The Impacts of the Clean Air Act Amendments of 1990 and Changes in Rail Rates on Western Coal

by

John Bitzan
Denver Tolliver
Wayne Linderman

Upper Great Plains Transportation Institute
North Dakota State University
Fargo, North Dakota

April 1996

ABSTRACT

This study examines the impacts of the Clean Air Act Amendments of 1990 (CAAA90) on coal production and coal flows. The CAAA90 take a markedly different approach to pollution control from stationary sources when compared to past `clean air' legislation. The new approach to limiting sulfur dioxide emissions from electric utilities allows the least cost method of pollution control to be used by those utilities that realize the lowest costs in reducing pollution. In many cases, the lowest cost method of reducing pollution will be to purchase low sulfur coal. Because 86 percent of the nation's recoverable low sulfur coal reserves are located in the west, this presents a great opportunity for western coal producers. Linear programs are estimated in the study, showing the large potential increases in western coal production resulting from the CAAA90. Finally, the study shows that future changes in nationwide transportation rates could have a major impact on regional coal production and market shares. To the extent that increases in railroad efficiency continue, western coal production should realize an even greater opportunity. This study also presents a model of rail rates, showing the influences of costs and competitive factors in determining individual rates for coal.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

INTRODUCTION

The market for western coal has grown immensely in recent years. This market growth is evident in production trends. In states comprising the Western Governor's Association,[1] there were 45 million tons of coal produced in 1970.[2] By 1991, annual production by these states had increased by more than 600 percent, reaching a level of more than 340 million tons.[3] Much of this rise in the demand for western coal has been a result of the increased desire for low sulfur coal by electric utilities in the United States.

Coal has been the dominant source of fuel used for generating electricity for many years, increasing its share of electric energy generation from 46 percent in 1970, to 53 percent in 1990.[4] Much of coal's dominance in the electric utility market can be attributed to its status as the lowest-cost fossil fuel in terms of price per BTU. Two characteristics of western coal that make its market potential great are low costs of production and low sulfur content. First, the majority of western coal is produced in surface mines with dense seams of coal that are easily accessible. This results in higher labor productivity, lower capital costs, and a resulting lower cost associated with mining this coal. Second, the majority of western coal is subbituminous coal which is generally low in sulfur. Nearly 95 percent of the recoverable reserves in the west have less than 1.67 pounds of sulfur per million BTU, and 55 percent of the recoverable reserves in the west have less than .6 pounds of sulfur per million BTU. By comparison, only 22 percent of the Appalachian Region's recoverable reserves have less than .6 pounds of sulfur per million BTU, and less than 1 percent of the Interior Region's recoverable reserves have less than.6 pounds of sulfur per million

---

[1]Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nebraska, Nevada, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming.

[2]Smith, James N. And Robert R. Rose. *Rail Transport of Western Coal*. Prepared for the Western Governor's Association, 1985.

[3]Energy Information Administration. *Coal Production, 1990.*

[4]Energy Information Administration. *Annual Outlook for U.S. Electric Power, 1991.*

BTU. More than 86 percent of the nation's low sulfur (less than .6 lbs. per million BTU) recoverable reserves are located in the west.

There is currently a window of opportunity for western coal producers that previously has not existed. Due to the Clean Air Act Amendments of 1990 (CAAA90), the demand for low sulfur coal is likely to grow significantly in the next several years. The Amendments place strict limitations on the amount of sulfur dioxide that may be emitted by electric utilities. However, they do not impose any requirements on the geographic distribution of these emissions, or on how these emission limitations must be achieved. Therefore, the least cost method of reducing sulfur dioxide emissions can be employed by those utilities that experience the least costs in reducing such emissions. In many cases, this entails switching to low sulfur coal.

One factor that may have a significant impact on the least cost method of reducing sulfur dioxide emissions by utilities is the transportation rates for coal. While western coal is generally produced more inexpensively than eastern coal, it faces a transportation disadvantage due to long distances to consuming markets and lack of transportation competition.

This study examines opportunities associated with the Clean Air Act Amendments of 1990 (CAAA90), and illustrates the impacts of various transportation rate changes on western coal production. By understanding the potential opportunities associated with the Clean Air Act, western coal producers will be better prepared to take advantage of such opportunities. An understanding of the dependence of coal producing regions on the various modes of transportation will similarly allow producers to adjust to changing conditions given a change in relative modal rates. The specific objectives of this study are as follows:

1. Examine coal production, coal markets, and transportation trends over time.

2. Examine the Clean Air Act Amendments of 1990 and the opportunities they provide to western coal producers.

3. Present a model of coal rail rates, showing how rail coal rates vary with intermodal, intramodal, geographic, and product competition. These factors will be assessed in coal producing regions and used to estimate western and eastern coal rail rates.

4. Present three spatial equilibrium models that show the optimal distribution of coal nationwide. The first model will minimize the production and transportation costs of coal shipped to electric utilities and will represent a base case. The second will minimize production, transportation, and scrubbing costs, and place limitations on sulfur dioxide emissions consistent with the Clean Air Act Amendments. This will estimate the impacts of the Amendments. The third model will be identical to the second, but will introduce changes in rail rates and will show the differential regional impacts of rail rate changes due to differences in dependence on rail.

5. Discuss the implications of the Clean Air Act Amendments and any transportation changes to western coal producers. This will include an assessment of the future outlook for western coal producers and the opportunities provided.

Coal Quality

In general, the input demands of a firm can be expressed as a function of input and output prices or quantities. However, the specific relationships that input demands have with input and output prices are intimately related to the production technology employed and the quality of inputs. In the case of coal, there is such a large variation in quality, technologies employed and electricity demand that the relationship between coal price and the demand for coal by electric utilities will vary widely. Coal can vary in the levels of moisture, ash, sulfur and heat it contains. It can vary in texture and hardness, as well as in many other ways.

Often the two primary quality variables used to classify coal are heat content and sulfur content. The heat content associated with a given volume of coal can be measured in British Thermal Units (BTUs).[5] The sulfur content of coal can be measured as the pounds of sulfur per million BTU. By combining these two quality variables, the amount of sulfur dioxide emitted per ton of coal burned can be estimated. Moreover, the quantity of coal required to achieve a given level of electricity generation can be estimated. The Energy Information Administration identifies five types of coal by BTU content (Table 1). These coals can be further broken down by six categories of sulfur content (Table 2). Thus, there are potentially 30 different kinds of coal according to this classification system.[6]

Table 1: Coal BTU Categories[7]

Coal Rank	**Million BTU per Short Ton**
Bituminous	>26
Bituminous	>23, and <26
Bituminous	>20, and <23
Sub-bituminous	>15, and <20
Lignite	<15

[5]One BTU is equal to the quantity of heat required to the raise the temperature of one pound of water by one degree Fahrenheit.

[6]However, in actuality less than 30 types exist. For example, almost all sub-bituminous coal will be categorized as low to medium sulfur coal.

[7]Energy Information Administration. *Estimation of U.S. Coal Reserves by Coal Type.* 1989.

Table 2: Coal Sulfur Content Categories[8]	
Coal Sulfur Category	**Pounds of Sulfur per Million BTU**
Low #1	<.40
Low #2	.41-.60
Medium #1	.61-.83
Medium #2	.84-1.67
High #1	1.68-2.50
High #2	>2.50

Coal Origin Regions

As Figure 1 shows, the majority of coal reserves in the United States are concentrated in three regions of contiguous fields. The three coal producing regions are the Appalachian region, the Interior region, and the Western region. The regions are defined in Table 3.

Table 3: Coal Producing Regions of the United States
Appalachian
Alabama, Georgia, Eastern Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia
Interior
Arkansas, Illinois, Indiana, Iowa, Kansas, Western Kentucky, Louisiana, Missouri, Oklahoma, and Texas
Western

[8]Energy Information Administration. *Estimation of U.S. Coal Reserves by Coal Type.* 1989. Sulfur categories are not named by EIA. However, the EIA considers low sulfur coal to be that with less than .6 lbs. of sulfur per million BTU, medium sulfur coal to be that with .61 - 1.67 lbs. of sulfur per million BTU, and high sulfur coal to be that with more than 1.67 lbs. of sulfur per million BTU.

Alaska, Arizona, California, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming

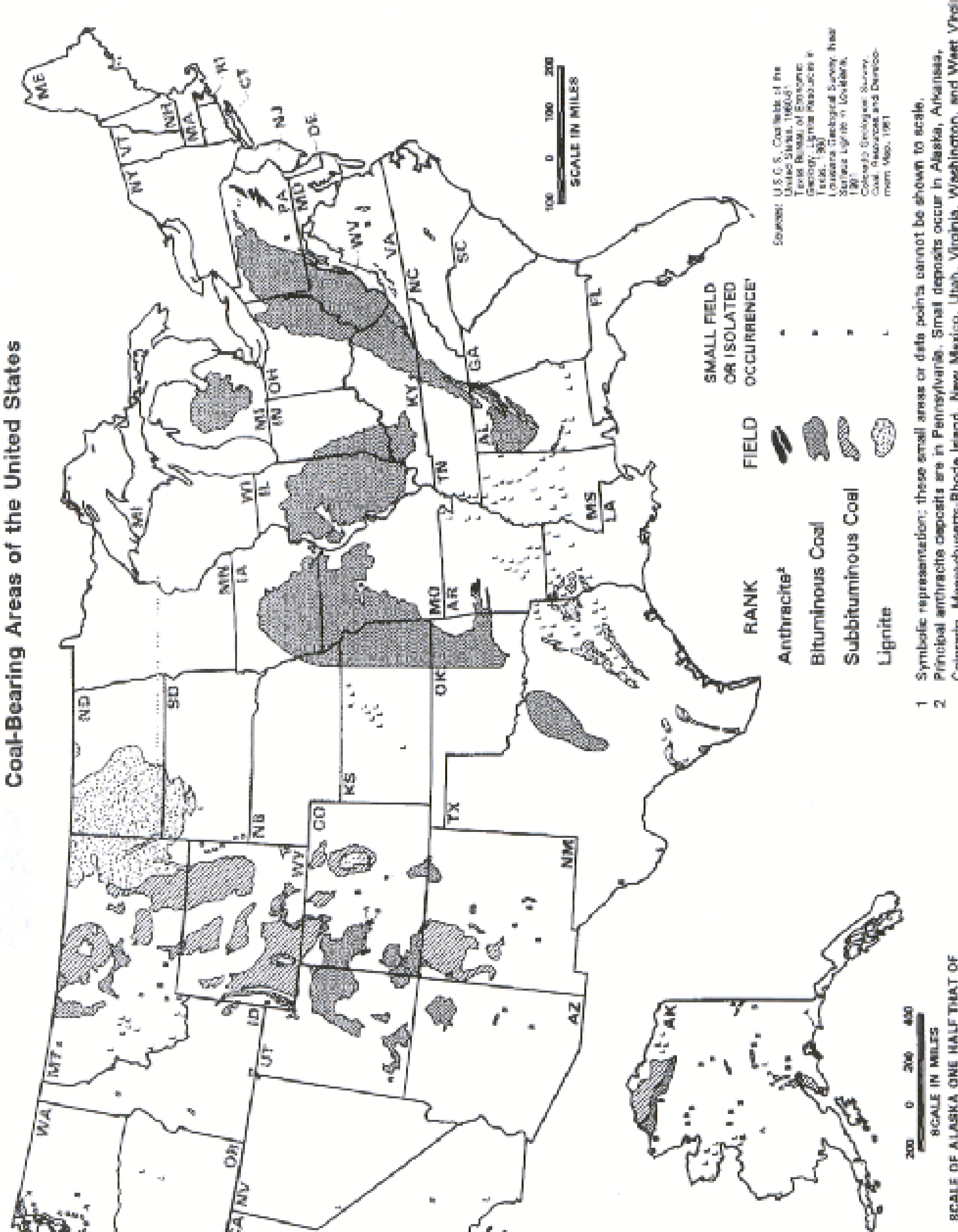
Coal-Bearing Areas of the United States
RANK
FIELD
SMALL FIELD OR ISOLATED OCCURRENCE[1]
Anthracite[2]
Bituminous Coal
Subbituminous Coal
Lignite
100 0 100 200
SCALE IN MILES
200 0 200 400
SCALE IN MILES
SCALE OF ALASKA ONE HALF THAT OF CONTIGUOUS UNITED STATES
1 Symbolic representation; these small areas or data points cannot be shown to scale.
2 Principal anthracite deposits are in Pennsylvania. Small deposits occur in Alaska, Arkansas, Colorado, Massachusetts-Rhode Island, New Mexico, Utah, Virginia, Washington, and West Virginia.

Figure 1

The Appalachian region contains over ninety-eight billion tons of coal reserves, or about twenty-one percent of the nation's total.[9] Nearly all of the coal reserves located in the Appalachian region are Bituminous. Thus, most of the coal reserves located in the Appalachian region contain more than twenty million BTU per short ton. Approximately 22 percent of the Appalachian region's coal reserves are low sulfur reserves (less than .61bs. per mmBTU), 38 percent are medium sulfur reserves, and the remaining 40 percent are high sulfur reserves. Because many of the region's coal reserves are underground, recoverable reserves in the Appalachian region only amount to about 55 billion tons. Moreover, the percentages of the region's recoverable reserves that are low, medium, and high sulfur are nearly identical to those of its demonstrated reserves.

The Interior region contains nearly 135 billion tons of coal reserves, or about 29 percent of the nation's total. Like the Appalachian region, the majority of the Interior region's reserves are bituminous. This region contains very few low sulfur coal reserves, fewer than 1 percent of the region's total reserves contain less than.61 pounds of sulfur per million BTU. More than 83 percent of the Interior region's coal reserves are considered high in sulfur content (more than 1.67 pounds of sulfur per million BTU). Since much of the Interior region's reserves are illegal to mine and many are underground, recoverable reserves amount to approximately 69 billion tons (51 percent of the region's demonstrated reserves). Roughly eighty percent of the region's recoverable reserves are high sulfur, and less than one percent are low sulfur.

The Western region contains about half of the nation's total coal reserves, or approximately 234 billion tons of coal. Unlike the Appalachian and Interior regions, the majority of the Western region's coal reserves are subbituminous. Thus, most of the region's coal reserves have a low energy content relative to Appalachian and Interior coal, containing less than 20 million BTU per short ton. On average, western

[9] Energy Information Administration. *Estimation of U.S. Coal Reserves by Coal Type,* 1989.

coal is much lower in sulfur than its eastern counterparts. More than 57 percent of all western coal reserves contain less than .61 pounds of sulfur per million BTU, and another 38 percent contain less than 1.68 pounds of sulfur per million BTU. This means that less than 5 percent of all western coal reserves are high sulfur reserves. The high proportion of the Western region's reserves that are legally minable and the large amounts of reserves in surface mines make a larger portion of the area's reserves recoverable. In total, more than 86 percent of the nation's recoverable low sulfur coal reserves, and more than 62percent of the nation's medium sulfur coal reserves reside in the west.

Table 4: Characteristics of Coal in the Three Producing Regions

Region	Total Demonstrated Reserves (million tons)	Total Recoverable Reserves (million tons)	Percent of Recov. Reserves that are Low Sulfur	Percent ofRecov. Reserves that are High Sulfur	Coal Rank
Appalachian	98695.6	55307.2	21.8	40.1	Bituminous
Interior	134810.1	69169.3	0.9	79.9	Bituminous and Lignite
West	233544.3	143482.5	55.2	5.5	Sub., Bit., and Lig.

Coal Production

In 1991, there were nearly one billion tons of coal produced in the United States (Figure 2). The Appalachian region was the nation's leading coal producer, supplying approximately 458 tons of coal, or 46 percent of the total. The second leading producer was the West region, supplying approximately 35 percent of the total. The Interior region produced less than 20 percent of the total.

This represents a marked change from the coal production shares that existed in 1980 (Figure 3) when the Appalachian region supplied 53 percent of the nation's coal, while the West region only supplied 26 percent of the total. The increase in electricity demand, combined with increased western development and stringent environmental laws have greatly increased the quantity of coal produced in the West. Western coal production has increased by 64 percent since 1980, and its market share has increased from 26 percent to 35 and its market share has declined from 53 percent to 46 percent. Finally, Interior coal

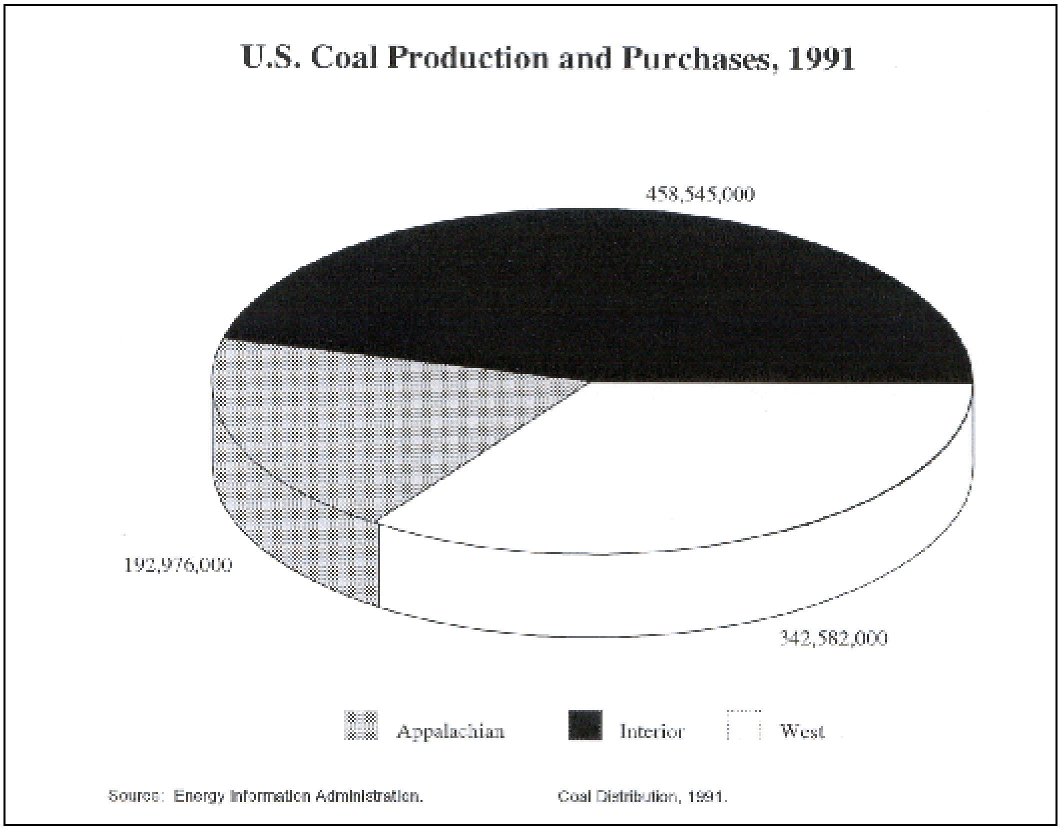

Figure 2

production has increased by 11 percent since 1980, and its market share has declined from 21 percent to 19 percent.

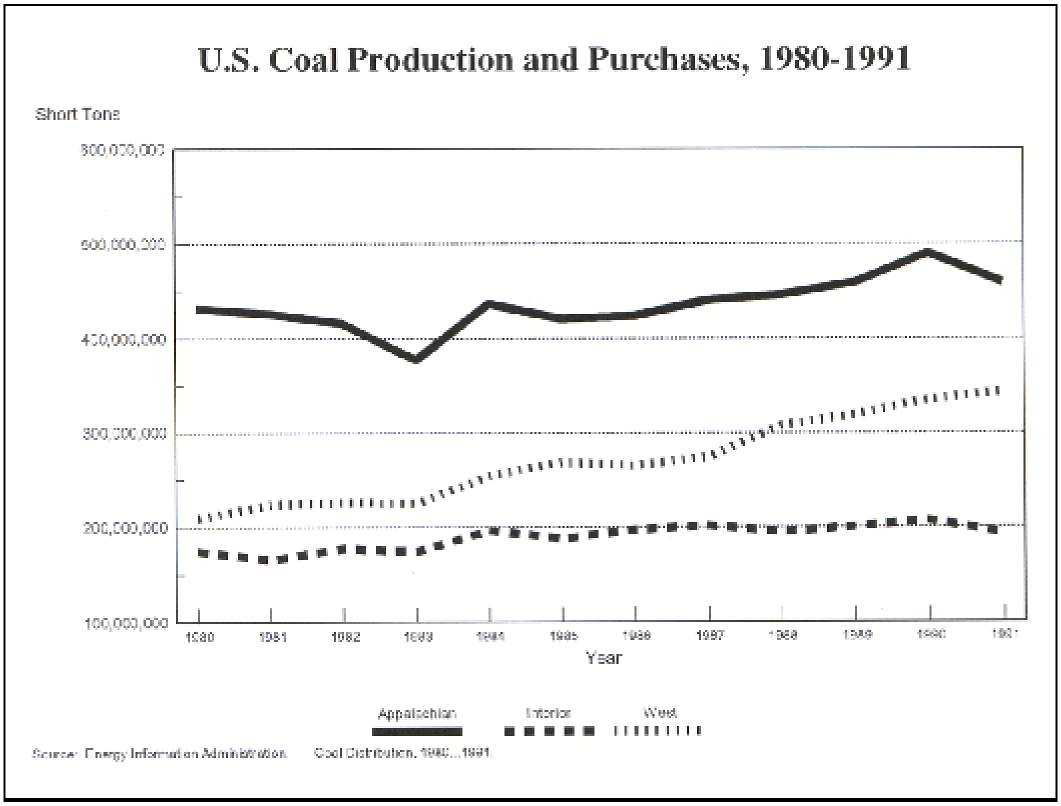

Figure 3

Coal Consumption

Nearly 80 percent of the coal produced in the United States is used for generating electricity (Figure 4). This is not surprising given the abundance of electricity used in the U.S. for residential and commercial purposes, and the relatively low costs of coal as a source of fuel for generating electricity. Exports account for only 11 percent of consumption of U.S. coal, while industrial plants, coke plants, and other miscellaneous uses account for 7, 3, and 1 percent of the consumption of U.S. coal, respectively.

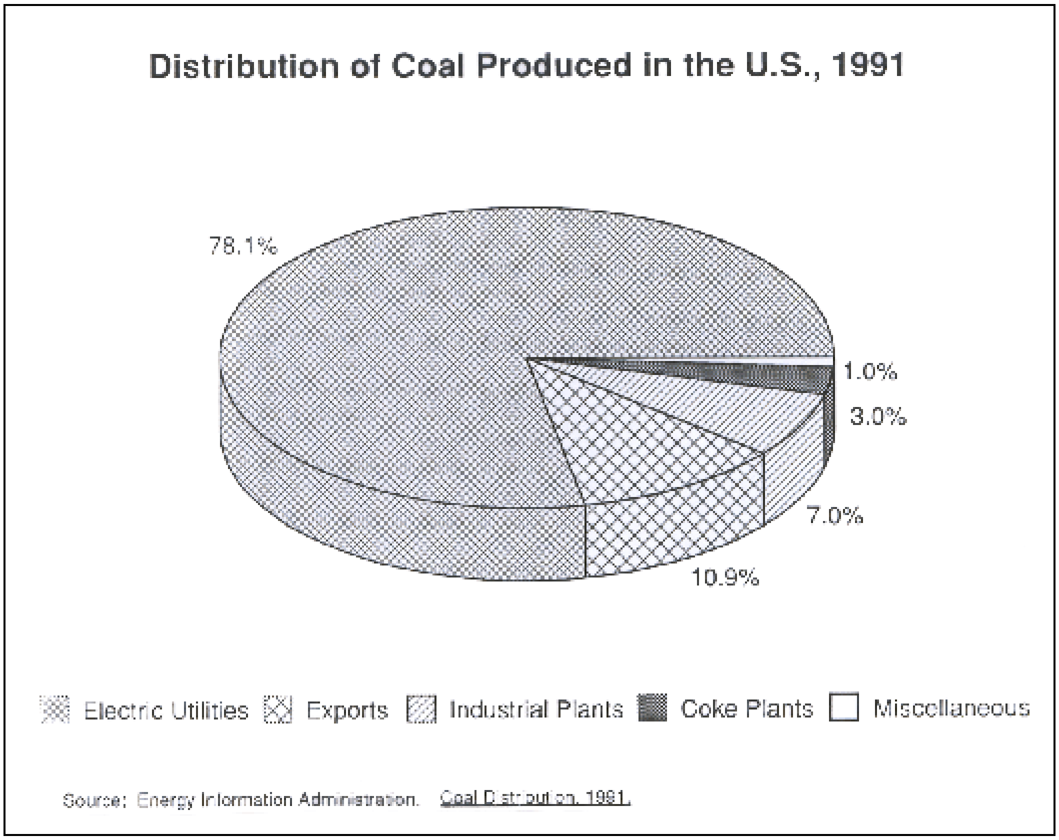

Figure 4

When examining the consumption of the coal produced by the individual regions, it is apparent that the West and Interior regions market their coal almost exclusively to electric utilities (Figure 5). The geographic location and transportation options available to Appalachian producers is somewhat responsible for the increased share of Appalachian coal being exported and consumed by domestic coke plants. However, some of this increase also is due to coal qualities. Because coking requires very high heat levels, anthracite is often the preferred coal for this process. Moreover, the concentration of environmental laws on domestic utilities makes their demand for low sulfur coal the greatest.

