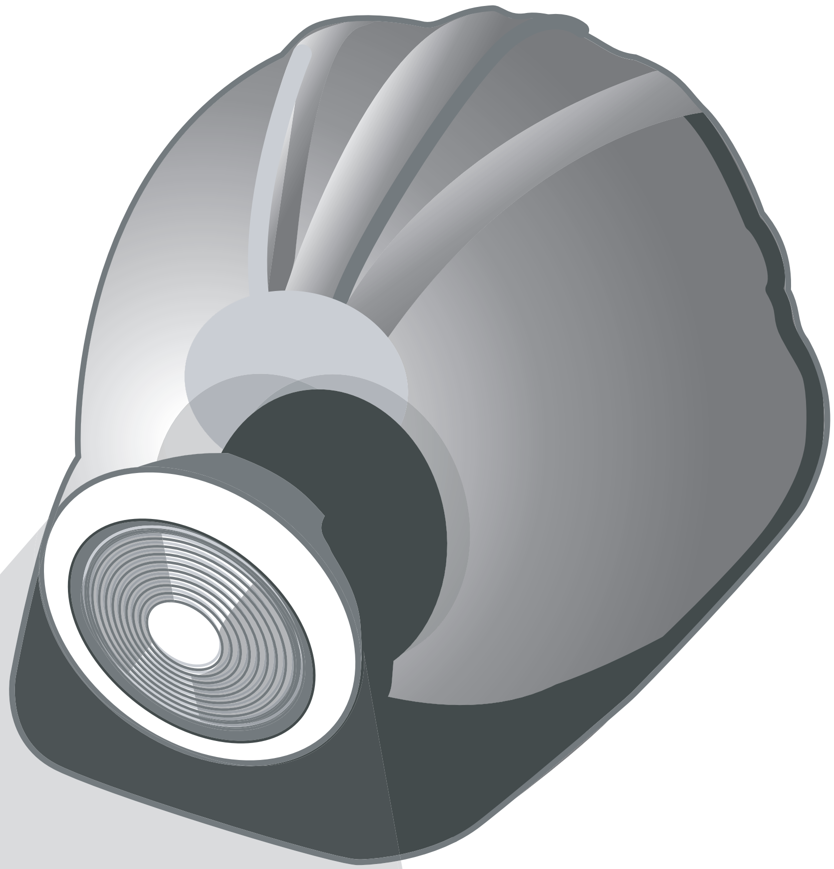

The Competitiveness of Kentucky's Coal Industry

Research Report No. 318

Legislative Research Commission
Frankfort, Kentucky
January 2004

Kentucky Legislative Research Commission

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The Commission functions as Kentucky's Commission on Interstate Cooperation in carrying out the program of the Council of State Governments as it relates to Kentucky.

The Competitiveness of Kentucky's Coal Industry

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FOREWORD

The 2002 General Assembly directed the Interim Joint Committee on Agriculture and Natural Resources to study issues concerning the competitiveness of Kentucky coal. HCR 244 specifically instructed the committee to study the market forces that affect the competitiveness of Kentucky coal and to consider how the allocation of nitrogen oxide credits and the regulatory activities of the Public Service Commission affect the competitiveness of Kentucky coal. This report represents the results of the study.

This report is the result of the dedicated effort of LRC staff. Our appreciation also is expressed to the many people from the public and private sectors who provided information, insights, and data for this report.

Robert Sherman
Director

Frankfort, Kentucky
January 2004

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EXECUTIVE SUMMARY

The 2002 General Assembly directed the Interim Joint Committee on Agriculture and Natural Resources to study the various factors that affect purchases of Kentucky coal.

Trends in the Coal Market

In 2002, Kentucky coal mines produced 11 percent of the coal mined in the nation. Only two other states, Wyoming and West Virginia, produced more coal than Kentucky. Coal production for the United States has generally increased over time. Production of Kentucky coal, however, peaked in 1990 at 173 millions tons and has steadily decreased since. By 2002, Kentucky production had fallen to 123 million tons.

Kentucky coal is shipped within Kentucky, to other states, and to foreign markets. The majority of Kentucky coal (80 percent) is shipped to other states. Eighteen percent is shipped within the state and 2 percent is shipped to foreign markets. Kentucky coal has lost market share in each of these markets. In domestic markets outside Kentucky and the foreign market, the lost market share was accompanied by a decrease in the amount of Kentucky coal purchased. The amount of Kentucky coal shipped within Kentucky, however, increased in spite of the lost market share. This increase occurred because firms that use coal in Kentucky have purchased more coal in recent years. While the amount of coal supplied by Kentucky coal producers to the state market has grown, the amount supplied by coal producers in other states has grown at a faster rate. As a result, Kentucky coal producers supply a greater amount of coal, but capture a smaller share of the Kentucky market.

Differences in the cost of mining coal and the demand for coal across different regions of the nation have contributed to regional differences in the price of coal. In 2001, the average price before transportation costs was $26.77 per ton for coal mined in Kentucky and $17.38 per ton for the United States. The difference between the average mine price of coal from Kentucky and the average mine price of coal from the entire nation has grown over time.

Factors Affecting the Competitiveness of Kentucky Coal

Several changes in recent years have affected the competitiveness of Kentucky coal. Most, but not all, of these changes were likely to have adversely affected Kentucky's coal industry. Some of these factors are tied to government regulation. Others are changes in various aspects of production or transportation.

The regulatory factors consist of federal environmental laws and the Kentucky Public Service Commission's oversight of the state's electric utilities. The federal government restricts the amount of sulfur dioxide and nitrogen oxide that may be released into the air. Federal restrictions on the amount of sulfur dioxide that may be emitted into the air have reduced the demand for Kentucky coal in general and western Kentucky coal specifically.

