidiaries.[22] However, there appears to be little integration between oil companies and electric utilities.

Coal. The 20 largest coal producers have diverse backgrounds. In addition to pure "coal companies," their ranks include companies that are chiefly known for their interest in other industries.[23] For example, most steel companies are substantial coal producers. In 1972 the sixth and seventh largest coal producers were owned by steel companies (approximately 6% of total U.S. production). Several oil companies are also substantial coal producers. In 1970, four of the top twenty coal producing companies were oil companies (approximately 19% of total U.S. production). Two of these four oil companies were among the top twenty oil producers in 1972.[24]

Some electric utilities are also heavily involved in coal mining. However, states differ markedly in their attitudes toward vertical integration in the utility industry. Integrated companies east of the Mississippi are limited to production of coal for their own use, whereas some western companies have become active in supplying coal to other utilities. For coal-fired electric units as a whole, however, only between 4.5 and 7% of the coal stems from captive coal

19. Mitchell, Edward J., *Vertical Integration in the Oil Industry*, American Enterprise Institute, Washington, D.C., 1976, pp. 47, 50.

20. Ibid., p. 58.

21. Energy Information Administration, *Natural Gas Monthly*, op. cit., Table FE2; and Oil & Gas Journal Special, *Pipeline Economics*, Tulsa, Oklahoma, November 27, 1989, p. 66.

22. PennWell Publishing Company, *1991 U.S.A. Oil Industry Directory*, Tulsa, Oklahoma, 1991.

23. Mitchell, Edward J., op. cit., p. 57.

24. Gordon, Richard L., *U.S. Coal and the Electric Power Industry*, Resources for the Future, Washington, D.C., 1975.

mines.[25] "Partial" integration is also an option for some utilities, where the utility owns the coal lands but extraction activities are performed by operating companies, or joint operations that lease the lands.

Approximately two-thirds of total coal supply to electric utilities is based on long-term contracts (ten years or more). The tendency to enter long term commitments is more pronounced for large utilities than for small. Much of the difference between small and large utilities with respect to contracting seems to be attributable to the availability of oil. Companies that might want to shift from coal to oil would not want their options foreclosed by contracts. The difference in contract use between large and small utilities may be a result of the fact that the largest utilities typically are older, and consequently have less flexibility for change in fuel type.[26]

Downstream Price Signals

Through refining processes, oil is converted into multiple fuel products with somewhat different carbon contents. As a result, the decision to implement permit trading prior to the refining process could have some distorting effects on consumer behavior downstream. Permit trading at the wellhead level could imply that price signals would be transferred downstream without consideration of these effects. That is, the change in fuel prices would not necessarily reflect each fuel type's carbon content.

For example, if permit trading was implemented at the wellhead level, an oil well would be likely to incorporate the price of permits acquired into the price of crude oil. The refineries would purchase the crude oil at a higher price, and would in turn incorporate the higher crude oil prices in the price of refined products. This could be done in a number of ways, such as: (a) the price increase could be allocated evenly to all products, (b) the refinery could increase the price only for less price sensitive products, or (c) the price increase could be allocated to reflect the carbon content of each product. The latter case is the least likely from a behavioral point of view, but the most desirable from the regulatory perspective.

Estimates of the differences in carbon content of various refined petroleum products indicate that the overall potential for such distortions may be minor (on the order of several percentage points of difference in carbon contents). However, a substantial portion of crude oil (about 28%) is destined for use as an industrial feedstock rather than for direct combustion. Since feedstocks do not always immediately contribute to carbon emissions, there might be reasons to exempt them from permits requirements to avoid potential downstream distortions of incentives. These considerations are added reasons to consider the point of permit trading better placed at or after the point of refining.

---

25. Gordon, Richard L., op. cit., Table 3.2.

26. Gordon, Richard L., op. cit., p. 57-59.

INDUSTRY STRUCTURE AT THE INDUSTRIAL COMBUSTION LEVEL

A second scheme for instituting tradeable permits would be to require permits at the point of emissions, as is typical of other environmental regulations. For the most part, this would be equivalent to trading at the point of fuel combustion. It can be contrasted to options for trading at the primary producer level on a number of grounds. Parallel to the discussion about primary producers, we now consider the structure of the fuel-using industries that would be affected.

Number of Sources

Volume 1 of this report identifies the major CO_2 emitting industries in the U.S. and estimates their emissions. The top three are chemicals, paper, and steel, although much of the paper industry emissions appears to be the result of wood burning. Cement is a more distant fourth, largely because of process-related production of CO_2 rather than burning of fossil fuels. Petroleum refining is fifth, although its combustion-related emissions are higher than those of cement. These five industries account for about 70% of CO_2 emissions in the non-utility part of the industry sector. Utility emissions alone, however, are more than twice as large as all other industry emissions combined. For this section, we assume that these six major emitting industries would be the target of a trading scheme at the industrial level. Table 2-3 shows the total number of plant units in each of these industries. We do not have information on the number of companies that own these units.

Table 2-3
NUMBER OF SOURCES AT THE INDUSTRY LEVEL

Industry	Number of plants
Electric utilities (SIC 491)	6,500
Chemicals (SIC 28)	8,500
Paper (SIC 261 - 263)	500
Steel (SIC 3312)	300
Cement (SIC 3241)	200
Petroleum refining (SIC 2911)	200
Total	16,200

(**Sources**: For utilities: Energy Information Administration, *Inventory of Power Plants in the United States 1989*, DOE/EIA-0095(89), Washington, D.C., 1989, Table 14; For all others: U.S. Department of Commerce, Bureau of the Census, *1987 Census of Manufacturers. Industry Series*, Washington, D.C., 1989.)

Comparing permit trading at the primary production level and the industry level, we find that depending on how we define source units at the primary production level, the number of units can be below or above the number of source units at the industry level. By defining a unit as well/mine, the number of primary production sources would be in the order of 860,000 units. If the source unit is defined as oil company, refinery, or transporter, the number of sources at the primary production level will probably be less than 10,000, closer to that of the industrial level.

Size and Regional Distribution

In examining size and regional distribution at the industrial fuel combustion level, we try to answer questions such as: Are industries generally located near fuel extraction sources, or are they located near markets, i.e., near population centers? What "drives" industry location? This information can provide insights about geographical transfer of wealth under different permit trading schemes. Observations in this section are primarily based on detailed data presented in Appendix A.

Figures 2-5 and 2-6 show regional location centers for utilities and other major CO_2 emitting industries, respectively. To derive Figure 2-5, the states were ranked according to their production of electricity (in GWh) with coal, oil, and gas, respectively. The top states for each fuel were then noted accordingly. (We used judgment to determine how many states belonged in the top categories for each fuel, by identifying the first clear gap in the ranking.) Coal-fired utilities account for substantially more electricity production than oil and gas-fired utilities, and also appear less geographically concentrated. This is reflected in Figure 2-5 by the larger representation of coal-fired generation. The geographical pattern that emerges is heavy coal use in the Appalachian and Western regions, which do have large coal deposits (see source regions illustrated in Figure 2-3). Gas is used most intensively in the South and Southwest. This is not necessarily closely tied to gas source regions. Oil is mostly used in the Northeast, again not closely tied to source regions. These patterns are consistent with the greater transportability of oil and, provided pipelines are present, gas.

Figure 2-6 indicates the top ten producing states in each industry, by value of shipments. Here it is clear that the Northeast, out to the Great Lakes Region, is highly industrialized, relying heavily on local coal as an energy source. The South and West in turn have a large volume of refined petroleum and chemicals production, consistent with the location of major extraction regions for petroleum.

State by state estimates of carbon emissions from the major industries listed in Table 2-3 can be estimated using the same data. This regional distribution of emissions is presented in Figure 2-7, which can be compared to Figure 2-4. From the figure, it appears that industrial carbon emissions are much more broadly distributed among states than is carbon extraction. Now ten states account for 50 percent of the carbon emissions, compared to four states in the case of carbon extraction. Thus, the welfare impacts of allowance trading on industrial consumers of energy would be less geographically concentrated than the impacts on producers of energy. However, there is still a reasonable amount of emissions concentrated in a few states, and these states tend to coincide with the top carbon extraction states. Figure 2-8 compares the top fifteen states for carbon extraction with those for major industrial emissions, using the information in the histograms of Figures 2-4 and 2-7.

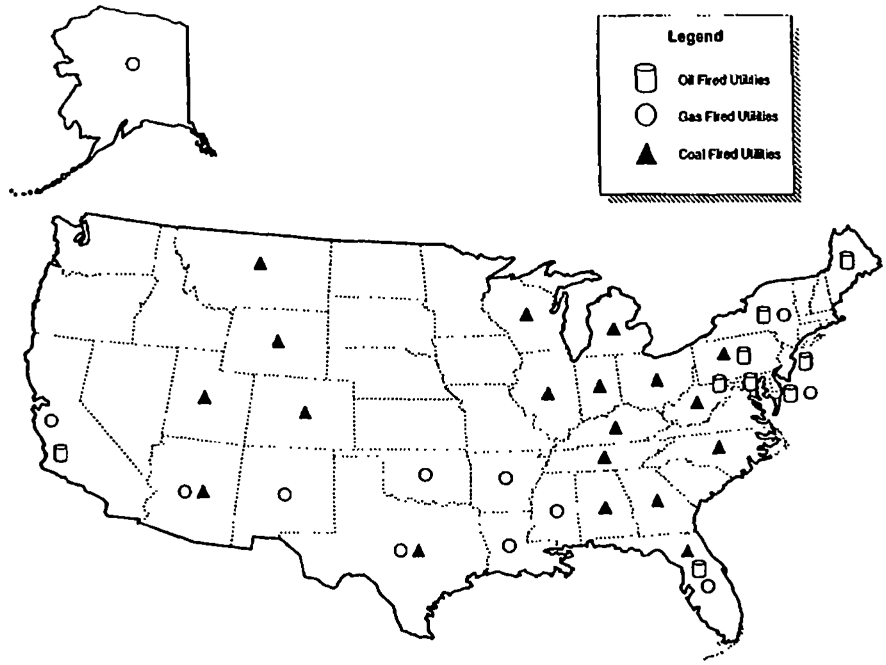


Figure 2-5. Key Locations for Electric Units Using Different Fuels

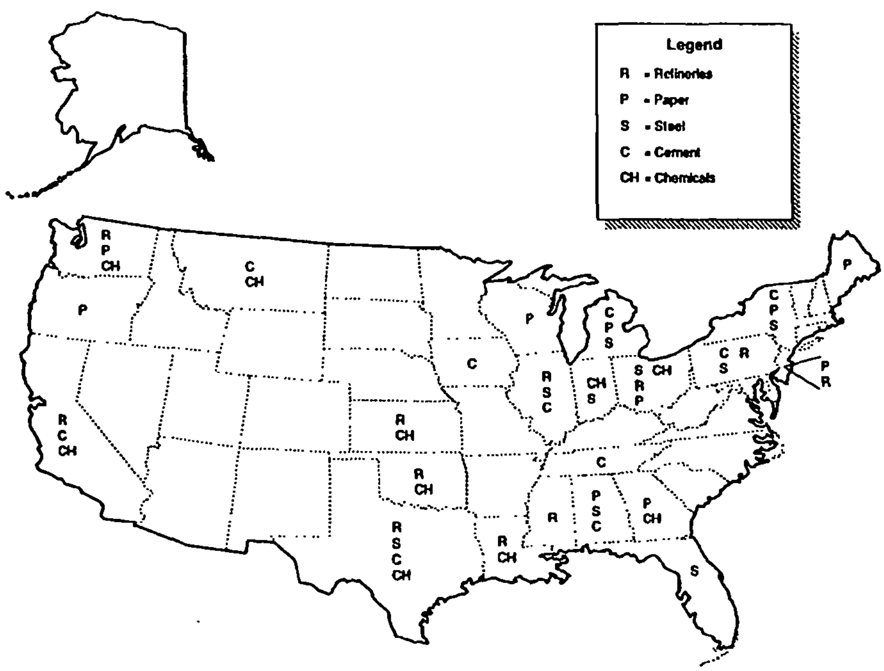
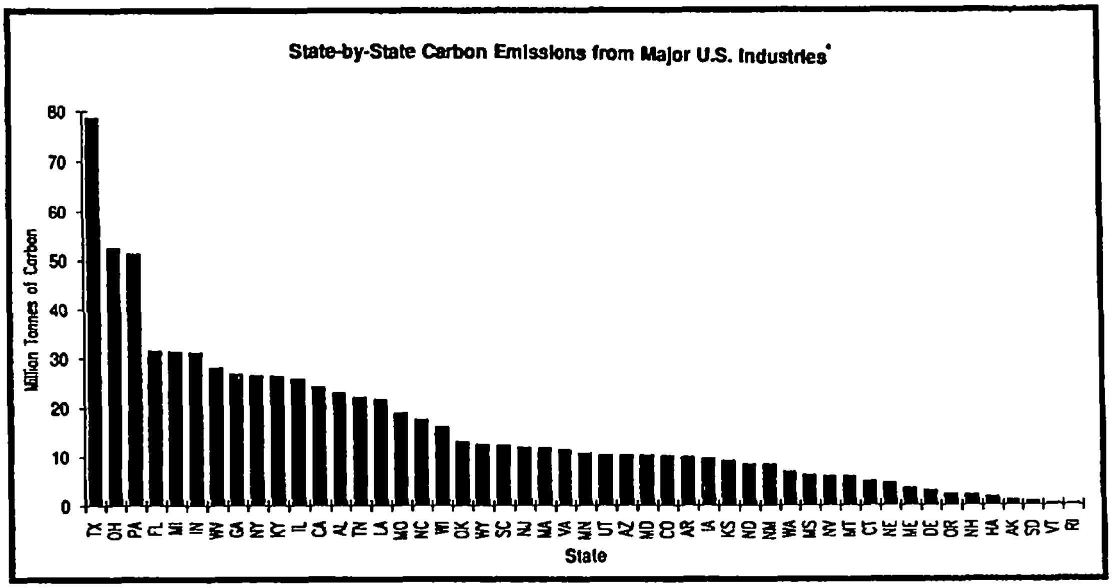


Figure 2-6. Geographical Locations of Major CO_2 Emitting Industries



* Major industries include electricity, chemicals, steel, paper, refining, and cement, and account for 90% of total U.S. industrial emissions.

Figure 2-7. Histogram of Carbon Emissions from Major Industrial Sources, by State

Electric Utilities. It is hardly surprising that electricity generation generally takes place around population centers (the correlation coefficient between state populations and state generation in GWh is 0.44). However, if this is broken down by fuel types, we find that the pattern is more pronounced for oil and gas-fired generation than for coal-fired generation (correlation coefficients of 0.23, 0.40, and 0.15, respectively). Oil-fired units are not necessarily found in large oil producing states (the correlation coefficient between state GWh and state oil production in barrels is 0.01). Exceptions to this trend are Florida, Pennsylvania, and California, for which both oil production and oil-fired electricity generation are high. For gas-fired units we found a strong correlation (0.61) between gas extraction and gas-fired electricity generation; gas-fired units tend to be located near gas extraction areas. Coal-fired units are often located near coal mines (correlation coefficient of 0.25).