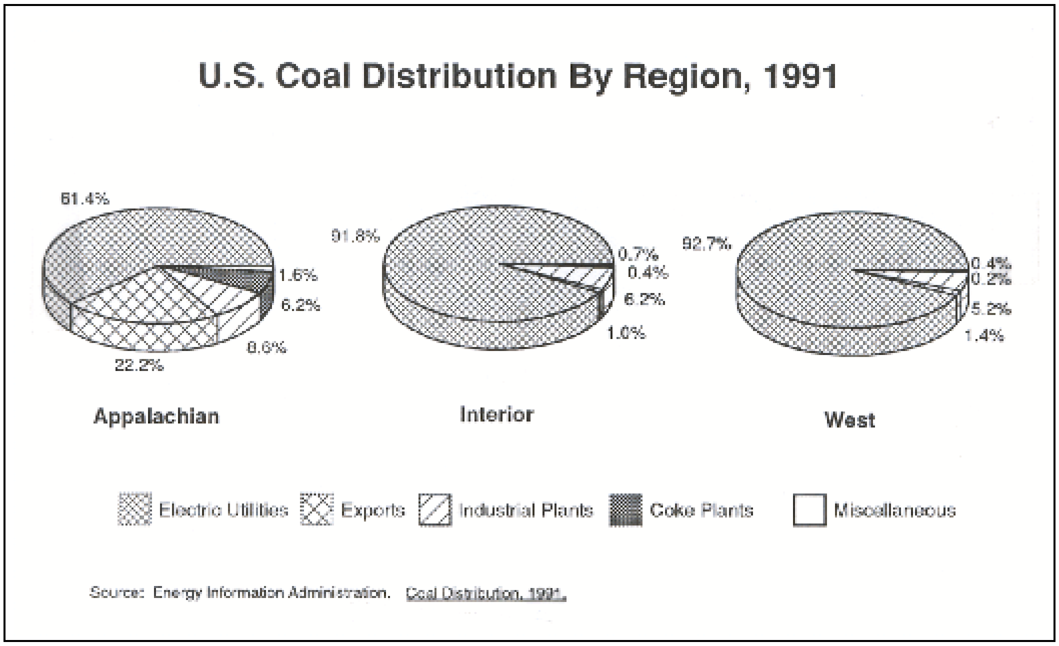

Figure 5

Figure 6 shows that the percentage of each region's coal consumed by electric utilities has remained relatively constant over time. Because of the new environmental regulations being placed on electric utilities and the transportation disadvantages that western coal has in the export market, it is likely that future opportunities for marketing western coal will be the greatest in the electric utility market. Thus, the remainder of this study focuses on the electric utility market for coal.[10]

It is not the intention of this study to suggest that the electric utility market is the only important market for western coal producers. this market is focussed on because of the great opportunities it currently presents.

[10]It is not the intention of this study to suggest that the electric utility market is the only important market for western coal producers. This market is focused on because of the great opportunities it currently presents.

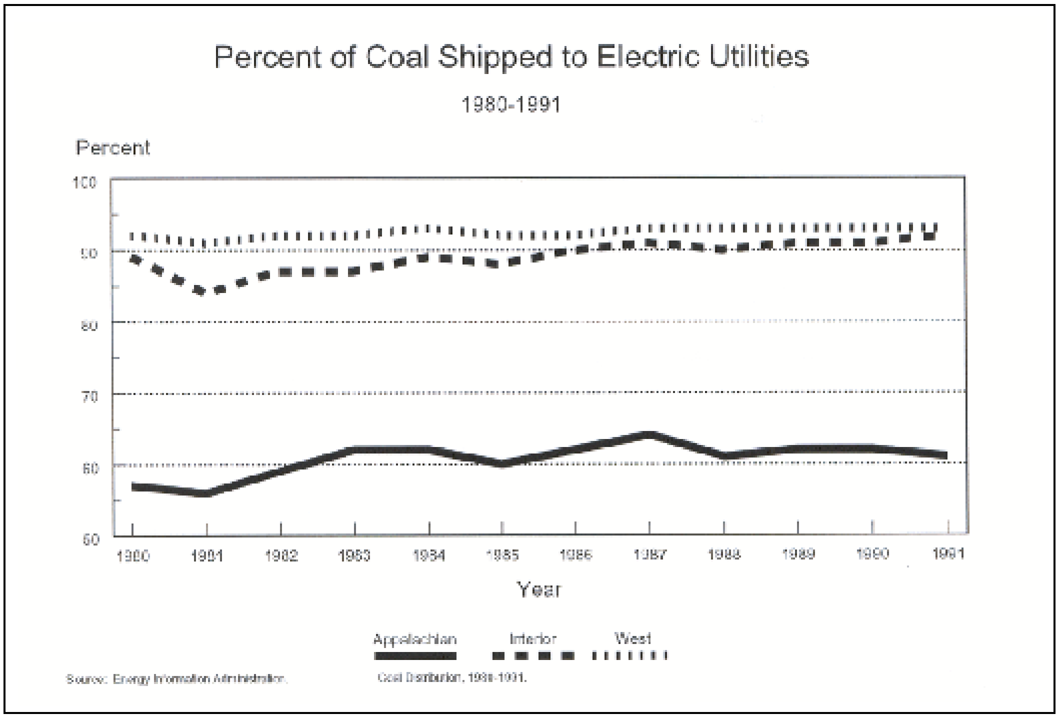

Figure 6

Electricity Demand Regions

The nine regions defined by the U.S. Bureau of Census, can be used to examine coal demand by electric utilities in the U.S. (Figure 7). These regions include New England, Middle Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain and Pacific regions.

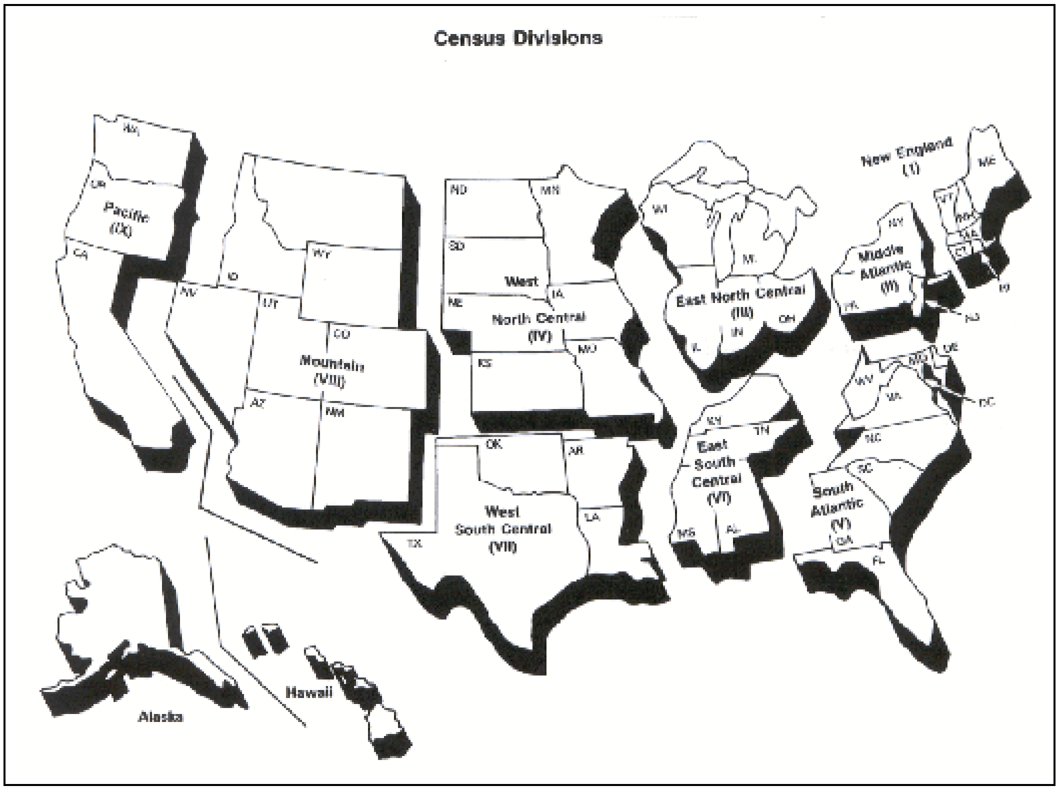

Figure 7

In 1991, five of these regions accounted for more than eighty percent of the coal receipts by electric utilities nationwide (Figure 8). Moreover, the top three regions received more than half of the coal received by U.S. electric utilities.

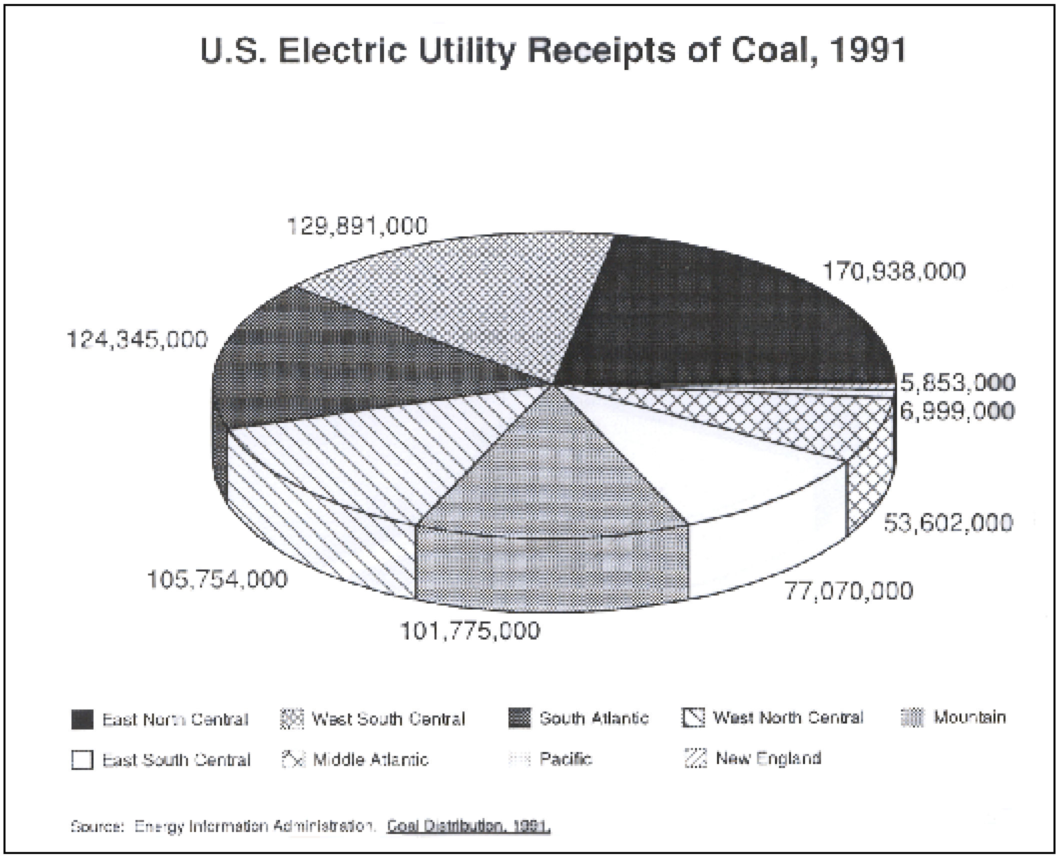

Figure 8

Figure 9 shows that the quantity of coal demanded by electric utilities has increased greatly since 1980. In the period between 1980 and 1991, the East North Central region has had the largest demand for coal by electric utilities. The West South Central region had the sixth highest quantity demanded by electric utilities in 1980 but its use of coal increased over the time period making it the second largest demander of coal for electricity generation by 1991. The South Atlantic region was the second largest consumer of coal for electricity generation throughout most of the period, but consumed slightly less than the West South Central region in 1991. The other major consumption regions during this time period were the West North Central region and the Mountain region. The remainder of this section will focus on these five regions.

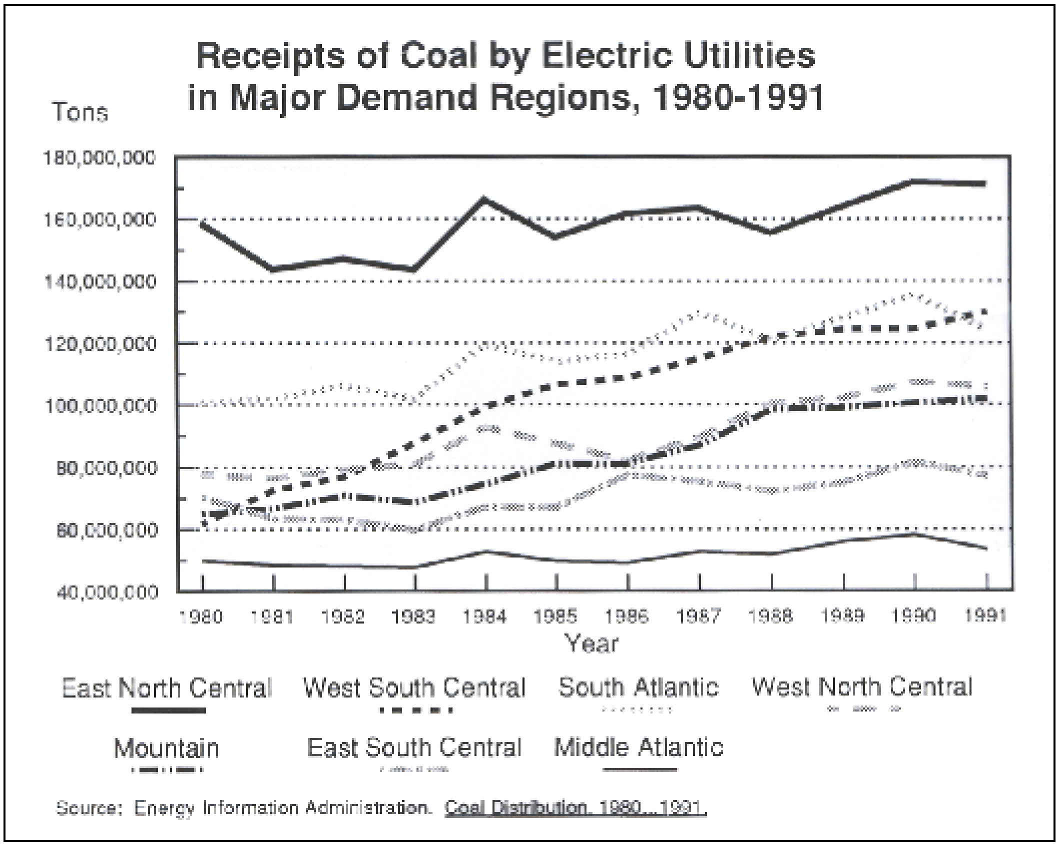

Figure 9

East North Central Region

In 1991, the Appalachian region supplied nearly 41 percent of the coal received by electric utilities in the East North Central region (Figure 10). The Interior region supplied the second most coal to this region, or about 33 percent. The West region's 26 percent share of this market is remarkable, considering the proximity of the market to the Appalachian and Interior producing regions.

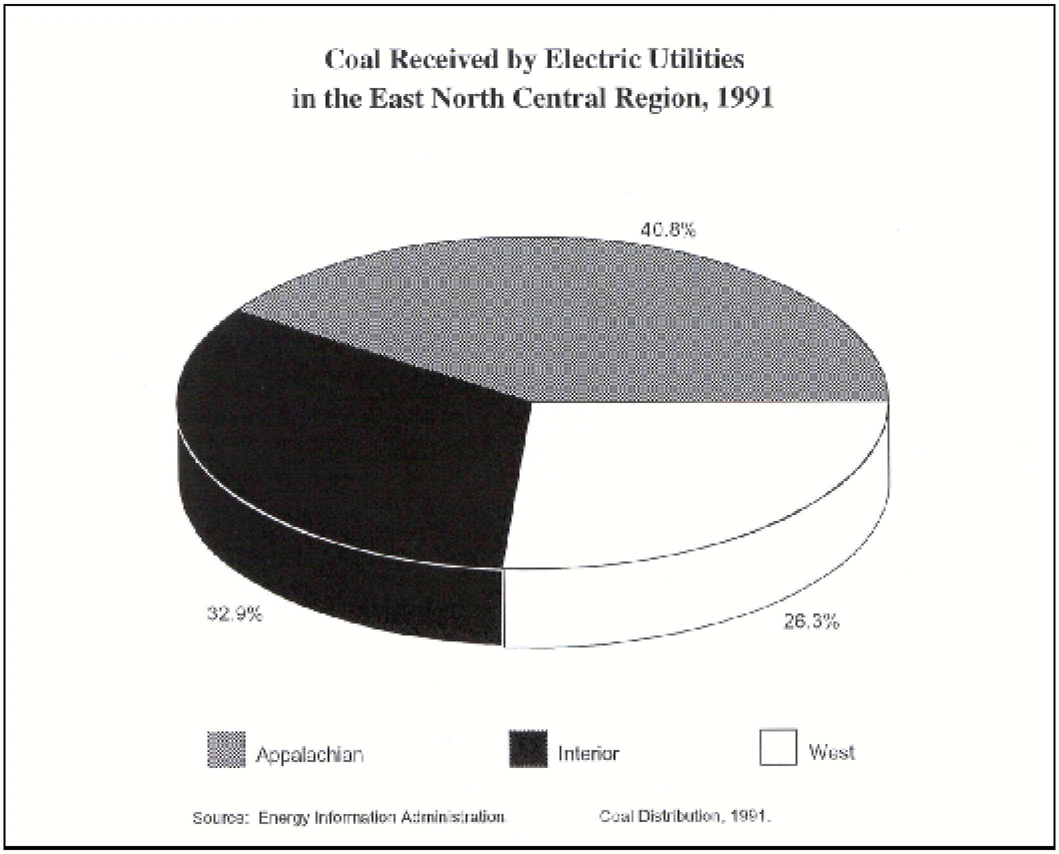

Figure 10

Throughout the 1980-1991 period, the Appalachian region maintained the largest market share in this region, consistently supplying between 40 and 41 percent of the East North Central region's coal for electricity generation (Figure 11). The Interior region maintained the second largest market share throughout this time period. However, its position in this market has weakened considerably since 1984, when it had a market share of 39 percent. By 1991, the Interior region's market share in the East North Central region had dropped to 33 percent. Much of the drop in the Interior region's market share can be attributed to a growth in the market share of the Western region. The Western region went from supplying a low of 17 percent of this market in 1984 to supplying an all time high of 26 percent in 1991.

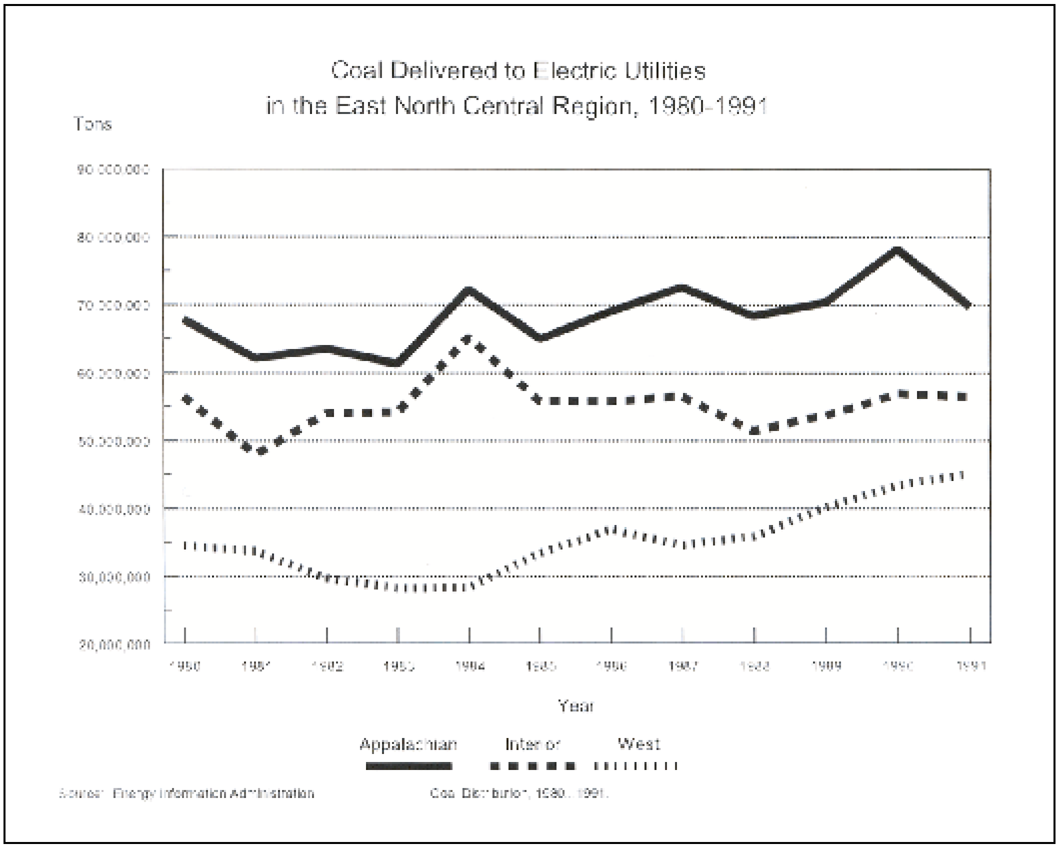

Figure 11

This penetration by western coal producers at the expense of interior coal producers provides an excellent example of the growing importance of sulfur content in coal purchases. Despite the fact that

this demand region encompasses much of the coal reserves in the Interior region, the high sulfur content of this coal has reduced its desirability. Furthermore, entry of the Chicago and Northwestern into the Powder River Basin in 1984 has increased transportation competitiveness to an area that previously had only one transportation option.