Western Kentucky coal generally has higher levels of sulfur content. The federal government also restricts the amount of nitrogen oxide that may be emitted by electric generators. These restrictions may cause utilities to shift from coal to other types of fuel, but does not appear to cause Kentucky coal to be less competitive relative to other coal.

Although the Public Service Commission (PSC) has no authority to set the price that utilities pay for coal or to require utilities to purchase coal from out-of-state suppliers, it can potentially affect the competitiveness of Kentucky coal. The PSC reviews purchases that utilities make and determines whether the expenses may be passed on to customers in the form of higher rates. If the PSC determines that a utility is paying more for Kentucky coal than it could for coal from another state, and there is no improvement in service from this purchase, then the PSC may not allow the utility to pass on to its customers the full cost of the coal purchase.

Productivity has improved both in Kentucky mines and mines located in other states. On average, the productivity improvements in other states were greater than in Kentucky. Greater productivity tends to reduce the cost of mining coal. As other states became relatively more productive than Kentucky, the price of coal from these states likely decreased relative to the price of Kentucky coal. Transportation costs have also reduced the competitiveness of Kentucky coal. In the past, transportation costs acted as a competitive barrier by making it more costly to ship coal into distant markets. In the past, the cost of shipping coal from western states to eastern states made it cheaper in some instances to purchase Kentucky coal. Recent decreases in the cost of rail transportation have eroded that barrier and reduced the competitiveness of Kentucky coal.

The one factor that has improved the competitiveness of Kentucky coal was the federal tax credit for synfuel. Synfuel is made by crushing large pieces of coal and spraying the coal with an oil based product. The federal tax credit makes it possible to sell synfuel produced using Kentucky coal cheaper than the cost of the coal used in the synfuel production. The tax credit, however, is set to expire in 2007.

Economic Impact of Kentucky's Coal Industry

Although total employment in Kentucky has generally grown, employment in Kentucky's coal mining industry has decreased. Coal mining employment for the state peaked in 1979 at just over 50,000 jobs. By 2001, coal mining employment had decreased to approximately 17,500 jobs. Currently, coal mining jobs account for less than a percent of Kentucky's total nonfarm employment.

Decreases in coal mining employment are due to two changes. First, worker productivity in coal mines has increased allowing coal mines to use fewer workers to produce the same amount of coal. Productivity improvements account for approximately 75 percent of the decline in Kentucky mining jobs since 1979. The remaining portion of the decline in employment was due to decreases in production levels. As Kentucky coal mines supplied smaller amounts of coal, fewer workers were needed.

Kentucky coal's lost market share affects more than just Kentucky's coal industry. Declining coal production translates to reductions in output, employment, and income in the coal industry, in industries that supply coal firms, and in sectors of the economy where employees of these firms spend their income. A 1 percent decrease in market share in the Kentucky market is estimated to result in a loss of 135 jobs and $5.3 million in earnings. Kentucky coal producers experienced a 22 percentage point market share decrease in Kentucky. Because a larger amount of Kentucky coal is shipped to other states than within Kentucky, the economic loss associated with a 1 percent decrease in market share in these other states would be greater (885 jobs and $35 million in earnings).

CHAPTER 1
TRENDS IN THE KENTUCKY COAL MARKET

In recent years, a number of changes in the coal market have reduced the competitiveness of Kentucky coal. Since 1990 Kentucky coal production has generally decreased.

Historically, the coal industry has played an important role in Kentucky's economy. According to the Kentucky Coal Education Website, the first commercial coal mine in Kentucky opened in 1820 and produced 328 tons of coal. While the amount of coal produced by Kentucky mines decreased in some years, production generally grew until 1990. In recent years, however, there have been a number of changes in the coal market that have reduced the competitiveness of Kentucky coal. These factors include several regulatory decisions and other changes. These changes have contributed to a decline in the amount of coal produced in Kentucky and have reduced the contribution that the coal industry makes to the state's economy.

The coal industry is cyclical in nature, experiencing periods of contraction and expansion. Typically, as economic conditions improve or prices of competing energy resources rise relative to coal, the coal industry benefits. As coal prices rise relative to other energy resources, or during times of slow economic growth, the coal industry can be negatively affected.

Various factors have been cited as contributing to Kentucky coal becoming less competitive.

These types of changes are common and affect coal producers that are located in different regions in similar ways. In recent years, however, there have been additional changes that affected various coal producers in different ways. Many of the changes have been cited as reducing the competitiveness of Kentucky coal relative to coal from other areas.

This study discusses the factors that have contributed to the decrease in the competitiveness of Kentucky coal.

As a result of these changes, the 2002 Kentucky General Assembly passed HCR 244, which directed the Interim Joint Committee on Agriculture and Natural Resources to study the various factors that have affected the competitiveness of Kentucky coal. The resolution specifically directed the LRC to study the following subjects:

1. The allocation method by which nitrogen oxide emission allowances are distributed to existing and new sources;

2. The role of the Public Service Commission (PSC) in the fuel purchasing and ratemaking process and the public policy that underlies that regulatory function. Specifically, the study shall examine the full effect of the awarding of coal contracts to out-of-state competitors on tax revenues, jobs, wages, benefits, and environmental compliance costs; and

3. The factors that hamper the ability of Kentucky coal to be competitive against foreign coal and coal from other states.