Based on these observations we may carve out the following picture to describe the electric utility industry:

- Coal-fired utilities are located around coal production areas. The observation that coal-fired utilities are located outside densely populated areas can have two explanations: transportation costs are high, or there are environmental/legislative disincentives to such siting.[27]

27. Gordon, Richard L., op. cit.

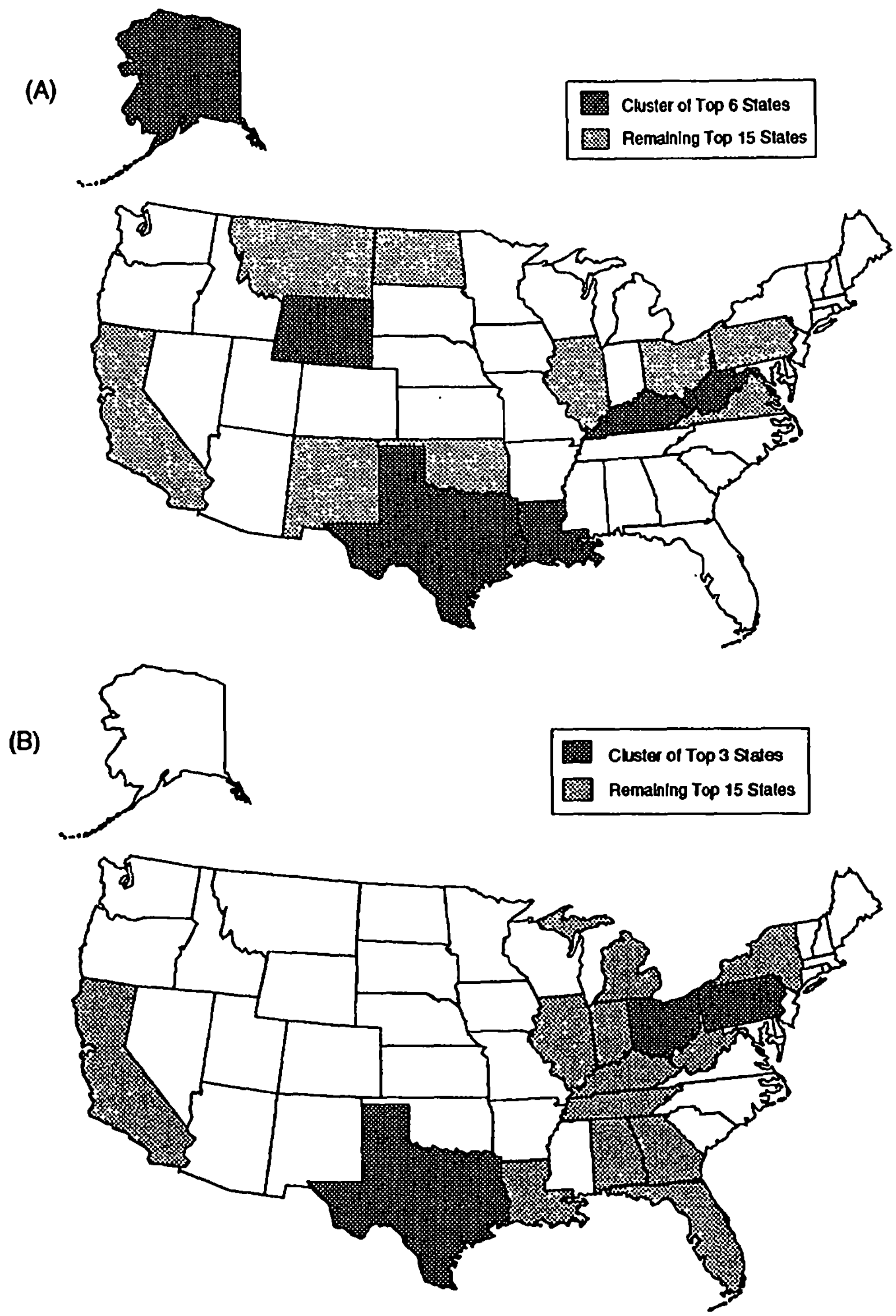


Figure 2-8. Comparison of Top Fifteen States when Ranked (A) by Carbon Extraction and (B) by Carbon Emissions from Major Industrial Sources

- For gas-fired utilities, the picture seems somewhat more complex. Gas-fired electricity and gas extraction seem to go hand in hand, and at the same time, gas-fired generation seems to take place near population centers. This may suggest that where gas extraction takes place around highly populated areas, it is a preferred source of power.

- Oil-fired utilities have little correlation to oil production centers, possibly because oil is highly transportable.[28]

Petroleum Refining. Petroleum refineries burn considerable amounts of oil and gas. Not surprisingly, refineries are often located close to oil and gas production centers in the South and in California (correlation coefficient of 0.57). Two exceptions to this tendency are Alaska and Washington. Alaska has a large oil production but a small refining production, whereas Washington has a small oil production and a relatively large refining production. Much of the oil processed in refineries in Washington comes from Alaska.

Paper Industry. Like petroleum refining, the sources of fuel and raw materials are similar. The single most important energy source for the paper industry is wood chips. As such, the paper industry is also concentrated where raw materials—and wood chips—are abundant.[29] The key paper processing areas are in the South, Northeast, and Northwest.

Cement. Cement plants are generally located close to raw materials, and if inland, close to their markets. However, imports have increased steadily in recent years to 18.5% of total consumption in 1988. Imports are primarily from Mexico, Canada, Japan, and Spain. In the future, imports from Mexico and other developing countries are expected to increase.[30]

Steel. The steel industry consumes large amounts of coal, and several steel mills are owners of coal mines. However, there is little evidence that the location of steel mills is triggered by the location of coal mines (correlation coefficient of 0.04). More important natural resource related factors determining the location of steel mills are likely to be proximity to iron ore and water, both of which are available in the South and Northeast. (Other important determinants are economic, such as the location of steel consumers and availability of scrap input.)

Chemicals Industry. The chemicals industry is very diverse, with multiple product groups, different fuel burning intensity, and different use of feedstocks. To accommodate this we divided the industry into five sub-categories; organic chemicals, inorganic chemicals, plastic

---

28. Mitchell, Edward J., op. cit., p. 43.

29. U.S. Department of Energy, *Industry Profiles/Paper*, Final Report Prepared by Energetics, Inc., Washington, D.C., December 1990, p. 1.

30. U.S. Department of Energy, *Industry Profiles/Cement*, op. cit., p. 3.

materials and resins, nitrogenous fertilizers, and other chemicals. Figure 2-9 displays the regional distribution of each of these sub-groups of the chemicals industry.

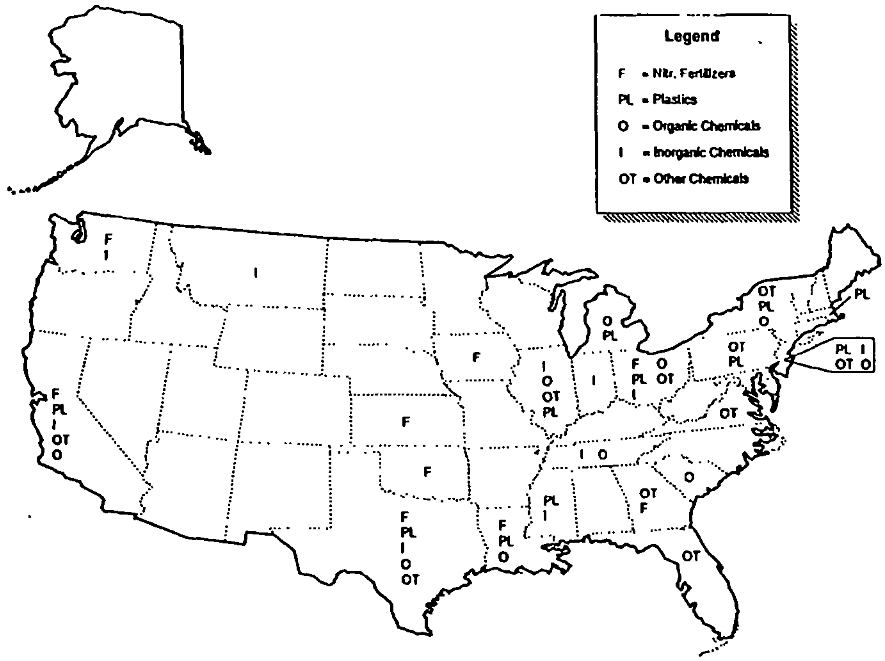


Figure 2-9. Geographical Concentrations of Various Types of Chemical Industries

- *Inorganic Chemicals.* This industry uses relatively more natural gas than other fuel types, but plant location does not appear to be triggered by gas production (correlation coefficient of 0.05). This again is consistent with the mobility of natural gas.

- *Plastic Materials and Resins.* This is a natural gas and LPG-intensive industry, which also uses a significant amount of oil as feedstock (about 9% of direct fossil fuel consumption). In general, plants seem to be located close to oil and gas production centers (correlation coefficients of 0.46 and 0.60, respectively).

- *Organic Chemicals.* This is also a natural gas and LPG-intensive industry, which uses considerable amounts of oil as feedstock (about 22% of direct fossil fuel consumption). There seems to be a good correlation between plant location and large oil/gas production centers (correlation coefficients of 0.48 and 0.77, respectively).

- *Nitrogenous Fertilizers.* This is a natural gas intensive industry, which also seems to be located around gas production centers (correlation coefficient of 0.53).

- *Other Chemicals.* These diverse production activities use relatively more natural gas than other fuel types, but there does not appear to be a relationship between gas production and plant locations (correlation coefficient of 0.04).

Market Distortions

A carbon emissions allowance market, like carbon taxes, has the potential to reduce the costs of emission reductions substantially below the costs that would be incurred by a command-and-control emissions policy. The degree to which an allowance market can reduce costs, however, can be lessened by market imperfections and barriers to market exchanges. Extensive rates regulation of electric utilities may create inefficiencies in an allowance market that includes utilities. This is a serious concern since utilities would be such a major factor in a market for carbon at the industrial level, accounting for about two-thirds of U.S. industrial carbon emissions and over one-third of total U.S. CO_2 emissions.

Regulations of the allowed rates of return of utilities can distort utilities' costs of capital investments for emission controls away from the true social costs of these investments. Regulations that require capital gains and losses to be passed on in whole or in part to utility customers can distort utilities' costs of purchases and sales of emission allowances if the regulations are applied to allowances. These distortions alter the relative costs of emission controls and allowance purchases that are perceived by electric utilities. Because of this, the combination of investment in emission control and purchases of allowances that individual utilities will choose may not be the efficient choices. The result will be an allocation of emission reductions across sources that will fail to achieve reductions at least cost.

Since utilities represent a large portion of CO_2 emissions, the regulatory distortions discussed above could cause significant efficiency losses for an emissions allowance market that includes utilities. However, it should be kept in mind that market imperfections caused by electric utility regulation would also influence the efficiency of other market-based approaches to emissions control. For example, a carbon tax also would rely on energy users to respond efficiently to energy prices, and may face similar implementation problems in the utility sector.

Volume 3 of this report, "Effects of Utility Regulation," discusses electric utility regulation and emission allowance trading in more detail. Included in the discussion are suggestions for the treatment of emission control investments and allowance purchases and sales in utility regulation to reduce efficiency losses in an emission allowance markets.

THE END-USE LEVEL OF THE FOSSIL FUELS MARKETS

While discussion about permit trading at the combustion level most often focuses on the utility industry and other major emitters in the industrial sector of the economy, it is important to keep in mind that large quantities of fossil fuels also are burned in other sectors; more specifically the transportation sector, the residential sector, and the commercial sector. Together, these sectors account for about 40% of U.S. CO_2 emissions (see Volume 1). Could permit trading be implemented at the combustion level for these sectors, as well? Following a brief outline of the structure of these sectors, we discuss how permit trading could be implemented so as to include these sectors.

Number of Sources

The transportation sector consists of private and commercial road vehicles (cars, trucks, motorbikes, etc.), aviation, rail transportation, and shipping. Table 2-4 provides rough estimates of the number of source units for cars and trucks, merchant vessels under the U.S. flag, and U.S. commercial airplanes. There is also a large number of additional sources, such as military aircraft, leisure vessels, and motorbikes.

The residential sector covers residential houses and buildings. Table 2-4 estimates owner-occupied houses in the U.S. at 55 million. In addition, approximately 35 million households live in rented houses and apartments. There is also a large number of second homes, vacant homes etc. Approximately 55% of occupied housing units are gas heated, 20% oil or LPG heated, 5% wood heated, and 0.4% coal heated.[31] Gas is also used for cooking in about 38% of housing units. Electricity, of course, is ubiquitous and accounts for about 19% of home heating.

The commercial sector accounts for commercial and public office buildings. Table 2-4 also provides information about such buildings in the U.S.

Regional Distribution

When all of the sources of emissions are added together, one might expect a more widespread regional distribution of emissions. However, locations of populations are largely correlated with industrial centers. Figure 2-10 provides a histogram of total state by state emissions, including all industrial, commercial, residential, and transportation sources.[32] By comparing Figure 2-10 with Figure 2-7, the regional emissions concentration appears equivalent to that based on location of key industrial emitters. Although high population states tend to have high total emissions, there is substantial variation in the state averages for emissions *per*

31. U.S. Department of Commerce, Bureau of the Census, op. cit., Table 1225.

32. The data for the total state-level emissions used here come from *The Heat Is On: America's CO_2 Polluters*, Citizens Fund, Washington, D.C., December, 1990, p. 37.

capita, and the ranking of the states is altered. For example, California ranks second for total emissions but is 45th in terms of *per capita* emissions among the states. Of the top fifteen states in Figure 2-10, only West Virginia and Louisiana have *per capita* emissions that are significantly different from the average. The top ranked states on a *per capita* emissions basis are Wyoming (by far the highest at 66,600 lbs./person of carbon), North Dakota (38,700 lbs. C/person), West Virginia (34,500 lbs. C/person), Alaska (31,500 lbs. C/person), and Louisiana (25,200 lbs. C/person). The average for all states is 11,800 lbs. C/person.

Table 2-4
SOURCE UNITS AT THE END-USE LEVEL, 1986

Category	Number of Sources
Cars and Trucks	177 million
Commercial Airplanes	215,000
Merchant Vessels*	738
Owner-occupied Homes	55 million
Rented Houses/Apartments	35 million
Commercial Buildings	4 million

* 1,000 gross tons and over. Not inclusive of "U.S." vessels under foreign flag.

(**Source**: U.S. Department of Commerce, *1987 Census of Manufactures*, Tables 992, 1028, 1044, 1221, 1237.)

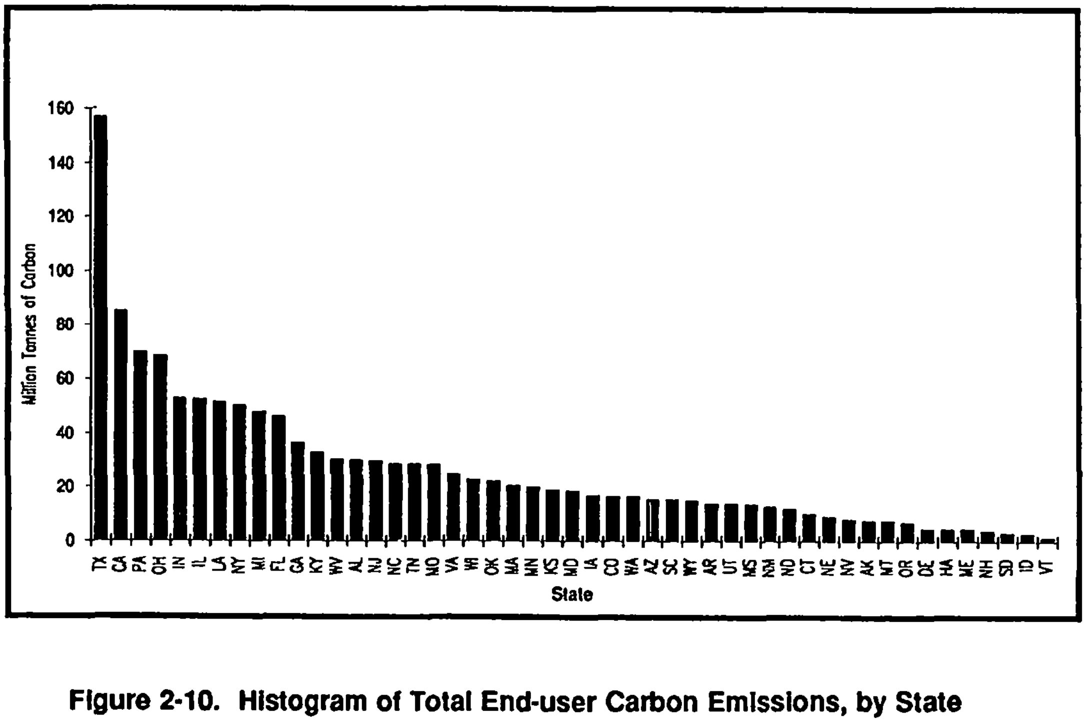


Figure 2-10. Histogram of Total End-user Carbon Emissions, by State

Implementing Permit Trading at the End-Use Level: An Hybrid Approach

Any attempt to directly include the transportation, residential, and commercial sectors in a permit trading program, using cars and buildings as source units, could easily lead to administrative overload. An alternative way to include these sectors in a permit trading program would be to focus on *producers of CO_2 emitting equipment;* for example car producers, manufacturers of oil and gas-fired heaters for residential and commercial buildings, etc. This would effectively result in an extension of the concept of trading at the industrial level rather than at the consumer level. Instead of confining the industrial groups to those that burn fossil fuels, any industry that produces goods that later burn fuels in the hands of a user would also become responsible for emissions of their products in the hands of their customers.