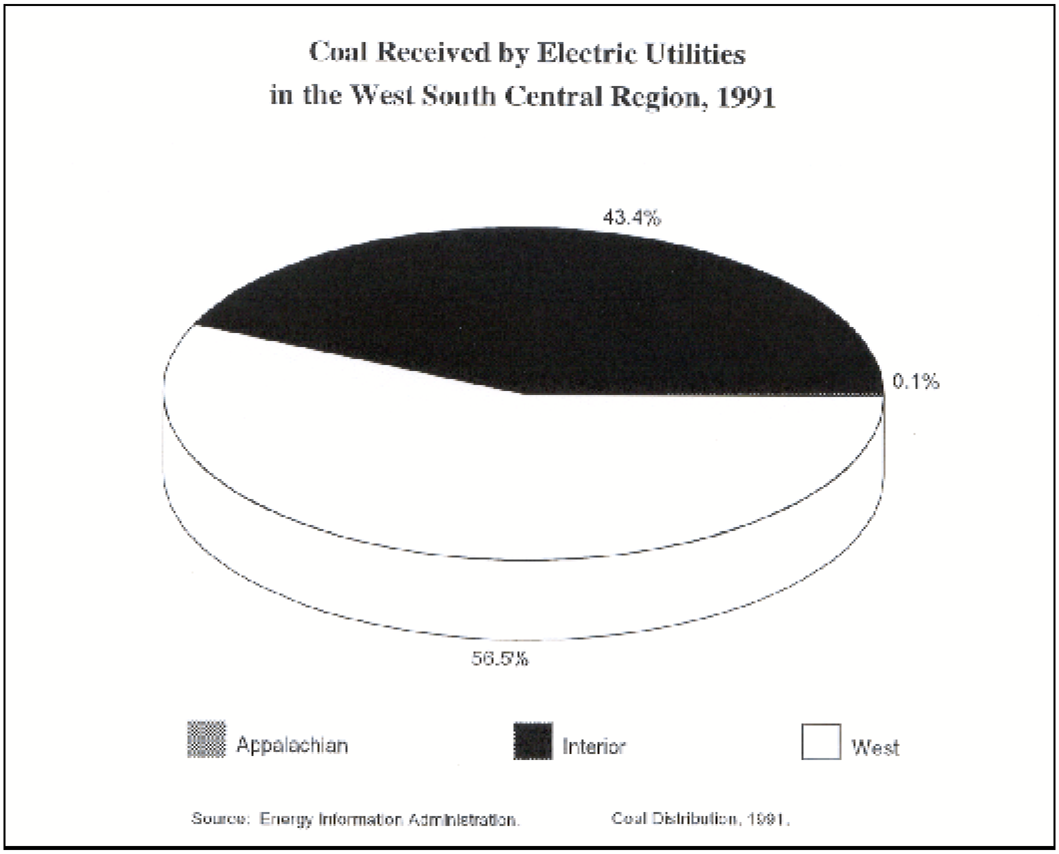

Figure 12

West South Central Region

As Figure 12 shows, the West region supplied more than half the coal used for electricity generation in the West South Central region in 1991. The Interior region also has a strong market share in this region, supplying more than 43 percent in 1991. This is not surprising, since the majority of the demand for coal for electricity generation in this region is in Texas, and the majority of low-sulfur coal reserves in this region are in Texas (low sulfur lignite). The Appalachian region's 1991 market share in this region was essentially zero.

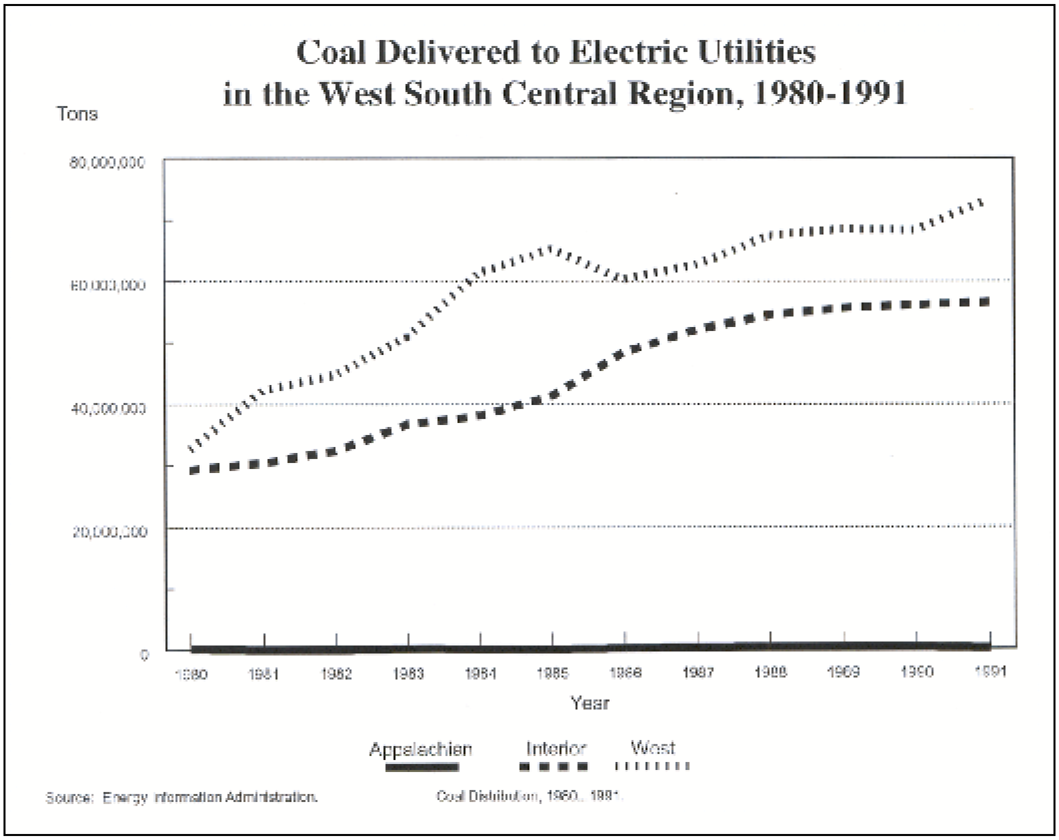

Figure 13

Figure 13 shows the steady growth in this market between 1980 and 1991 when the West region was its leading supplier. In 1980, the Western producing region had a market share of 53 percent. After a growth in market share to a level of 62 percent in 1984, its market share has leveled off somewhat with the West region supplying 57 percent of the coal used for electricity generation in 1991. The Interior region supplied the remainder of this market throughout the period.

South Atlantic Region

In 1991, the Appalachian producing region dominated the market for coal by electric utilities in the South Atlantic. It supplied nearly 87 percent of the coal to this market (Figure 14). In contrast, the Interior region supplied approximately 12 percent of the coal received by electric utilities in this region in 1991. The West region supplied only 1 percent. The low market share of the West region is apparently the result of a lack of proximity to this market caused by long distances and a lack of transportation alternatives resulting in high transportation rates for western coal shipping. In addition, the heart of the low sulfur Appalachian reserves are in eastern Kentucky, southern West Virginia, and Virginia, in close proximity to the market.

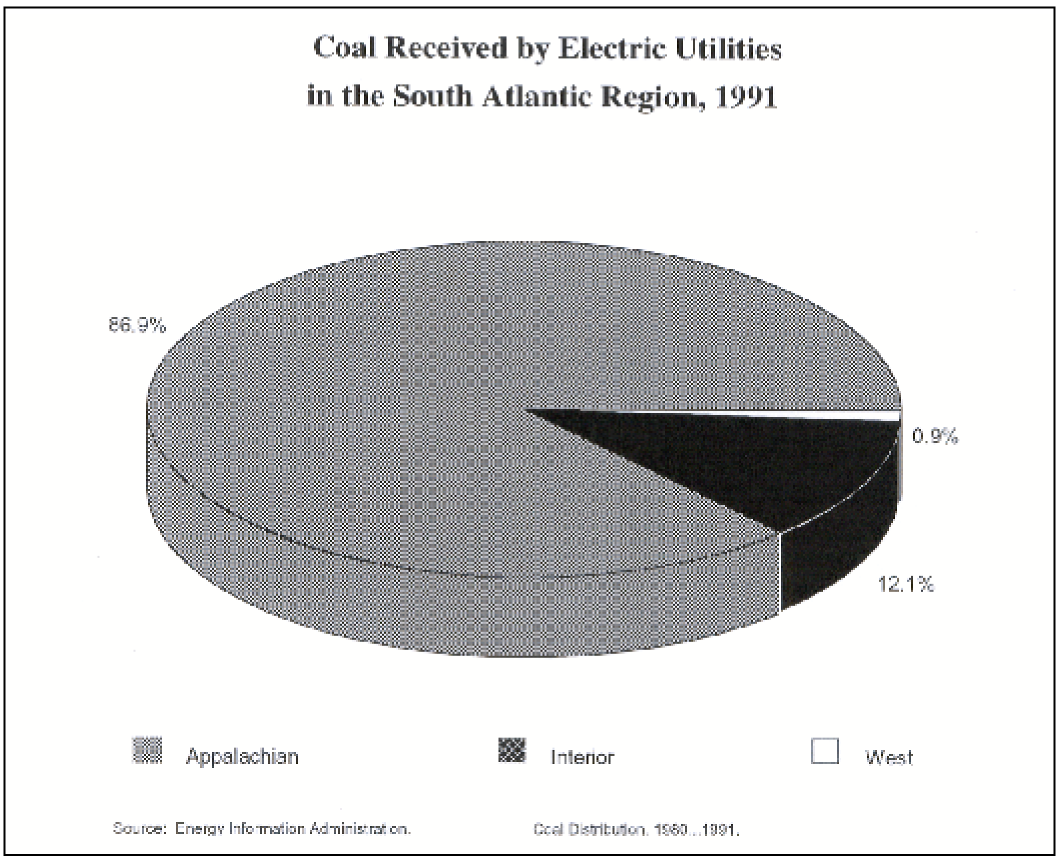

Figure 14

Throughout the 1980-1991 period, the Appalachian producing region dominated this market, consistently supplying more than 86 percent of the coal received by electric utilities in the South Atlantic (Figure 15). The Interior region supplied most of the remaining coal demanded throughout this period. While the West generally supplied 0 percent of the coal demanded by electric utilities in this region throughout the 1980s, the West gained a market share of 2 and 1 percent in 1990 and 1991, respectively. Although this is not a significant amount of coal, this market could develop into a significant one for western producers. The small amounts of coal shipped to this market in 1990 and 1991 suggest that in some cases the advantages that western coal has over interior coal in sulfur content may be able to overcome its transportation disadvantage in this market. However, the potential to displace Appalachian coal in this market appears to be small due to the proximity of low sulfur Appalachian coal to this market.

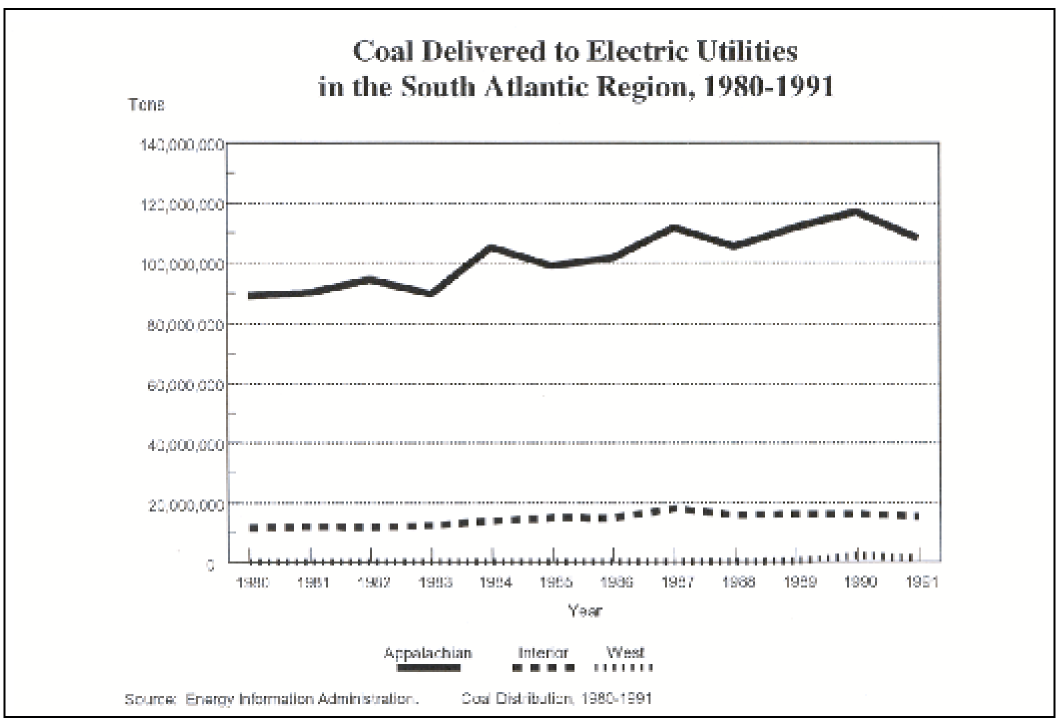

Figure 15

West North Central Region

In 1991, the West producing region dominated the West North Central region's electric utility market for coal by supplying more than 81 percent of the 77 million tons received (Figure 16). The Interior region supplied most of the remaining coal received by electric utilities in this region; approximately eighteen percent. The Appalachian region's market share was less than one percent in 1991 .

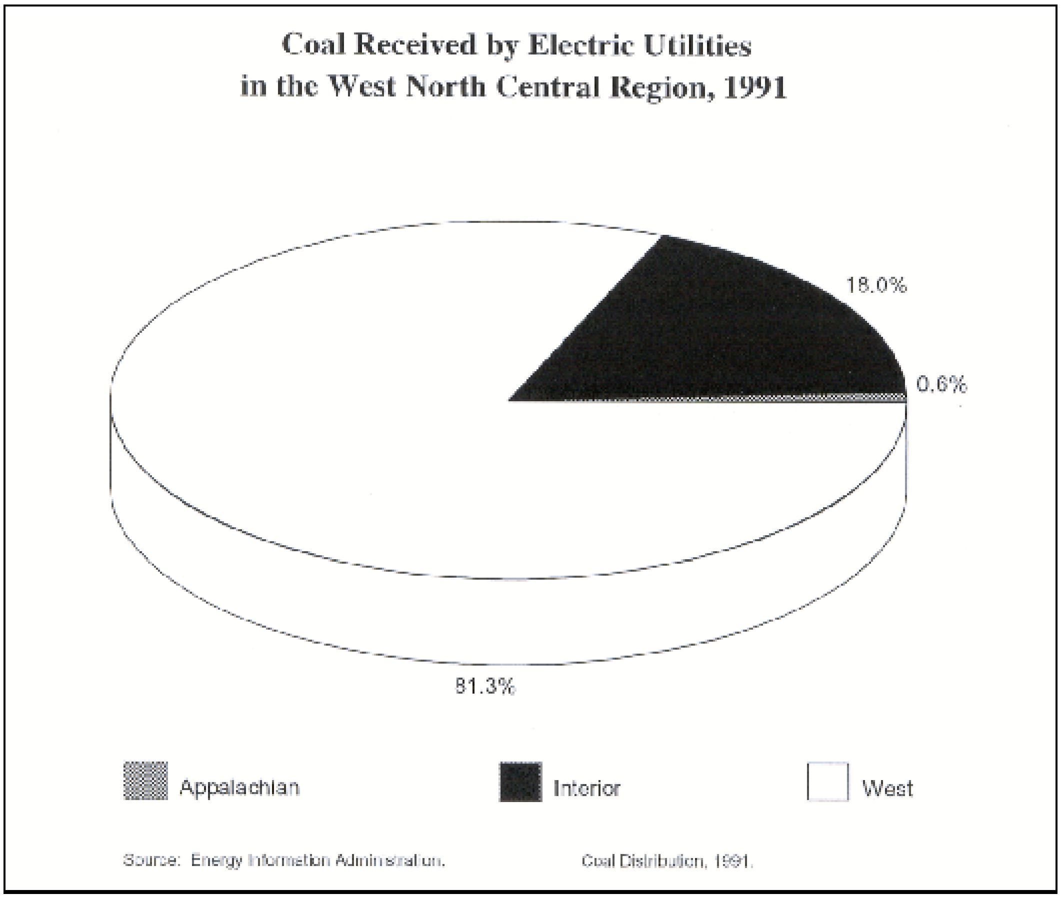

Figure 16

The West North Central region provides an excellent example of a market where the Western production region was able to increase its share over time because of an increasing demand for low sulfur coal and an increase in western transportation competitiveness (Figure 17). In 1980, the Western coal production region supplied 67 percent of the West North Central market for coal by electric utilities. This share steadily rose to a high of 81 beginning in 1984. This occurred as the Chicago Northwestern gained access to the Powder River Basin in Wyoming; an area previously served solely by the Burlington Northern. By contrast, the Interior production region's market share dropped from 32 to 18 percent between 1980 and 1991. This is remarkable, as a large concentration of this region's coal receipts have been in Missouri, Minnesota, and Iowa; states near the heart of the Interior coal reserves.

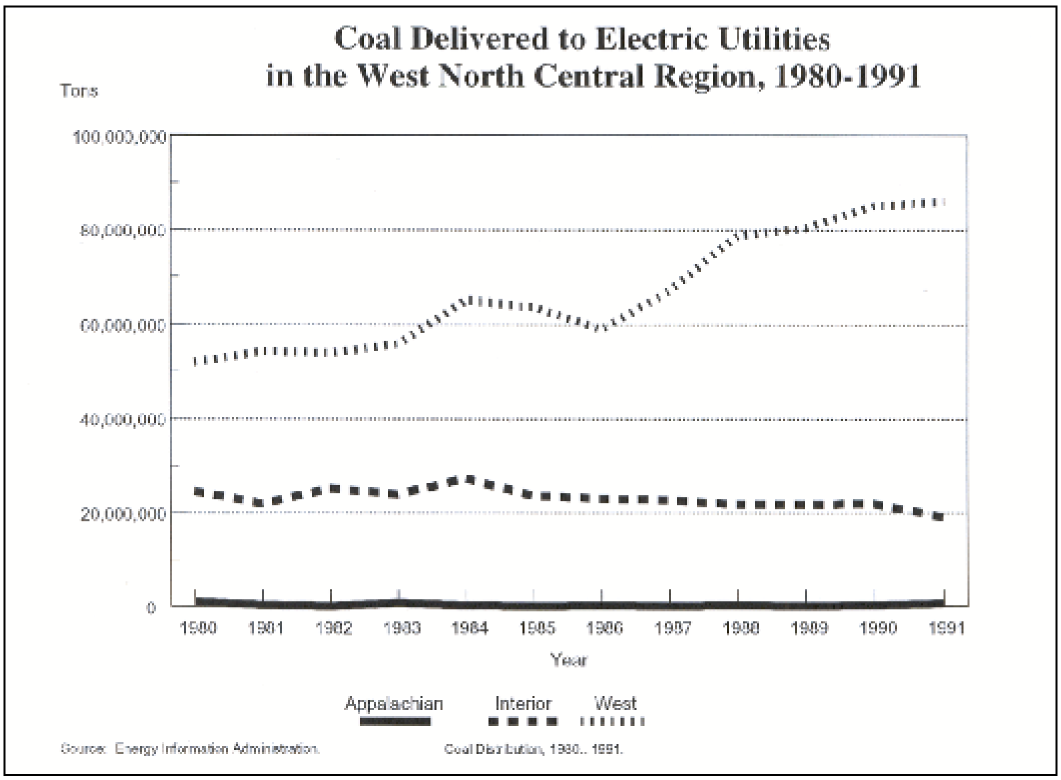

Figure 17

Mountain Region

Virtually all of the coal received by electric utilities in the Mountain region was supplied by the West producing region in 1991 (Figure 18). This was the case throughout the 1980-1991 period. This market is an example of the Western producing region's dominance where proximity exists.

When considered collectively, these five electric utility markets consumed more than 630 million tons of coal in 1991. The Western producing region supplied more than 49 percent of this coal, or approximately 310 million tons.

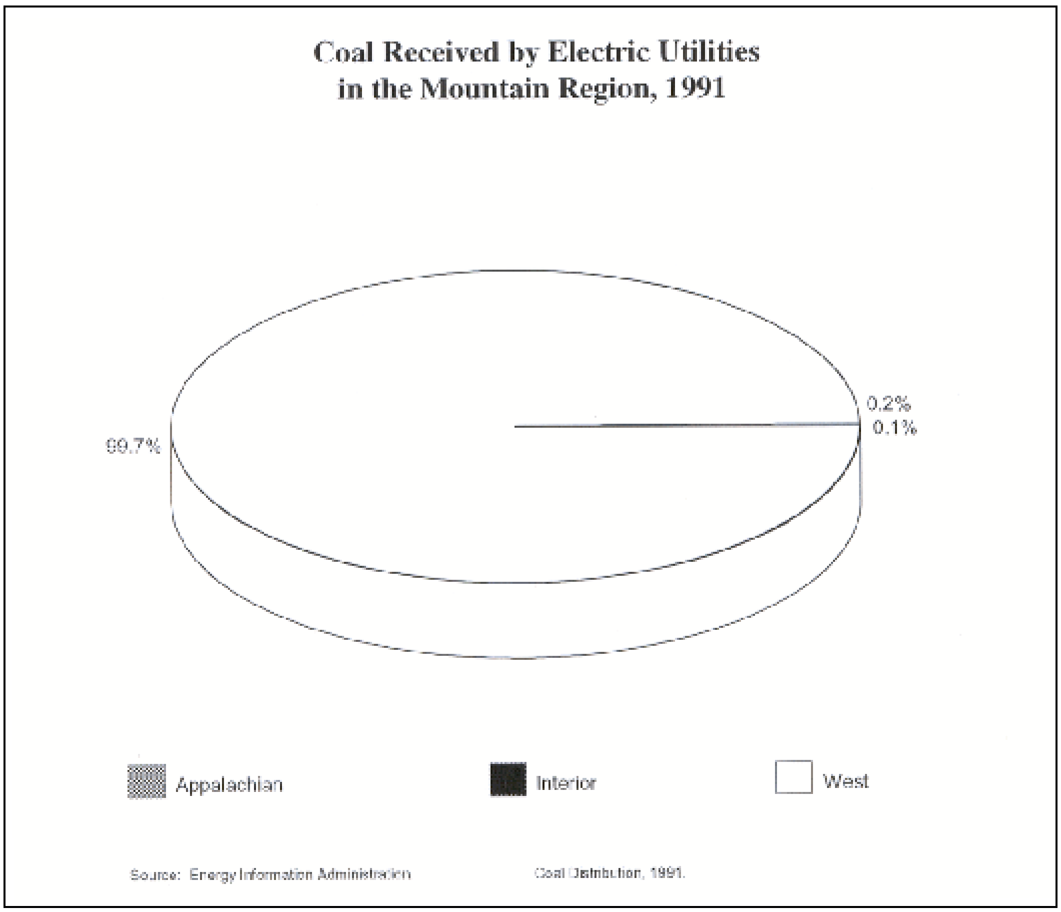

Figure 18

Coal Transportation

Several transportation options exist for coal producers nationwide. However, the majority of coal in the United States is transported by rail; approximately 58 percent of the total in 1991 (Figure 19).[11] The second leading mode of transportation in the United States for delivering coal in 1991 was water transportation. Most of the coal delivered by water in the U.S. makes use of the inland river system, while few transporters use the Great Lakes and tidewater ports. The third leading mode of transportation for coal in 1991 was tramway, conveyer, and slurry pipeline. Tramway and conveyer movements generally travel very short distances and are the primary methods of transporting coal to mine mouth power plants. On the other hand, the only coal slurry pipeline in operation in the U.S. travels a distance of 273 miles.[12] Finally, only 11 percent of the nation's coal moves solely by truck. These movements generally cover short distances.

[11] In Figures 19 and 20, the method of transportation is defined as follows: **water transportation** includes coal hauled to or from water loading facilities by other modes of transportation; **rail transportation** includes coal hauled to or from the railroad siding by truck; **truck transportation** includes shipments where truck was used as the only mode of transportation.

[12] This pipeline is the Black Mesa Pipeline that travels from Black Mesa, Arizona, to southern Nevada.