Description of Study

How the Study Was Conducted

In conducting this study, staff analyzed data from several sources. The primary sources of data were the Annual Coal Report and Coal Industry Annual, both published by the United States Energy Information Administration (EIA). These reports, along with other reports from the EIA, provide a very detailed picture of trends in the coal industry. Staff also relied on interviews with various parties who are connected to the coal industry, including staff of the PSC, representatives of electric utilities, and representatives of the coal industry. To determine the impact that Kentucky's coal industry has on the state's economy, staff analyzed data from the United States Bureau of Economic Analysis and used an econometric model of the state's economy.

Organization of the Report

The structure of the report is as follows:

- The remainder of Chapter 1 provides a comparison of the characteristics of Kentucky coal to coal mined in the rest of the nation and discusses recent trends in the Kentucky coal market.

- Chapter 2 discusses the various factors that affect the competitiveness of Kentucky's coal industry.

- Chapter 3 describes the economic impact that Kentucky's coal industry has on the state's economy. The chapter also discusses the effect that decreased production in Kentucky coal mines may have on the state's economy and on revenue collected by the state government.

Major Conclusions

The study's major conclusions are as follows:

1. While national coal production has increased in recent years, Kentucky coal producers' market share has decreased. Kentucky coal's share of the Kentucky market decreased from 82 percent in 1992 to 60 percent in 2001. Kentucky coal's share of the market in the 10 other states to which Kentucky

ships a large amount of coal decreased from 48 percent in 1993 to 33 percent in 2001. The average price of coal mined in Kentucky is higher than the average price of coal mined in the United States, and this difference has grown over time.

2. Several factors have contributed to the Kentucky coal's lost market share. Some of these factors are the result of regulatory decisions. Because western Kentucky coal has a relatively higher sulfur content compared to coal from other parts of the nation, federal restrictions on the amount of sulfur that may be emitted by electric utilities have shifted demand to coal from other parts of the nation. Federal restrictions on the amount of nitrogen oxide that may be emitted by electric utilities may cause utilities to shift from coal to other fuels. The restrictions, however, would likely affect the national coal market, not just the Kentucky coal market.

3. The PSC has some regulatory authority that can potentially affect the demand for Kentucky coal. The PSC's authority does not, however, allow it to determine what price electric utilities must pay for coal or to determine from which companies coal producers utilities must purchase coal. The PSC does have the authority to review utilities' purchases and expenses. This review is intended to ensure that electricity is delivered reliably and at the lowest cost possible, but the review can cause utilities to shift to non-Kentucky coal or other types of fuel if it is cheaper than Kentucky coal.

4. Nonregulatory factors have also affected the competitiveness of Kentucky coal. The cost to mine coal in Kentucky is relatively higher than in the western United States. The cost difference is due to the smaller size of Kentucky mines and smaller size of Kentucky coal seams. The cost to transport coal has decreased in recent years allowing coal from the western United States to more cheaply move into Kentucky's traditional market.

5. A federal tax credit for the production of synfuel has increased the demand for Kentucky coal because Kentucky coal is well suited for the production of synfuel. The credit, however, is scheduled to expire in 2007.

6. The number of jobs in Kentucky's coal industry decreased from more than 50,000 at its peak in 1979 to 17,500 in 2001. The decrease was attributable primarily to improvements in productivity, but also to decreases in production. As Kentucky

coal producers lost market share to other producers, fewer employees were needed. The lost market share had effects outside the coal industry as well. Other sectors of the state's economy that supply Kentucky's coal producers or provide goods or services to coal employees were also adversely affected. The lost market share also resulted in lower tax revenues than would otherwise have been collected.

Characteristics of Coal

Three characteristics distinguish the quality of coal.

According to the EIA's Energy Glossary, coal is a combustible rock mined for its ability to produce energy. Coal that is mined across the country, and even across Kentucky, can vary significantly in its characteristics, or quality. The Natural Science Program at the University of Wyoming cites three primary characteristics when discussing the quality of coal: heat content, sulfur content, and ash content. These characteristics affect the marketability and price of coal. Generally, a higher heat content and a lower sulfur and ash content are desirable, especially for the electric utility market.

Heat content refers to the amount of energy that coal can produce.

Heat content, as measured in British Thermal Units (Btus), indicates the amount of energy that coal can produce. Heat content is an important characteristic for electric utilities because coal with a higher heat content can produce more electricity than the same amount of coal with a lower heat value.

Sulfur is a component of coal that contributes to pollution.

The second characteristic of coal is its sulfur content. Sulfur is an element that is typically found in fossil fuels, such as coal. The sulfur content of coal indicates the amount of sulfur it contains. When coal is burned, sulfur is released into the atmosphere as sulfur dioxide. As sulfur dioxide reacts with moisture in the air, acid rain is produced. Federal environmental regulations restrict the amount of sulfur that can be released into the air when coal is burned.

Ash is the unburnable portion of coal.

The final characteristic of coal that can affect its marketability is its ash content. According to the EIA, ash is the unburnable part of coal. Coal with a higher ash content weighs more per cubic foot, making it more difficult and costly to handle. Ash must be removed and disposed of when the coal is burned or it pollutes the air by being released as fly ash. The higher the percentage of ash, the more costly it is for a utility to use it.

Representatives of electric utilities in Kentucky indicated that disposal of ash is expensive and that ash content is a consideration when making purchasing decisions. Most did not see ash disposal as a significant problem, however, because there are some markets for the ash by-product. For example, ash can be used for cinders on icy roads and for gypsum, the material used to make wallboards. Ash that is not recycled must be stored on site or hauled away. According to representatives from Louisville Gas and Electric and Kentucky Utilities, coal with higher ash values can be economical because the lower price of coal with a higher ash content can offset the cost of disposing of the additional ash.