Table 2-5 provides information about the number of U.S. plants for car producers, aircraft manufacturers, ship-builders, and producers of heating devices. The list is not intended to give a complete picture of all the sources that would need attention, but merely indicate that the number of source units now would be reduced to a more practical level.

Table 2-5
PRODUCERS OF CO_2 EMITTING DEVICES, 1986

Industry	SIC Code	Number of Plants
Motor Vehicles and Equipment	371	3,867
Aircraft Products and Parts	372	1,471
Ship Building and Repair	373	2,566
Heating and Plumbing Manufacturers	343	1,177

(**Source:** U.S. Department of Commerce, *1987 Census of Manufactures*, Table 1242.)

The way such controls would work would be that each piece of equipment sold would have an emissions rating. (This is probably easily obtained from current rating requirements such as fuel economy on cars.) The average lifetime and usage patterns of the equipment and change in emissions rating over its lifecycle would have to be estimated. With these data, a total lifecycle CO_2 emissions estimate could be derived, and the equipment manufacturer would be required to have sufficient permits to cover all equipment sold.[33] However, each company would have a very complicated trading problem, since every line of car or type of equipment would require its own lifecycle emissions estimate. Appendix C demonstrates how emissions estimates for the car manufacturing industry, as well as car manufacturers can be derived.

33. This type of regulatory approach would not be unlike the use of CAFE standards where vehicle manufacturers are allowed to average their fleet fuel economy ratings. The key difference is that the performance of the fuel economy would have to be demonstrated over ten or more years of vehicle usage, rather than at time of sale.

Clearly the manufacturer cannot completely control lifecycle emissions because this is ultimately in the hands of the user. The user would still have no incentive to adjust the lifetime of a piece of equipment, nor to use it less frequently, nor to maintain it in its most efficient state. All of these actions can be very important cost-effective ways of reducing emissions over equipment lifecycles. Manufacturers might develop maintenance programs or early retirement programs as a way of obtaining a lower requirement for allowances, but this type of permitting system would still primarily affect incentives to improve lifecycle performance in terms of technical design. The technology focus of this approach would probably also fail to provide sufficient incentives for end-users to turn to cost-effective alternatives with lower emissions. For example, more efficient and more costly furnace technology would provide little incentive to invest in home insulation. Only an approach focused on actual emissions, either through consumer behavior or consumer fuel usage, can completely address lifecycle emissions incentives. Another caveat to this approach is that it would only apply to new equipment. Old and less efficient units would not automatically be affected. In fact, a disincentive to replacing the existing stock could be created.

An interesting feature appears with this hybrid approach that deserves further consideration. In regulating the actual points of combustion, there is no question of "leakage" of responsibility for emissions. However, whenever the regulations affect a party that is up or downstream of the point of emissions, one must face questions of how to regulate non-U.S. entities (the importers of goods). By transferring responsibility for controlling emissions from the vehicle owner to the vehicle manufacturer, one is transferring the responsibility onto multiple foreign companies.

Clearly the regulations must face importers as well as domestic producers. Otherwise production abroad would become more competitive and imports might increase. Such international transfers of production could reduce the effectiveness of unilateral regulation. On the other hand, if imports were to be included in the permits requirements, permits would have to be allocated to foreign producers. As is frequently noted in the theoretical literature on trading, free allocation of tradeable permits amounts to an allocation of wealth. The concept of giving permits to foreign companies may therefore meet considerable resistance politically. However, even allowing foreign interests to purchase such permits has implications for the transfer of U.S. capital assets abroad, and may create serious political concerns. Imports instead could be required to meet specific technology standards, but this works against the concept of free trade. It could even be in violation of trade agreements. More needs to be considered regarding treatment of imported goods that create emissions when used after purchase.

Other hybrid approaches are also possible. For example, industrial source permits could be combined with permits for distributors of fuels to the transportation and household sectors. This approach would close the leakage gap without requiring estimation of lifecycle emissions. On the other hand, it is somewhat less integral than the former approach: distributors would be regulated, but only for a part of their activities. If this hybrid approach were advantageous, then it would probably be even more advantageous to institute the entire permits market at the distribution level.

SUMMARY

A carbon emission allowance market for producers of energy would include approximately 6,000 companies as participants in the market. These 6,000 companies own and operate nearly 900,000 extraction facilities such as oil wells, gas wells, and coal mines. They also own and operate about 200 domestic oil refineries, 3,600 coal processing plants, and 130 gas pipeline companies.

The extraction facilities are geographically concentrated in the Gulf states, Ohio River Valley states, and North Central states. The six states that extract the greatest quantities of fossil energy carbon are Texas, Wyoming, Louisiana, Kentucky, West Virginia, and Alaska. Together they extract 63% of domestic fossil energy carbon. Only four states account for over half of all U.S. carbon extraction.

Given relatively inelastic demands for fossil energy, an allowance market for producers is likely to transfer surplus from consumers to producers. This transfer may be concentrated in the regions where fossil energy production is concentrated. The six states which account for 63% of carbon extraction could capture large gains. Note, however, that if ownership of these energy resources is not concentrated in the production regions, the transfer will be more dispersed than suggested by the geographical concentration of production.

Within the regions that do benefit, the gains may be distributed very unevenly. For example, any policy that significantly reduces carbon emissions will likely require reductions in coal production. Owners of coal resources will benefit from a rise in the price of coal, but with the reduction in coal production comes a reduction in coal industry employment. There will also be reductions in payments for other factors used in the production of coal which may have negative impacts on coal regions.

A market for carbon allowances for energy production may not be a perfectly competitive market in the sense that it will not be composed of very large numbers of very small buyers and sellers. If a producer permit market for carbon is implemented at the level of energy extraction, the ten and twenty largest participants will represent roughly 35% and 45% of the market, which is not a particularly high degree of concentration relative to other industries. The implication is that, although some market participants may possess some degree of market power, it is not expected that this will be a serious problem for efficiency of an allowance market at the producer level.

An emission allowance market for industrial consumers of energy would include 10,000 to 20,000 participants. Industrial sources, defined here to include electric utilities, emit roughly 60% of total U.S. CO_2 emissions. The six industrial sectors with the largest CO_2 emissions account for approximately 90% of industrial emissions and 55% of total emissions. The largest emitting industries are electric utilities, chemicals, paper, steel, cement, and petroleum refining.

Although industrial emissions are heavily concentrated in these six industrial sectors, the six sectors include nearly 17,000 industrial plants. Concentration ratios in each industry are similar to those in the primary energy sector, but these would be greatly reduced when aggregated into an emissions-based concentration ratio. Although we do not have emissions data by plant to compute that ratio, it is likely that an allowance market for industrial sources would be much less concentrated than an allowance market for energy producers. Thus we would not expect market concentration and market power to be a problem in this market.

Industrial emissions of CO_2 are somewhat concentrated geographically, but less so than is the extraction of carbon. Up to ten states are required to account for half of U.S. emissions. Three states stand out with the greatest industrial emissions of CO_2: Texas, Ohio, and Pennsylvania.

The regional concentration of industrial emissions should not be interpreted to mean that the social welfare losses of emission reductions will fall disproportionately upon the states where emissions are concentrated. An emission allowance system, whether it be for energy producers or consumers, will raise the industrial costs of producing goods. Industrial consumers of energy will suffer losses and highly CO_2 intensive industries may reduce employment. But a large portion of the costs of emission reductions will be passed on to the final consumers of the goods produced by industry. These consumers are widely distributed across the U.S. and in foreign markets. The geographic distribution of ownership of industrial sources is also likely to differ from the geographic distribution of industrial plants.

Electric utilities represent a large share of industrial CO_2 emissions. Due to the structure of electricity markets and regulations of electric utilities, the incentives faced by utilities in an emission allowance market will be distorted. This may cause utilities to choose a sub-optimal mix of investment in emission control and purchases of allowances that would lessen the efficiency of the allowance market. Although this distortion should be addressed for any market-based emissions control scheme, it is even more salient for trading at the industrial end user level of the market.

A policy focusing on industrial emissions alone neglects large emissions from residential, commercial, and transportation end uses. Omitting these end uses from an emission reduction policy could significantly raise the costs of achieving an emission target, but extending an emission allowance market to include them directly would be prohibitively costly. One alternative is to estimate lifecycle emissions for energy-using equipment in the residential, commercial, and transportation sectors and to require equipment manufacturers to obtain allowances for the equipment that they sell. This option is also likely to be administratively costly and fails to provide end users with incentives to reduce emissions by operating their equipment efficiently. Other alternatives would be to require distributors of energy to these sectors to obtain permits for the energy sold, or to combine an industrial emission allowance market with carbon taxes for fuels distributed to other end users. These options create administrative burdens and a relatively complex regulatory structure. However, some such hybrid approach is probably advisable if a carbon emissions market is to be implemented other than at the energy producer level of the market.

3

WHAT AMOUNT OF EMISSIONS WOULD BE SUBJECT TO CONTROL?

In this section we discuss how permit trading at different levels of the economy would affect how much of total emissions would be subject to control, and for what possible control options would incentives to take action be lost.

PERMIT TRADING AT THE PRIMARY PRODUCTION LEVEL

As discussed in Section 2, CO_2 permit trading at the primary producer level would target fossil fuel production close to the source of extraction (see Figure 2-1) rather than at the point of emissions. Possible sources of "leakage" that may arise in controlling emissions when the responsibility is shifted upstream to primary producers are summarized as "considerations" in Figure 3-1, and discussed below.

Imports of Fossil Fuels. Crude oil imports accounted for approximately 32% of U.S. oil consumption in 1986.[34] By contrast, imports of natural gas and coal accounted for only 4.5%[35] and 0.2%,[36] respectively. The discussion of imports and exports of fossil fuels assumes that foreign countries with which we trade energy do not implement their own policies raising the prices of traded energy to reflect the carbon content of the energy. If the contrary were true, care would be needed in the treatment of imports and exports in a carbon permit market to ensure that traded energy is constrained neither more nor less than energy that is not traded in international markets. Equating the treatment of the two may be a very complex task, particularly if other countries do not adopt market incentive approaches to reducing carbon emissions.

If permits are required only at the wellhead, a leakage problem would occur. Importers could be required to obtain a number of permits equal to the carbon imported, thereby solving this leakage problem, but also bringing foreign interests into the permits market. To some extent, this leakage problem also could be circumvented by instead implementing permit trading

34. U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States 1988*, Washington, D.C., 1988, Table 1166.

35. Ibid., Table 1173.

36. Ibid., Table 1175.

at the refinery level. Each refinery would be required to have permits independent of where the oil came from. Domestic production and imports of crude oil would therefore compete on the same terms as without trading.

Imports of refined petroleum products, however, are also significant. They accounted for approximately 14% of U.S. consumption in 1986.[37] Unless this is also accounted for under a permit trading program, foreign producers would be likely to gain a competitive advantage over U.S. refineries; imports would go up, thereby neutralizing the environmental gain. One could, in fact, also have instances where the net environmental effect would be negative; for example if foreign refineries with less fuel efficient production were able to increase their U.S. market share.

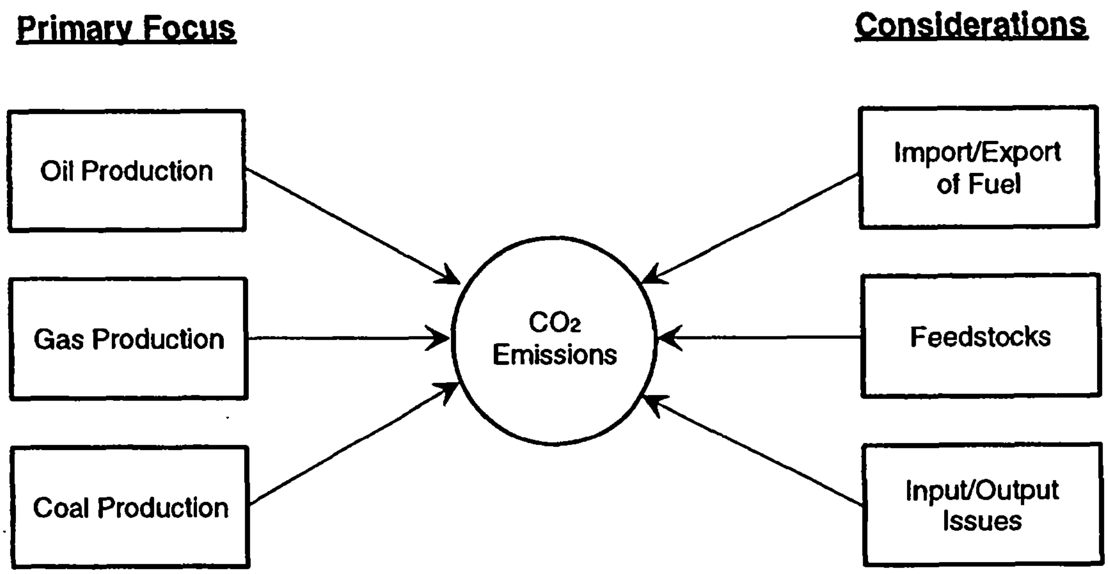


Figure 3-1. Considerations in Trading at Primary Production Level

If none of the importer-trading options are acceptable, it would be wise to implement trading at some point in the system that distributes refined petroleum products. This would increase the number of parties involved to several thousand rather than the several hundred refineries. Probably this is wise, if only to also avoid market power problems that could arise in the case of only a few hundred parties (many of which belong to the same oil company anyway).

Export of Unrefined or Refined Fuels. Fuel exports account for approximately 1.8% of crude oil production, 5% of domestic refined products,[38] approximately 0.4% of natural gas

37. Ibid., Table 1166.

38. Ibid., Table 1166.

production,[39] and approximately 10% of coal production.[40] There is the question as to whether or not fuel exports should be subject to control. One could argue that the U.S. unilaterally should set an example to the world, but setting an example would have its costs in terms of lost foreign revenue. On the other hand, as the carbon trading in the U.S. reduces domestic demand for coal, coal exports might increase beyond the current 10%, partially offsetting any reductions in emissions inside the U.S. Thus, this source of emissions leakage should be carefully addressed if implementing trading at the primary producer level.

Feedstocks. Feedstocks accounted for approximately 28% of petroleum product consumption in the U.S. industrial sector in 1988.[41] A feedstock is a part of the fossil fuel production that is used as an ingredient in a production process, but is not part of fuel combustion. For example, plastics are made from petroleum products. Thus no CO_2 emissions arise directly from use of feedstocks. Based on this, one could argue that feedstocks should be subject to a "permit refund," or should otherwise be exempted from the calculation of required permits. This would be easy to implement if trading were to occur at a level of the market after refining, such as at the final distribution to consumers. A bigger accounting problem arises for trading prior to the refined product distribution. In this case, it would be quite difficult to determine which units of fuel products will ultimately go to feedstocks, or even what fraction of a refiner's output goes to feedstocks. It would be virtually impossible to account for at the wellhead. Again, we find an argument for defining primary producers as the final distributors rather than the extractors or the refiners.