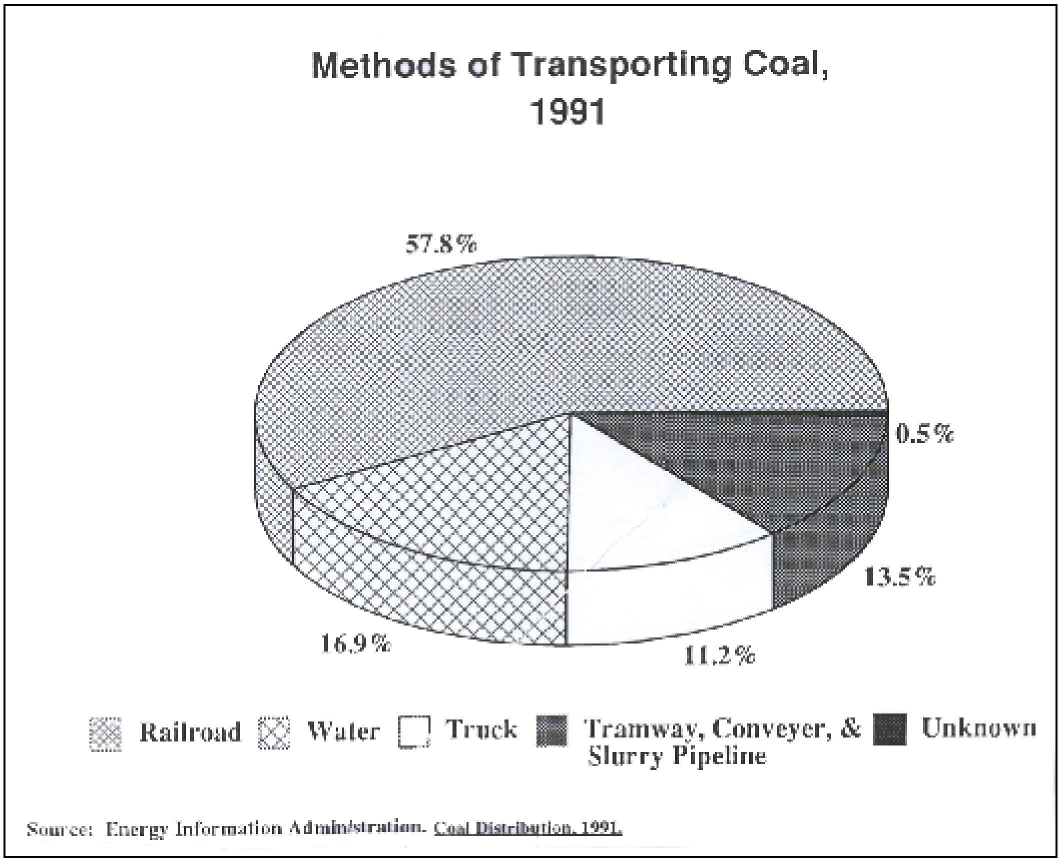
Methods of Transporting Coal,
1991
57.8%
0.5%
13.5%
11.2%
16.9%
Railroad
Water
Truck
Tramway, Conveyer, & Slurry Pipeline
Unknown
Source: Energy Information Administration. Coal Distribution, 1991.

Figure 19

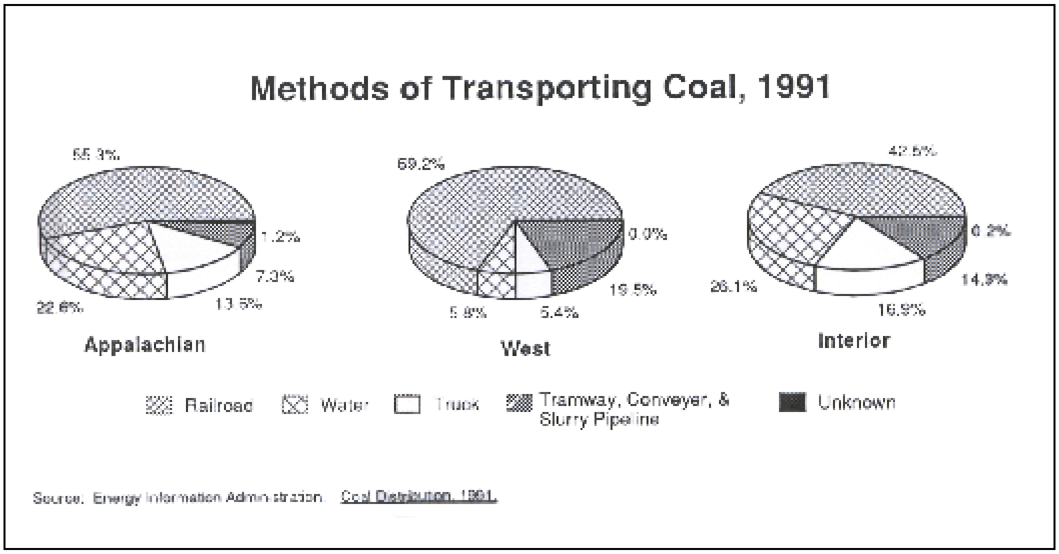

Figure 20

As Figure 20 shows, the West region is far more dependent on rail for transporting its coal than its eastern counterparts. In 1991, nearly 70 percent of the West regions shipments were transported by rail, 6 percent were transported by water, and 5 percent were transported by truck. By comparison, the Appalachian and Interior regions transported 55 and 43 percent of their shipments by rail in 1991, respectively. Moreover, they transported 23 percent and 26 percent of their coal by water, respectively, and 14 percent and 17 percent by truck, respectively. The larger percentages of shipments transported by water and truck from the Appalachian and Interior regions are a function of their proximity to the inland waterway system, and their proximity to major markets. The larger percentage of West coal shipments that are transported by tramway, conveyer and slurry pipeline is primarily a function of the sizeable mine mouth generation in the west.

Figure 21 shows that the West region has traditionally been much more dependent on rail for transporting coal than the Appalachian or Interior regions. The heavy dependence on rail for transporting coal to consumers by western producers suggests that continued efficient rail transportation is essential to future marketing opportunities. Because of this dependence on rail, much of the remainder of this study focuses on rail transportation of coal to electric utilities.

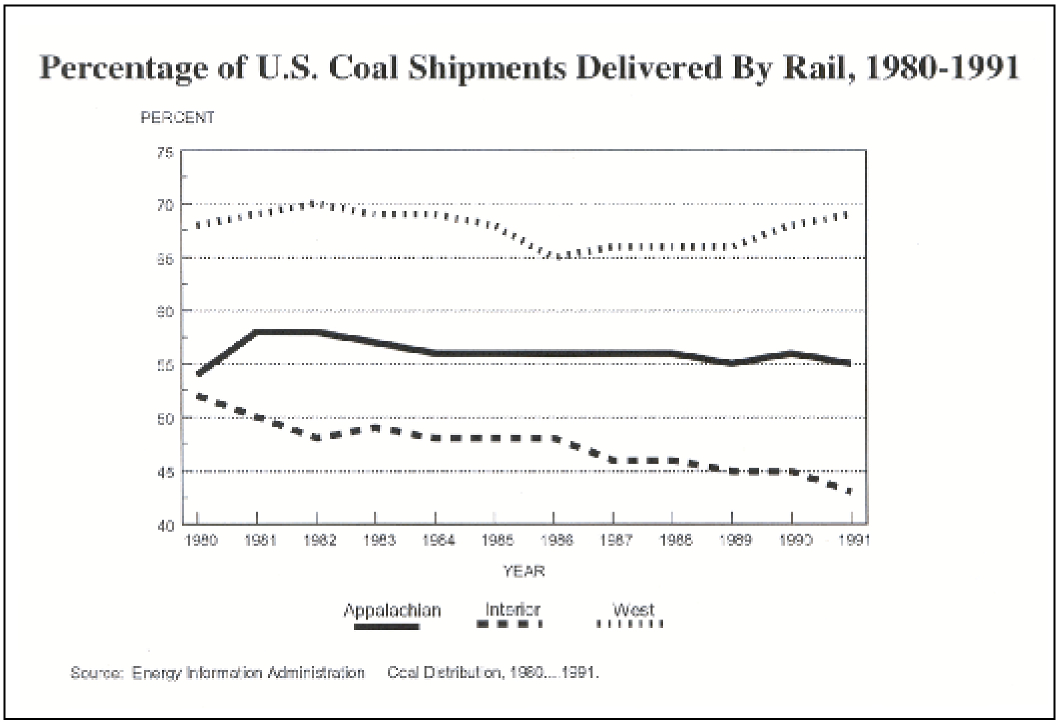

Figure 21

Rail Transportation of Western Coal

As Figure 22 shows, coal is an important commodity for the railroads in terms of total freight and revenues. Coal comprises the most tonnage originated and the highest percentage of revenues of any commodity hauled by Class I railroads. In 1991, coal represented 41 percent of revenue freight originated and 23 percent of total revenues for Class I railroads. The second leading commodity in terms of tonnage originated was farm products, at 10 percent. The second leading commodity in terms of revenues was non-metallic minerals, representing 13 percent of revenues.

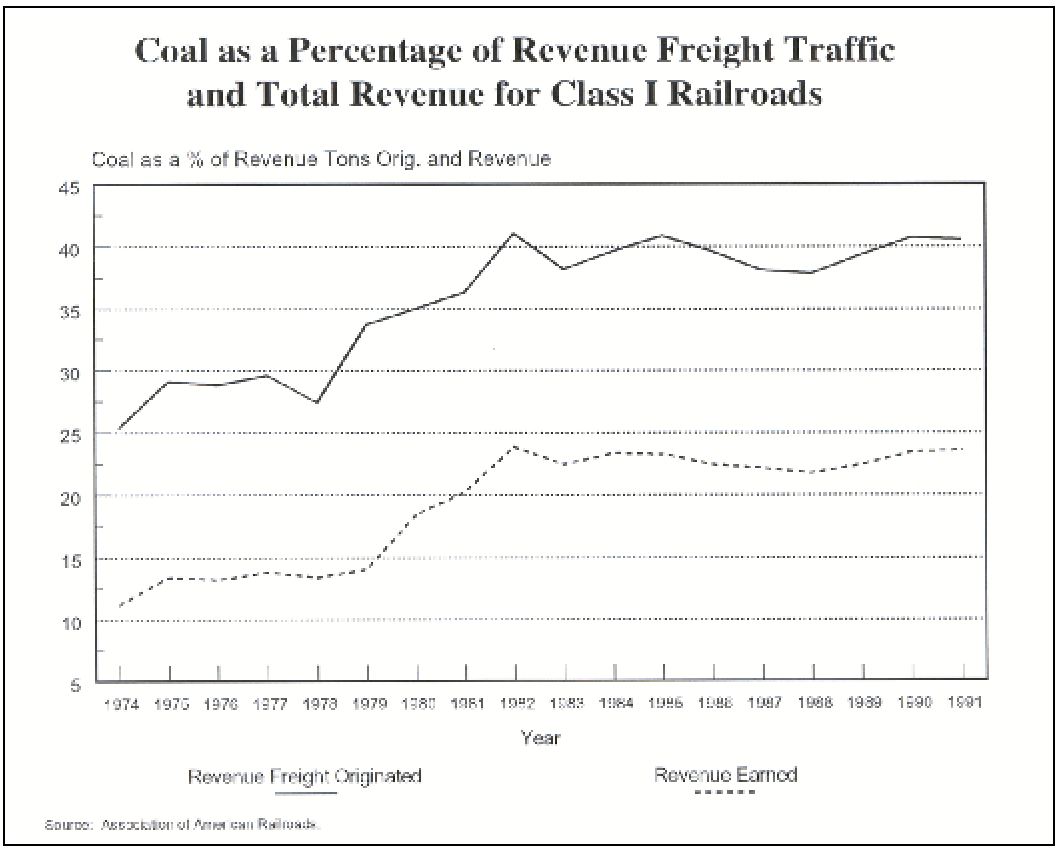

Figure 22

In 1980, coal represented only 11 percent of total revenue freight originated, and 25 percent of revenue earned. Since that time, coal has grown in importance for the railroads and has consistently represented 35 to 41 percent of freight tonnage originated and 21 to 25 percent of total revenues for Class I railroads. Much of this increase in importance of coal as a commodity for railroads can be attributed to the increased exploitation of western coal reserves. The major coal hauling railroads in the west are discussed briefly in the following paragraphs.

There are eight major coal hauling railroads serving western producers.[13] These include the Atchison, Topeka, and Santa Fe, the Burlington Northern, the Chicago & Northwestern, the Denver & Rio Grande, the Kansas City Southern, the Southern Pacific, the Union Pacific, and Utah Railway. Seven of these railroads are Class I railroads, while the Utah is a regional railroad.

The Atchison, Topeka, and Santa Fe (ATSF) serves coal producers in Colfax and McKinley counties in New Mexico. Furthermore, the ATSF handles coal shipments originated by other carriers in the Powder River Basin and in Colorado. In 1989, coal represented only 8 percent of the ATSF's freight revenue, as the railroad carried more than 28 million tons of coal; 8.5 million which were originated by the ATSF.

The Burlington Northern is the west's largest coal hauling railroad, carrying over 172 million tons of coal in 1994, and originating more than 166 million tons.[14] Coal also represents BN's most important commodity in terms of freight revenue and accounted for more than 33 percent of revenues in 1994. The BN originates more than 90 percent of its coal in the Powder River Basin in Wyoming and Montana - an area that accounts for approximately 60 percent of annual coal production in the west. Other origins of coal by the BN include coal produced in the Illinois Basin, Oklahoma, and North Dakota.

---

[13]Fieldston Coal Transportation Manual, 1991.

[14]Moody’s Transportation Manual is used to obtain 1994 carloadings and revenues when available.

Until 1984, the Burlington Northern essentially had a monopoly in the Powder River Basin. In 1984, Western Rail Properties, Inc. (WRPI), a subsidiary of the Chicago & North Western opened, a connector line with the Union Pacific that allowed it to transport coal from the southern portion of the Powder River Basin in Wyoming. In 1986, after the Interstate Commerce Commission (ICC) gave the C&NW permission to build and operate a 10.7 mile spur north of its existing terminal in the PRB, the BN agreed to sell half of the interest in its existing line to the C&NW. Since that time coal has become the C&NW's leading revenue producing commodity, supplying more than 26 percent of freight revenues in 1989, and accounting for more than 65 million tons; 45 million that were originated. Almost all of the C&NW's coal traffic is originated from the Powder River Basin.

The Union Pacific (UP) serves coal producers in the Illinois Basin and the Hanna Basin in Wyoming. However, most of the UP's coal traffic originates in the Powder River Basin on WRPI or in the Uinta Basin in western Colorado and eastern Utah on the Utah Railway and the Denver & Rio Grande Western. The UP is a major western coal hauler, hauling more than 129 million tons of coal in 1994, and originating more than 20 million tons in 1994. In 1994 coal was the second leading commodity hauled on the UP in terms of revenue.

The Denver & Rio Grande Western purchased the Southern Pacific railroad and the St. Louis Southwestern railroad in 1988. These lines operate as one integrated system and are referred to as Southern Pacific Lines (SPL). These lines serve metallurgical (coking) coal producers and steam coal producers in Colorado and Utah. In 1989, coal was the SPL's seventh leading commodity accounting for more than 15 million tons, almost all of which was originated by SPL.

The Kansas City Southern (KCS) railroad hauled more than 15 million tons of coal in 1989, accounting for more than 32 percent of the KCS's revenues in 1989. The KCS serves mostly as a terminating carrier of coal traffic. The KCS terminates much of the coal traffic that originates in the

Powder River Basin on the Burlington Northern and the Chicago & North Western. KCS also originates some coal in Texas.

Finally, the Utah railway (UTAH) serves coal producers in Carbon and Emery Counties in Utah. In 1989, the UTAH originated about four million tons of coal in these counties. This traffic accounted for more than 99 percent of the carrier's traffic, most of which was interchanged with the UP.

The purpose of this section has been to highlight some the major transporters of western coal, and to illustrate the importance of coal to these railroads. Later in the report, competition between railroads will be examined, along with the effects of competition on rates. The next section of the study highlights the history of environmental regulations, and their effects on coal production and markets.

THE CLEAN AIR ACT AMENDMENTS OF 1990

The Clean Air Act Amendments of 1990 were considered a major breakthrough in the nation's and the world's fight against environmental decline. The Clean Air Act of 1990 not only expanded and strengthened existing environmental law, but included a new market-based approach to dealing with the problem of acid rain. The market-based approach for dealing with the problem of acid rain provides a pivotal market opportunity for western coal producers. This section of the report reviews some of the history of environmental laws, how the recent changes represent a marked change in environmental regulation, and how these changes provide opportunity for western coal interests.

The first major federal environmental policy took place in 1963 with the passage of the Clean Air Act. This act increased funding for researching the causes of pollution, and established a legal process for municipalities, states, and the federal government to take regulatory action against sources of pollution. The act gave some focus to emissions by stationary sources such as electric utilities, but placed the major focus of pollution control on automobile emissions.

In 1967, the first attempt by the federal government to create standards for air pollution was made with the passage of the Air Quality Act. This Act called for the establishment of metropolitan air quality regions throughout the United States. Air quality standards were to be developed by states with plans implemented to achieve them. Failure to establish standards and implement plans by the states could result in federal government intervention by the Department of Health, Education, and Welfare. Implementation of the provisions of this act was slow to develop, as the federal government had designated only a small portion of air quality regions. States had not established standards or implemented plans by 1970.[15] Moreover, this act did not establish specific standards for stationary sources such as electric utilities.

As a result of the lack of comprehensive regulations and a concern about the comparative disadvantages that were possible for firms in states where standards and plans were being implemented, President Richard Nixon called for extensive environmental regulations in his January 1970 State of the Union address.[16] In December of 1970, the Clean Air Act was passed. It shifted the responsibility of developing air quality standards to the federal government (through national ambient air quality standards), but continued to place the burden of implementation plans on the states. Thus, while each plan was to include limitations for pollution emissions from stationary sources (e.g. electric utilities), the limitations placed on existing electric utilities could vary widely among states based on the implementation plans put in place by the states. However, some nationwide regulations on new electric utilities regarding emissions were put in place.

The next major piece of legislation that attempted to reduce nationwide pollution levels was the Clean Air Act Amendments of 1977. In the face of a shutdown of automobile production due to a failure

---

[15]Bryner, Gary C. *Blue Skies, Green Politics - The Clean Air Act of 1990.*

[16]Ibid.

to meet tailpipe emission standards, President Jimmy Carter urged Congress to pass amendments before the August congressional recess.[17] The amendments extended the deadlines for meeting various pollution levels and standards by regions, cities, and industries. However, the amendments also increased penalties for noncompliance by stationary sources of pollution, and called for state collection of permit fees from these sources. This act contained a key provision that affected the regional distribution and market share of coal producers. This provision required that all *new* fossil-fuel burning utilities install scrubbers. This stipulation, in essence, prevented high sulfur coal producers in the east from being at a competitive disadvantage.[18] It not only prevented western coal producers from realizing a prime opportunity in terms of market share and production, but it prevented electric utilities from choosing the least cost method of reducing emissions of pollutants. Authorization for the Clean Air Act ended in 1981. Funding for the implementation of this act was achieved by Congress continually passing appropriations resolutions.

Several industry groups, as well as environmental groups, were not satisfied with the 1977 amendments and sought revisions of the Clean Air Act. Industry groups pointed to problems in the Act such as its failure to take into consideration the costs of pollution control equipment, the high price of acquiring permits, and other various provisions. Environmentalists and many in congress were dissatisfied with the perceived lenient methods of enforcement of the Act by the Environmental Protection Agency. The problem of acid rain also had been linked to the emission of sulfur dioxide (SO,) and nitrogen oxides (NO), and the requirement to install scrubbers in plants built since 1977 had largely ignored the major problem of sulfur dioxide emissions, since older plants constituted such a large portion of coal burned.

---

[17]Earlier legislation had mandated that tailpipe emission standards be met by the 1978 model year. The automobile industry had indicated that these standards would not be met. Bryner, Gary C. *Blue Skies, Green Politics - The Clean Air Act of 1990.*

[18]See Ackerman and Hassler. *Clean Coal/Dirty Air - or How the Clean Air Act Became a Multibillion-Dollar Bail-Out for High Sulfur Coal Producers and What Should Be Done About It.*

Steps toward reducing acid rain producing emissions were deemed as important for international relations (particularly with Canada), and as an important issue to the American public.[19]

Throughout the 1980s attempts to amend the Clean Air Act were made, but without resolution due to the conflicting regional, industrial, and environmental interests. Two changes in leadership were considered major breakthroughs in the efforts to amend the Clean Air Act: the election of George Bush as president, and the replacement of Robert Byrd as Senate Majority Leader with George Mitchell.[20] Bush had made several campaign promises regarding the environment, and used environmental issues to distance himself from Ronald Reagan. Byrd had consistently blocked efforts to amend the Clean Air Act, as he was concerned about the loss of jobs in the coal mining industry in West Virginia where high sulfur coal is produced. Furthermore, Mitchell had been one of the leaders in the attempts to amend the Clean Air Act. Both of these developments renewed the belief that effective amendments to the Clean Air Act could be put in place.

In 1989, the Bush Administration introduced an amended Clean Air Act that was markedly different from previous environmental law. The bill contained an innovative market approach that dealt with the problem of acid rain. Whereas traditional environmental regulation placed limitations on pollution sources in terms of the amounts that they could emit, the Bush bill provided a method for allocating pollution rights in the most cost-effective manner. In 1990, the Clean Air Act was finally amended by Congress. In many ways, the act was similar to the bill introduced by the Bush Administration.

For the most part, the Clean Air Act as amended represents a comprehensive, economic, and longrange plan for pollution control. The major provision of the Act is Title IV, the acid rain provision. Likewise, this is the provision that is likely to have the greatest effect on coal production and coal markets,

---

[19]Bryner, Gary C. *Blue Skies, Green Politics - The Clean Air Act of 1990.*

[20]Bryner, Gary C. *Blue Skies, Green Politics - The Clean Air Act of 1990.*

nationwide. The following paragraphs explain the causes of acid rain and highlight the provisions associated with reducing it in the 1990 Clean Air Act Amendments.

In 1990, more than 70 percent of all electricity was generated from fossil fuels, and more than 50 percent from coal.[21] When fossil fuels are burned, significant amounts of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) are emitted. Coal and oil are the two highest emitters of these substances. Scientific evidence has shown that several chemical reactions can occur to sulfur dioxide and nitrogen oxides when they are released into the atmosphere causing their transformation into various chemical products such as sulfates, nitrates, sulfuric acid, and nitric acid.[22] Furthermore, these chemical products can travel several miles or fall to the ground near their source, dropping to the earth in dry form as gases, aerosols, or particulates, or in wet form as rain, fog, or snow. Damage to the environment and animals has led many to believe that these forms of pollution also represent a threat to human health.

The 1990 Clean Air Act targets electric utilities for reducing the emissions of SO, and NO,, because more than two-thirds of all SO, emissions and more than one-third of NO,, emissions are the result of the generation of electricity.[23] The Act has a goal of reducing total annual sulfur dioxide emissions by electric utilities to 10 million tons below the level emitted in 1980, calling for a national cap of 8.95 million tons of sulfur dioxide emissions per year by electric utilities. Furthermore, nitrogen oxides also must be reduced by electric utilities. While both of these acid rain-contributing chemicals are reduced by the Act, the approach used to reduce each is very dissimilar. The reduction of nitrogen oxides is done with the traditional approach of mandating the use of a certain technology. The reduction of sulfur dioxide is

---

[21]Energy Information Administration. *Annual Outlook for U.S. Electric Power, 1991.*

[22]Federal Register. *40 CFR Parts 72 and 73 - Acid Rain Allowance Allocations and Reserves; Proposed Rules.*

[23]Federal Register. *40 CFR Parts 72 and 73 - Acid Rain Allowance Allocations and Reserves; Proposed Rules.*

achieved by limiting total nationwide emissions and allowing those utilities whose costs of reducing emissions are highest to keep on polluting. Thus, the important factor in the amendments that is likely to affect market shares of various coal producers is the SO_2 reduction provision.

The nationwide[24] reduction of sulfur dioxide is to be achieved in three stages. The first stage of the reduction occurred on Jan. 1, 1995, when the 110 largest utilities located in 21 states were required to collectively meet an intermediate level of SO_2 emissions (averaging 2.5 pounds of sulfur dioxide per million BTU used on average from 1985 through 1987) as a maximum. This stage was officially known as Phase I. The second stage of the reduction occurs on Jan. 1, 2000, when essentially all electric utilities in the contiguous United States are required to collectively meet another intermediate (but more stringent) level of SO_2 emissions (averaging 1.2 pounds of sulfur dioxide per million BTU used on average from 1985 through 1987) as a maximum. This stage is known as Phase II, part 1. In the second part of Phase II and beginning in the year 2010, the same electric utilities must collectively reduce sulfur dioxide emissions even further.

Achievement of the various reductions discussed above is realized through a nationwide allocation of sulfur dioxide emission allowances. Each allowance provides the right to emit one ton of sulfur dioxide and can be used by any electric utility. Thus, electric utilities can freely buy and sell sulfur dioxide allowances. They are not bound by any other mandate in regard to sulfur dioxide emissions than to have an allowance for every ton that is emitted. By allowing utilities to trade pollution rights, the most cost-effective solution to reducing pollution should be achieved in theory.[25] This should occur, since

---

[24]It is important to remember that the Clean Air Act (as amended) does not consider the regional distribution of sulfur dioxide. Only the total nationwide production of SO_2 is considered. Several observers have leveled criticism at the amendments for this reason.