United States and Kentucky Coal Characteristics

Kentucky coal has relatively higher heat content and more sulfur than coal from rest of the nation.

The quality of coal mined in the United States varies across regions. Data from the EIA's Coal Industry Annual 2000 is shown in Table 1.1. The data show that, on average, the heat content of coal produced in the United States in 2000 was 10,115 Btus. Kentucky coal, however, had a higher heat content at 12,219 Btus. The sulfur content of Kentucky coal is, on average, much higher than the United States average sulfur content. Coal from Kentucky had an average sulfur content of 1.52 percent while the average sulfur content of coal nationwide was lower at 0.93 percent in 2000. Coal in the U.S. consists of, on average, 8.84 percent ash while coal in Kentucky contains a higher level of ash, at 10.55 percent.

Eastern and Western Kentucky Coal

Western Kentucky coal has a lower heat content and more sulfur than eastern Kentucky coal.

Coal in Kentucky is mined from two separate parts of the state, eastern and western Kentucky. The characteristics of coal mined from these two parts of the state vary significantly. Eastern Kentucky coal is relatively more competitive because of its higher heat value and lower sulfur and ash contents. Eastern Kentucky coal had an average heat value of 12,500 Btus, a sulfur content of approximately 0.99 percent and an average ash content only slightly above the national average at 9.95 percent (U.S. EIA. Coal Industry Annual). Western Kentucky coal has a higher sulfur content, making it less marketable. The average sulfur content of coal from western Kentucky was 3.19 percent, significantly higher than eastern Kentucky coal and coal nationwide. The heat content of coal from western Kentucky was not much different from that of coal from eastern Kentucky with an average heat value of approximately 11,500 Btus. Western Kentucky coal also had a higher ash content at 12.51 percent.

Table 1.1
Quality of Coal Received by Electric Utilities, 2000

	Average Heat Value (Btu/lb)	Average Sulfur Content (%/lb)	Average Ash Content (%/lb)
United States	10,115	0.93	8.84
Kentucky	12,219	1.52	10.55
Eastern Kentucky	12,500	0.99	9.95
Western Kentucky	11,500	3.19	12.51

Source: United States. Energy Information Administration. Coal Industry Annual 2000, and the Kentucky Coal Association, Kentucky Coal Facts 2000.

Coal Production

Kentucky contributes 11 percent of the nation's total coal production and is the third largest coal-producing state in the nation.

Preliminary estimates from the EIA's Annual Coal Report 2002 show that the United States produced 1,093 million tons of coal in 2002. Coal produced in the United States accounted for approximately one-quarter of the world's total coal production. There are 26 coal-producing states in the U.S. Table 1.2 shows the top 10 coal-producing states, which account for 85 percent of the nation's coal production. In 2002, Kentucky produced 124 million tons of coal or 11 percent of the nation's total production. Only Wyoming and West Virginia produce more coal than Kentucky.

Table 1.2
Top 10 Coal-Producing States in 2002

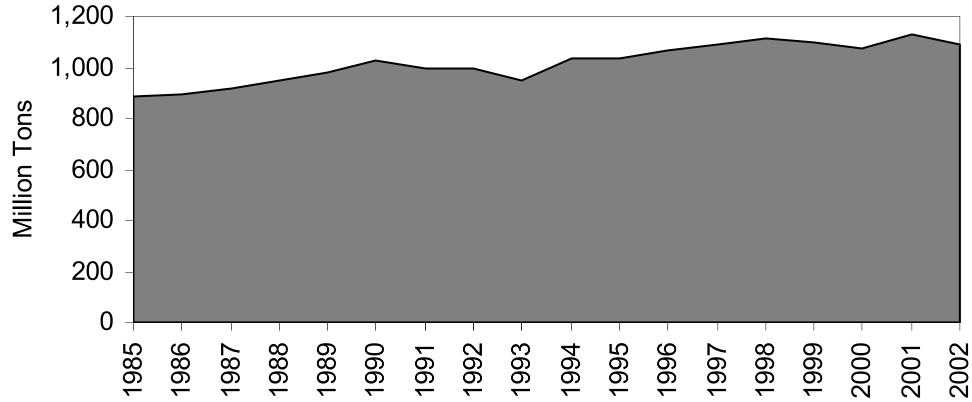
Rank	State	Millions of Tons	Percent of Total U.S. Production
1	Wyoming	373	34%
2	West Virginia	150	14%
3	Kentucky	124	11%
4	Pennsylvania	68	6%
5	Texas	45	4%
6	Montana	37	3%
7	Indiana	35	3%
8	Colorado	35	3%
9	Illinois	33	3%
10	North Dakota	31	3%

Source: U.S. EIA. Annual Coal Report 2002. Preliminary Tables. <http://www.eia.doe.gov/cneaf/coal/ page/acr/tables/table1.html>. Accessed Nov 14, 2003.

While coal production for the nation has increased, coal production in Kentucky has decreased.