Input/Output Issues. In addition to determining at what level of the economy permit trading should take place, one must also decide whether emissions estimates should be input or output-based. For example, if emissions trading were implemented at the fuel extraction level, emissions estimates could be based on fuel extraction volumes, or alternatively, volume sold. While fuel extraction volumes could account for losses in the extraction process, measuring fuel volume sold (or shipped out) would probably be easier in terms of monitoring and control. This may be a fairly small error that is considered not a serious issue compared to others. For example, it has been estimated that approximately 1.8% of natural gas produced in the U.S. is either lost in transmission, or vented and flared.[42] However, if trading occurs after the refining stage, all of the emissions associated with refining might not be captured by the regulation, unless careful consideration is given to this in the regulatory design. As has been shown, the refining emissions are likely the fifth highest industrial source of CO_2 emissions.

39. Ibid., Table 1173.

40. Ibid., Table 1175.

41. See Volume 1 of this report, Table A-1.

42. American Petroleum Institute, *Basic Petroleum Data Book. Petroleum Industry Statistics*, Vol. XI, No. 1, Washington, D.C., 1991, Section XIII, Table 5a.

Table 3-1 provides estimates of fossil fuel consumption that would be covered under a permit trading program at the primary producer level. We have included some of the caveats discussed above; accounting for imports and exports (assuming exports are outside the permit trading market), including all production units, subtracting feedstocks, and adding wood burning.

Table 3-1
U.S. FOSSIL FUEL CONSUMPTION, 1989
(trillion Btu *)

	Oil	Gas	Coal	Wood	Total
U.S. extraction**	15,285	18,045	24,721	1,236	59,197
Imports,unref.***	8,255	750	50		9,055
Imports,refi.***	3,916				3,916
Exports,unref.***	-308	-60	-2,167		-2,535
Exports,refin.***	-1,243				-1,243
Feedstocks ****	-6,446				-6,446
Net fuel consumption	19,459	18,735	22,604	1,236	61,944

* To convert from physical production units to energy equivalents, units of a million barrels of oil were multiplied with 5.5 to obtain trillion Btu, trillion cubic feet of natural gas with 1,000, and million short tons of coal with 25.2. These conversion numbers are provided in a publication from the U.S. Department of Commerce; *Energy Interrelationships. A Handbook of Tables & Conversions Factors for Combining and Comparing International Energy Data,* prepared by National Energy Information Center, Washington, D.C., 1977, pages 34-36.

** Oil and gas extraction data from Energy Information Administration, *Natural Gas Annual 1989,* DOE/EIA-0131(89), Washington, D.C., 1989. Coal extraction data from Energy Information Administration, *Coal Production 1989,* DOE/EIA-0118(89), Washington, D.C., 1989. Wood burning is all in the pulp and paper industry from 1985 data; from Energy Information Administration, *Consumption of Energy 1988,* DOE/EIA-0512(88), Washington, D.C., 1991, Table 1.

*** 1986 data from U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States 1988,* Washington, D.C., 1988.

**** Energy data from Energy Information Administration, *Consumption of Energy 1988,* DOE/EIA-0512(88), Washington, D.C., 1991, Table 1.

Table 3-2 shows CO_2 emissions estimates for each fuel type. We multiplied the net energy values for each fuel type with a corresponding emissions factor. For simplicity, we assumed that imports and exports of refined petroleum products had the same carbon content as crude oil.

Table 3-2
TOTAL U.S. CO_2 EMISSIONS ESTIMATED FROM FUEL PRODUCTION, 1989
(million tonnes of carbon)

Fuel Type	Oil**	Gas**	Coal**	Wood***	Total
Emissions *	410	271	576	27	1,284

* Emissions estimates were calculated by first multiplying the "net fuel consumption" for each fuel type with a corresponding emissions factor; oil = 73,113 gram of CO_2/GJ, gas = 50,257 g/GJ, coal = 88,440 g/GJ, and wood = 75,000 g/GJ. Next, these products were multiplied with 1.056 10E-6 to yield million tonnes of CO_2, and finally, multiplied with 12/44 to convert from CO_2 to carbon.

** The numbers follow United Nations convention, and is detailed in Marland (1983).

*** Emissions factor for wood from U.S. Environmental Protection Agency's; *Policy Options for Stabilizing Global Climate*, Vol 1, Washington, D.C., 1989, p. IV-21.

PERMIT TRADING AT THE INDUSTRY LEVEL

Volume 1 estimates CO_2 emissions at the industry level, repeated here as Table 3-3. The estimates are based on fossil fuel consumption (less feedstocks) in each industry, plus process-based emissions from cement manufacture.

Since Tables 3-2 and 3-3 show emissions estimates for different years, a precise comparison is not feasible. However, the tables indicate that total emissions covered under permit trading at the industrial level are substantially lower than under permit trading at the primary production level. Only on the order of one-half to two-thirds of the carbon emissions would be regulated if <u>all</u> industry were to be involved in trading. Note that if only the top six industries (including electric utilities) were to be regulated, almost equivalent regulatory coverage would be attained. Some of the reasons for this low coverage are:

- *Sectors of the economy.* Fossil fuel combustion in the transportation, residential and commercial sectors of the economy is not included at the industry level. For example, gasoline consumption for road vehicles would not be covered, and neither would fossil fuel fired heating of residential and commercial buildings. While permit trading at the industrial level would capture emissions from electric utilities, competing energy sources like oil and gas-heated buildings would be exempt. The transportation sector accounts for about 30% of U.S. CO_2 emissions, and the residential and commercial sector account for about 11%.

Table 3-3
EMISSIONS ESTIMATES IN U.S. INDUSTRIAL SECTOR, 1988
(million tonnes of carbon)

Industry	SIC	Estimate
Electric Utilities	491	527
Chemicals	28	60
Paper	261 - 263	45*
Steel	3312	44
Cement	3241	15**
Petroleum Refining	2911	13
Glass & Stone	32 ex 3241	9
Transport Equipment	37	4
Other, non-utility industry	20-39	40
Other, non-manufacturing	1-17	32
Total		**789**

* The estimate for paper mills includes about 27 million tonnes of carbon emissions from wood, which may have lower net emissions when accounting for the offsetting reduction due to replacement growth of trees.

** The estimate for cement include emissions from calcining, which is unrelated to fossil fuel consumption. Calcining emissions from cement manufacturing are estimated at roughly 9 million tonnes carbon, and fuel combustion emissions at 6 million tonnes.

- *Fuel lost in transit.* As fuels move from the point of extraction, through refineries and distributors, and finally reach the final user, each transportation, storage and processing link is likely to have losses in terms of fuel spills, leakages, etc. These fuel losses would not be included in an accounting of emissions at more upstream levels of market where the permit trading might be implemented. This is probably a relatively small effect, especially compared to the previous point. It is also unclear if "lost" fuels should be treated as if carbon emissions occur from them. Like feedstocks, these may not result in emissions of CO_2, although VOCs will be affected.

- *Point versus non-point sources.* Emissions at the industry level could be measured indirectly via fuel purchases, or it could be measured directly by monitoring each stack. (The estimates provided here are based on fuel purchase data.) The direct method may be preferred by regulators,[43]

43. The 1990 Clean Air Act actually sets the groundwork for this approach by requiring utilities to start continuous stack monitoring of CO_2.

however, it would not automatically capture non-point emissions sources, creating further possible leakage for regulating industry emissions.

- *Global emissions.* Over time, implementing permit trading at the industry level would also bring about the risk of increased "importing" of emissions.[44] For example, permit trading would be likely to make the cement industry even more vulnerable to foreign competition. If foreign producers are less fuel efficient, one may in fact see a net increase in global CO_2 emissions as a result of industrial regulations to reduce them. This paradox could be counteracted by taxing imports according to the fossil fuel used in the production process.

Thus it is apparent that an implementation of trading at the industrial level creates many more opportunities for leakage of emissions than trading at the primary producer level. Even more importantly, regulation of industrial emissions does not address up to 40 percent of all man-made CO_2 sources in the U.S. If a goal of carbon emissions stabilization or reduction is to be achieved, these industries would have to bear a much heavier control burden than if a better coverage of the other 40 percent of emissions were to be designed into the regulations.

PERMIT TRADING AT THE END-USE LEVEL

By definition, permit trading among all end-users of fossil fuels would provide the most comprehensive regulatory coverage. Only by observing emission-causing activities directly can the problems of leakages and overcounting be avoided completely. However, the millions of parties involved in such regulations (mostly individual citizens who individually make up a miniscule fraction of the total) would create another problem altogether. It would be very difficult to administer and enforce such a program.

In Section 2, a hybrid approach was suggested, to regulate the producers of equipment that individuals use to burn fuels. This avoids the numbers problem of the end-use level, but is a very indirect and incomplete way to regulate emissions. Approximation of eventual emissions based on fuel sales was one of the drawbacks noted for trading among primary producers. The degree of approximation that follows from the suggested industry/end-user hybrid is much greater. Not only must the emissions rate be estimated, but so also the fuel usage of the average consumer over time. Potentials for error are large, and systematic leakages will almost certainly occur in such a regulatory scheme. Further, the incentives for finding the most cost-effective responses are incomplete. On the other hand, it would almost double the coverage that can be obtained from trading at the industrial level without a disproportionate increase in the parties involved in the regulation.

44. This problem will be true to some degree of any regulation that increases domestic costs relative to foreign costs. However, it may be greater when the burden of control falls fully on only one portion of the economy.

SUMMARY

The cost-effectiveness of CO_2 emission reductions in a carbon permit market can be reduced by excluding from coverage carbon sources that contribute to emissions. Imports of fossil fuels represent one potential leakage and a permit market implemented at the level of energy production would need to take this into account. Inclusion of imports in a producer permit market probably presents no serious administrative problems, but needs to be considered in the regulatory design.

Another potential source of leakage is the emissions associated with refining, processing, and transporting energy. Emissions from oil refining represent the fifth largest industrial source of CO_2 emissions. If carbon permits are required for the sale or purchase of refined or processed energy products, the emissions from these processes will not be directly constrained unless carbon permit requirements are calculated after accounting for all upstream emissions in the processing of raw materials into fuels consumed.

The high cost of administering a permit market for all energy consumers (including residential, commercial, and transportation) creates a large potential leakage, because a workable permit market for energy consumers would likely be reduced in scope to cover only major industrial sources. However, the major sources, even broadly defined, only account for about 60% of emissions. This leakage could be plugged by complementing a permit market for industrial sources with other policies directed at the remaining energy consuming sectors.

The cost-effectiveness of CO_2 emission reductions in a carbon permit market might also be reduced by including carbon that does not contribute to emissions. For example, energy feedstocks sequester carbon in products and, thus, do not contribute to CO_2 emissions. Identifying and exempting energy that is bound for use as feedstocks will be difficult in a carbon permit market for producers and less difficult in a carbon permit market for consumers. Renewable energy that contains carbon presents problems for both producer and consumer permit markets. Depending upon how renewable carbon energy stocks are managed, and the time horizon considered relevant, use of these resources may or may not result in net CO_2 emissions.

4

WHAT ARE THE MECHANISMS FOR MONITORING AND ENFORCEMENT?

An EPA scoping study on emissions trading issues[45] elucidates how incentives to cheat in a permit market exist, regardless of the fact that such a market can function competitively. Neither buyer nor seller in a permit market would have an incentive to see that the emissions reductions transacted would actually occur. This fact has been observed in the case of enforcing the phase-down of lead in gasoline.[46] The possible lack of incentives to comply, combined with the diversity of the sources included in a permit trading market for CO_2 indicate that effective monitoring and means of enforcement could be key issues in ensuring that an emissions market will work. This section discusses specific implementation issues connected with permit trading at different levels of the economy, including how emissions will be monitored and the effect of the number of sources.

NUMBER OF SOURCES

The number of source units included in a permit trading market has important implications for monitoring; the more source units there are and the more dispersed they are, the more resources will be required for effective monitoring. From the perspective of effective monitoring; the fewer sources the better. On the other hand, basic economic theory argues that market efficiency is a function of the number of market participants. Thus, the design of a permit trading market would require policy decision makers to make a tradeoff where both considerations are sufficiently accounted for.

From Section 2, we know that depending on how we define a source unit at the primary production level, the number can vary from less than 6,000 to almost 900,000 (see Figure 2-2). At the industry combustion level, the major emitting industries (Table 2-3) add up to about 16,000. If we include some of the producers of products with a life-cycle of emissions (car producers, home appliances, etc., from Table 2-5) to represent emissions from the transportation and commercial and residential sectors, the total number will still likely be below 30,000 source units. At the end-use level, there would be millions of sources.

45. Smith, A. E., A. R. Gjerde, and D. Cohan, *Practical Considerations in Using Emissions Trading to Control Greenhouse Gases*, EPA Report Under Contract No. 68-CO-0021, January 1991, p. 15.

46. Loeb, Alan P., *Three Misconceptions About Emissions Trading*, Air & Waste Management Association Conference, Paper No. 90-155.8, 1990.

ESTIMATING AND REPORTING EMISSIONS

Enforcement of the trading program will be a concern for implementation at any of the market levels. However, because trading would proceed on different bases, enforcement issues may be quite different among the implementation options. For example, controls at the primary level would have to be based on the carbon content of fuel products while controls at the industrial level could be based on measured emissions as well. The ability to track the two may be quite different.

Fuel purchases or sales may be relatively easy to monitor wherever there is a distinct market, and in fact there are already very reliable systems in place for such data. (We have relied on such data to prepare this analysis.) Problems with such data may arise when markets are not easily distinguished, as in the case of vertical integration.

Stack monitoring may seem more appealing because it directly addresses actual emissions. However, it requires that new equipment be placed on many thousands of sources. (Tailpipe monitoring for vehicles is not even considered an option at this point.) Where it is feasible, stack monitoring may be costly and may be subject to reliability problems.[47] It also may fail to detect much of the emissions, if fugitive CO_2 emissions are common among the industrial processes. Given these concerns, it would be reasonable to choose to measure fossil fuel use as a proxy for emissions, even where stack monitoring would be an option. This is because CO_2 is one of the few pollutants for which the main control option is not a technological change of the manufacturing process or equipment. The key control options that are cost-effective today are to use less carbon-intensive sources of energy, or less energy itself. Both actions would be reflected directly in fossil fuel use statistics.

Thus it is likely that monitoring would proceed on the basis of measured fuel use. However, as has been noted in earlier sections, the fuel used may be measured in terms of either fuel purchased or fuel sold for all levels and sub-levels of the market through to the point where the fuel is burned. At that point, fuel purchased is the only fuel-based monitoring option, and stack monitoring becomes the other alternative. Table 4-1 shows some of the alternative ways in which emissions can be measured at different levels of the economy.

Note from the table that the quantity sold at one sub-level of the primary production categories should be equal in aggregate to the quantity purchased at the next sub-level. The main difference in the two options consists of the form of disaggregation in which the data will be available. Data on quantities sold will be disaggregated by the seller, and data on total quantity purchased will be disaggregated by the purchasing entities, even though the two quantities would be identical when summed. It is possible that data may already be collected in one of the two forms, but not the other. If so, this would have implications for which side of the market would be easiest to monitor, should that market be identified as the appropriate level where trading should occur.

47. Discussions about how to achieve acceptable levels of reliability in continuous monitors required under the 1990 Clean Air Act Amendments have been quite protracted. The technology is however developing rapidly.

Table 4-1
OPTIONS FOR ESTIMATING EMISSIONS

Level of Economy	Examples	Input-based Measuring	Output-based Measuring
Fuel Extraction Sub-level	Oil and gas wells, coal mines	Quantity of crude oil, natural gas or coal extracted	Quantity of raw products sold or otherwise shipped out
Refining Sub-level	Petroleum refineries, and coal cleaning/ blending units	Quantity of crude oil or uncleaned coal purchased	Quantities of refined fuels sold, by fuel type, and cleaned coal
Distribution to End-User Sub-level	Gas pipeline, gasoline distributors, coal distributors, etc.	Quantity of fuel purchased from gas well, refinery, or coal refiner	Quantity sold to end-users (industry and retailers)
Industry Level	Electric utilities, chemical plants, etc.	Quantities of fuel types purchased	Stack monitoring
End-User Level	Motor vehicles, home appliances, etc.	Fuel and electricity purchased	None

If permit trading were implemented at the fuel extraction level, it would probably be more difficult to monitor fuel extraction volumes than volumes sold or shipped from the well. Other than in cases of long term on-site storage, there should be little difference between the two measures.