[25]Again, it is important to remember that this ignores the distributional impacts of sulfur emissions on the environment.

utilities that would incur high costs from reducing emissions will place a higher value on the sulfur allowances than the utilities where the costs from reducing emissions are not so high. Thus, in an open bidding process, the minimum total costs of pollution control should be achieved as the utilities where the costs of reducing emissions are high will purchase allowances at a price less than or equal to the cost of reducing emissions, while the utilities where the costs of reducing emissions are low will reduce emissions rather than holding allowances.

In many cases the lowest cost method of reducing pollution is likely to be low sulfur coal, as the costs associated with scrubber installation and maintenance are very high. Since more than 86 percent of recoverable low sulfur coal reserves (those emitting less than 1.2 pounds of sulfur dioxide per million British Thermal Units (BTUs) of heat inputs) are located in the west, a great opportunity for market expansion exists for western coal producers.[26] Because of the great distances that western coal producers are from most major population centers, rail transportation will play a critical role in the ability of western coal producers to capitalize on this opportunity. The next section of the report examines rail rates for hauling coal, focussing on the competitive factors influencing rates.

Rail Rates for Coal Transport

As shown previously, nearly two-thirds of western coal is transported by rail to its final destination. Since most of the electric utilities located at distances from western mines where trucking is cost competitive already use western coal, it is likely that most of the future growth in western coal production will depend on low cost rail transportation to shippers. Long distances from consumption regions increase the portion of delivered coal costs of western coal that is due to transportation, and

---

[26]Energy Information Administration. *Estimation of U.S. Coal Reserves by Coal Type - Heat and Sulfur Content.*

therefore magnify the importance of efficient transportation for western coal producers. This section of the report presents a model of rail rates and highlights factors influencing rates that differ between western, midwestern, and eastern coal shipments.

Several studies have examined coal rail rates and the economic rents captured by railroads in transporting western coal. Three of these studies are reviewed in the following paragraphs.

Atkinson and Kerkvliet (1986) developed a model to estimate economic rents captured by railroads, mines, electric utilities, and the state for Wyoming low sulfur coal sold to electric utilities. They measured maximum potential rent captured by the buyer or the seller as the difference between the price of a substitute input and the marginal cost of production (including rail transport). Using a 1980-1982 data set, they found that railroads and coal producers each captured 23 percent of potential rents and that electric utilities captured 47 percent of potential rents. They found that since railroad deregulation, rents shifted toward the railroads. Their study also examined the extent of discriminatory pricing by railroads and coal producers. Their model for examining price discrimination by railroads measures the variation in the percentage markup of rail rates over marginal costs by the volume of coal purchased — a dummy variable equal to unity when the best alternative fuel for the utility is another coal — the percentage contribution of Wyoming coal to BTU input, and the date when the coal contract was signed. The only significant variables in this estimation were volume and the percentage contribution of Wyoming coal to BTU input. Volume had a negative sign suggesting that the elasticity of demand for Wyoming coal was higher for high volume purchasers. The percentage contribution of Wyoming coal to BTU input had a positive sign suggesting that the elasticity of demand is lower for utilities that are heavily dependent on Wyoming low sulfur coal.

Garrod and Miklius (1987) also attempted to measure the ability of railroads to capture rents in the shipment of western coal after deregulation. The authors focused on western coal shipments because of their similarity to a captive market. They estimated the portion of the rents captured by railroads as the outcome of an indeterminate bargaining process between railroads and electric utilities. Economic rents were measured in several ways. First, they measured potential economic rents as the difference between the delivered price of natural gas and the summation of railroad cost and mine mouth price of delivering western coal. In estimating the economic rent captured by railroads in this way, they found that railroads captured a smaller share of rents in 1983 than in 1970, but a larger real dollar amount of rents. Next, they measured potential economic rents as the difference between the delivered price of the best alternative coal and the summation of the railroad cost and mine mouth price of delivering western coal. When estimating economic rents captured with this definition, assuming that western railroads take eastern and midwestern coal rates as a given, they found that railroads serving western coal mines captured almost 20 percent of the potential rent. When estimating, this model assumed that western, eastern, and midwestern rail rates are determined simultaneously, they found that railroads captured 25 percent of potential rents. The authors show that if utilities were truly captive, one would expect the railroads' share of monopoly rent to be one. They suggest that other factors such as geographic competition may constrain railroad pricing power.

Dunbar and Mehring (1990) use the Public Use Waybill sample to construct a hedonic price index for rail coal prices between 1973 and 1983. To construct this price index, they regressed real rail revenues per ton-mile for certain origin-destination pairs on distance and volume. They then fixed volume and distance at their 1973 levels to estimate 1978 and 1983 rail rates at 1973 volume and distance levels. This allowed them to examine rail coal rate changes not due to changes in volume and distance. They found that rail coal rates have increased slightly since deregulation, but that some markets have realized rate decreases while others have realized increases.

Determinants of Variations in Rail Coal Rates

This study does not attempt to measure rents obtained by railroads in shipping coal. A rail rate model was formulated for purposes of providing a greater understanding of factors influencing rail rate variations and for providing predicted rail rates between all origins and destinations of coal to be used in a later section of the report. Rail rates for coal shipments are examined in this study by an analysis of revenue per ton-mile for electric utility contract shipments of coal. Revenue per ton-mile standardizes rail rates on a volume and distance basis for comparison.

Almost all coal is purchased under supply contracts that last one year or more. Nearly 75 percent of the coal supply contracts in existence in 1986 and 1987 were for more than 11 years. Such long-term contracts are prevalent, as utilities attempt to obtain a stably priced future supply of coal. Because of the desire to assure a stable price for some future time period, rail contracts to transport the coal typically coincide with the coal supply contracts. Thus, an analysis of factors influencing rail rates should examine relevant factors at the time when the coal supply contract (and probably the rail contract) was made. This study makes use of a data set that provides information on when coal supply contracts were made.

To examine the variation in rail rates per ton-mile for annual rail volumes of coal moving between coal mines and electric utilities, the influence of supply characteristics and factors influencing the price elasticity of demand are considered. The general model used to explain rail rates for coal is as follows:

$$R = R(S,D)$$

where: R = revenue per ton-mile
S = a vector of supply characteristics
D = a vector of variables affecting the elasticity of demand.

The vector of supply characteristics includes factors influencing costs such as shipment distance, annual volume shipped, and shipment size. These variables all are expected to have a negative influence on revenue per ton-mile, as each displays a negative relationship with unit costs. The vector of supply characteristics also includes the number of railroads in the origin county, as a proxy for market concentration and is expected to have a negative influence on rates.

The vector of variables influencing the elasticity of demand for rail service includes the distance of the origin county from coal barge loading facilities, the prices of alternative fuels at the destination in the year that the coal supply contract was negotiated, and regional and product dummy variables. The distance of the origin county from barge loading facilities and the prices of alternative fuels at the destination are expected to have a positive influence on rates, while the product and regional dummy variables have indeterminant signs, *a priori*. The specific model used to estimate coal rail rates is the following:

$$\begin{aligned} InRTM = {} & \beta_0 + \beta_1 lnVOL + \beta_2 lnDIST + \beta_3 lnUNIT + \beta_4 lnNRR + \\ & \beta_5 InBDIST + \beta_6 lnALTF + \beta_7 0WNRC + \textit{Quality Dummies} + \\ & \textit{Regional Dummies} \end{aligned}$$

where:	RTM	=	revenue per ton-mile
	VOL	=	annual volume shipped over a given route
	DIST	=	rail distance between the origin and destination
	UNIT	=	dummy variable for unit train shipments (1 =unit, 0=single/multi)
	NRR	=	number of railroads in the origin county
	BDIST	=	distance of the origin from the nearest coal barge loading facility
	ALTF	=	alternative fuel price at the destination in the first year of the coal contract (average of oil and natural gas price at the destination)
	OWNRC	=	dummy variable for private ownership of rail cars.

The log-linear specification used allows the estimation of non-linear relationships with a model that does not violate the classical assumption of linearity in parameters. The specification allows the parameter estimates to be interpreted as elasticities.

Each of these variables is expected to have an important relationship with rail rates for coal. Because the model does not include a measure of individual shipment size other than the unit train dummy variable, annual shipment volume measures two effects: the effect of individual shipment size on rates, and the effect of annual volume on rates. Both of these effects are expected to be negative. First, many rail costs such as clerical costs, train crew wages, and locomotive ownership costs are relatively fixed with respect to the volume of an individual shipment. Thus, as individual shipment volume increases, unit costs per ton decline at a decreasing rate. Because variables affecting the elasticity of demand for rail service and the supply characteristics of the rail service are included in the regression, the volume variable is expected to have a negative sign. Second, large volume shippers are likely to have greater bargaining power with the railroads in negotiating shipments, and thus, are likely to experience lower rates, all else constant.

Shipment distance also is expected to have a negative influence on rail rates for coal. Many rail costs such as loading and unloading costs and clerical costs are incurred for every rail movement, and are invariant to distance. These costs are referred to as terminal costs. As rail distance increases, these terminal costs become a smaller portion of total shipment costs that cause costs per mile to decrease. Revenues per ton-mile also are expected to decrease with distance, since demand and other cost variables are included.

In the data sample used, there are single car and unit train shipments. Unit train shipments are those train shipments that are made as part of a dedicated service between a particular origin and destination. They generally are comprised of very large shipment sizes. Because of the increased efficiency associated with such a dedicated service and with large car size blocks, and because other relevant demand and supply factors are included in the estimation, the parameter estimate of the unit train dummy is expected to be negative.

The number of railroads in the origin county is included as a proxy for the degree of intramodal competition realized for a given movement. As the number of carriers in the origin county is increased, the potential for different railroads to compete in direct movements or in interconnections with other railroads increases. Thus, the number of railroads in the origin county is expected to have a negative influence on the revenue per ton-mile realized.

In measuring the degree of intermodal competition, competition is considered for long-haul shipments only. For short-haul movements, the only mode that is cost competitive with rail, and is often preferred to rail, is trucking. Because of the vast interstate highway system in the U.S. and the lack of barriers to entry into the trucking industry, the degree of price competition provided by trucks for short-haul shipments is fairly homogeneous among markets. On long-haul shipments, trucks are not cost competitive with rail and the only form of transportation that can compete with rail on these shipments is barge, truck/barge, or rail/barge combinations. Thus, the degree of intermodal competition realized for a rail coal movement can be proxied by the highway distance of the origin county from coal barge loading facilities. As this distance increases, the revenue per ton-mile realized for a shipment is expected to increase, holding all other variables constant.

The dummy variable included for private ownership of cars is expected to have a negative influence on rail revenue per ton-mile. With private car ownership, the shipper rather than the railroad incurs the car ownership costs. Thus, rail rates using shipper-owned cars do not include the car rental charges associated with shipments made with railroad-owned cars.

The natural gas price at the destination and the oil price at the destination, in the year that the coal supply contract was negotiated, are measures of product competition. Product competition is defined as a constraint on a rail carrier's market power that results from the receiver's ability to substitute other commodities for the commodity being shipped, where the substitute commodities are transported by a different carrier. In this case, natural gas price and oil price changes, relative to coal prices at the destination, may alter the electric utility's fuel choice. The carrier's pricing power should be limited by these alternative fuel prices, which are expected to have a positive influence on revenue per ton-mile.

Regional and quality dummies also are included to capture the effects of geographic and product competition. Geographic competition is defined as a limit on rail rates resulting from the receiver's ability to purchase the same kind of fuel from a different source, when the other source is served by a different carrier. Quality dummies are expected to measure the effects of both geographic and product competition. Because there is a wide variation in coal quality in U.S. coal mines and because many electric utility plants were built for specific types of coal, shipments of coal that are in abundance in several different regions or are easily substituted for are likely to realize lower rates than those that are produced in only a few areas and that are not easily substituted for with another coal. Moreover, regional dummies also are expected to measure geographic and product competition. Shipments of coal from regions where the primary type of coal produced is also produced abundantly elsewhere, or can easily be substituted for, are likely to realize lower rates that those from regions where the primary type of coal produced is not produced abundantly elsewhere and cannot be easily substituted for by another coal. The next section of the report discusses the data problems in examining rail coal rates and the data base used.

Data

An examination of rail rates for coal presents unique data problems. While the Waybill Sample is most often used in rail rate analyses, the extensive use of contracts in the rail transport of coal make any waybill analysis of coal rates misleading. The use of contracts in the rail transport of coal has been increasing over time, and by 1989 more than 90 percent of all rail coal traffic moved by contract. Often the revenues reported to the ICC on particular movements in the Waybill Sample differ substantially from actual revenues. [27]

This study uses the actual rail revenues reported by utilities in their reports to the Federal Energy Regulatory Commission (FERC).[28] The FERC sample covers all jurisdictional utilities with a steam electric generating station greater than 50 megawatts. Between 1979 and 1987 these utilities purchased between 69 and 75 percent of all utility contract tonnage of coal purchased in those years. Due to missing transportation rates for some records, the coverage of the data used in this estimation is somewhat smaller.

The rail rate estimation described above is performed using 1991 FERC data for all shipments that originated and terminated by rail that did not have missing values for transportation rates.[29] The next section of the report shows the rail rate estimation results.

Estimation Results

Table 5 shows the parameter estimates obtained from the rail rate estimation. As the table shows, the model explains nearly 75 percent of the variation in rail contract rates. All parameter estimates have the expected signs, and many are significant at conventional levels.

As the table shows, variables affecting the costs of rail shipments all have the expected signs. Annual volume, the unit train dummy, and distance have parameter estimates that are negative and significant at the 5 percent level. This suggests that rates per ton-mile decrease at a decreasing rate with

[27]See Wolfe for a discussion of the problems associated with using Waybill revenues to approximate actual revenues.

[28]The Coal Transportation Rate Data Base (CTRDB) was developed by the Energy Information Administration from FERC Form 580.

[29]Shipments that traveled by more than one mode are not used in the rate analysis, as transportation rates for each mode are often not separable.

increases in annual volume, shipment volume, and distance. The sign on the parameter estimate for the shipper-owned car's dummy is negative as expected, but is not significant at conventional levels.

TABLE 5: ESTIMATION OF REVENUE PER TON MILE FOR COAL RAIL SHIPMENTS

VARIABLE	PARAMETER ESTIMATE	T-RATIO
Intercept	0.2488	0.85
VOL	-0.0458	4.06*
DIST	-0.5809	18.47*
NRR	-0.0604	1.41
BDIST	0.0514	2.50*
UNIT	-0.1387	2.33*
ALTF	0.0865	1.15
OWNRC	-0.1613	1.28
Interior Region Dummy	-0.3068	3.61*
West Region Dummy	-0.0287	0.11
Quality Dummy (sulfur<.41 lbs. per mmBTU, mmBTU per Ton 14.98-19.99)	-0.26	0.81
Quality Dummy (sulfur .41-.61bs per - mmBTU, mn1BTU per Ton >26)	0.6145	2.78*
Quality Dummy (sulfur .41-.61bs per mmBTU, mmBTU per Ton 23-25.99)	0.2674	0.84
Qualtiy Dummy (sulfur .41-.61bs per mmBTU, mmBTU per Ton 14.98-19.99)	-0.3186	0.94
Quality Dummy (sulfur .61-.831bs per mmBTU, mmBTU per Ton >26)	0.1532	0.65

TABLE 5: ESTIMATION OF REVENUE PER TON MILE FOR COAL RAIL SHIPMENTS

VARIABLE	PARAMETER ESTIMATE	T-RATIO
Quality Dummy (sulfur .61-.831bs per mmBTU, mmBTU per Ton 23-25.99)	0.1569	0.95
Quality Dummy (sulfur .61-.83 lbs per mmBTU, mmBTU per Ton 14.98-19.99)	-0.625	1.75**
Quality Dummy (sulfur .84-1.67 lbs per mmBTU, mmBTU per Ton >26)	0.3421	2.33*
Quality Dummy (sulfur .84-1.671bs per mmBTU, mmBTU per Ton 23-25.99)	0.0477	0.33
Quality Dummy (sulfur .84-1.671bs per mmBTU, mmBTU per Ton 20-22.99)	0.1304	0.48
Quality Dummy (sulfur .84-1.671bs per mmBTU, mmBTU per Ton < 14.98)	-0.2823	0.73
Quality Dummy (sulfur 1.68-2.501bs per mmBTU, mmBTU per Ton > 26)	0.4454	3.05*
Quality Dummy (sulfur 1.68-2.501bs per mmBTU, mmBTU per Ton 23-25.99)	0.262	1.97*
Quality Dummy (sulfur 1.68-2.501bs per mmBTU, mmBTU per Ton 20-22.99)	0.2123	1.29
Quality Dummy (sulfur >2.501bs per mmBTU, mmBTU per Ton > 26)	0.6886	3.61*
Quality Dummy (sulfur >2.501bs per mmBTU, mmBTU per Ton 23-25.99)	-0.0358	0.32

all continuous variables are in natural logarithms
*significant at the 5 percent level
**significant at the 10 percent level
Adj. R^Z = .7482
N=212 F=26.08

The variables used to measure the degree of intermodal and intermodal competition realized for the rail coal shipments also have the expected signs. The number of railroads, a proxy for the level of intermodal competition, has a negative sign in the estimation suggesting that rail rates decrease with decreases in railroad market concentration. However, the parameter estimate was not significant at the 5 percent level. The distance from barge loading facilities, a proxy for intermodal competition realized, has a positive sign and is significant at the 5 percent level. This suggests that barges and truck1barge combinations effectively serve as rate constraints on rail movements.

Geographic and product competition also appear to play an important role in explaining variations in rail rates. As Table 5 shows, the sign on the parameter estimate of the average price of alternative fuels at the destination when the rail contract began is positive, as expected. This suggests, that rail rates are limited by the electric utility's ability to substitute alternative fuels for coal. While the parameter estimate is not significant, its t-ratio is above one suggesting an important role for this variable. Many regional and quality variables are significant as well, and suggest that railroads consider the utility's ability to obtain fuels from other regions or to substitute other fuels for coal.

This section of the report has shown the important roles that factors influencing the supply and price elasticity of demand for rail service play in determining rail coal rates. The next section of the report presents linear programming models that attempt to show the changes in coal flows likely to result from the Clean Air Act Amendments of 1990.

The Impact of the Clean Air Act Amendments on Western Coal

As mentioned in a previous section of the report, the preponderance of the reduction in sulfur dioxide emissions by electric utilities is scheduled to occur in the year 2000, when total sulfur dioxide emissions by electric utilities are limited to 8.95 million tons. While electric utilities are already starting to plan for the change, a greater knowledge of the change in coal flows will be useful to government agencies and coal producers.

This study simulates coal flows that would take place with a minimization of acquisition costs, and the impact that the sulfur limitations and potential transportation rate changes are likely to have on coal flows. This study estimates several linear programming models that provide insight into changes taking place with the CAAA90 and with potential changes in future transportation rates. The base case linear program, which provides a starting point for comparing all other linear programs, minimizes total coal acquisition costs (including transport costs) for electric utilities. Because all of the models make simplifications and abstractions from reality for purposes of tractability, they will not necessarily approximate actual coal flows. Thus, it is the comparison of the impact models to the base case that will provide insight into the possible magnitude of change - not the flows estimated by the various models. The first impact case model simulates coal flows resulting from a minimization of total coal acquisition and boiler retrofitting costs for low sulfur coal, subject to the constraint that utilities limit emissions to the 8.95 million tons of sulfur dioxide specified by the CAAA90 (while accounting for the scrubber installations that are scheduled to take place in Phase I of the CAAA90 as specified in applications to the EPA for Phase I bonuses). The model is expected to show the maximum amount of switching to low sulfur coal that could occur due to the CAAA90, with current transportation rates. There are two reasons that the magnitude of the switch are likely to be overstated. First, some of the coal purchases that currently take place already include sulfur considerations due to early switching or previous environmental regulations. Thus, the base case probably understates the portion of total coal purchased by utilities that is low in sulfur. Second, the impact model does not allow scrubber installation by utilities that do not already have scrubbers in place. Another impact model estimates the costs of scrubber installation and acquisition costs under the scenario where utilities must meet the 8.95 million tons of sulfur dioxide limitation by installing scrubbers. This case estimates the costs of compliance for electric utilities if scrubber installation were the only option that can be compared to the costs of compliance for electric utilities if switching to low sulfur coal were the only option. It will provide an estimate of where scrubbers could be installed most efficiently. The other impact models simulate coal flows under a scenario where coal acquisition (including transportation) costs and boiler retrofitting costs for low sulfur coal are minimized, subject to CAAA90 sulfur limitations, under various changes in nationwide rail rates. Several recent changes in the rail industry and its regulation raise the possibility of large future rail rate changes. Due to large differences among producing regions in the portion of total acquisition costs that are attributed to

$$Min\ Z = \sum_i \sum_j (OP_i + r_{ij}) * Q_{ij}$$

$$s.t. \sum_j Q_{ij} \le a_i \ \forall\ i\ ,$$

$$\sum_i Q_{ij} * BTT_i \ge b_j \ \forall\ j$$

transportation, nationwide changes in rail rates could have a significant impact in regional shares of coal production. These impact models are designed to show the possible magnitude of such changes.

The base case model, which will provide a starting point for assessing the impacts of changes in the other models, is shown below:

where:	Q_{ij}	=	quantity shipped from mines in county I to plants in county j in tons
	Op_i	=	average origin price per ton of coal from mines in county I
	r_{ij}	=	the average rail rate per ton of transporting coal from origin county I to destination county j
	BTT_i	=	average BTU per ton of coal from mines in county I
	a_i	=	capacity in tons of mines in county I
	b_j	=	quantity demanded by utilities in county j in BTUs.

In this base case model, there are no constraints on coal sulfur content. The reason that no sulfur constraints are included in the base case is because previous “clean air” legislation mandated scrubber installation, rather than allowing utilities to pursue the least cost methods of sulfur reduction. Thus, under pre-CAAA90 laws, utilities did not have the option of choosing low sulfur coal or scrubber installation depending on costs. Instead, they installed scrubbers when mandated to do so, and purchased the coal that could provide the most energy production at the least private cost (where transportation is one component of this cost).

In issuing permits to utilities to emit sulfur dioxide, and allowing these permits to be freely exchanged, the CAAA90 allow electrical utilities to choose the least cost method of reducing pollution. They also suggest that a minimization of overall electric utility sulfur dioxide control costs will take place. The reason is very simple, as shown by a hypothetical example. Suppose that there are a total of two electrical utilities in the U.S. Utility A has a cost of reducing sulfur dioxide of $300 per ton, while utility B has a cost of reducing sulfur dioxide of $100 per ton. Further, suppose that each utility has one permit to emit a ton of sulfur dioxide, and that each utility would emit two tons of sulfur dioxide without any attempts at reducing pollution. Utility A would be willing to pay a price only slightly smaller than $300 for utility B's permit, while utility B would be willing to sell its permit for a price slightly higher than $100. After the sale, utility A will own both permits and utility B will pursue operations aimed at reducing sulfur dioxide. The total resource cost associated with reducing sulfur dioxide will amount to $200. On the other hand, under a system where no exchange is allowed, the total resource cost associated with reducing sulfur dioxide would amount to $400. Thus, under a system where exchange is allowed, mutually beneficial exchange ensures that firms with the lowest costs of reducing pollution are the ones that use resources for pollution control.