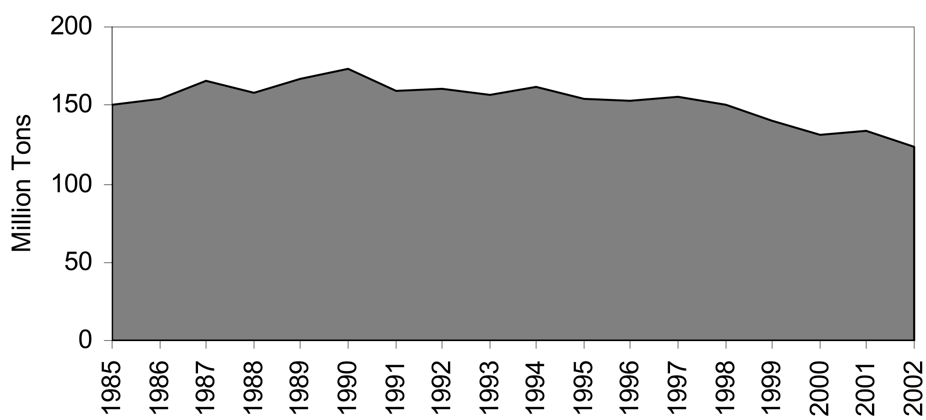
Coal production in the United States has fluctuated over the last decade (Figure 1.A) but generally grew and reached an all-time high in 2001. Since 1990, Kentucky coal production has primarily decreased (Figure 1.B), although coal production in 2001 did increase slightly. Overall, Kentucky coal production decreased from its high in 1990 by approximately 2.8 percent annually through 2002. Both eastern and western Kentucky coal production have steadily declined since 1990. Eastern Kentucky coal production, however, decreased at a slower rate than western Kentucky production.

Figure 1.A
United States Coal Production



Source: United States. Department of Energy. Energy Information Administration. Coal Industry Annual 1985 - 2000, and Annual Coal Report 2001 - 2002.

Figure 1.B
Kentucky Coal Production



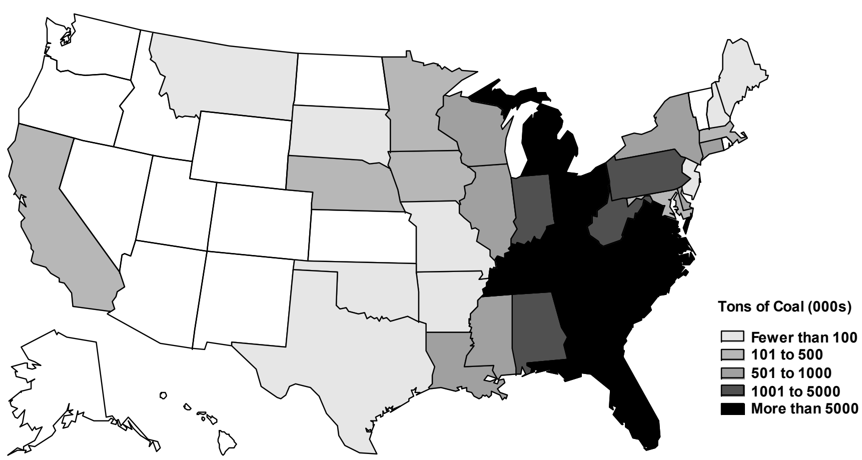
Source: United States. Department of Energy. Energy Information Administration. Coal Industry Annual 1985 - 2000, and Annual Coal Report 2001 - 2002.

The Market for Kentucky Coal

There are three primary geographic markets for Kentucky coal: Kentucky, United States, and other countries.

Kentucky coal producers ship coal within Kentucky, to other states, and to other countries. Data on Kentucky coal shipments was obtained from various issues of the EIA's Annual Coal Report and Coal Industry Annual. Approximately 19 percent of the coal shipped from Kentucky in the past 11 years was sent to end-users located in the state. Exports to other countries accounted for a relatively small share of Kentucky's market. The majority (81 percent) of Kentucky coal was shipped out-of-state, making the out-of-state market the most important for Kentucky coal producers. Figure 1.C shows the states that received Kentucky coal in 2001. Kentucky coal producers have lost market share in each of these markets.

Figure 1.C
Shipments of Kentucky Coal
(2001)



Source: United States. Energy Information Administration. Coal Distribution Report.

The Kentucky Market

Kentucky coal producers ship more tons of coal to Kentucky, but have lost market share in the state.

Figure 1.D shows shipments of coal to Kentucky, including shipments from Kentucky coal producers to end-users located in Kentucky. Although there have been years during which total shipments to Kentucky decreased, generally shipments have increased. Shipments from both Kentucky coal producers and producers from other states have increased; however, shipments from other states have grown at a faster rate. This has resulted in Kentucky coal producers losing market share within the state. In

1992, Kentucky coal producers supplied 82 percent of the coal shipped to Kentucky. By 2001, Kentucky coal producers only provided 60 percent of the coal shipped to Kentucky. Coal primarily from three other states, West Virginia, Colorado, and Wyoming, have gained market share in Kentucky.