At the refining sub-level,[48] monitoring could take place in terms of the unrefined fuel entering the refining process, or it could be attached to volumes sold or shipped after refining. However, for petroleum, output-based measuring would require accounting for multiple products (e.g., gasoline, diesel, residual fuel oil), whereas input-based measurement would apply to the crude fuel only. This has advantages and disadvantages. The relative carbon content of specific refined fuels could be defined more precisely. Also, products headed for feedstock usage might be more easily accommodated. There is a substantial use of fuels during the refining process that should be accounted for, however.

At the refined product distribution sub-level, one is very close to actual end-use. Feedstock sales should be easiest to identify at this level, and imports of fossil fuels, either refined or unrefined, largely must go through the distribution system, thus reducing that problem area. Again, fuels used in the extraction and refining processes should be accounted for when estimating the carbon contents at this level. Fuel losses from distribution itself would mostly account for any differences between quantities input and output from this level. These may be relatively small, so either measure would probably be acceptable.

48. There is no equivalent to the refining sub-level for natural gas. For coal, cleaning and processing would be the equivalent activity, but the "refined" product would still be coal, rather than the array of fuel products that would be obtained from crude oil.

At the industry level of the economy, monitoring could be attached to fuel purchases, or each stack could be monitored. While stack monitoring is the most direct way of measuring emissions, it would probably be relatively costly to install such devices, and would probably affect small scale operations more than large scale. Further, stack monitoring would not automatically capture non-point emissions, and may not be exceptionally reliable for continuous monitoring.

At the end-user level of the economy, the only feasible way to monitor emissions would be through fuel purchases. Even this will be difficult to monitor, as it would require accounting for every gasoline purchase for every car. Without an extremely cumbersome comparison of sales records of gasoline stations with declarations by millions of consumers, there would be no way to introduce quality assurance. Tailpipe monitoring seems only slightly less cumbersome, should there ever be a technology that could perform such monitoring on a cumulative basis that could be tallied at periodic intervals. No such technology exists, nor is known to be under development. The only alternative would involve letting fuel sellers buy the allowances for the consumers, and then charge consumers on a per purchase basis for such permits. This would become equivalent to trading among fuel distributions.

VERTICAL INTEGRATION

As mentioned in Section 2, vertical integration may create difficulties in obtaining the necessary data for controlling emissions at specific levels of the market. Where large portions of a market level are internalized within several major integrated firms, reporting requirements may require the development of new regulatory infrastructure. In addition to the start-up and administrative costs, there would also some potential concern with the quality of such data. It would be far more straightforward to implement a trading system that could depend on readily available market data. Thus, trading at market levels beyond the point where vertical integration is no longer a major aspect of market structure would be favored. Vertical integration is a common feature in primary energy production, through to the point of energy consumption. This makes a case for trading at the distribution sub-level, or else among energy end users.

SUMMARY

It is clear that the end-use level would present extraordinary burdens for enforcement. The industrial combustion level has a more limited number of entities that would have to be subject to reporting requirements, but information on fuels used rather than stack monitoring would seem to be the more cost-effective and reliable approach for assessing permit requirements. As such, there should be no difference whether their fuel suppliers or they themselves should be required to obtain the sufficient number of permits. However, monitoring may be easier still for the distributors, and this would provide coverage of a much broader range of emissions sources than just the industrial fuel users.

Referring back to information presented in Sections 2 and 3, it appears that any primary market sub-level may be acceptable for obtaining a sufficiently sized market that also provides good coverage of emissions. The only possible exception might be the refining level where there are only about 200 refining units. Since refining does not pose itself as exceptionally advantageous from any other standpoint, it should perhaps be given less attention as a possible point of emissions trading.

The primary production level in general seems to offer the greatest flexibility in terms of monitoring and enforcement. From the point of view of monitoring, the point where sales are made from the distributors to fuel users appears to have the most advantages from the point of view of manageability of monitoring and enforcement, and in terms of having reasonable sources of sales data from which to estimate permit requirements.

5

CONCLUSIONS

This report has described a series of options for implementing CO_2 emissions trading, and has reviewed a number of the considerations in choosing among them. The requirements of each option were described, and a theoretical formulation showed how economically equivalent options may seem to be different in terms of "fairness." The focus of the report, however, has been on criteria of cost and effectiveness. Considerations that should be incorporated into the implementation decision include how much of the emissions would be controllable, the size of the trading market, how much market concentration there might be, geographical transfers of wealth that might result as well as geographical concentrations of groups that might wish to trade in a similar fashion, monitoring feasibility, and administrative burdens.

Table 5-1 summarizes how the three levels of the market might compare along these dimensions, based on the data developed for this study, and presented in earlier sections of this report. In the table, the primary producer level has been split into three intermediate stages (extraction, refining, and distribution), as Section 2 explained. The table also includes one of many possible hybrid approaches, where industrial emissions trading would be expanded to include the energy equipment manufacturing industry, which would be held accountable for lifecycle emissions from the equipment that is produced and sold.

Table 5-1
EVALUATION OF CO_2 ALLOWANCE TRADING AT DIFFERENT MARKET LEVELS

	# Involved	Market Dysfunction Potential	Degree of Geographical Concentration	Enforce-ability	Emissions Coverage	Import Issues?
Extraction	1,000s	None	High	Moderate	High	Yes
Refining	1,000s	None	High	Moderate	High	Yes
Distribution to Users	1,000s	None	Low	High	High	No
Industries	10,000s	Electric utility rates regulations	Moderate	High	Low	No
All End-Users	100,000,000s	None	Low	Low	High	No
Hybrid (Equipment Manufacturers & Industry)	10,000s	Electric utility rates regulations	Moderate	High	Moderate	Yes

From Table 5-1, a couple of immediate conclusions can be drawn. Trading that includes all end users seems unwise. Although they have good coverage of total carbon sources, both levels may be very costly to administer and enforce.

Similarly, the option to institute trading among major industrial end users, although a very obvious one with a long regulatory precedent, may be dominated by other options on a cost-effectiveness basis. The problems of utility incentives could be very serious for effective market functioning.[49] Coverage of emissions is also lowest for this option. The hybrid approach improves on the coverage problem of trading at the industry level, but retains the utility incentives problem that could lead to market dysfunction. It also provides only incomplete incentives for control among end-users.

Thus, trading at the primary producer level appears to be most promising on a cost-effectiveness basis. However, it is not immediately clear which of the three sub-levels would be the best candidate. At the extraction and refining sub-levels, there could be problems associated with data availability because of the substantial degree of vertical integration. Also, accounting fairly for feedstocks and for imports could be difficult. Finally, the distribution of impacts may be relatively concentrated geographically. A system introduced at the fuels distribution level, after the refining/processing stage, would avoid these drawbacks but add a new one. Emissions of carbon upstream are significant. The refining industry is one of the major industrial source categories in the U.S. Some method for accounting for these upstream emissions may be important to develop, and may not be straightforward to do. Nevertheless, for the primary producer level in general, the number of sources is manageable, emissions coverage is high, and enforceability is good.

Each of the three key market levels that were considered is summarized in more detail in the remainder of this section.

TRADING AT THE PRIMARY PRODUCER LEVEL

This is not a simple market level, but has numerous sub-levels, from extraction activities through processing and refining, to distribution systems that get the final products to the end-users. Vertical integration is a common feature, but not enough so that the entire set of sub-levels should be considered as one. Of the sub-levels, it appears that the most reasonable one in terms of controllability of total emissions sources, monitoring feasibility, and geographical dispersion would be the distribution-to-end-users sub-level.

This set of parties sells to both industrial consumers and retailers. At this sub-level the products have well defined uses that can be directly tied to CO_2 emissions. Also, fuel products destined for use as feedstocks can be easily separated out of the trading system, and all forms of energy imports can be included without special provisions for how to treat foreign enterprises.

49. This is a concern for implementation of any market approach to emissions control, including emissions taxes as well as emissions trading.

Some special considerations would have to be made to handle emissions caused by fuel use among the other sub-levels, with refining operations at the focal point. That is, upstream emissions should be estimated for each fuel distributed and these emissions added into the carbon content assessed.

TRADING AT THE INDUSTRIAL LEVEL

The industrial level seems like the most natural level of the market to initiate a trading program. It is where the largest point sources exist, monitoring can be performed directly on emissions, and the trading would appear to target the emissions problem directly. Even though emissions would be the commodity traded, the indirect effect on fuel markets would result in changes in energy supplied, much like one would expect if the primary producers were the locus of trading.

However, the results of trading industrial emissions would not be equivalent to those of trading carbon content of primary fuels. The key reason is that industrial emissions only account for half to two-thirds of all emissions of CO_2 in the U.S. Any regulation of industry would only provide incentives affecting the use of fuels in the mix relevant to industry. A large number of cost-effective control options might be missed, such as those associated with transportation. Also, the energy supply effects that would trickle back to the primary producers could be quite different than if carbon content of all fossil fuels were directly the basis of trading.

In return for these gaps associated with trading among industries only, there are few gains among the other criteria noted above. The number of entities affected is of a similar order of magnitude as for trading among primary producers, and options for monitoring compliance are very similar. Although stack monitoring is an option here, it is probably more precise, straightforward, and less costly to base emissions estimates on fuel use by industry. Other than in terms of the way such fuel use data is disaggregated, it is equivalent information to that of distributors' sales.

Regulation of industrial emissions is more likely to present problems of geographical concentration in where emissions reductions occur than it is for either other market level. Thus industrial trading has a greater potential than other forms of trading to be undermined by local regulatory intervention that would try to avoid loss of the coincidental benefits of reductions in other pollutants. On top of this can be added the problem of how the electric utilities would participate in trading, given their rate setting process. Since the electric utilities account for more than half of the industrial emissions, any potential for poor participation on their part would have significant implications for the trading market as a whole.

TRADING AT THE END-USE LEVEL

The only advantage noted for the option of having all end-users participate in trading was that it would provide the most complete coverage of actual emissions in the U.S. However, a very similar level of coverage is attained with regulating primary producers, but with a reduction in the number of parties that must be monitored by a factor of as much as 10,000. Although large numbers are important to a competitively functioning market, it looks like there are sufficient numbers at the primary producer level (particularly if applied at the distributor level). To move in the direction of millions of parties, as is found at the end-use level, is unnecessary and probably infeasible to enforce effectively. The end-use level does provide the most widespread geographical distribution of permits and impacts, with little likelihood of intervention by local authorities. However, the distributor system is probably equally widespread geographically.

CONTROLLING END-USES AT THE MANUFACTURER LEVEL

An hybrid approach has been discussed to incorporate emissions from the transportation, residential, and commercial sectors without requiring trading among end-users. This would be to include all the emissions of fuel-using equipment over equipment lives in the estimate of emissions for which the equipment manufacturers must obtain permits. Trading would include large industrial fuel consumers as well as equipment manufacturers, with the only difference between the two categories being whether an estimate of life-cycle emissions would be added to the on-site emissions for which permits would be required. Thus the much broader coverage of most emissions categories can be attained with only a few thousand parties added to the trading scheme.

This definitely has advantages over the option for trading at the end-user level of the market, and at the industrial level, as defined in this study. However, the crucial question is how well it compares to trading at the primary producer level. (Assume that this would mean trading among distributors to industrial consumers and retailers.) Here it appears that the decision will depend on the relative disadvantages of forcing manufacturers to be responsible for the emissions of their customers. The latter problem is one of both of precision in making the life-cycle emissions estimates and of incomplete user incentives. Another possible disadvantage of the hybrid approach is that it raises possible concerns of geographical concentration, and management problems for how to include importers of fuel-using equipment into the trading scheme.

RECOMMENDATIONS FOR FURTHER STUDY

At this point in the study, it appears as if the most viable place that trading could be implemented would be among the distributors of fuels to end-users, both industries and retailers. The resulting economic impacts are the same as requiring emissions reductions as long as there are no cost-effective measures for removing CO_2 from the stacks or tailpipes after the carbon-containing fuel has been burned.

The possibility of developing additional programs that are hybrids of the three options presented here should be noted. Two hybrid approaches were described in Section 2, and one noted above does have some promising features. Similarly, if trading were to be implemented among fuel distributors, then additional consideration of emissions from primary producer activities, such as refinery fuel use, should also be folded into the program in some way. Further work should identify and look closely at other possible hybrid options.

Another area that requires further consideration is how additional greenhouse gases could be incorporated into each possible implementation plan. Especially in the case where the trading might be implemented in terms of the carbon content of fuel supplied, the extension to other forms of emissions is not immediately apparent. Can some system of offsets for the other gases be added to the trading, or is it necessary to go back to the concept of trading at the point where emissions occur to obtain the desired integration of all emissions in a comprehensive approach?

International trading issues are also of interest. The issue of how to incorporate foreign enterprises into a national trading scheme has been briefly mentioned. It is quite feasible, but could present some political concerns. Similarly, what would happen to the conclusions presented here if an international trading scheme were to be considered rather than a national one?

Finally, this study has focused on identifying ways in which there might be barriers to the functioning or acceptable implementation of a trading scheme. Nothing in the analysis helps determine who would trade with whom, or what the transactions of permits might look like under any of the schemes. Inter-regional flows of permits, and inter-industry flows may be of interest. To obtain a better understanding of these patterns, further analytical modeling must be done. This line of work would provide interesting complementary information for the deliberation on the best market level for trading, and hybrid options.

Appendix A

DETAILED INDUSTRY DATA

This Appendix presents for each industry, the number of source units in each state, production volumes, total CO_2 emissions, and average CO_2 emissions per source unit. Following a discussion of data sources, and a brief outline of how we calculated emissions estimates, the data table is displayed in Table A-3.

DATA AND DATA SOURCES

Data sources were not readily available to us for the same year. However, since the data is relatively recent (1987 or later), and for the purposes of this report, we do not think that any conclusions drawn would be affected. Table A-1 shows the year for which the different data were collected.

Table A-1
YEAR OF DATA SOURCES

	Number of Sources	Production Volumes	Emissions Estimates
Primary Production Level	1989	1989	1989
Electric Utilities	1989	1989	1989
Petroleum Refineries	1990	1987	1988
Other Industries	1987	1987	1988

Source units were defined as a single physical unit; well or mine at the primary production level, and a production plant at the industry level. Production volumes at the primary production level are physical production volumes; thousand barrels of oil, million cubic feet of gas, and thousand short tons of coal. For electric utilities, production volumes are measured in gigawatthours. For all other industries, we measured production volumes as "value of shipment" (million dollars). Total CO_2 emissions are reported in million tonnes of carbon, and emissions per source unit in thousand tonnes of carbon.

Data on number of source units and production volumes were taken from the following sources:

Oil and Gas Wells:	American Petroleum Institute, *Basic Petroleum Data Book. Petroleum Industry Statistics*, Vol. XI, No. 1, Washington, D.C., 1991.
Coal Mines:	Energy Information Administration, "*Coal Production 1989*, DOE/EIA-0118(89), Washington, D.C., 1989.
Electric Utilities:	Energy Information Administration, *Inventory of Power Plants in the United States 1989*, DOE/EIA-0095(89), Washington, D.C., 1989.
Petroleum Refineries:	Number of units; PennWell Publishing Company, *International Petroleum Encyclopedia 1990*, Tulsa, Oklahoma, 1991.
	Production volume; U.S. Department of Commerce, Bureau of the Census, *1987 Census of Manufactures. Industry Series*, Washington, D.C., 1989.
Other Industries:	U.S. Department of Commerce, Bureau of the Census, *1987 Census of Manufactures. Industry Series*, Washington, D.C., 1989.