For each firm that does use resources for pollution control, the lowest cost method of reducing pollution may entail a switch to low sulfur coal or the installation of a scrubber. The switch to low sulfur coal may result in higher acquisition costs due to longer distance transportation, or may result in some capital investment costs, as plants often must be retrofitted to use western coal. Similarly, the installation of a scrubber will result in capital investment costs. Ideally, an impact case linear (or nonlinear) program

$$\min Z = \sum_i \sum_j [(OP_i + r_{ij} + ER_j \cdot BTT_i \cdot E_i \cdot LS_i \cdot PHS_j +$$

$$WR_j \cdot BTT_i \cdot W_i \cdot LS_i \cdot PHS_j) \cdot Q_{ij}] + \sum_j NS_j \cdot SC_j \cdot \theta_j$$

$$\sum_j \text{[illegible]} \le \sum_j \text{[illegible]}$$

$$\sum_i Q_{ij} \le a_i \ \forall\ i.$$

$$\sum_i (Q_{ij} * BTT_i) \ge b_j \ \forall\ j$$

would minimize the total scrubbing and acquisition costs of coal, allowing each utility to pursue the least cost method of reducing pollution. Such a program could be formulated as follows (non-linear program):

where: TSE = $(S_i * 2)(1 - V_j * .9)$

	Q_{ij}	=	quantity shipped from mines in county i to plants in county j in tons
	V_i	=	proportion of county j's generation that is scrubbed (Each utility is assumed to have a scrubber if the plant was built after 1977. Plants that stated their intention to retrofit for scrubbers to comply with Phase I requirements also are assumed to have a scrubber.)
	SA_j	=	sulfur allowances for utility plants in county j (one allowance permits the plant to emit one ton of sulfur per year)
	Op_i	=	average origin price per ton of coal from mines in county i
	S_i	=	average tons of sulfur per ton of coal from mines in county i
	ER_j	=	the average cost per BTU of retrofitting plants in county j for low sulfur eastern coal (less than .61 lbs. of sulfur per million BTU)
	Wr_j	=	the average cost per BTU of retrofitting plants in county j for low sulfur western coal (less than.61 lbs. of sulfur per million BTU)
	NS_j	=	new scrubber capacity installed in county j
	SC_j	=	average cost per BTU of retrofitting and operating scrubbers on plants in county j
	BTT_i	=	average BTUs per ton of coal from county i
	E_i	=	dummy for counties located in the eastern coal producing region
	W_i	=	dummy for counties located in the western coal producing region
	LS_i	=	dummy for counties where the average sulfur content of coal is less than .61 lbs. per million BTU
	PHS_i	=	dummy for destination counties that use coal with a sulfur content of more than .61bs. per BTU in the base case
	r_{ij}	=	the average rail rate per ton of transporting coal from origin county i to destination county j
	a_i	=	capacity in tons of mines in county i
	b_j	=	quantity demanded by utilities in county in BTUs.

By minimizing the total scrubbing and acquisition cost of coal, and by limiting the total sulfur dioxide emissions by electrical utilities to the number of allowances issued, the above impact case nonlinear program would simulate the coal purchases and scrubber installations under circumstances where the firms with the lowest pollution control costs are those that use resources to control sulfur dioxide emissions and where each firm uses the lowest cost method of reducing pollution. Thus, the coal purchases and scrubber installations that are likely to take place under the CAAA90 are simulated by this model. However, because of the large computer resources needed to estimate this model, it could not be estimated in this study.[30] Thus, two models are estimated to show the potential extremes of the impacts of the CAAA90. The first model minimizes acquisition costs and retrofit costs for low sulfur coal subject to the total sulfur constraint imposed by Phase 11 of the CAAA90, without allowing scrubber installation. The second model minimizes retrofit and operation costs of new scrubbers installed to meet Phase II requirements of the CAAA90, without allowing fuel switching.

The first impact case linear program is exactly the same as the linear program that allows utilities to choose the least cost method of reducing pollution, with the exception of its failure to allow scrubber installations. As previously stated, the model is likely to overstate the switch to low sulfur coal. Nonetheless, it will provide insight into the potential magnitude of the switch. The linear program used to

$$\begin{aligned} Min\ Z = \textstyle\sum_i \sum_j \ [(&OP_i + r_{ij} + ER_j * BTT_i * E_i * LS_i * PHS_j + \\ &WR_j * BTT_i * W_i * LS_i * PHS_j\ ) * Q_{ij}] \\ s.t.\ \textstyle\sum_{ij} (TSE_{ij} * Q_{ij}) &\le \textstyle\sum_j SA_j\ . \\ \textstyle\sum_j\ Q_{ij} &\le a_i\ \forall\ i\ , \\ \textstyle\sum_i\ (Q_{ij} * BTT_i) &\ge b_j\ \forall\ j \end{aligned}$$

model the first impact case is shown as follows:

where:	TSE	(Si * 2) (1 - V_j*.9)
	Qij	quantity shipped from mines in county i to plants in county j in tons
	V_j	proportion of county j's generation that is scrubbed (Each utility is assumed to have a scrubber if the plant was built after 1977. Plants that stated their intention to retrofit for scrubbers to comply with Phase I requirements also are assumed to have a scrubber.)

[30]The computer program necessary to estimate this model has been written, and the data necessary to estimate it has been collected. However, upon trying to run the model, the computer ran out of memory.

SA_j sulfur allowances for utility plants in county j (one allowance permits the plant to emit one ton of sulfur per year)

Op_i average origin price per ton of coal from mines in county i

S_i average tons of sulfur per ton of coal from mines in county i

ER_j the average cost per BTU of retrofitting plants in county j for low sulfur eastern coal (less than .61 lbs. of sulfur per million BTU)

WR_j the average cost per BTU of retrofitting plants in county j for low sulfur western coal (less than.61 lbs. of sulfur per million BTU)

BTT_i average BTUs per ton of coal from county i

E_i dummy for counties located in the eastern coal producing region

Wi dummy for counties located in the western coal producing region

LS_i dummy for counties where the average sulfur content of coal is less than .61 lbs. per million BTU

PHS_j dummy for destination counties that use coal with a sulfur content of more than .6 lbs. per BTU in the base case

r_{ij} the average rail rate per ton of transporting coal from origin county i to destination county j

a_i capacity in tons of mines in county i

b_j quantity demanded by utilities in county j in BTUs.

While the first impact model overstates the potential coal switching that would take place under the Phase II requirements of the CAAA90, the second impact model simulates scrubber installations in the event that CAAA90 sulfur limitations were met without fuel switching. Although neither of the two models will simulate the coal flow changes that will take place with the Clean Air Act Amendments, each will provide insight into the potential costs to utilities from switching and from scrubber installation, the potential extremes in terms of the number of utilities switching or installing scrubbers, and the potential extremes in terms of the market share gains made by producing regions. Since the first model requires utilities to meet sulfur limitations through switching and the second requires them to meet sulfur limitations through scrubber retrofitting, a comparison of utility locations that take the action of switching in impact Case I to those locations that take the action of installing scrubbers in impact Case II may provide insight into some of the utility locations where there is a definite advantage associated with pursuing one strategy or the other. The second impact model is formulated as follows:

$$\min Z = \sum_j SC_j * b_j * NS_j$$

$$s.t. \sum_{ij} (TSE_{ij} - (NS_j * 2 * .9 * S_i)) * QB_{ij} \leq \sum_j SA_j$$

$$NS_j + V_j \leq 1$$

where: V_j = proportion of county j's generation that is scrubbed (Each utility is assumed to have a scrubber if the plant was built after 1977. Plants that stated their intention to retrofit for scrubbers to comply with Phase I requirements are also assumed to have a scrubber.)

NS_j = new scrubber capacity installed in county j

SCj = average cost per BTU of retrofitting and operating scrubbers on plants in county j

b_j = quantity demanded by utilities in county j in BTUs

SA_j = sulfur allowances for utility plants in county j (one allowance permits the plant to emit one ton of sulfur per year)

S_i = average tons of sulfur per ton of coal from mines in county I

QB_{ij} = quantity shipped from origin county i to destination county j in the base case

In addition to the two impact case studies presented above, the change in coal flows is simulated under the model where all sulfur dioxide reductions are made through fuel switching and where nationwide coal rail rates change. Because of continual improvements in rail productivity, recent changes in rail regulatory oversight, and a changing structure of the rail industry, it is highly likely that overall real rail rates will change in the future. By understanding the potential changes in coal flows resulting from various rail rate changes, a greater understanding of potential market opportunities can be obtained by making an assessment of the likely future changes in rail rates.

Data Used for the Linear Programs

To estimate these models, several data items are necessary. These include: the origin price of coal per BTU at each origin mine in the U.S., an estimate of plant retrofitting costs for switching to western coal for those not previously using western coal, identification of plants already using western coal, an estimate of the rail rate per BTU of transporting coal from each mine to each utility plant, an estimate of the truck rate per BTU of transporting coal from each mine to each utility plant, an estimate of the cost of installing and operating scrubbers in utilities not previously equipped with them, an estimate of sulfur and BTU content of coal produced at each mine, the total number of sulfur allowances available to all utilities, a three year average of the amount of electricity that has been generated by each utility, the heat rate - or number of BTUs needed to generate a kilowatt-hour for each utility, and an estimate of the available reserves of each mine. Descriptions of the data items are provided in Table 6.

Table 6: Data Sources for the Linear Programs

Data Item	Source
Average tons of sulfur per ton of coal from each producing county	U.S. Geological Survey. *Coal Quality Database: Version 1.3.*
Average BTU per ton of coal from each producing county	U.S. Geological Survey. *Coal Quality Database: Version 1.3.*
Average price per ton of coal from each producing county (1991 $)	Energy Information Administration. *Resource Allocation and Mine Costing Model (1992).*
Capacity of mines in each producing county (existing and new)	Energy Information Administration. *Resource Allocation and Mine Costing Model (1992).*
Number of railroads in each producing county	TRANSCAD - GIS Software and the FRA GIS railroad database
Distance of each producing county to coal barge loading facilities	TRANSCAD - GIS Software, Oak Ridge Laboratories facilities highway database, and Fieldstone Coal Transportation Manual
Average annual (three year avg. 1991-93) electric utility generation in KWH for each county (total county generation done where coal is the primary fuel)	Energy Information Administration, EIA *759,* “Monthly Power Plant Report.”
Average heat rate - BTU per KWH - for each destination county	Energy Information Administration, EIA 860, “Annual Electric Generator Report.”

Table 6: Data Sources for the Linear Programs

Data Item	Source
Average cost per KWH of retrofitting utility plants for low sulfur eastern and western coal	Case study estimates by Rupinskas and Hiller, "Considerations for Switching from High-Sulfur Coal to Low Sulfur Coal," are used for estimates of retrofit costs per kilowatt of nameplate capacity. Annualized costs are estimated using a *30* year plant life and an interest rate of *7* percent (annualization factor = .0806).
Year of initial operation for each coal burning utility plant in the U.S.	Energy Information Administration. *Inventory of Power Plants in the United States, 1993.*
Average rail rate from each origin county to each destination county	Rail rates are estimated using the rate function shown previously, along with the rail distances between each origin and destination estimated with TRANSCAD and the FRA's rail line database, the number of railroads in each producing county, the distance of each origin county to barge loading facilities, and mean values of other variables included in the rate function.
Total Phase II allowances available to utilities that currently use coal to produce electricity	Environmental Protection Agency. *Acid Rain Allowance Allocations and Reserves; Proposed Rules,* and EIA form 759.
Plants that have or will install scrubbers as part of Phase I requirements	Energy Information Administration. *Electric Utility Phase I Acid Compliance Strategies for the Clean Air Act Amendments of 1990.*
Average operating and maintenance costs for retrofitted scrubbers	A study by Decision Analysis Corporation of Virginia, "Regression Models for Analysis of Retrofit Flue Gas Desulfurization Unit Cost and Performance," is used to estimate costs per killowatt of nameplate capacity. The costs are annualized using the 30 year plant life and 7 percent interest used earlier. Annualized costs are divided by generation to get costs per KWH.
Average retrofit costs for scrubbers	Estimated in an ensuing regression.

One important data issue that has not been addressed deals with estimating a scrubber retrofit cost per killowatt-hour for all electric utilities that don't already have scrubbers in place. Fortunately, previous estimates of scrubber retrofitting costs have been made.

Two different approaches have been used to estimate the costs associated with scrubber retrofitting. These two approaches include an econometric approach that uses actual scrubber retrofitting and operation data, and an economic engineering approach that examines the typical characteristics of an electric boiler and estimates installation costs of the most efficient scrubber retrofit configuration.

There are advantages and disadvantages associated with each approach. Advantages of the econometric approach are that it uses actual data and shows the variations in costs associated with different configurations and boiler characteristics. Disadvantages are that it uses data that is based on the technology in existence at the time of scrubber retrofitting, while the engineering approach makes retrofit cost estimates based on current technology. Because of the wide variation in the sizes of electrical utility plants in the U.S., an estimate of retrofitting costs that shows variations with plant size is imperative. Thus, the econometric approach to estimating scrubber retrofit costs is used.

A previous study by Decision Analysis Corporation (DAC) has estimated both capital construction costs and operating and maintenance costs for retrofitting electrical utilities with scrubbers using a sample of 32 utilities that had scrubbers retrofitted to their plants between 1972 and 1990.[31] This sample of 32 included all of the retrofits that occurred on electrical utility plants with at least 100 megawatts of generating capacity that were in operation between 1985 and 1991.

In estimating the capital construction costs, DAC used measures of the retrofit scrubber size needed for the particular plant, the design operating efficiency of the scrubber, the type of scrubber technology used, and the vintage of the boiler as explanatory variables. Specifically, their estimation of capital construction costs was formulated as follows:

$$CAPKW = \beta_0 + \beta_1 FGDMOD + \beta_2 MAXMW + \beta_3 BGYEAR +$$

$$\beta_4 \mathrm{SULFDEF} + \beta_5 TYPE2 + \epsilon$$

[31]Decision Analysis Corporation of Virginia, "Regression Models for Analyzing Retrofit Flue Gas Desulfurization Unit Costs and Performance," report prepared for the Energy Information Administration (Vienna, VA, May 1993).

where:	CAPKW	=	real installed capital construction costs per killowatt of nameplate electric capacity
	FGDMOD	=	number of absorber modules
	MAXMW	=	generator nameplate capacity in megawatts
	BGYEAR	=	boiler in-service year
	SULFDEF	=	percentage design sulfur removal efficiency
	TYPE2	=	absorber type dummy variable (1=tray type, 0=otherwise)
	ϵ	=	error term.

While DAC obtained the expected results in estimating this model, the extremely limited degrees of freedom provided by the data set and the linear estimation procedure are problematic. While the sample size of utilities in operation between 1985 and 1991 that had scrubbers retrofitted cannot be changed, the functional form that was estimated can be.

There is intuitive and empirical support for believing that estimated relationship is not linear. First, the intuitive support for a nonlinear relationship is provided by examining the reasons for particular sign expectations on some of the variables. In particular, DAC hypothesized that increases in the size of the scrubber to be installed would result in decreased capital construction costs per kilowatt of generating capacity. These economies are presumably the result of a large fixed cost component associated with retrofitting a scrubber, and some incremental costs associated with increasing scrubber size. Thus, as scrubber size increases, the fixed cost component becomes a smaller and smaller portion of total costs, suggesting that average cost decreases. However, this explanation does not suggest that there is a linear relationship between scrubber size and capital construction costs per kilowatt of generating capacity. It does suggest that total capital construction costs increase at a decreasing rate with increased scrubber size and, that as a result, average costs decrease at a decreasing rate with increases in scrubber size. Similarly, the relationships between average capital construction costs per kilowatt of generating capacity and the sulfur removal efficiency or the initial year of operation also are unlikely to be linear. In addition to the intuitive support for nonlinearity, there is empirical support. In using the parameter estimates obtained from the linear model with mean characteristics of all variables except MAXMW, estimated capital construction costs per kilowatt of generating capacity are negative for some nameplate capacities used in the sample. This suggests that the linear estimation does not provide a good fit.

Because of the problem, we re-estimated the same model with a semi-log specification. This allows the nonlinear relationships to be captured with a model that remains linear in parameters. Specifically, the following specification is used:

$$CAPKW = \beta_0 + \beta_1 FGDMOD + \beta_2 MAXMW + \beta_3 BGYEAR +$$
$$\beta_4 \mathrm{SULFDEF} + \beta_5 TYPE2 + \epsilon$$

This specification is exactly the same as that used by DAC with the exception of the nonlinear relationships between the dependent and independent variables. The estimated model is shown in Table 7. As the table shows, the nonlinear model provides a good fit with an adjusted R^2 of .81. The estimated parameters, along with the mean values of FGDMOD, SULFDEF, and B GYEAR are used to estimate a scrubber retrofit cost for all electrical utilities that were built before 1977.

Table 7: Estimation of ln(CAPKW)

Variable	**Parameter Estimate**	**t-ratio**
Intercept	-0.7123	0.71
FGDMOD	0.3825	4.09*
MAXMW	-0.0018	2.43*
BGYEAR	0.0169	1.28
SULFDEFF	0.0486	7.59*
TYPE2	0.4227	1.67

*significant at the 5 percent level
Adjusted R^2=.8069
F = 21.06
S.E.E. = 0.4215

Model and Data Issues

As previously discussed, the models used in this study make abstractions from reality so that they may be tractable. Some important abstractions include, but are not limited to, the model's use of an exogenous price, the use of only coal burning utilities, and a focus that is strictly on the electrical utility sector. Certainly, it must be recognized that these and other abstractions also may cause the model results to stray from reality. However, such abstractions must be made to assure a model that is manageable and estimable with available resources.

Similarly, the data contains several apparent anomalies. These include apparent inaccuracies in several prices and coal quality. However, the data used is believed to be the best available. It would be unscientific to make corrections in apparent anomalies where one is familiar with the data, while not knowing whether the other data is correct or not. Therefore, this study uses the unaltered data.

Base Model Results

Table 8 shows the coal production simulated by the model that minimizes acquisition costs with no consideration of sulfur dioxide limitations. As the table shows, western Kentucky is simulated to be the largest coal producer with a market share of more than 21 percent. Second is Wyoming at nearly 19 percent. If the state tonnages are aggregated into the three producing regions, the base model shows 51 percent of the coal to be produced in the Interior region, 26 percent in the Western region, and 23 percent in the Appalachian region. This is much different than the actual percentages where approximately 20 percent is produced in the Interior region, 35 percent produced in the Western Region, and 45 percent produced in the Appalachian region. While there are several potential reasons for this, it backs the notion that the base model is most useful for comparison purposes. These percentages may differ so much from reality for several reasons, including: some utilities have already begun to switch to low sulfur coal due to previous regulations or to make a smoother adjustment to the ensuing switch; the flows modeled are only for electric utility purchases of coal, which comprises only two-thirds of the Appalachian region's coal sales; and more than 90 percent of the other two regions' coal sales, and/or because the coal quality and price data may not be reflective of actual data. Table Al shows the coal flows between origin and destination states under the base case.

TABLE 8: COAL PRODUCTION SIMULATED BY MINIMIZING TRANSPORT COSTS WITH NO CONSIDERATION OF COAL SULFUR CONTENT

STATE	TONS (1,000)	MARKET SHARE
WKY	156,671	21.02%
WY	138,443	18.57%
TX	113,340	15.20%
IN	76,120	10.21%
PA	48,071	6.45%
WV	45,260	6.07%
OH	27,014	3.62%
ND	21,424	2.87%
VA	20,124	2.70%
EKY	13,560	1.82%
AZ	12,900	1.73%
TN	10,842	1.45%
IL	10,650	1.43%
MT	9,543	1.28%
IA	9,461	1.27%
OK	8,214	1.10%
UT	7,850	1.05%
MD	6,850	0.92%
CO	6,504	0.87%
LA	2,623	0.35%

As previously stated, Western coal producers are extremely reliant on efficient transportation. Often large portions of total acquisition costs by utilities are accounted for by transport costs. Table 9 shows the origin price, the total acquisition costs, and the portion of total acquisition costs accounted for by transportation for coal from all origin states. As the table shows, Wyoming's shipments are heavily dependent on efficient and reliable transportation as nearly 60 percent of the total acquisition costs of

Wyoming coal are due to transportation charges. Second is North Dakota, where more than 32 percent of acquisition costs are due to transportation. This is amazing in light of the fact that all North Dakota Coal is simulated to stay in North Dakota.

TABLE 9: TRANSPORTATION AS A PERCENTAGE OF TOTAL ACQUISITION COSTS BASED ON FLOWS SIMULATED BY MINIMIZING TRANSPORT COSTS WITH NO CONSIDERATION OF SULFUR CONTENT

PRODUCING STATE	ORIGIN PRICE (AVERAGE)	RAIL RATE (AVERAGE)	PROPORTION OF TOTAL COST DUE TO TRANSPORTATION (%)
WY	$8.20	$12.78	58.82
ND	$7.84	$3.75	32.19
MD	$24.96	$8.30	24.96
VA	$27.45	$8.76	23.69
TX	$12.20	$4.31	22.34
WKY	$23.14	$6.40	21.14
AZ	$19.69	$5.41	20.06
IA	$18.77	$4.74	19.81
EKY	$23.99	$4.32	14.67
TN	$27.63	$4.61	13.89
WV	$27.17	$4.82	13.49
IN	$23.60	$3.74	12.71
OK	$27.48	$2.73	8.67
UT	$23.14	$2.18	7.93
PA	$28.90	$2.73	7.82
1L	$28.48	$0.80	2.55
OH	$27.37	$0.47	1.45
CO	$20.64	$0.00	0.00
LA	$15.58	$0.00	0.00
MT	$11.03	$0.00	0.00

Table 10 shows the coal production simulated by the impact case model that minimized acquisition and retrofitting costs for low sulfur coal subject to meeting the sulfur dioxide restrictions mandated by the

CAAA90. As the table shows, Wyoming gained a large boost in market share with an increase of more than seven percentage points. The West and Appalachian regions gained a great deal of market share at the expense of the Interior region. The West's market share increased from 26 percent in the base case to 34 percent, while the Appalachians increased from 23 percent to 33 percent. Conversely, the Interior region's share dropped from 51 percent to 33 percent. Not only did the West's market share increase, but its tonnage produced increases greatly. The West realized an increase in coal production of nearly 12 percent in this case. The Appalachian region realized an increase in coal production of more than 41 percent. Table A2 shows coal flows under this impact case.

TABLE 10: COAL PRODUCTION SIMULATED BY MINIMIZING TRANSPORT COSTS SUBJECT TO SULFUR LIMITATIONS, WITH CURRENT RAIL RATES

STATE	TONS	MARKET SHARE
WY	190,670	25.67%
TX	131,614	17.72%
W V	123,054	16.57%
WKY	53,779	7.24%
VA	50,570	6.81%
IN	43,561	5.87%
EKY	28,005	3.77%
ND	21,148	2.85%
PA	20,652	2.78%
AZ	12,900	1.74%
TN	12,898	1.74%
MT	10,263	1.38%
UT	7,850	1.06%
IA	7,700	1.04%
MD	7,651	1.03%
CO	6,509	0.88%
OK	6,392	0.86%
AR	4,507	0.61%
LA	2,623	0.35%

Table 11 shows the estimated origin price per ton, the estimated transport cost per ton, and the portion of transport and origin price accounted for by transportation. As the table shows, transportation charges now account for nearly 62 percent of total acquisition costs for Wyoming coal on average. For several other states, the charges for transportation account for more than 20 percent of the total acquisition costs.

TABLE 11: TRANSPORTATION AS A PERCENTAGE OF TOTAL ACQUISITION COSTS (DOES NOT INCLUDE RETROFIT COSTS) BASED ON FLOWS SIMULATED BY MINIMIZING TRANSPORT COSTS SUBJECT TO SULFUR LIMITATIONS

PRODUCING STATE	ORIGIN PRICE PER TON (AVERAGE)	RAIL RATE PER TON (AVERAGE)	PROPORTION OF TOTAL COST DUE TO TRANSPORTATION
WY	$8.05	$13.95	61.64%
ND	$7.84	$4.57	36.81%
VA	$27.45	$10.92	28.05%
TX	$12.20	$5.18	25.68%
EKY	$25.66	$8.84	24.91%
AR	$32.57	$9.47	22.47%
MD	$27.11	$7.75	22.32%
IA	$18.77	$5.44	21.96%
AZ	$19.69	$5.75	21.01%
WV	$29.58	$7.35	19.11%
WKY	$22.96	$5.08	17.47%
TN	$28.48	$5.26	15.11%
IN	$23.68	$4.19	14.51%
OK	$27.56	$3.82	10.62%
IL	$29.96	$2.93	8.92%
UT	$23.14	$2.18	7.93%
PA	$29.71	$2.68	7.31%
MT	$11.03	$0.64	3.11%
CO	$20.65	$0.00	0.00%
LA	$15.58	$0.00	0.00%

Table 12 provides a comparison of the acquisition costs in the base case and those in the switching case. As the table shows, Illinois utilities incur the greatest increase in costs as the preponderance of Illinois coal switches from Illinois origins to Wyoming origins. Similarly, the majority of Kentucky coal purchased by electric utilities in Kentucky switches from western Kentucky to eastern Kentucky.