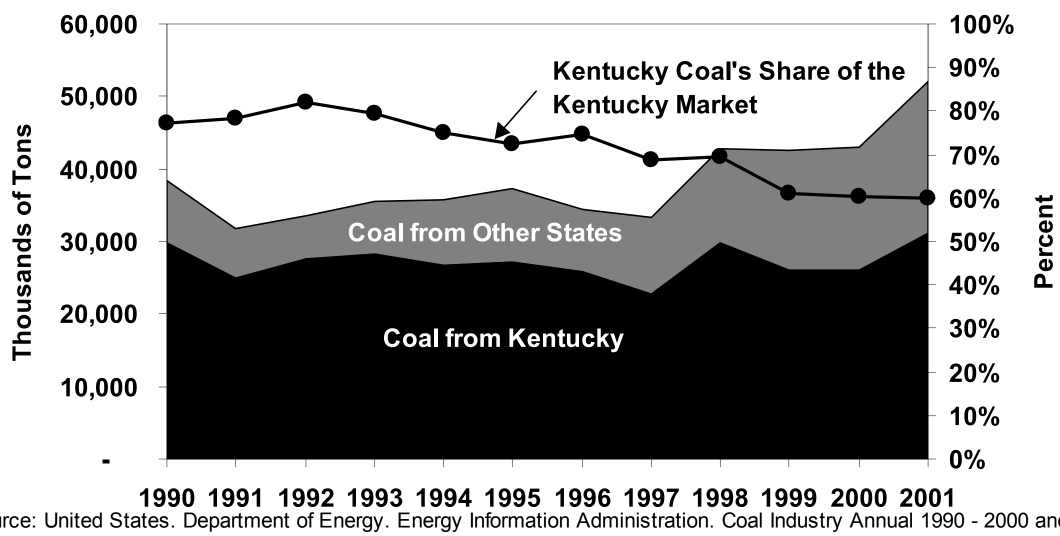
The Domestic Market

Kentucky producers shipped coal to 34 states and Washington, D.C., in 2001. Eighty-nine percent of the coal shipped from Kentucky to the domestic market, however, went to the following 10 states: Alabama, Florida, Georgia, Indiana, Michigan, North Carolina, Ohio, South Carolina, Tennessee, and Virginia. These states make up Kentucky coal producers' primary out-of-state market.

Kentucky coal producers have also lost market share in other states.

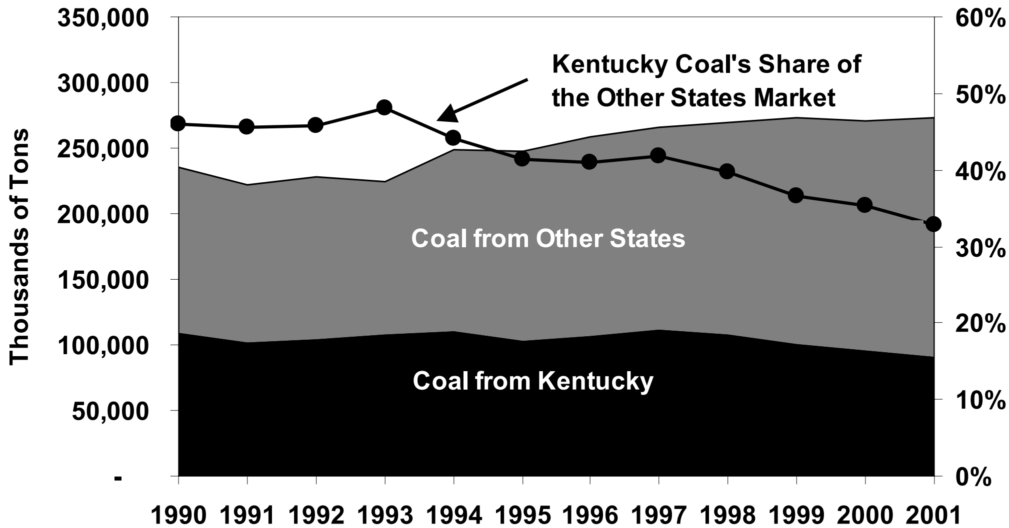
Figure 1.E shows the total amount of coal imported by these states and the portion of this coal that was supplied from Kentucky and other states. In total, the amount of coal shipped to these states grew during much of the 1990s, but this growth has diminished in recent years. Shipments from Kentucky to these states have decreased over time while shipments from other states have grown.

Figure 1.D
Shipments of Coal to Kentucky
(includes coal shipped within Kentucky)



Source: United States. Department of Energy. Energy Information Administration. Coal Industry Annual 1990 - 2000 and Annual Coal Report 2001.

Figure 1.E
Shipments to Other States*



Source: United States. Department of Energy. Energy Information Administration. Coal Industry Annual 1990 - 2000 and Annual Coal Report 2001.
*While coal from Kentucky is shipped to 34 states in total, 10 states account for 89 percent of the coal shipped to other states. Only these states are included in the chart. These states are Alabama, Florida, Georgia, Indiana, North Carolina, Ohio, South Carolina, Tennessee, Michigan, and Virginia.

The net effect is that Kentucky coal is capturing a smaller share of the market in the states that form Kentucky's traditional market for coal. In terms of market share, Kentucky coal's share of the total coal shipped to these states has fallen from a high of 48 percent in 1993 to 33 percent in 2001. Coal from West Virginia and Wyoming has gained a relatively large amount of this market.

The Foreign Market

Currently, Kentucky sends fewer tons of coal to foreign markets than in past years.

In 2001, Kentucky producers shipped approximately 2.8 million tons of coal to foreign markets. This amount accounts for a relatively small share of the coal shipped from Kentucky. Kentucky producers are supplying a smaller amount of coal to this market. In 1990, Kentucky producers shipped over 15 million tons of coal to the foreign market.

Coal Prices

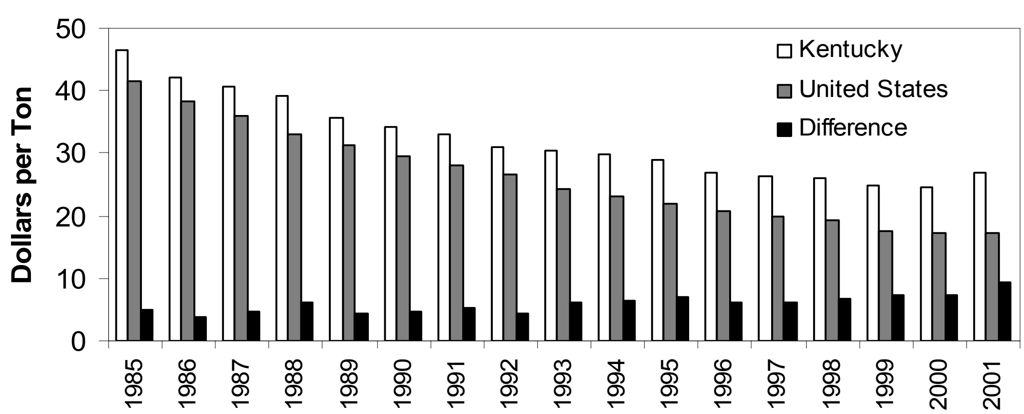
Coal prices are determined by the cost of producing coal and the demand for coal.