CALCULATING EMISSIONS ESTIMATES

Primary Production Level. Emissions estimates for the primary production level were calculated by converting fuel production volumes for each fuel type into energy equivalents, and multiplying these with a corresponding emissions factor.

Table A-2 provides the multipliers used to convert physical energy volumes into energy equivalents (trillion Btu), and the emissions factors we used for each fuel type.

We converted grams of CO_2/gigajoule into million tonnes of CO_2/trillion Btu by multiplying with 1.056 10E-6,[50] and converted CO_2 into carbon equivalents by multiplying with 12/44.

Electric Utilities. Emissions estimates from the electric utilities industry are based on energy consumption from oil, gas, and coal-fired utilities.[51] There is some difference between these

50. U.S. Department of Commerce, National Technical Information Service, *Energy Interrelationships. A Handbook of Tables & Conversions Factors for Combining and Comparing International Energy Data*, Washington, D.C., 1977.

51. Energy Information Administration, *Electric Power Annual 1988*, Washington, D.C., January 1990, Table 10.

estimates and those reported by the Energy Information Administration;[52] our estimate is 580 million tonnes of carbon, versus EIA's 530 million tonnes.

Table A-2
CONVERSION FACTORS

Conv. From	Conv. To	Oil	Gas	Coal
Million barrels oil	Trillion Btu	5.5 *		
Trill. cubic feet gas	Trillion Btu		1,000 **	
Million sh.tons coal	Trillion Btu			25.2 ***
Fossil Fuel	Gram CO_2/GJ ****	73,113	50,257	88,400

* U.S. Department of Commerce, National Technical Information Service, *Energy Interrelationships. A Handbook of Tables & Conversions Factors for Combining and Comparing International Energy Data,* Washington, D.C., 1977, p. 34.

** Ibid., p. 35.

*** Ibid., p. 36.

**** The emissions factors comply with the United Nations convention, and is detailed in Marland (1983).

Other Industries. Total emissions estimates for other industries at the combustion level were calculated in Volume 1 of this report. We allocated these estimates to the different states based on production volume (as represented by value of shipment). For some industries, our data on production volume breakdown was incomplete. In these cases, we allocated emissions to each state based on number of plants.

52. Ibid., Table 31.

Table A-3
INDUSTRY CHARACTERISTICS (10^6 tonnes C)

STATE		# Oil wells	# Gas wells	# Coal mines	Oil Prod. (th.bbl)	Gas Prod. (m.cu.ft)	Coal Prod. (th.sh.t)	Emiss. fr.oil mill metr ton C	Emiss. fr.gas mill metr ton C	Emiss. fr.coal mill metr ton C	Emiss. per oil well th.m.t.C	Emiss. per gas well th.m.t.C	Emiss. per coal mine th.m.t.C
AL	Alabama	931	1701	105	19813	128411	27900	2	2	18	2.46	1.09	170.55
AK	Alaska	1337	108	1	683980	393729	1600	79	6	1	59.25	52.77	1026.98
AZ	Arizona	25	3	2	138	1360	11900	0	0	8	0.64	6.56	3819.08
AR	Arkansas	7865	2830	7	11261	168300	70	1	2	0	0.17	0.86	6.42
CA	Calif.	43745	1214	1	364249	362860	40	42	5	0	0.96	4.33	25.67
CO	Colorado	6362	5125	23	30655	216737	17100	4	3	11	0.56	0.61	477.21
CT	Connect.	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
DE	Delaware	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
FL	Florida	101	0	0	7289	7534	0	1	0	0	8.36	0.00	0.00
GA	Georgia	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
HA	Hawaii	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
ID	Idaho	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
IL	Illinois	32441	241	48	20377	1477	59300	2	0	38	0.07	0.09	792.97
IN	Indiana	7543	1310	60	3310	416	33600	0	0	22	0.05	0.00	359.44
IA	Iowa	0	0	5	0	0	400	0	0	0	0.00	0.00	51.35
KS	Kansas	44969	13935	5	55484	587320	900	6	9	1	0.14	0.61	115.54
KY	Kentucky	22859	11248	1099	5414	72417	167400	1	1	107	0.03	0.09	97.77
LA	Louisiana	22872	16309	2	404615	5078125	3000	47	74	2	2.05	4.51	962.79
ME	Maine	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
MD	Maryland	0	8	31	0	34	3400	0	0	2	0.00	0.06	70.40
MA	Massach.	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
MI	Michigan	5557	1207	0	21566	155988	0	2	2	0	0.45	1.87	0.00
MN	Minnesota	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
MS	Mississip.	3598	543	0	27403	102645	0	3	1	0	0.88	2.74	0.00
MO	Missouri	807	4	9	136	4	3400	0	0	2	0.02	0.01	242.48
MT	Montana	4001	2700	9	20956	51307	37700	2	1	24	0.61	0.28	2688.69
NE	Nebraska	1787	15	0	6232	878	0	1	0	0	0.40	0.85	0.00
NV	Nevada	46	0	0	3218	0	0	0	0	0	8.10	0.00	0.00
NH	New Hamp	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
NJ	New Jerse	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
NM	New Mexic	17787	17087	8	68713	854615	23700	8	12	15	0.45	0.72	1901.52
NY	New York	4350	5304	0	495	20433	0	0	0	0	0.01	0.06	0.00
NC	N Carolina	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
ND	N Dakota	3442	61	13	36744	51174	30000	4	1	19	1.24	12.14	1481.22
OH	Ohio	30194	34450	184	10219	159730	33700	1	2	22	0.04	0.07	117.56
OK	Oklahoma	96344	27443	21	117493	2185240	1800	14	32	1	0.14	1.15	55.02
OR	Oregon	0	18	0	0	2500	0	0	0	0	0.00	2.01	0.00
PA	Pennsylv.	27218	30000	681	2702	191774	70600	0	3	45	0.01	0.09	66.54
SC	S Carolina	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
SD	S Dakota	156	53	0	1613	4369	0	0	0	0	1.20	1.19	0.00
TN	Tennessee	713	700	98	532	1900	6500	0	0	4	0.09	0.04	42.57
TX	Texas	186226	48609	15	715790	6241425	53400	83	90	34	0.45	1.86	2285.03
UT	Utah	2234	834	21	28416	120089	20100	3	2	13	1.47	2.08	614.35
VT	Vermont	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
VA	Virginia	20	752	365	21	17935	43000	0	0	28	0.12	0.35	75.62
WA	Washingto	0	0	4	0	0	5000	0	0	3	0.00	0.00	802.33
WV	W Virginia	15940	36240	773	2243	198200	153600	0	3	99	0.02	0.08	127.54
WI	Wisconsin	0	0	0	0	0	0	0	0	0	0.00	0.00	0.00
WY	Wyoming	11539	2431	30	107713	665699	171600	12	10	110	1.08	3.96	3671.45
		603009	262483	3620	2778790	18044625	980710	322	262	629	0.53	1.00	173.89

Table A-3
INDUSTRY CHARACTERISTICS (continued)

STATE		# Oil fired util.	# Gas fired util.	# Coal fired util.	Oil fired Prod. gigawhrs	Gas fired Prod. gigawhrs	Coal fired Prod. gigawhrs	Emiss. from oil fired pl. m.m.t.C	Emiss. from gas fired pl. m.m.t.C	Emiss. from coal fired pl. m.m.t.C	Emiss. per oil-fired unit th.m.t.C	Emiss. per gas-fired unit th.m.t.C	Emiss. per coal-fired unit th.m.t.C
AL	Alabama	2	8	41	107	236	48835	0.02	0.04	15.82	12.08	5.54	385.92
AK	Alaska	347	26	5	356	2588	316	0.08	0.49	0.10	0.23	18.71	20.48
AZ	Arizona	6	62	13	119	2341	28391	0.03	0.44	9.20	4.48	7.10	707.59
AR	Arkansas	34	21	5	143	2065	19876	0.03	0.39	6.44	0.95	18.48	1287.96
CA	Calif.	59	149	0	7621	53893	0	1.72	10.13	0.00	29.17	67.97	0.00
CO	Colorado	53	38	31	39	649	27801	0.01	0.12	9.01	0.17	3.21	290.57
CT	Connect.	48	0	1	11356	111	2094	2.56	0.02	0.68	53.42	0.00	678.46
DE	Delaware	23	2	5	2848	317	5788	0.64	0.06	1.88	27.96	29.79	375.06
FL	Florida	192	130	29	25387	14744	57516	5.73	2.77	18.64	29.86	21.31	642.59
GA	Georgia	39	4	39	260	119	64834	0.06	0.02	21.01	1.51	5.59	538.62
HA	Hawaii	73	0	0	7597	0	0	1.72	0.00	0.00	23.50	0.00	0.00
ID	Idaho	4	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
IL	Illinois	170	75	61	697	435	52994	0.16	0.08	17.17	0.93	1.09	281.48
IN	Indiana	37	15	80	383	317	82813	0.09	0.06	26.83	2.34	3.97	335.39
IA	Iowa	270	52	53	49	417	23345	0.01	0.08	7.56	0.04	1.51	142.71
KS	Kansas	233	177	20	147	1489	23089	0.03	0.28	7.48	0.14	1.58	374.04
KY	Kentucky	13	9	57	126	40	73847	0.03	0.01	23.93	2.19	0.84	419.76
LA	Louisiana	10	106	6	272	24286	18431	0.06	4.56	5.97	6.14	43.05	995.27
ME	Maine	57	0	0	2944	0	0	0.66	0.00	0.00	11.66	0.00	0.00
MD	Maryland	60	16	14	3547	402	23316	0.80	0.08	7.55	13.35	4.72	539.60
MA	Massach.	109	7	9	19908	1802	11687	4.50	0.34	3.79	41.24	48.38	420.73
MI	Michigan	178	67	82	1414	585	68578	0.32	0.11	22.22	1.79	1.64	270.97
MN	Minnesota	168	47	55	142	410	26726	0.03	0.08	8.66	0.19	1.64	157.44
MS	Mississip.	5	37	9	659	2800	12051	0.15	0.53	3.90	29.76	14.22	433.84
MO	Missouri	176	80	47	131	112	49051	0.03	0.02	15.89	0.17	0.26	338.14
MT	Montana	0	3	6	30	37	16462	0.01	0.01	5.33	0.00	2.32	888.95
NE	Nebraska	106	118	12	69	163	12225	0.02	0.03	3.96	0.15	0.26	330.08
NV	Nevada	32	16	8	542	899	16764	0.12	0.17	5.43	3.82	10.56	678.94
NH	New Hamp	7	0	5	2828	5	3197	0.64	0.00	1.04	91.23	0.00	207.17
NJ	New Jerse	50	52	9	5052	4276	7163	1.14	0.80	2.32	22.82	15.45	257.87
NM	New Mexic	6	29	13	45	1979	24245	0.01	0.37	7.86	1.69	12.82	604.26
NY	New York	167	89	32	39865	14012	22761	9.00	2.63	7.37	53.91	29.59	230.46
NC	N Carolina	38	8	47	225	55	46090	0.05	0.01	14.93	1.34	1.29	317.73
ND	N Dakota	29	2	14	18	0	25450	0.00	0.00	8.25	0.14	0.00	588.99
OH	Ohio	76	30	120	415	63	114564	0.09	0.01	37.12	1.23	0.39	309.32
OK	Oklahoma	26	85	10	29	17688	24273	0.01	3.32	7.86	0.25	39.11	786.45
PA	Pennsylv.	109	11	65	7915	211	106239	1.79	0.04	34.42	16.40	3.60	529.56
RI	Rhode Isl.	24	0	0	749	15	0	0.17	0.00	0.00	7.05	0.00	0.00
SC	S Carolina	44	12	24	96	226	23485	0.02	0.04	7.61	0.49	3.54	317.05
SD	S Dakota	39	9	6	15	11	2605	0.00	0.00	0.84	0.09	0.23	140.67
TN	Tennessee	20	20	37	187	16	51122	0.04	0.00	16.56	2.11	0.15	447.66
TX	Texas	33	325	33	756	102521	112876	0.17	19.27	36.57	5.17	59.28	1108.24
UT	Utah	13	20	14	59	5	28806	0.01	0.00	9.33	1.02	0.05	666.65
VT	Vermont	24	0	0	26	0	0	0.01	0.00	0.00	0.24	0.00	0.00
VA	Virginia	45	3	24	2838	102	21413	0.64	0.02	6.94	14.24	6.39	289.08
WA	Washingto	10	7	2	8	153	8670	0.00	0.03	2.81	0.18	4.11	1404.54
WV	W Virginia	1	0	33	260	10	80747	0.06	0.00	26.16	58.71	0.00	792.79
WI	Wisconsin	107	19	54	97	180	31867	0.02	0.03	10.32	0.20	1.78	191.20
WY	Wyoming	9	0	19	62	18	38279	0.01	0.00	12.40	1.56	0.00	652.76
		3385	1992	1250	148438	252803	1540682	33.52	47.51	499.18	9.90	23.85	399.34

Table A-3
INDUSTRY CHARACTERISTICS (continued)