TABLE 12: COMPARISON OF COAL ACQUISITION COSTS FOR UTILITIES BETWEEN THE BASE CASE AND THE SWITCHING CASE (SWITCHING CASE INCLUDES RETROFIT COSTS)

DESTINATION STATE	BASE (MILLION $)	IMPACT (MILLION $)	PERCENT CHANGE
IL	680.06	779.22	14.58
KY	853.19	951.01	11.46
MO	562.83	619.55	10.08
MA	154.15	169.54	9.98
PA	1,210.27	1,330.60	9.94
OH	1,411.05	1,550.03	9.85
WI	460.39	505.04	9.70
MI	806.51	884.46	9.66
FL	794.01	867.91	9.31
IN	1,068.15	1,152.55	7.90
CT	28.16	30.29	7.57
NH	47.40	50.98	7.55
NJ	72.67	78.07	7.43
WV	745.84	798.68	7.08
GA	761.26	808.52	6.21
DE	63.79	67.71	6.14
IA	313.69	332.89	6.12
SC	327.80	346.50	5.70
ND	248.41	262.55	5.69
NY	308.78	325.17	5.31
MS	106.41	112.03	5.28
AL	784.35	822.20	4.83
LA	123.82	129.38	4.49
MD	302.84	315.96	4.33
VA	291.83	303.50	4.00
TN	612.30	628.01	2.57
NC	676.56	690.73	2.09
MT	116.02	116.90	0.76
OK	329.80	331.57	0.54
KS	321.35	322.43	0.33
MN	359.75	360.39	0.18
AZ	20.30	420.70	0.10

TABLE 12: COMPARISON OF COAL ACQUISITION COSTS FOR UTILITIES BETWEEN THE BASE CASE AND THE SWITCHING CASE (SWITCHING CASE INCLUDES RETROFIT COSTS)

DESTINATION STATE	BASE (MILLION $)	IMPACT (MILLION $)	PERCENT CHANGE
NV	241.61	241.61	0.00
NM	327.65	327.64	0.00
NE	157.23	157.23	0.00
UT	344.92	344.92	0.00
CO	321.67	321.67	0.00
WA	126.73	126.73	0.00
WY	350.37	350.37	0.00
SD	36.33	36.33	0.00
OR	53.22	53.22	0.00
TX	1,158.11	1,154.14	-0.34
AR	246.76	243.06	-1.50
TOTAL	**18,728.33**	**19,821.99**	**5.84%**

Table 13 shows the proportion of generation that switched to a low sulfur coal under the impact case in each destination state. As the table shows, the majority of generation in some states such as Wisconsin and Illinois switched to low sulfur coal, while none of the generation switched to low sulfur in others such as Texas, Kentucky, and West Virginia. However, this is somewhat misleading, since utilities that switched from high sulfur to medium sulfur don't show a switching. An example of this type of switching occurred in Kentucky, with the shift from western Kentucky to eastern Kentucky.

TABLE 13: COAL SWITCHING SIMULATED BY THE IMPACT MODEL THAT DOES NOT ALLOW SCRUBBER INSTALLATION TO TAKE PLACE

DESTINATION STATE	GENERATION (KWH)	PROPORTION OF GENERATION USING COAL WHERE SWITCHING TOOK PLACE
TX	1.22E+11	0.00%
OH	1.2E+11	0.03%
PA	1.01E+11	2.51%
IN	9.7E+10	2.61%
KY	7.56E+10	0.00%
WV	7.09E+10	0.00%
MI	6.27E+10	18.20%
AL	6.18E+10	15.42%
FL	6.15E+10	3.65%
GA	6.05E+10	0.00%
IL	5.45E+10	53.96%
NC	5.34E+10	0.00%
TN	5.21E+10	12.27%
MO	4.51E+10	41.01%
WY	3.94E+10	0.00%
AZ	3.46E+10	0.00%
WI	3.32E+10	65.77%
UT	3.08E+10	0.00%
CO	2.98E+10	0.00%
OK	2.76E+10	0.00%
ND	2.66E+10	0.00%
MN	2.59E+10	0.00%
IA	2.58E+10	14.87%
NM	2.43E+10	0.00%
SC	2.42E+10	0.00%
KS	2.41E+10	1.85%
MD	2.37E+10	0.00%
VA	2.31E+10	5.29%
NY	2.22E+10	8.43%
AR	1.92E+10	0.00%
NV	1.61E+10	0.00%
MT	1.57E+10	0.00%
NE	1.36E+10	0.00%
MA	1.09E+10	0.00%
LA	1.09E+09	0.00%

TABLE 13: COAL SWITCHING SIMULATED BY THE IMPACT MODEL THAT DOES NOT ALLOW SCRUBBER INSTALLATION TO TAKE PLACE

DESTINATION STATE	GENERATION (KWH)	PROPORTION OF GENERATION USING COAL WHERE SWITCHING TOOK PLACE
WA	8.75E+09	0.00%
MS	8.46E+09	0.00%
NJ	5.37E+09	0.00%
DE	4.53E+09	0.00%
OR	3.33E+09	0.00%
NH	3.21E+09	0.00%
SD	2.66E+09	0.00%
CT	2.06E+09	0.00%

As mentioned previously, there are many factors that could cause future overall rail rates to change from one direction to the other. Because of the heavy reliance of western coal on efficient and effective transportation relative to the others, it is expected that reductions in overall rail rates will benefit Western producers, while increases will hurt Western producers. The following table simulates coal production under the first impact case scenario with a 10 percent overall increase in nationwide rail coal rates. As the Table shows, the 10 percent increase leads to a reduction in Western coal production as compared to the previous impact case.

TABLE 14: COAL PRODUCTION SIMULATED BY MINIMIZING TRANSPORT COSTS SUBJECT TO SULFUR LIMITATIONS, WITH A 10 PERCENT OVERALL INCREASE IN RAIL RATES

STATE	TONS (1,000)	MARKET SHARE
WY	152,826	21.02%
WV	131,417	18.08%
TX	120,538	16.58%
WKY	51,913	7.14%
VA	50,570	6.96%
IN	45,298	6.23%
EKY	28,006	3.85%
PA	23,930	3.29%
ND	21,148	2.91%
UT	17,650	2.43%
AZ	12,900	1.77%
TN	12,898	1.77%
MT	10,160	1.40%
OK	9,806	1.35%
IA	9,250	1.27%
MD	7,651	1.05%
CO	6,509	0.90%
IL	5,120	0.70%
AR	4,507	0.62%
LA	2,623	0.36%
NM	2,292	0.32%

Table 15 shows that an overall 10 percent reduction in rail rates is simulated to have the opposite effect. As the table shows, Western coal production increases as compared to the impact case with current rail rates. In reality, this reduction in rail rates may show up in a price increase for Western coal in addition to an increase in production. Nonetheless, the simulation shows that overall U.S. rail rate reductions due to gains in railroad productivity or other factors would be comparatively beneficial to Western producers, due to their greater dependence on long-distance transportation.

TABLE 15: COAL PRODUCTION SIMULATED BY MINIMIZING TRANSPORT COSTS SUBJECT TO SULFUR LIMITATIONS, WITH A 10 PERCENT OVERALL REDUCTION IN RAIL RATES

STATE	TONS (1,000)	MARKET SHARE
WY	207,751	27.73%
TX	134,605	17.96%
WV	112,893	15.07%
WKY	55,409	7.40%
VA	50,570	6.75%
IN	37,996	5.07%
EKY	29,757	3.97%
ND	21,341	2.85%
PA	19,507	2.60%
AZ	12,900	1.72%
TN	12,898	1.72%
MT	9,645	1.29%
MD	8,470	1.13%
UT	7,850	1.05%
IA	7,700	1.03%
CO	6,504	0.87%
OK	6,392	0.85%
AR	4,507	0.60%
LA	2,623	0.35%

Tables A3 and A4 of the appendix show that similar changes in coal production occur with changes in overall U.S. rail rates by 20 percent. These four tables suggest that gains in railroad efficiency and productivity that might be gained through mergers, labor policies, or other factors should be encouraged by Western coal producers.

As previously suggested another impact case model that can be estimated is to allow electric utilities to retrofit existing boilers for scrubbers, but not to allow them to switch fuel sources. This case shows the costs that would take place if all sulfur dioxide emission limitations were achieved through scrubber installation. It also provides insight into the locations where utilities can scrub most cheaply, in comparison to other utilities. Table 16 shows the proportion generation that is simulated to be scrubbed by new scrubbers under this impact case. As the table shows, a large portion of utilities in Ohio, Michigan, and Illinois are able to scrub with new capacity more efficiently than utilities in other states. Of these three states, Ohio is one that appears to have a clear comparative advantage in installing scrubbers, as it is not simulated to switch fuels in the other impact case.

TABLE 16: NEW SCRUBBER INSTALLATIONS SIMULATED BY THE IMPACT MODEL THAT DOES NOT ALLOW FUEL SWITCHING

DESTINATION STATE	GENERATION (KWH)	PROPORTION OF STATE GENERATION COVERED BY NEW SCRUBBER INSTALLATIONS
TX	1.22E+11	0.00%
OH	1.20E+11	79.43%
PA	1.01E+11	43.08%
IN	9.70E+10	41.31%
KY	7.56E+10	42.26%
WV	7.09E+10	19.78%
MI	6.27E+10	76.42%
AL	6.18E+10	13.43%
FL	6.15E+10	36.88%
GA	6.05E+10	43.75%
IL	5.45E+10	62.84%
NC	5.34E+10	0.00%
TN	5.21E+10	31.11%
MO	4.51E+10	46.51%
WY	3.94E+10	0.00%
AZ	3.46E+10	0.00%
WI	3.32E+10	49.71%
UT	3.08E+10	0.00%
CO	2.98E+10	0.00%

TABLE 16: NEW SCRUBBER INSTALLATIONS SIMULATED BY THE IMPACT MODEL THAT DOES NOT ALLOW FUEL SWITCHING

DESTINATION STATE	GENERATION (KWH)	PROPORTION OF STATE GENERATION COVERED BY NEW SCRUBBER INSTALLATIONS
OK	2.76E+10	0.00%
ND	2.66E+10	0.00%
MN	2.59E+10	0.00%
IA	2.58E+10	14.22%
NM	2.43E+10	0.00%
SC	2.42E+10	0.00%
KS	2.41E+10	1.85%
MD	2.37E+10	24.91%
VA	2.31E+10	0.00%
NY	2.22E+10	40.96%
AR	1.92E+10	0.00%
MT	1.57E+10	0.00%
NE	1.36E+10	0.00%
MA	1.09E+10	0.00%
LA	1.09E+10	0.00%
WA	8.75E+09	0.00%
MS	8.46E+09	0.00%
NJ	5.37E+09	0.00%
DE	4.53E+09	28.57%
OR	3.33E+09	0.00%
NH	3.21E+09	0.00%
SD	2.66E+09	0.00%
CT	2.06E+09	0.00%

Table 17 shows a comparison of the costs realized by electric utilities from acquiring coal in the base case with the costs realized by electric utilities from acquiring coal, retrofitting scrubbers, and operating new scrubbers under sulfur dioxide limitations. As the table shows, the costs of complying with the CAAA90 would be much higher if scrubber installation were the only means of compliance. The overall increase in costs to electric utilities is estimated at nearly 16 percent compared to an acquisition cost increase of only 6 percent under the impact case where only switching is allowed. In actuality, some utilities would switch coal, while others would install scrubbers. Thus, if the resources were available to estimate the non-linear program that minimizes the total cost of compliance and coal acquisition, the estimated total increase in compliance costs would be lower.

TABLE 17: COMPARISON OF COAL ACQUISITION COSTS FOR UTILITIES BETWEEN THE BASE CASE AND THE SCRUBBER RETROFIT CASE (IMPACT CASE INCLUDES SCRUBBER RETROFIT COSTS)

DESTINATION STATE	BASE (MILLION $)	IMPACT (MILLION $)	PERCENT CHANGE
OH	1,411.05	2,025.63	43.56%
MI	806.51	1,142.68	41.68%
IL	680.06	928.35	36.51%
WI	460.39	595.94	29.44%
MO	562.83	718.40	27.64%
IN	1,068.15	1,357.42	27.08%
KY	853.19	1,078.03	26.35%
NY	308.78	375.65	21.65%
PA	1,210.27	1,455.27	20.24%
TN	612.30	735.61	20.14%
FL	794.01	948.79	19.49%
GA	761.26	893.79	17.41%
DE	63.79	72.59	13.79%
IA	313.69	355.83	13.43%
MD	302.84	338.75	11.86%
WV	745.84	831.12	11.43%
AL	784.35	834.14	6.35%
KS	321.35	324.97	1.12%
TX	1,158.11	1,158.11	0.00%
NC	676.56	676.56	0.00%
WY	350.37	350.37	0.00%
AZ	420.30	420.30	0.00%
UT	344.92	344.92	0.00%

TABLE 17: COMPARISON OF COAL ACQUISITION COSTS FOR UTILITIES BETWEEN THE BASE CASE AND THE SCRUBBER RETROFIT CASE (IMPACT CASE INCLUDES SCRUBBER RETROFIT COSTS)

DESTINATION STATE	BASE (MILLION $)	IMPACT (MILLION $)	PERCENT CHANGE
CO	321.67	321.67	0.00%
OK	329.80	329.80	0.00%
ND	248.41	248.41	0.00%
MN	359.75	359.75	0.00%
NM	327.64	327.64	0.00%
SC	327.80	327.80	0.00%
VA	291.83	291.83	0.00%
AR	246.76	246.76	0.00%
NV	241.61	241.61	0.00%
MT	116.02	116.02	0.00%
NE	157.23	157.23	0.00%
MA	154.15	154.15	0.00%
LA	123.82	123.82	0.00%
WA	126.73	126.73	0.00%
MS	106.41	106.41	0.00%
NJ	72.67	72.67	0.00%
OR	53.22	53.22	0.00%
NH	47.40	47.40	0.00%
SD	36.33	36.33	0.00%
CT	28.16	28.16	0.00%
TOTAL	**18,728.33**	**21,680.63**	**15.76%**

CONCLUSION

This study has shown the great growth in coal production in the west. Since 1970, western coal production has increased by more than 600 percent. Much of this increase has been due to an increased desire for low sulfur coal by electric utilities. The Clean Air Act Ammendments of 1990 provide an opportunity for a large increase in future coal production in the west. These amendments, which place a cap on total sulfur dioxide emissions by U.S. utilities, allow electric utilities to use the least cost method of reducing sulfur dioxide. This is in sharp contrast to previous environmental legislation, which has often mandated scrubber installation. Because more than 80 percent of the nation's recoverable low sulfur reserves are in the west, a great opportunity exists.

Linear programs were estimated, showing the large potential increases in annual western coal production given the provisions of the Clean Air Act Ammendments of 1990. Because of a lack of computer resources, a nonlinear program that minimizes total utility compliance costs while allowing switching to low sulfur coal or scrubber installation could not be estimated. However, all of the data required to estimate such a model have been collected and all of the programming required to estimate such a model has been completed. Thus, when future computer resources become available, such a model could be estimated.

While the linear programs estimated in this study show many of the expected changes with regard to coal flows, they still do not come close to approximating reality. There are several problems with the linear programs used in this study. First, they include many major simplifying assumptions such as an exogenously-determined coal mine price, the use of only one transportation mode, the restriction of demand points to electric utilities that already use coal as a primary fuel source, the elimination of exports and imports from the model, and many others. These simplifications are made for purposes of tractability. Second, they use data that is somewhat suspect. Many of the data items, particularly those related to coal quality, appear to be inaccurate. However, the best known data sources are used. Finally, there may be many other considerations by electric utilities in their fuel purchases, in addition to those modeled in the linear programs. For example, many electric utility boilers in the U.S. were built with a particular fuel type in mind. Changes in coal moisture content, ash content, and other volatile matter may have a large impact on the efficiency with which coal is converted into electricity. However, no quantification of such effects is known to exist.

Finally, the study shows that future changes in nationwide transportation rates could have a major impact on regional coal production and coal market shares. Due to the west's lack of proximity to many major utilities, transportation rates often consume a large portion of total acquisition costs by utilities in purchasing western coal. To the extent that the increases in railroad efficiency that we have seen over the past 15 years continue, western coal production should realize an even greater opportunity. However, various trends affecting individual rates such as changes in railroad infrastructure, changes in the prices of alternative fuels, and other factors will be equally important. This study also presents a model of rail rates, showing the influences of costs and competitive factors in determining individual rates for coal.

REFERENCES

Ackerman and Hassler. *Clean Coal/Dirty Air - or How the Clean Air Act Became a Multibillion-Dollar Bail-Out for High Sulfur Coal Producers and What Should Be Done About It*, New Haven, 1981.

Atkinson, Scott E. and Joe Kerkvliet. "Measuring the Multilateral Allocation of Rents: Wyoming Low Sulfur Coal, *The Rand Journal of Economics*, Autumn 1986.

Bryner, Gary *C. Blue Skies, Green Politics - The Clean Air Act of 1990 and Its Implementation*, Washington, D.C., 1995.

Decision Analysis Corporation of Virginia, "Regression Models for Analyzing Retrofit Flue Gas Desulfurization Unit Costs and Performance," report prepared for the Energy Information Administration Vienna, VA, May 1993.

Dunbar, Frederick C. and Joyce S. Mehring, "Coal Rail Prices During Deregulation: A Hedonic Price Analysis," *Logistics and Transportation Review, Vol.* 26, No. 1, 1990.

Energy Information Administration. *Acid Rain Compliance Strategies for the Clean Air Act Amendments of 1990, U.S.* Department of Energy, Washington, D.C., 1994.

Energy Information Administration. *Annual Outlook for U.S. Electric Power,U.S.* Department of Energy, Washington, D.C., various years.

Energy Information Administration. *Coal Production, U.S.* Department of Energy, Washington,D.C., various years.

Energy Information Administration. *Coal Distribution,U.S.* Department of Energy, Washington, D.C., various years.

Energy Information Administration. *Coal Transportation Rate Database,U.S.* Department of Energy, Washington, D.C., 1991.

Energy Information Administration. *Estimation of U.S. Coal Reserves by Coal Type,U.S.* Department of Energy, Washington, D.C., 1989.

Energy Information Administration. *Inventory of Power Plants in the United States 1993,U.S.* Department of Energy, Washington, D.C., 1994.

Energy Information Administration. *Resource Allocation and Mine Costing Model,U.S.* Department of Energy, Washington, D.C., 1992.

Energy Information Administration. *The U.S. Coal Industry, 1970-1990: Two Decades of Change, U.S.* Department of Energy, Washington, D.C., 1993.

Energy Information Administration. *Trends in Contract Coal Transportation 1979-1987,U.S.* Department of Energy, Washington, D.C., 1991.

Energy Information Administration. "Annual Electric Generator Report, "U.S. Department of Energy, Washington, D.C., 1991-1993, available on the internet.

Energy Information Administration. "Monthly Power Plant Report "U.S. Department of Energy, Washington, D.C., 1991-1993, available on the internet.

Environmental Protection Agency, "40 CFR Parts 72 and 73 - Acid Rain Allowance Allocations and Reserves; Proposed Rules," *Federal Register*, 1992.

Fieldston Company, *Fieldston Coal Transportation Manual*, Washington, D.C., 1991.

Garrod, P.V. and W. Miklius. "Captive Shippers and the Success of Railroads in Capturing Monopoly Rent," *Journal of Law and Economics, vol.* 30, 1987.

Moody's Investor Service, *Moody's Transportation Manual*, New York, NY, 1995.

Rupinskas, Romas L. and Paul A. Hiller, "Considerations for Switching from High-Sulfur Coal to Low Sulfur Coal," Sargent and Lundy, paper presented at the 1992 International Joint Power Generation Conference and Exposition, Atlanta, GA, 1992.

Smith, James N. and Robert R. Rose. *Rail Transport of Western Coal.* Prepared for the Western Governor's Association, 1985.

U.S. Geological Survey. *Coal Quality Database: Version 1.3, 1995.*

Zimmerman, M.B. "Rent and Regulation in Unit Train Rate Determination" *Bell Journal of Economics,* 1979.

APPENDIX - SUPPLEMENTARY TABLES

TABLE A1: COAL FLOWS SIMULATED IN THE BASE CASE

DESTINATION STATE	ORIGIN STATE	TONS (1,000)	SHARE OF DEST. STATE'S COAL REC.
AL	WK	16,638.61	57.00%
AL	TX	9,471.65	32.45%
AL	TN	3,081.78	10.56%
AR	TX	11,119.21	90.85%
AR	OK	1,120.00	9.15%
AZ	AZ	12,900.00	77.59%
AZ	WY	3,726.83	22.42%
CO	WY	10,505.05	61.76%
CO	CO	6,503.77	38.24%
CT	PA	762.75	100.00%
DE	WV	1,642.05	100.00%
FL	WK	24,389.17	91.94%
FL	TX	2,137.87	8.06%
GA	WK	19,958.35	86.30%
GA	TN	3,168.25	13.70%
IA	WY	8,253.94	57.26%
IA	IA	6,160.59	42.74%
IL	IL	10,650.08	45.47%
IL	IN	8,654.71	36.95%
IL	WK	3,482.02	14.87%
IL	IA	634.58	2.71%
IN	IN	41,257.01	97.63%
IN	WK	999.62	2.37%
KS	WY	14,688.97	98.63%
KS	OK	203.85	1.37%
KY	WK	19,740.32	59.44%

TABLE Al: COAL FLOWS SIMULATED IN THE BASE CASE

DESTINATION STATE	ORIGIN STATE	TONS (1,000)	SHARE OF DEST. STATE'S COAL REC.
KY	EK	6,969.69	20.99%
KY	IN	6,499.08	19.57%
LA	TX	4,508.33	63.22%
LA	LA	2,622.71	36.78%
MA	WV	2,868.76	65.50%
MA	WK	1,511.27	34.50%
MD	WV	4,727.70	55.55%
MD	MD	3,783.76	44.46%
MI	WK	13,823.01	52.08%
MI	IN	12,720.55	47.92%
MN	WY	15,301.17	99.41%
MN	IA	90.93	0.59%
MO	WK	11,125.05	47.32%
MO	WY	9,763.11	41.53%
MO	IA	1,543.60	6.57%
MO	OK	1,079.82	4.59%
MS	TX	4,967.52	100.00%
MT	MT	9,543.13	93.02%
MT	WY	715.95	6.98%
NC	VA	14,836.66	80.68%
NC	WK	2,140.62	11.64%
NC	EK	789.49	4.29%
NC	WV	623.74	3.39%
ND	ND	21,424.01	100.00%
NE	WY	8,151.66	100.00%
NH	WK	1,424.13	100.00%
NJ	WV	1,198.53	62.27%

TABLE A1: COAL FLOWS SIMULATED IN THE BASE CASE

DESTINATION STATE	ORIGIN STATE	TONS (1,000)	SHARE OF DEST. STATE'S COAL REC.
NJ	PA	726.32	37.73%
NM	WY	14,669.40	100.00%
NV	WY	9,520.15	100.00%
NY	PA	8,056.35	92.50%
NY	WV	653.46	7.50%
OH	OH	27,013.69	54.90%
OH	WK	8,786.06	17.86%
OH	EK	5,033.42	10.23%
OH	IN	3,566.57	7.25%
OH	PA	3,251.46	6.61%
OH	WV	1,553.76	3.16%
OK	TX	8,436.28	59.22%
OK	OK	5,810.49	40.79%
OR	WY	2,063.46	100.00%
PA	PA	35,274.45	89.74%
PA	MD	3,066.24	7.80%
PA	WV	968.62	2.46%
SC	WK	9,334.93	100.00%
SD	WY	1,683.90	100.00%
TN	WK	13,565.88	65.51%
TN	TN	4,591.82	22.17%
TN	VA	1,783.68	8.61%
TN	EK	766.99	3.70%
TX	TX	72,699.41	94.50%
TX	WY	4,234.40	5.50%
UT	UT	7,849.51	55.77%
UT	WY	6,224.21	44.23%

TABLE A1: COAL FLOWS SIMULATED IN THE BASE CASE

DESTINATION STATE	ORIGIN STATE	TONS (1,000)	SHARE OF DEST. STATE'S COAL REC.
VA	WV	4,945.84	58.52%
VA	VA	3,503.49	41.45%
VA	WY	2.09	0.03%
WA	WY	5,119.13	100.00%
WI	WK	9,752.42	60.80%
WI	IN	3,422.41	21.34%
WI	WY	1,833.76	11.43%
WI	IA	1,030.92	6.43%
WV	WV	26,077.38	100.00%
WY	WY	21,986.01	100.00%