The price of coal is determined by the cost of mining coal and by the demand for coal. As coal producers face changes in the cost of mining, these changes will be reflected in the price paid by purchasers. For example, if the cost of labor increases, the price of coal will increase to reflect the higher labor cost. Changes in demand can also affect the price of coal. When the price of oil or natural gas increases, for example, some electric utilities may decide to use more coal to generate electricity. As utilities purchase more coal, coal producers will be able to charge higher prices. Over time, these changes in the costs of providing coal and the demand for coal cause prices to change.

Kentucky coal prices are higher than national prices and the difference has grown over time.

Although coal is generally considered a commodity, there are regional differences that affect the cost of producing coal and the demand for coal. These differences cause the price for coal to differ across regions. Figure 1.F shows inflation-adjusted average mine prices for the United States and Kentucky. Average mine prices were obtained from the EIA Annual Coal Reports. Mine prices in the United States have steadily declined from 1985 through 2000, but increased slightly (1 percent) from 2000 to 2001. The average mine price in Kentucky also decreased from 1985 through 2000. Like the national mine price, Kentucky's mine price increased in 2001, but the increase for Kentucky was significantly higher at 9 percent. Kentucky's average mine price has historically been higher than mine prices for the nation. In 2001, Kentucky's mine price was approximately 54 percent higher than the nation's mine price.

Figure 1.F
United States and Kentucky Average Mine Prices
(Stated in 2001 Dollars)



Source: United States. Department of Energy. Energy Information Administration, Coal Industry Annual 1985 - 2000 and Annual Coal Report 2001.

CHAPTER 2
FACTORS AFFECTING THE COMPETITIVENESS OF KENTUCKY COAL

Several factors have contributed to Kentucky coal being relatively less competitive.

As shown in Chapter 1, the amount of coal produced in Kentucky has generally decreased since 1990. Kentucky's decrease has occurred in spite of the fact that coal production for the nation has generally increased over this same time period. These changes have resulted in Kentucky providing a smaller share of the nation's coal production. Ultimately, the loss in market share for Kentucky coal can be attributed to higher prices and the higher cost of using Kentucky coal. There are, however, numerous factors that contribute to Kentucky coal being relatively more costly to use than its alternatives. These factors have resulted in Kentucky coal being relatively less competitive than coal produced in the rest of the nation.

These factors include government regulations and changes in various aspects of production.

These factors can be categorized into two broad groups. The first category consists of regulatory factors. Regulatory factors are policies set by federal and state governments that can affect the demand for Kentucky coal. Examples of regulatory factors include environmental regulations and tax incentives for alternative uses of Kentucky coal. Regulatory policies can cause Kentucky coal to be relatively more or less expense to use. Other factors that affect the competitiveness of Kentucky coal are nonregulatory factors that affect the cost of producing or shipping coal. As with regulatory policies, changes in the cost of producing or delivering Kentucky coal can result in higher or lower costs for purchasers.

Regulatory Factors Affecting the Competitiveness of Kentucky Coal

The Clean Air Act Amendments of 1990 increased the cost of using high-sulfur coal such as the coal mined in western Kentucky.

Regulation of Sulfur Emissions

The Clean Air Act Amendments of 1990 (CAAA90) reduced the competitiveness of Kentucky coal. The amendments increased the cost of using high-sulfur coal, which is the type of coal mined in western Kentucky. As the cost of using western Kentucky coal increased, it became relatively less competitive. Shipments of eastern Kentucky coal to electric utilities have decreased, but to a lesser extent than that of coal from western Kentucky (U.S., EIA. Coal Distribution Report).

The Amendments were aimed at reducing the amount of acid rain, by placing limits on the amount of sulfur dioxide emitted from electric utilities.

According to a 1997 report from the EIA, the provisions of the amendments were aimed at reducing acid rain, which can be partially caused by sulfur dioxide released when fossil fuels are burned (U.S., EIA. The Effects). To accomplish this goal, new standards were imposed that limit the emissions of sulfur dioxide (SO_2) from fossil-fueled electric generating plants. The new standards were implemented in two phases. Phase I, which began in 1995, primarily affected plants that emitted large amounts of SO_2. To control SO_2 emissions, a cap was placed on the amount of emissions that these plants could produce. Emission allowances were allocated to the owners of electric generating units that were affected by the new standards. An emission allowance authorizes the owner of the plant to emit one ton of SO_2 into the atmosphere during a specified period. Phase I electric utilities had to have a sufficient number of allowances to cover the amount of SO_2 produced by its generating units. If its emissions exceeded its allowances, the utility faced a penalty of $2,000 for each ton over its allowances. Allowances were allocated to the owners of plants based on historical emissions produced by the plants. The initial quantities of allowances allocated, in most cases, were insufficient to meet the amount of SO_2 emitted in 1985, the base year, under existing conditions.

Phase I of the CAAA90 affected plants with generating units that could produce 100 megawatts of electricity and had an SO_2 emission rate of 2.5 pounds per million Btu or greater in 1985. Almost all of the plants affected by Phase I were located in the eastern half of the United States. In Kentucky, 17 generating units, belonging to 10 electric utilities, were affected by Phase I (U.S., EIA. The Effects).