STATE		# Refiner.	# Paper uts	# Steel mls	Refiner. Value of shipm. mill $	Paper Value of shipm. mill $	Steel mls Value of shipm. mill $	Refiner. CO_2 emiss m.m.t.C	Paper CO_2 emiss m.m.t.C	Steel CO_2 emiss m.m.t.C	Refiner. CO_2 emis/ Unit th.m.t.C	Paper CO_2 emis/ Unit th.m.t.C	Steel CO_2 emis/ Unit th.m.t.C
AL	Alabama	3	16	13	830	3835	1449	0.09	3.82	1.84	30.58	238.89	141.49
AK	Alaska	6	2	0	1490	130	0	0.16	0.13	0.00	27.45	64.55	0.00
AZ	Arizona	1	2	0	0	130	0	0.00	0.13	0.00	0.00	64.55	0.00
AR	Arkansas	3	7	4	499	1491	446	0.06	1.49	0.57	18.39	212.22	141.49
CA	Calif.	31	27	18	15639	1312	571	1.73	1.31	0.73	55.79	48.44	40.28
CO	Colorado	2	0	2	564	0	223	0.06	0.00	0.28	31.16	0.00	141.49
CT	Connect.	0	9	3	0	583	334	0.00	0.58	0.42	0.00	64.55	141.49
DE	Delaware	1	0	1	298	0	111	0.03	0.00	0.14	32.95	0.00	141.49
FL	Florida	0	9	13	0	1089	1449	0.00	1.09	1.84	0.00	120.62	141.49
GA	Georgia	2	22	5	0	3329	557	0.00	3.32	0.71	0.00	150.81	141.49
HA	Hawaii	2	0	0	596	0	0	0.07	0.00	0.00	32.95	0.00	0.00
ID	Idaho	0	1	0	0	65	0	0.00	0.06	0.00	0.00	64.55	0.00
IL	Illinois	6	9	28	6458	583	2760	0.71	0.58	3.50	119.02	64.55	125.16
IN	Indiana	4	8	14	2383	518	1560	0.26	0.52	1.98	65.89	64.55	141.49
IA	Iowa	0	2	2	0	130	223	0.00	0.13	0.28	0.00	64.55	141.49
KS	Kansas	8	0	0	2771	0	0	0.31	0.00	0.00	38.31	0.00	0.00
KY	Kentucky	2	4	8	894	259	891	0.10	0.26	1.13	49.42	64.55	141.49
LA	Louisiana	17	12	2	17500	2348	223	1.94	2.34	0.28	113.83	195.02	141.49
ME	Maine	0	15	0	0	2871	0	0.00	2.86	0.00	0.00	190.78	0.00
MD	Maryland	0	4	5	0	259	557	0.00	0.26	0.71	0.00	64.55	141.49
MA	Massach.	0	32	0	0	2072	0	0.00	2.07	0.00	0.00	64.55	0.00
MI	Michigan	4	35	17	1490	2458	2691	0.16	2.45	3.42	41.18	70.00	201.00
MN	Minnesota	2	9	4	894	983	446	0.10	0.98	0.57	49.42	108.82	141.49
MS	Mississip.	5	10	1	2383	648	111	0.26	0.65	0.14	52.71	64.55	141.49
MO	Missouri	0	0	5	0	0	557	0.00	0.00	0.71	0.00	0.00	141.49
MT	Montana	4	1	0	892	65	0	0.10	0.06	0.00	24.66	64.55	0.00
NE	Nebraska	0	0	1	0	0	111	0.00	0.00	0.14	0.00	0.00	141.49
NV	Nevada	1	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
NH	New Hamp	0	10	0	0	402	0	0.00	0.40	0.00	0.00	40.03	0.00
NJ	New Jerse	6	19	10	3855	1178	1114	0.43	1.17	1.41	71.04	61.81	141.49
NM	New Mexic	3	0	0	632	0	0	0.07	0.00	0.00	23.30	0.00	0.00
NY	New York	1	45	14	0	2018	1560	0.00	2.01	1.98	0.00	44.69	141.49
NC	N Carolina	0	10	1	0	648	111	0.00	0.65	0.14	0.00	64.55	141.49
ND	N Dakota	1	0	0	298	0	0	0.03	0.00	0.00	32.95	0.00	0.00
OH	Ohio	4	29	35	3682	2233	7047	0.41	2.23	8.95	101.78	76.75	255.66
OK	Oklahoma	6	5	6	2883	324	126	0.32	0.32	0.16	53.13	64.55	26.67
OR	Oregon	1	11	3	0	1601	334	0.00	1.60	0.42	0.00	145.02	141.49
PA	Pennsylv.	8	30	50	6640	1640	6525	0.73	1.63	8.29	91.79	54.49	165.71
SC	S Carolina	0	9	10	0	1622	1114	0.00	1.62	1.41	0.00	179.67	141.49
SD	S Dakota	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
TN	Tennessee	1	13	9	596	1249	1003	0.07	1.24	1.27	65.89	95.76	141.49
TX	Texas	31	10	14	34470	648	1560	3.81	0.65	1.98	122.96	64.55	141.49
UT	Utah	6	0	2	2681	0	223	0.30	0.00	0.28	49.42	0.00	141.49
VT	Vermont	0	7	0	0	205	0	0.00	0.20	0.00	0.00	29.25	0.00
VA	Virginia	1	12	5	596	1179	557	0.07	1.18	0.71	65.89	97.96	141.49
WA	Washingto	7	21	9	3499	1911	1003	0.39	1.90	1.27	55.27	90.71	141.49
WV	W Virginia	2	2	5	596	130	557	0.07	0.13	0.71	32.95	64.55	141.49
WI	Wisconsin	1	45	5	1192	4361	557	0.13	4.35	0.71	131.78	96.59	141.49
WY	Wyoming	5	0	0	1017	0	0	0.11	0.00	0.00	22.49	0.00	0.00
		188	514	324	118216	46506	38663	13.07	46.35	49.09	69.53	90.18	151.52

Table A-3
INDUSTRY CHARACTERISTICS (continued)

STATE		# Glass	# Cement	Glass Value of shipm. mill $	Cement Value of shipm. mill $	Glass CO2 emiss m.m.t.C	Cement CO2 emiss m.m.t.C	Glass CO2 emis/ Unit th.m.t.C	Cement CO2 emis/ Unit th.m.t.C
AL	Alabama	9	7	140	190	0.08	0.66	9.19	93.87
AK	Alaska	0	0	0	0	0.00	0.00	0.00	0.00
AZ	Arizona	20	3	26	97	0.02	0.33	0.77	111.60
AR	Arkansas	16	3	148	97	0.09	0.33	5.46	111.60
CA	Calif.	329	21	2347	621	1.39	2.15	4.22	102.27
CO	Colorado	27	4	63	129	0.04	0.45	1.38	111.60
CT	Connect.	25	0	98	0	0.06	0.00	2.32	0.00
DE	Delaware	0	0	0	0	0.00	0.00	0.00	0.00
FL	Florida	81	8	297	2	0.18	0.01	2.17	0.86
GA	Georgia	31	2	216	65	0.13	0.22	4.12	111.60
HA	Hawaii	0	0	0	0	0.00	0.00	0.00	0.00
ID	Idaho	0	0	0	0	0.00	0.00	0.00	0.00
IL	Illinois	77	7	756	226	0.45	0.78	5.81	111.60
IN	Indiana	53	5	554	6	0.33	0.02	6.18	4.15
IA	Iowa	15	5	56	161	0.03	0.56	2.22	111.60
KS	Kansas	11	5	41	85	0.02	0.29	2.22	58.79
KY	Kentucky	18	3	217	97	0.13	0.33	7.12	111.60
LA	Louisiana	3	0	68	0	0.04	0.00	13.33	0.00
ME	Maine	0	0	0	0	0.00	0.00	0.00	0.00
MD	Maryland	17	5	46	103	0.03	0.36	1.60	71.24
MA	Massach.	43	0	282	0	0.17	0.00	3.87	0.00
MI	Michigan	70	7	852	273	0.50	0.94	7.19	134.88
MN	Minnesota	23	0	213	0	0.13	0.00	5.47	0.00
MS	Mississip.	8	0	135	0	0.08	0.00	9.97	0.00
MO	Missouri	29	8	288	244	0.17	0.84	5.87	105.48
MT	Montana	0	3	0	97	0.00	0.33	0.00	111.60
NE	Nebraska	0	1	0	32	0.00	0.11	0.00	111.60
NV	Nevada	0	1	0	32	0.00	0.11	0.00	111.60
NH	New Hamp	2	0	8	0	0.00	0.00	2.22	0.00
NJ	New Jerse	136	0	1246	0	0.74	0.00	5.41	0.00
NM	New Mexic	0	0	0	0	0.00	0.00	0.00	0.00
NY	New York	150	9	853	290	0.50	1.00	3.36	111.60
NC	N Carolina	54	0	754	0	0.45	0.00	8.25	0.00
ND	N Dakota	0	0	0	0	0.00	0.00	0.00	0.00
OH	Ohio	118	10	1035	116	0.61	0.40	5.19	40.12
OK	Oklahoma	23	4	478	67	0.28	0.23	12.27	57.93
OR	Oregon	19	0	65	0	0.04	0.00	2.02	0.00
PA	Pennsylv.	124	20	2140	387	1.26	1.34	10.20	66.92
RI	Rhode Isl.	2	0	22	0	0.01	0.00	6.40	0.00
SC	S Carolina	21	3	257	97	0.15	0.33	7.25	111.60
TN	Tennessee	37	7	487	226	0.29	0.78	7.78	111.60
TX	Texas	114	20	993	329	0.59	1.14	5.15	56.89
UT	Utah	0	4	0	66	0.00	0.23	0.00	57.06
VT	Vermont	0	0	0	0	0.00	0.00	0.00	0.00
VA	Virginia	31	5	250	92	0.15	0.32	4.76	63.63
WA	Washingto	33	5	134	63	0.08	0.22	2.41	43.58
WV	W Virginia	42	1	513	32	0.30	0.11	7.22	111.60
WI	Wisconsin	35	0	247	0	0.15	0.00	4.17	0.00
WY	Wyoming	0	0	0	0	0.00	0.00	0.00	0.00
		1846	186	16324	4322	9.65	14.95 *	5.23	80.36

*includes emissions from calcining

Table A-3
INDUSTRY CHARACTERISTICS (continued)

STATE		# Nitr.fert.	# Plast.mat.	# Inorg.	Nitr.fert. Value of shipm. mill $	Plast.mat. Value of shipm. mill $	Inorg. Value of shipm. mill $	Nitr.fert. CO2 emiss m.m.t.C	Plast.mat. CO2 emiss m.m.t.C	Inorg. CO2 emiss m.m.t.C	Nitr.fert. CO2 emis/ Unit th.m.t.C	Plast.mat. CO2 emis/ Unit th.m.t.C	Inorg. CO2 emis/ Unit th.m.t.C
AL	Alabama	0	0	15	0	0	286	0.00	0.00	0.07	0.00	0.00	4.90
AK	Alaska	2	0	0	39	0	0	0.10	0.00	0.00	49.06	0.00	0.00
AZ	Arizona	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
AR	Arkansas	3	3	7	58	108	200	0.15	0.05	0.05	49.06	10.18	7.34
CA	Calif.	18	64	63	348	2875	533	0.88	0.90	0.14	49.06	12.71	2.17
CO	Colorado	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
CT	Connect.	0	11	5	0	494	143	0.00	0.14	0.04	0.00	12.71	7.34
DE	Delaware	0	3	4	0	135	114	0.00	0.05	0.03	0.00	12.71	7.34
FL	Florida	0	10	17	0	449	54	0.00	0.15	0.01	0.00	12.71	0.82
GA	Georgia	5	13	36	97	381	424	0.25	0.13	0.11	49.06	8.29	3.03
HA	Hawaii	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
ID	Idaho	0	0	3	0	0	441	0.00	0.00	0.11	0.00	0.00	37.78
IL	Illinois	0	33	29	0	1483	464	0.00	0.50	0.12	0.00	12.71	4.11
IN	Indiana	4	11	20	77	494	571	0.20	0.14	0.15	49.06	12.71	7.34
IA	Iowa	6	2	7	116	90	200	0.29	0.05	0.05	49.06	12.71	7.34
KS	Kansas	5	0	6	97	0	171	0.25	0.00	0.04	49.06	0.00	7.34
KY	Kentucky	0	10	6	0	449	171	0.00	0.13	0.04	0.00	12.71	7.34
LA	Louisiana	8	16	32	546	2434	617	1.38	0.69	0.16	173.07	43.03	4.96
ME	Maine	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
MD	Maryland	0	0	9	0	0	169	0.00	0.00	0.04	0.00	0.00	4.83
MA	Massach.	0	15	11	0	674	314	0.00	0.19	0.08	0.00	12.71	7.34
MI	Michigan	0	16	11	0	719	314	0.00	0.20	0.08	0.00	12.71	7.34
MN	Minnesota	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
MS	Mississip.	1	8	9	19	359	257	0.05	0.10	0.07	49.06	12.71	7.34
MO	Missouri	5	5	17	97	225	485	0.25	0.06	0.12	49.06	12.71	7.34
MT	Montana	0	0	5	0	0	66	0.00	0.00	0.02	0.00	0.00	3.39
NE	Nebraska	3	0	0	72	0	0	0.18	0.00	0.00	60.86	0.00	0.00
NV	Nevada	2	0	0	39	0	0	0.10	0.00	0.00	49.06	0.00	0.00
NH	New Hamp	0	3	0	0	135	0	0.00	0.04	0.00	0.00	12.71	0.00
NJ	New Jerse	0	39	33	0	1752	714	0.00	0.55	0.18	0.00	12.71	5.56
NM	New Mexic	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
NY	New York	0	20	28	0	899	160	0.00	0.25	0.04	0.00	12.71	1.47
NC	N Carolina	0	13	17	0	584	380	0.00	0.19	0.10	0.00	12.71	5.74
ND	N Dakota	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
OH	Ohio	10	27	39	193	1213	1067	0.49	0.37	0.27	49.06	12.71	7.03
OK	Oklahoma	5	0	15	97	0	428	0.25	0.00	0.11	49.06	0.00	7.34
OR	Oregon	0	7	0	0	315	0	0.00	0.13	0.00	0.00	12.71	0.00
PA	Pennsylv.	9	26	46	49	1043	346	0.12	0.29	0.09	13.81	11.35	1.93
RI	Rhode Isl.	0	0	4	0	0	114	0.00	0.00	0.03	0.00	0.00	7.34
SC	S Carolina	0	7	8	0	315	228	0.00	0.11	0.06	0.00	12.71	7.34
SD	S Dakota	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
TN	Tennessee	1	7	18	19	315	1554	0.05	0.09	0.40	49.06	12.71	22.19
TX	Texas	16	58	63	310	7678	985	0.78	2.17	0.25	49.06	37.44	4.02
UT	Utah	0	0	6	0	0	40	0.00	0.00	0.01	0.00	0.00	1.71
VA	Virginia	0	4	11	0	180	314	0.00	0.05	0.08	0.00	12.71	7.34
WA	Washingto	9	3	17	174	135	485	0.44	0.05	0.12	49.06	12.71	7.34
WV	W Virginia	0	0	6	0	0	171	0.00	0.00	0.04	0.00	0.00	7.34
WI	Wisconsin	0	7	8	0	315	228	0.00	0.11	0.06	0.00	12.71	7.34
WY	Wyoming	0	0	0	0	0	0	0.00	0.00	0.00	0.00	0.00	0.00
		112	441	631	2447	26246	13212	6	9	3	55.40	16.83	5.38

Table A-3
INDUSTRY CHARACTERISTICS (continued)

STATE		# Organic	# Other che	Organic Value of shipm. mill $	Other che Value of shipm. mill $	Organic CO2 emiss m.m.t.C	Other che CO2 emiss m.m.t.C	Organic CO2 emis/ Unit th.m.t.C	Other chem. CO2 emis/ Unit th.m.t.C
AL	Alabama	15	90	522	1853	0.32	0.28	21.00	3.10
AK	Alaska	0	0	0	0	0.00	0.00	0.00	0.00
AZ	Arizona	0	21	0	376	0.00	0.06	0.00	2.70
AR	Arkansas	8	22	279	226	0.17	0.03	21.00	1.55
CA	Calif.	58	862	2020	13351	1.22	2.01	21.00	2.34
CO	Colorado	0	24	0	510	0.00	0.08	0.00	3.20
CT	Connect.	13	75	453	1327	0.27	0.20	21.00	2.67
DE	Delaware	7	10	244	546	0.15	0.08	21.00	8.23
FL	Florida	13	308	453	5072	0.27	0.76	21.00	2.48
GA	Georgia	19	237	445	4253	0.27	0.64	14.12	2.71
HA	Hawaii	0	1	0	21	0.00	0.00	0.00	3.21
ID	Idaho	0	3	0	64	0.00	0.01	0.00	3.21
IL	Illinois	40	441	1587	5485	0.96	0.83	23.93	1.88
IN	Indiana	8	160	279	2435	0.17	0.37	21.00	2.29
IA	Iowa	5	98	174	2306	0.11	0.35	21.00	3.55
KS	Kansas	11	36	383	610	0.23	0.09	21.00	2.56
KY	Kentucky	10	84	348	1173	0.21	0.18	21.00	2.11
LA	Louisiana	29	72	6600	1751	3.98	0.26	137.25	3.67
ME	Maine	0	2	0	67	0.00	0.01	0.00	5.02
MD	Maryland	3	93	104	1674	0.06	0.25	21.00	2.71
MA	Massach.	9	175	313	2819	0.19	0.43	21.00	2.43
MI	Michigan	20	240	696	3224	0.42	0.49	21.00	2.03
MN	Minnesota	0	88	0	1102	0.00	0.17	0.00	1.89
MS	Mississip.	6	15	209	394	0.13	0.06	21.00	3.96
MO	Missouri	17	209	592	3546	0.36	0.53	21.00	2.56
MT	Montana	0	0	0	0	0.00	0.00	0.00	0.00
NE	Nebraska	2	27	70	674	0.04	0.10	21.00	3.77
NV	Nevada	0	0	0	0	0.00	0.00	0.00	0.00
NH	New Hamp	2	5	70	32	0.04	0.00	21.00	0.96
NJ	New Jerse	77	516	2913	8691	1.76	1.31	22.81	2.54
NM	New Mexic	5	8	26	51	0.02	0.01	3.14	0.96
NY	New York	38	428	754	8304	0.45	1.25	11.97	2.93
NC	N Carolina	21	153	731	4186	0.44	0.63	21.00	4.13
ND	N Dakota	0	24	0	523	0.00	0.08	0.00	3.29
OH	Ohio	43	421	965	6181	0.58	0.93	13.53	2.21
OK	Oklahoma	5	41	174	430	0.11	0.06	21.00	1.58
OR	Oregon	0	62	0	814	0.00	0.12	0.00	1.98
PA	Pennsylv.	23	365	692	5719	0.42	0.86	18.14	2.36
RI	Rhode Isl.	0	22	0	345	0.00	0.05	0.00	2.37
SC	S Carolina	18	71	627	3486	0.38	0.53	21.00	7.40
TN	Tennessee	13	152	1339	3298	0.81	0.50	62.11	3.27
TX	Texas	87	520	16595	8473	10.01	1.28	115.03	2.46
UT	Utah	0	24	0	315	0.00	0.05	0.00	1.98
VT	Vermont	0	2	0	18	0.00	0.00	0.00	1.38
VA	Virginia	16	72	557	2523	0.34	0.38	21.00	5.28
WA	Washingto	0	53	0	655	0.00	0.10	0.00	1.86
WV	W Virginia	15	26	522	536	0.32	0.08	21.00	3.11
WI	Wisconsin	13	139	453	1588	0.27	0.24	21.00	1.72
WY	Wyoming	0	11	0	161	0.00	0.02	0.00	2.21
		669	6508	42189	111187	25	17	37.50	2.58

Appendix B

TOP TWENTY PRODUCERS IN SUPPLIER MARKETS

Tables B-1 through B-6 show the top twenty U.S. producers for some of the industries discussed in this document, including oil producers, natural gas producers, gas pipeline companies, petroleum refineries, petroleum marketers, and coal producers.