TABLE A2: COAL FLOWS SIMULATED IN THE IMPACT CASE THAT DOES NOT ALLOW SCRUBBER INSTALLATION

DESTINATION STATE	ORIGIN STATE	TONS (1,000)	SHARE OF DEST. STATE'S COAL REC.
AL	TX	12,789.77	45.09%
AL	WK	5,484.25	19.33%
AL	TN	5,156.54	18.18%
AL	VA	3,525.55	12.43%
AL	AR	1,410.22	4.97%
AR	TX	12,608.91	100.00%
AZ	AZ	12,900.00	77.59%
AZ	WY	3,726.83	22.42%
CO	WY	10,498.44	61.73%
CO	CO	6,508.50	38.27%
CT	W V	710.47	100.00%
DE	WV	1;629.91	100.00%
FL	WK	10,329.05	41.77%
FL	VA	4,611.71	18.65%
FL	TX	3,253.68	13.16%
FL	AR	3,096.45	12.52%
FL	EK	2,547.83	10.30%
FL	OK	890.22	3.60%
GA	VA	13,950.48	64.96%
GA	WK	3,761.54	17.52%
GA	EK	3,221.52	15.00%
GA	TN	542.00	2.52%
IA	WY	11,526.13	77.08%
IA	IA	3,407.34	22.79%
IA	OK	19.13	0.13%
IL	WY	16,929.82	60.21%
IL	IN	10,224.14	36.36%

TABLE A2: COAL FLOWS SIMULATED IN THE IMPACT CASE THAT DOES NOT ALLOW SCRUBBER INSTALLATION

DESTINATION STATE	ORIGIN STATE	TONS (1,000)	SHARE OF DEST. STATE'S COAL REC.
IL	IA	512.51	1.82%
IL	IL	450.23	1.60%
IN	IN	28,531.14	67.47%
IN	WK	9,996.64	23.64%
IN	WY	1,388.98	3.29%
IN	EK	1,358.54	3.21%
IN	WV	1,013.20	2.40%
KS	WY	15,007.38	100.00%
KY	EK	16,366.05	51.31%
KY	WK	14,330.80	44.93%
KY	IN	1,197.05	3.75%
LA	TX	4,483.20	63.09%
LA	LA	2,622.71	36.91%
MA	WV	3,864.96	100.00%
MD	MD	4,633.78	54.23%
MD	WV	3,910.94	45.77%
MI	WV	15,064.21	59.49%
MI	WY	6,649.48	26.26%
MI	IN	3,609.03	14.25%
MN	WY	15,301.17	99.34%
MN	MT	102.29	0.66%
MO	WY	20,803.20	78.34%
MO	TX	3,964.75	14.93%
MO	WK	1,069.08	4.03%
MO	OK	717.31	2.70%
MS	TX	5,045.81	100.00%
MT	MT	10,160.42	100.00%

TABLE A2: COAL FLOWS SIMULATED IN THE IMPACT CASE THAT DOES NOT ALLOW SCRUBBER INSTALLATION

DESTINATION STATE	ORIGIN STATE	TONS (1,000)	SHARE OF DEST. STATE'S COAL REC.
NC	VA	17,546.51	94.80%
NC	W V	963.09	5.20%
ND	ND	21,148.04	100.00%
NE	WY	8,151.66	100.00%
NH	W V	1,154.91	100.00%
NJ	W V	1,868.59	100.00%
NM	WY	14,669.40	100.00%
NV	WY	9,520.15	100.00%
NY	WV	4,190.16	48.68%
NY	PA	2,280.35	26.50%
NY	WK	2,136.32	24.82%
OH	W V	39,826.46	90.75%
OH	EK	3,295.47	7.51%
OH	VA	745.82	1.70%
OH	WY	18.55	0.04%
OK	TX	10,332.03	68.44%
OK	OK	4,765.00	31.56%
OR	WY	2,063.46	100.00%
PA	PA	18,371.76	48.54%
PA	W V	16,460.25	43.49%
PA		3,017.02	7.97%
SC	VA	6,927.64	79.51%
SC	EK	843.52	9.68%
SC	WV	810.45	9.30%
SC	WK	131.70	1.51%
SD	WY	1,683.90	100.00%
TN	TN	7,199.46	31.85%

TABLE A2: COAL FLOWS SIMULATED IN THE IMPACT CASE THAT DOES NOT ALLOW SCRUBBER INSTALLATION

DESTINATION STATE	ORIGIN STATE	TONS (1,000)	SHARE OF DEST. STATE'S COAL REC.
TN	TX	6,693.69	29.61%
TN	WK	6,539.98	28.93%
TN	VA	1,797.58	7.95%
TN	EK	372.58	1.65%
TX	TX	72,441.80	94.48%
TX	WY	4,234.40	5.52%
UT	UT	7,849.51	55.77%
UT	WY	6,224.21	44.23%
VA	WV	6,585.54	81.78%
VA	VA	1,464.71	18.19%
VA	WY	2.09	0.03%
WA	WY	5,119.13	100.00%
WI	WY	15,165.47	79.46%
WI	IA	3,780.09	19.81%
WI	WV	139.03	0.73%
WV	WV	24,861.94	100.00%
WY	WY	21,986.01	100.00%

TABLE A3: COAL PRODUCTION SIMULATED BY MINIMIZING TRANSPORT COSTS SUBJECT TO SULFUR LIMITATIONS, WITH A 20 PERCENT OVERALL INCREASE IN RAIL RATES

STATE	TONS (1,000)	MARKET SHARE
WV	135,698	18.84%
WY	133,608	18.55%
TX	117,127	16.26
WKY	51,846	7.20%
VA	50,570	7.02%
IN	48,690	6.76%
PA	29,925	4.16%
EKY	26,465	3.67%
ND	21,341	2.96%
UT	17,650	2.45%
AZ	12,900	1.79%
TN	12,898	1.79%
IL	12,033	1.67%
OK	10,348	1.44%
MT	10,160	1.41%
CO	8,800	1.22%
IA	5,768	0.80%
AR	4,507	0.63%
MD	4,380	0.61%
LA	2,623	0.36%
NM	2,292	0.32%
OH	592	0.08%

94

TABLE A4: COAL PRODUCTION SIMULATED BY MINIMIZING TRANSPORT COSTS SUBJECT TO SULFUR LIMITATIONS, WITH A 20 PERCENT OVERALL REDUCTION IN RAIL RATES

STATE	TONS (1,000)	MARKET SHARE
WY	255,070	33.26%
TX	142,573	18.59%
WV	90,347	11.78%
WKY	55,605	7.25%
VA	49,350	6.43%
IN	32,113	4.19%
EKY	28,394	3.70%
ND	21,341	2.78%
PA	17,970	2.34%
AZ	12,900	1.68%
TN	12,898	1.68%
MD	11,230	1.46%
MT	9,730	1.27%
IA	8,882	1.16%
UT	7,850	1.02%
OK	5,689	0.74%
LA	2,623	0.34%
AR	2,253	0.29%
CO	179	0.02%

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
AL	BIBB
AL	BLOUNT
AL	CULLMAN
AL	FAYETTE
AL	JEFFERSON
AL	MARION
AL	SHELLBY
AL	ST CLAIR
AL	TUSCALOOSA
AL	WALKER
AL	WINSTON
AR	JOHNSON
AR	SALINE
AR	SEBASTIAN
AZ	NAVAJO
CA	AMADOR
CO	DELTA
CO	FREMONT
CO	GARFIELD
CO	GARFIELD
CO	GUNNISON
CO	JACKSON
CO	LA PLATA
CO	LAS ANIMAS
CO	MOFFAT
CO	MONTROSE
CO	PITKIN

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
CO	RIO BLANCO
CO	ROUTT
CO	WELD
IA	MARION
IA	MONROE
IL	CHRISTIAN
IL	CLINTON
IL	DOUGLAS
IL	EDGAR
IL	FRANKLIN
IL	FULTON
IL	GALLATIN
IL	HAMILTON
IL	JACKSON
IL	JEFFERSON
IL	LOGAN
IL	MACOUPIN
IL	MCDONOUGH
IL	PERRY
IL	RANDOLPH
IL	SALINE
IL	SANGAMON
IL	SCHUYLER
IL	ST CLAIR
IL	WABASH
IL	WASHINGTON
IL	WHITE

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
IL	WILLIAMSON
IN	CLAY
IN	DAVIESS
IN	DUBOIS
IN	GIBSON
IN	GREENE
IN	KNOX
IN	MARTIN
IN	OWEN
IN	PERRY
IN	PIKE
IN	SPENCER
IN	SULLIVAN
IN	VERMILLION
IN	VIGO
IN	WARRICK
KS	CRAWFORD
KS	LINN
KY	BELL
KY	BOYD
KY	BREATHITT
KY	BUTLER
KY	CALDWELL
KY	CARTER
KY	CHRISTIAN
KY	CLAY
KY	CLINTON

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
KY	DAVIESS
KY	EDMONSON
KY	ELLIOTT
KY	FLOYD
KY	GREENUP
KY	HANCOCK
KY	HARLAN
KY	HENDERSON
KY	HOPKINS
KY	JACKSON
KY	JOHNSON
KY	KNOTT
KY	KNOX
KY	LAUREL
KY	LAWRENCE
KY	LEE
KY	LESLIE
KY	LETCHER
KY	MAGOFFIN
KY	MARTIN
KY	MCCREARY
KY	MCLEAN
KY	MORGAN
KY	MUHLENBERG
KY	OHIO
KY	OWSLEY
KY	PERRY

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
KY	PIKE
KY	PULASKI
KY	UNION
KY	WAYNE
KY	WEBSTER
KY	WHITLEY
KY	WOLFE
LA	DE SOTO
LA	RED RIVER
MD	ALLEGANY
MD	GARRETT
MO	BARTON
MO	BATES
MO	PUTNAM
MO	RALLS
MO	RANDOLPH
MO	VERNON
MT	BIG HORN
MT	MUSSELSHELL
MT	RICHLAND
MT	ROSEBUD
ND	BOWMAN
ND	MCLEAN
ND	MERCER
ND	OLIVER
ND	STARK
ND	WILLIAMS

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
NM	COLFAX
NM	MCKINLEY
NM	SAN JUAN
OH	ATHENS
OH	BELMONT
OH	CARROLL
OH	COLUMBIANA
OH	COSHOCTON
OH	GALLIA
OH	GUERNSEY
OH	HARRISON
OH	HOCKING
OH	HOLMES
OH	JACKSON
OH	JEFFERSON
OH	LAWRENCE
OH	MAHONING
OH	MEIGS
OH	MONROE
OH	MUSKINGUM
OH	NOBLE
OH	PERRY
OH	STARK
OH	TUSCARAWAS
OH	VINTON
OH	WASHINGTON
OK	COAL

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
OK	CRAIG
OK	HASKELL
OK	LATIMER
OK	LE FLORE
OK	MCINTOSH
OK	MUSKOGEE
OK	NOWATA
OK	OKMULGEE
OK	ROGERS
OK	WAGONER
PA	ALLEGHENY
PA	ARMSTRONG
PA	BEAVER
PA	BEDFORD
PA	BLAIR
PA	BUTLER
PA	CAMBRIA
PA	CARBON
PA	CENTRE
PA	CLARION
PA	CLEARFIELD
PA	CLINTON
PA	COLUMBIA
PA	ELK
PA	FAYETTE
PA	FULTON
PA	GREENE

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
PA	INDIANA
PA	JEFFERSON
PA	LACKAWANNA
PA	LAWRENCE
PA	LUZERNE
PA	LYCOMING
PA	MERCER
PA	NORTHUMBERLAND
PA	SCHUYLKILL
PA	SOMERSET
PA	SULLIVAN
PA	TIOGA
PA	VENANGO
PA	WASHINGTON
PA	WESTMORELAND
TN	ANDERSON
TN	BLEDSOE
TN	CAMPBELL
TN	CLAIBORNE
TN	CUMBERLAND
TN	FENTRESS
TN	GRUNDY
TN	MARION
TN	MORGAN
TN	RHEA
TN	SCOTT
TN	SEQUATCHIE

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
TX	ATASCOSA
TX	BASTROP
TX	FREESTONE
TX	GRIMES
TX	HARRISON
TX	HOPKINS
TX	LEON
TX	MILLAM
TX	PANOLA
TX	RUSK
TX	TITUS
TX	WEBB
UT	CARBON
UT	EMERY
UT	SEVIER
UT	SUMMIT
VA	BUSHANAN
VA	DICKENSON
VA	LEE
VA	RUSSELL
VA	SCOTT
VA	TAZEWELL
VA	WISE
WA	KING
WA	LEWIS
WA	THURSTON
WV	BARBOUR

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
WV	BOONE
WV	BRAXTON
WV	BROOKE
WV	CLAY
WV	FAYETTE
WV	GILMER
WV	GRANT
WV	GREENBRIER
WV	HARRISON
WV	KANAWHA
WV	LEWIS
WV	LINCOLN
WV	LOGAN
WV	MARION
WV	MARSHALL
WV	MASON
WV	MCDOWELL
WV	MERCER
WV	MINERAL
WV	MINGO
WV	MONOGALIA
WV	NICHOLAS
WV	OHIO
WV	PRESTON
WV	RALEIGH
WV	RANDOLPH
WV	TAYLOR

TABLE A5: COAL PRODUCING STATES AND COUNTIES INCLUDED IN THE LINEAR PROGRAMMING MODELS

COAL PRODUCING STATE	COAL PRODUCING COUNTY
WV	TUCKER
WV	UPSHUR
WV	WAYNE
WV	WEBSTER
WV	WYOMING
WY	CAMPBELL
WY	CARBON
WY	CONVERSE
WY	HOT SPRINGS
WY	LINCOLN
WY	SHERIDAN
WY	SWEETWATER

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES

DESTINATION STATE	DESTINATION COUNTY
AL	COLBERT
AL	COVINGTON
AL	ETOWAH
AL	GREENE
AL	JACKSON
AL	JEFFERSON
AL	MOBILE
AL	SHELBY
AL	WALKER
AL	WASHINGTON
AR	BENTON
AR	INDEPENDENCE
AZ	APACHE
AZ	COCHISE
AZ	COCONINO
AZ	NAVAJO
AZ	PIMA
CO	ADAMS
CO	BOULDER
CO	DENVER
CO	EL PASO
CO	FREMONT
CO	LARIMER
CO	LAS ANIMAS
CO	MESA
CO	MOFFAT
CO	MONTROSE

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES	
DESTINATION STATE	**DESTINATION COUNTY**
CO	MORGAN
CO	PUEBLO
CO	ROUTT
CT	FAIRFIELD
CT	HARTFORD
DE	NEW CASTLE
DE	SUSSEX
FL	ALACHUA
FL	BAY
FL	CITRUS
FL	DUVAL
FL	ESCAMBIA
FL	HILLSBOROUGH
FL	JACKSON
FL	ORANGE
FL	POLK
FL	PUTNAM
GA	BARTOW
GA	BIBB
GA	CHATHAM
GA	COBB
GA	COWETA
GA	DOUGHERTY
GA	EFFINGHAM
GA	FLOYD
GA	HEARD
GA	MONROE

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES

DESTINATION STATE	DESTINATION COUNTY
GA	PUTNAM
GA	WORTH
IA	ALLAMAKEE
IA	BLACK HAWK
IA	CLAY
IA	CLINTON
IA	DES MOINES
IA	DUBUQUE
IA	HENRY
IA	HUMBOLDT
IA	LINN
IA	LOUISA
IA	MARION
IA	MARSHALL
IA	MUSCATINE
IA	POTTAWATTAMIE
IA	SCOTT
IA	STORY
IA	WAPELLO
IA	WOODBURY
IL	CHRISTIAN
IL	COOK
IL	CRAWFORD
IL	FULTON
IL	JACKSON
IL	JASPER
IL	LAKE

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES	
DESTINATION STATE	**DESTINATION COUNTY**
IL	MADISON
IL	MASON
IL	MASSAC
IL	MONTGOMERY
IL	MORGAN
IL	PEORIA
IL	PIKE
IL	PUTNAM
IL	RANDOLPH
IL	SANGAMON
IL	TAZEWELL
IL	VERMILLION
IL	WILL
IL	WILLIAMSON
IN	CASS
IN	DEARBORN
IN	DUBOIS
IN	FLOYD
IN	GIBSON
IN	HAMILTON
IN	JASPER
IN	JEFFERSON
IN	KNOX
IN	LA PORTE
IN	LAKE
IN	MARION
IN	MIAMI

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES	
DESTINATION STATE	**DESTINATION COUNTY**
IN	MONTGOMERY
IN	MORGAN
IN	PIKE
IN	PORTER
IN	POSEY
IN	SPENCER
IN	SULLIVAN
IN	VERMILLION
IN	VIGO
IN	WARRICK
IN	WAYNE
KS	CHEROKEE
KS	DOUGLAS
KS	FINNEY
KS	LINN
KS	POTTAWATOMIE
KS	SHAWNEE
KS	WYANDOTTE
KY	BELL
KY	BOONE
KY	CARROLL
KY	CLARK
KY	DAVIESS
KY	HANCOCK
KY	HENDERSON
KY	JEFFERSON
KY	LAWRENCE

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES

DESTINATION STATE	DESTINATION COUNTY
KY	MASON
KY	MCCRACKEN
KY	MERCER
KY	MUHLENBERG
KY	OHIO
KY	PULASKI
KY	TRIMBLE
KY	WEBSTER
KY	WOODFORD
LA	CALCASIEU
LA	DE SOTO
LA	RAPIDES
MA	BRISTOL
MA	ESSEX
MA	HAMPDEN
MD	ANNE ARUNDEL
MD	BALTIMORE
MD	CHARLES
MD	MONTGOMERY
MD	PRINCE GEORGES
MD	WASHINGTON
MI	BARAGA
MI	BAY
MI	BRANCH
MI	CHARLEVOIX
MI	DELTA
MI	EATON

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES	
DESTINATION STATE	**DESTINATION COUNTY**
MI	GRAND TRAVERSE
MI	HILLSDALE
MI	HURON
MI	INGHAM
MI	MARQUETTE
MI	MONROE
MI	MUSKEGON
MI	OTTAWA
MI	ST CLAIR
MI	WAYNE
MN	BROWN
MN	CHIPPEWA
MN	CLAY
MN	DAKOTA
MN	HENNEPIN
MN	ITASCA
MN	KANDIYOHI
MN	MARTIN
MN	MOWER
MN	OLMSTED
MN	OTTER TAIL
MN	RAMSEY
MN	SHERBURNE
MN	ST LOUIS
MN	WASHINGTON
MO	BOONE
MO	BUCHANAN

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES	
DESTINATION STATE	**DESTINATION COUNTY**
MO	CLAY
MO	FRANKLIN
MO	GREENE
MO	HENRY
MO	JACKSON
MO	JASPER
MO	JEFFERSON
MO	LIVINGSTON
MO	NEW MADRID
MO	OSAGE
MO	PLATTE
MO	RANDOLPH
MO	SALINE
MO	SCOTT
MO	ST LOUIS
MO	ST CHARLES
MS	HARRISON
MS	JACKSON
MS	LAMAR
MS	LEFLORE
MT	RICHLAND
MT	ROSEBUD
MT	YELLOWSTONE
NC	BUNCOMBE
NC	CATAWBA
NC	CHATHAM
NC	CLEVELAND

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES	
DESTINATION STATE	**DESTINATION COUNTY**
NC	GASTON
NC	NEW HANOVER
NC	PERSON
NC	ROBESON
NC	ROCKINGHAM
NC	ROWAN
NC	STOKES
NC	WAYNE
ND	MCHENRY
ND	MCLEAN
ND	MERCER
ND	MORTON
ND	OLIVER
NE	ADAMS
NE	DODGE
NE	DOUGLAS
NE	HALL
NE	LANCASTER
NE	LINCOLN
NE	OTOE
NH	MERRIMACK
NH	ROCKINGHAM
NJ	CAPE MAY
NJ	CUMBERLAND
NJ	HUDSON
NJ	MERCER
NJ	SALEM

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES

DESTINATION STATE	DESTINATION COUNTY
NM	COLFAX
NM	MCKINLEY
NM	SAN JUAN
NV	CLARK
NV	HUMBOLDT
NY	BROOME
NY	CHAUTAUQUA
NY	CHENANGO
NY	ERIE
NY	NIAGARA
NY	ORANGE
NY	ROCKLAND
NY	STEUBEN
NY	TOMPKINS
NY	YATES
OH	ADAMS
OH	ASHTABULA
OH	AUGLAIZE
OH	BELMONT
OH	BUTLER
OH	CLERMONT
OH	COSHOCTON
OH	CUYAHOGA
OH	FRANKLIN
OH	GALLIA
OH	HAMILTON
OH	JEFFERSON

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES	
DESTINATION STATE	**DESTINATION COUNTY**
OH	LAKE
OH	LORAIN
OH	LUCAS
OH	MAHONING
OH	MIAMI
OH	MONTGOMERY
OH	MORGAN
OH	PICKAWAY
OH	RICHLAND
OH	SUMMIT
OH	TUSCARAWAS
OH	WASHINGTON
OH	WAYNE
OK	CHOCTAW
OK	MAYES
OK	MUSKOGEE
OK	NOBLE
OK	ROGERS
OR	MORROW
PA	ALLEGHENY
PA	ARMSTRONG
PA	BEAVER
PA	BERKS
PA	CHESTER
PA	CLEARFIELD
PA	DELAWARE
PA	GREENE

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES

DESTINATION STATE	DESTINATION COUNTY
PA	INDIANA
PA	LANCASTER
PA	LAWRENCE
PA	LUZERNE
PA	MONTOUR
PA	NORTHAMPTON
PA	SNYDER
PA	WARREN
PA	WASHINGTON
PA	YORK
SC	AIKEN
SC	ANDERSON
SC	BERKELEY
SC	COLLETON
SC	DARLINGTON
SC	GEORGETOWN
SC	HORRY
SC	LEXINGTON
SC	RICHLAND
SD	GRANT
SD	LAWRENCE
SD	PENNINGTON
TN	ANDERSON
TN	HAWKINS
TN	HUMPHREYS
TN	RHEA
TN	ROANE

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES

DESTINATION STATE	DESTINATION COUNTY
TN	SHELBY
TN	STEWART
TN	SUMNER
TX	ATASCOSA
TX	BEXAR
TX	FAYETTE
TX	FORT BEND
TX	FREESTONE
TX	GOLIAD
TX	GRIMES
TX	HARRISON
TX	LAMB
TX	LIMESTONE
TX	MILAM
TX	POTTER
TX	ROBERTSON
TX	RUSK
TX	TITUT
TX	WILBARGER
UT	CARBON
UT	EMERY
UT	MILLARD
UT	SALT LAKE
UT	UINTAH
UT	UTAH
VA	ALEXANDRIA
VA	CHESAPEAKE

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES

DESTINATION STATE	DESTINATION COUNTY
VA	CHESTERFIELD
VA	FLUVANNA
VA	GILES
VA	PRINCE WILLIAM
VA	RUSSELL
VA	YORK
WA	LEWIS
WI	ASHLAND
WI	BROWN
WI	BUFFALO
WI	COLUMBIA
WI	DANE
WI	GRANT
WI	KENOSHA
WI	MANITOWOC
WI	MARATHON
WI	MILWAUKEE
WI	OZAUKEE
WI	ROCK
WI	SHEBOYGAN
WI	VERNON
WI	WINNEBAGO
WI	WOOD
WV	GRANT
WV	HARRISON
WV	KANAWHA
WV	MARION

TABLE A6: STATES AND COUNTIES WITH COAL CONSUMING ELECTRIC UTILITIES

DESTINATION STATE	DESTINATION COUNTY
WV	MARSHALL
WV	MASON
WV	MONONGALIA
WV	PLEASANTS
WV	PRESTON
WV	PUTNAM
WY	CAMPBELL
WY	CONVERSE
WY	LINCOLN
WY	PLATTE
WY	SWEETWATER
WY	WESTON