Table B-1
TOP 20 OIL PRODUCERS, 1989[53]

Company	Production (1000 bbl/day)	Percent of U.S. Production	Accumulated Percent
BP America	784.0	8.5%	8.5%
Exxon	693.0	7.5%	16.0%
ARCO	660.0	7.2%	23.2%
Shell	494.0	5.4%	28.5%
Chevron	481.9	5.2%	33.8%
Texaco	479.5	5.2%	39.0%
Amoco	390.0	4.2%	43.2%
Mobil	293.2	3.2%	46.4%
Phillips	254.0	2.8%	49.1%
Unocal	165.0	1.8%	50.9%
Oryx Energy	143.8	1.6%	52.5%
USX	143.5	1.6%	54.0%
Occidental	135.0	1.5%	55.5%
DuPont	112.0	1.2%	56.7%
Amerada Hess	71.0	0.8%	57.5%
Union Pacific	63.8	0.7%	58.2%
City of Long Beach	53.9	0.6%	58.8%
Enron	53.3	0.6%	59.3%
Santa Fe Pacific	50.7	0.5%	59.9%
Valero Energy	43.7	0.5%	60.4%
U.S. TOTAL	**9219.0**	**100.0%**	**100.0%**

53. American Petroleum Institute, *Basic Petroleum Data Book. Petroleum Industry Statistics*, Vol. XI, No. 1, Washington, D.C., 1991, Section IV, Table 7c.

Table B-2
TOP 20 NATURAL GAS PRODUCERS, 1989[54]

Company	Production (bill cu. ft)	Percent of U.S. Production	Accumulated Percent
Chevron	880.7	5.1%	5.1%
Amoco	756.3	4.4%	9.6%
Texaco	729.0	4.3%	13.8%
Exxon	666.9	3.9%	17.7%
Mobil	644.0	3.8%	21.5%
ARCO	558.1	3.3%	24.7%
Shell	532.1	3.1%	27.9%
USX	333.2	1.9%	29.8%
Phillips	319.0	1.9%	31.7%
Unocal	277.0	1.6%	33.3%
DuPont	273.8	1.6%	34.9%
Oryx Energy	269.7	1.6%	36.5%
Occidental	266.5	1.6%	38.0%
Union Pacific	153.3	0.9%	38.9%
Cons. Natural Gas	147.0	0.9%	39.8%
Anadarko	141.1	0.8%	40.6%
Mesa	137.2	0.8%	41.4%
Pennzoil	134.8	0.8%	42.2%
Enron	123.3	0.7%	42.9%
Amerada Hess	122.3	0.7%	43.6%
U.S. TOTAL	**17115.0**	**100.0%**	**100.0%**

54. Ibid., Section XIII, Table 12b.

Table B-3
TOP 20 GAS PIPELINE COMPANIES, 1988[55]

Company	Sales Delivered (bill. cu. ft)	Percent of U.S. Production	Accumulated Percent
Texas Eastern Trans. Corp.	679.0	10.6%	10.6%
Natural Gas PL of America	394.0	6.2%	22.3%
Enron Corp.	387.0	6.1%	28.4%
Tenneco Inc.	381.0	6.0%	41.5%
Columbia Gas Trans. Co.	353.0	5.5%	16.2%
Florida Gas Trans. Co.	236.0	3.7%	32.1%
Transco Inc.	234.0	3.7%	51.4%
CNG Transmission Co.	221.0	3.5%	35.6%
Texas Gas Trans. Co.	211.0	3.3%	47.8%
ANR Pipeline Co.	188.0	2.9%	44.5%
El Paso Natural Gas Co.	185.0	2.9%	59.2%
Trunkline Gas Co.	157.0	2.5%	56.3%
Southern Natural Gas Co.	153.0	2.4%	53.8%
Williams Natural Gas Co.	152.0	2.4%	61.6%
Colorado Interstate Gas Co.	114.0	1.8%	63.4%
Northwest Pipeline Co.	100.0	1.6%	68.3%
Transwestern Gas Pipeline	90.0	1.4%	64.8%
Panhandle Eastern Pipeline	51.0	0.8%	65.6%
United Gas Pipeline Co.	76.0	1.2%	66.8%
KN Energy Co.	31.0	0.5%	68.8%
U.S. TOTAL	**6384.0**	**100.0%**	**100.0%**

55. Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(91/03), Washington, D.C., March 1991, Table FE2; Oil & Gas Journal Special, *Pipeline Economics*, Tulsa, Oklahoma, November 27, 1989, p. 66.

Table B-4
TOP 20 REFINERIES, 1989[56]

Company	Production (1000 bbl/day)	Percent of U.S. Production	Accumulated Percent
Chevron	1621.0	10.7%	10.7%
Exxon	1147.0	7.6%	18.2%
Shell	1078.6	7.1%	25.3%
Amoco	956.0	6.3%	31.6%
Mobil	838.0	5.5%	37.1%
BP America	756.6	5.0%	42.1%
USX	603.0	4.0%	46.1%
Texaco	595.0	3.9%	50.0%
Sun	595.0	3.9%	53.9%
ARCO	559.0	3.7%	57.6%
DuPont	406.5	2.7%	60.3%
Ashland	346.5	2.3%	62.6%
Petroleos de Venezuela	344.5	2.3%	64.9%
Koch	310.0	2.0%	66.9%
Phillips	305.0	2.0%	68.9%
Coastal	302.8	2.0%	70.9%
Unocal	295.8	1.9%	72.8%
Aramco	295.0	1.9%	74.8%
Solomon	277.1	1.8%	76.6%
Total Petroleum	190.1	1.3%	77.9%
U.S. TOTAL	**15183.6**	**100.0%**	**100.0%**

56. American Petroleum Institute, op. cit., Section VIII, Table 11c.

Table B-5
TOP 20 PETROLEUM MARKETERS, 1973[57]

Company	Percent of U.S. Market	Accumulated Percent
Texaco	8.0%	8.0%
Exxon	7.6%	15.6%
Shell	7.5%	23.1%
Indiana Standard	6.9%	30.0%
Gulf	6.8%	36.8%
Mobil	6.5%	43.3%
Socal	4.8%	48.1%
ARCO	4.4%	52.5%
Phillips	3.9%	56.4%
Sun	3.7%	60.1%
Union	3.1%	63.2%
Continental	2.3%	65.5%
Cities Service	1.7%	67.2%
Marathon	1.5%	68.7%
Ashland	1.5%	70.2%
Clark	1.3%	71.5%
Sohio	1.2%	72.7%
Hess	1.0%	73.7%
BP	0.8%	74.5%
Tenneco	0.8%	75.3%
U.S. TOTAL	**100.0%**	**100.0%**

57. Mitchell, Edward J., *Vertical Integration in the Oil Industry*, published by American Enterprise for Public Policy Research, Washington, D.C., 1976, Table 7.

Table B-6
TOP 20 COAL COMPANIES, 1972[58]

Company	Production (mill short tons)	Percent of U.S. Production	Accumulated Percent
Peabody Coal Co.	71.6	12.1%	12.1%
Consolidation Coal	64.9	11.0%	23.1%
Island Creek Coal	22.6	3.8%	27.0%
Pittson Coal	20.6	3.5%	30.5%
Amax	16.4	2.8%	33.2%
U.S. Steel	16.3	2.8%	36.0%
Bethlehem Mines	13.3	2.3%	38.3%
Eastern Assoc. Coal Corp.	12.5	2.1%	40.4%
North American Coal Co.	12.0	2.0%	42.4%
Old Ben Coal Corp.	11.2	1.9%	44.3%
General Dynamics	10.0	1.7%	46.0%
Westmoreland Coal Co.	9.1	1.5%	47.5%
Pittsburgh & Midway	7.5	1.3%	48.8%
Utah International	6.9	1.2%	50.0%
American Electric Power	6.3	1.1%	51.1%
Western Energy Co.	5.5	0.9%	52.0%
Rochester & Pittsburgh	5.1	0.9%	52.8%
Valley Camp Coal	4.8	0.8%	53.7%
Zeigler Coal Co.	4.2	0.7%	54.4%
Midland Coal	3.9	0.7%	55.0%
U.S. TOTAL	**590.0**	**100.0%**	**100.0%**

58. Ibid., Table 10.

Appendix C

CAR MANUFACTURERS IN A PERMIT TRADING PROGRAM

This Appendix provides rough estimates of CO_2 emissions for car manufacturers, based on lifetime emissions from cars and trucks produced.

Lifetime CO_2 emissions for a particular car can be estimated based on fuel type used, average fuel efficiency (MPG), expected lifetime, and expected mileage. This information combined with each car producer's production volume makes it possible to estimate total CO_2 emissions that would accrue to each manufacturer. Table C-1 provides rough emissions estimates per car and truck over the vehicle's lifetime, annual total emissions from cars and trucks, and average annual emissions per manufacturing plant.

Table C-1
CO_2 EMISSIONS FROM U.S. AUTOMOBILES

	Fuel consumption (gallons)	Emissions * (tonnes carbon)
Lifetime emissions/car **	5,200	10
Lifetime emissions/truck **	14,300	26
Emissions/year cars and trucks, 1986	130 billion	238 million
Emissions/manufacturing plant/year, 1986 ***	23 million	43,000

* Emissions calculations based on emissions factor for gasoline; 54,900 g CO_2/ gigajoule (EPA, *Policy Options for Stabilizing Global Climate*, Vol. 1, Washington, D.C., 1989, p. IV-21). Conversion factor from CO_2 to carbon; 12/44. Conversion from gallons of gasoline to gigajoule; multiply with 0.123 (U.S. Department of Commerce, *Energy Interrelationships. A Handbook of Table & Conversions Factors for Combining and Comparing International Energy Data*, Washington, D.C., 1977).

** Assumptions: miles/year; cars 10k, trucks 14k. MPG; cars 19.3, trucks 9.8. Derived from Gas Research Institute's *Baseline Projection Data Book*, Washington, D.C., 1990, p. 351-352. Lifetime of cars and trucks here assumed to be 10 years.

*** Reduces annual emissions by 30% to account for imports of cars,[59] and divides remaining emissions by number of plants from Table 2-10; 3,867.

59. U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States 1988*, Washington, D.C., 1988, Table 992.

REFERENCES

American Petroleum Institute, *Basic Petroleum Data Book. Petroleum Industry Statistics*, Vol. XI, No. 1, Washington, D.C., 1991.

Citizens Fund, *The Heat is On: America's CO_2 Polluters*, Washington, D.C., December, 1990.

Energy Information Administration, *Consumption of Energy 1985*, DOE/EIA-0512(85), Washington, D.C., 1988.

Energy Information Administration, *Inventory of Power Plants in the United States 1989*, DOE/EIA-0095(89), Washington, D.C., 1989.

Energy Information Administration, *Coal Production 1989*, DOE/EIA-0118(89), Washington, D.C., 1989.

Energy Information Administration, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves. 1989 Annual Report*, DOE/EIA-0216(89), Washington, D.C., 1989.

Energy Information Administration, *Natural Gas Annual 1989*, DOE/EIA-0131(89), Washington, D.C., 1989.

Energy Information Administration, *Electric Power Annual 1988*, Washington, D.C., January 1990.

Energy Information Administration, *Improving Technology: Modeling Energy Futures for the National Energy Strategy*, SR/NES/90-01, Washington, D.C., 1990.

Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(91/03), Washington, D.C., March 1991.

Gas Research Institute, *Baseline Projection Data Book. GRI Baseline Projection of U.S. Energy Supply and Demand to 2010. 1990 Edition.* Washington, D.C., 1990.

Gordon, Richard L., *U.S. Coal and the Electric Power Industry*, Resources for the Future, Washington, D.C., 1975.

Loeb, Alan P., *Three Misconceptions About Emissions Trading*, Air & Waste Management Association Conference, Paper No. 90-155.8, 1990.

Marland, G. and R. M. Rotty, *Carbon Dioxide Emissions from Fossil Fuels: A Procedure for Estimation and Results for 1950-1981*, DOE/NBB-0036, 1983.

Mitchell, Edward J., *Vertical Integration in the Oil Industry*, published by American Enterprise for Public Policy Research, Washington, D.C., 1976.

Oil & Gas Journal Special, *Pipeline Economics*, Tulsa, Oklahoma, November 27, 1989.

Oil & Gas Journal, *Annual Refining Report*, Tulsa, Oklahoma, March 18, 1991.

PennWell Publishing Company, *1991 U.S.A. Oil Industry Directory*, Tulsa, Oklahoma, 1991.

PennWell Publishing Company, *International Petroleum Encyclopedia 1990*, Tulsa, Oklahoma, 1991.

Scheraga, J. D. and N. A. Leary, "Efficiency of Climate Policy," *Nature*, Vol. 354, November 21, 1991, p. 193.

Scheraga, J. D. and N. A. Leary, *Improving the Efficiency of Environmental Policy: The Implementation of Strategies to Reduce CO_2 Emissions.* Paper Presented to Stanford University's Energy Modeling Forum #12, Boulder, Colorado, August 27-29, 1991.

Smith, A. E., A. R. Gjerde, and D. Cohan, *Practical Considerations in Using Emissions Trading to Control Greenhouse Gases*, EPA Report Under Contract No. 68-CO-0021, January 1991.

Torrens, Ian M., *Electric Utility Options of Greenhouse Gas Emissions*, submitted to the Air & Waste Management Association, Vancouver, British Columbia, June 1991.

University of California at Berkeley, Lawrence Berkeley Laboratory, *Summary of Presentations at the Workshop on Energy Efficiency and Structural Change: Implications for the Greenhouse Problem*, Oakland, California, May 1988.

U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States 1988*, Washington, D.C., 1988.

U.S. Department of Commerce, International Trade Administration, *A Competitive Assessment of the U.S. Cement Industry*, Washington, D.C., 1987.

U.S. Department of Commerce, National Technical Information Service, *Energy Interrelationships. A Handbook of Tables & Conversions Factors for Combining and Comparing International Energy Data*, Washington, D.C., 1977.

U.S. Department of Commerce, Bureau of the Census, *1987 Census of Manufactures. Industry Series*, Washington, D.C., 1989.

U.S. Department of Energy, *Industry Profiles/Cement*, Final Report Prepared by Energetics, Inc., Washington, D.C., December 1990.

U.S. Department of Energy, *Industry Profiles/Paper,* Final Report Prepared by Energetics, Inc., Washington, D.C., December 1990.

U.S. Environmental Protection Agency, *Policy Options for Stabilizing Global Climate,* Vol. 1, Washington, D.C., 1989.