Phase II of the CAAA90 became effective on January 1, 2000. Data from the EIA show that Phase II extended the restrictions to the majority of electric power producers affecting more than 2,000 units nationwide and 71 units in Kentucky.

Some electric utilities complied with the limits by switching to low-sulfur coal. Others installed equipment called scrubbers to prevent sulfur dioxide from being released into the air.

Utilities had several options to comply with the new emission standards. One option was to switch to low-sulfur fuel. Switching fuels could be a complete change to coal that meets the sulfur dioxide levels set by the CAAA90. Electric utilities could also choose to blend low-sulfur and high-sulfur coal to produce a mix of coal with a sulfur content that met emission limits. Another option was to invest in flue gas desulfurization equipment, or scrubbers. This equipment prevents the sulfur emissions from being released into the air and allowed utilities to continue to use high-sulfur coal. Utilities could also purchase additional emission allowances. A utility that has emitted more sulfur than it has allowances may purchase additional allowances from another utility that has more than it needs. Finally, utilities could retire older generating units that produce a large amount of sulfur. Fuel-switching has been the most utilized strategy for meeting the CAAA90 requirements. According to a report by the Kentucky Energy Policy Advisory Board, utilities in Kentucky have also installed a large number of scrubbers on their generating plants. Forty-eight percent of Kentucky power plants have scrubbers, a higher percentage than any other eastern state.

In some instances, switching to low-sulfur coal was cheaper than installing scrubbers. One utility that has installed scrubbers continues to purchase low-sulfur coal because it is cheaper.

Although there are drawbacks to burning low-sulfur coal, the price advantage of switching fuels compared to other compliance strategies was sufficient to overcome these problems. One drawback to switching to low-sulfur coal is that it is typically lower in heat value, and therefore, may require the firing of larger volumes of coal to generate the same amount of power. The need for larger volumes of coal creates higher handling and storage costs. Burning more coal also could require additional investments to handle the increased fly ash. According to a representative from East Kentucky Power Cooperative, while the cooperative has installed a scrubber on its largest generating unit, the low cost and availability of low-sulfur coal has made switching fuels more economical than running the scrubber. Representatives of the cooperative, however, indicated that if low-sulfur coal prices increase, the cost advantage to switching fuel will diminish and it will utilize its scrubber.

Some utilities have purchased allowances to comply with the limits in sulfur emissions. Each credit allows the holder of the credit to emit one ton of sulfur dioxide.

Purchasing allowances is the second most popular choice for compliance (U.S., EIA. The Effects). Allowances are so inexpensive today that a utility can purchase allowances to be used in future years for less than the cost of installing and operating capital equipment. To remain competitive, many high-sulfur coal companies are buying allowances that can be packaged with their coal sales to increase their competitiveness with low-sulfur coal. At least one utility in Kentucky, East Kentucky Power Cooperative, has taken advantage of this type of coal/allowance packaging.

The majority of electric utilities have lowered emission levels beyond what was mandated by Phase I through fuel switching/blending or installing scrubbers, or have purchased additional allowances (U.S., EIA. The Effects). This overcompliance was done to save emission allowances for use during Phase II, when the cap on sulfur dioxide emission will be even lower.

Limits on the amount of sulfur dioxide that may be emitted decreased the demand for Kentucky coal.

The sulfur dioxide emission limits imposed by the CAAA90 decreased the demand for Kentucky coal. The 1997 EIA study found that the majority of utility plants chose to comply with emission limits by switching to low-sulfur coal or blending a low-sulfur coal with other high-sulfur coal. This choice was made mainly because utility officials determined that, in many cases, switching to low-sulfur coal was less expensive than the other options for complying with the emissions limits. Low-sulfur coal from the western United States was the logical choice for most utilities. As demand grew for low-sulfur coal from the western United States, demand decreased for higher-sulfur coal produced in the eastern United States and western Kentucky.

Regulation of NOx Emissions

The Clean Air Act authorizes the EPA to regulate the emissions of NOx, which contribute to pollution.

Nitrogen oxide (NOx) is a by-product of combusting fossil fuels. NOx is produced when the heat from burning the fuel releases nitrogen gas, which combines with nitrogen and oxygen in the air and is a source of pollution. The Clean Air Act authorizes the United States Environmental Protection Agency (EPA) to regulate NOx emissions.

The EPA determined that electric generators were a major source of NOx emissions.

In 1997, the EPA estimated that over 23 million tons of NOx were emitted into the air in the United States from various sources including motor vehicles, electric generators, and other industrial sources (U.S., EIA. Reducing). A large proportion of NOx emissions, however, came from nonmobile sources like electric generators. These sources are much easier to isolate, measure, and impose emissions limitations on. Roughly one-third of the nation's NOx emissions (Carlin) come from electric generating units (EGUs). This percentage may be higher in southern states like Kentucky given the reliance on coal as the principal fuel for electric generation.

The EPA required several states to develop plans to reduce the amount of NOx emissions produced.

On September 24, 1998, the EPA published a final rule titled "*Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone*". This final rule, along with later technical amendments, required some states to reduce NOx emissions during the ozone season—May 1 to September 30. The rule affects 22 states—Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin—and the District of Columbia. The rule required states to adopt or revise a state implementation plan (SIP) to reduce NOx emissions by September 30, 1999, and that NOx emission control technologies be implemented by electric power plants no later than May 1, 2003. NOx emission reductions will be enforced during the ozone season beginning in 2004.

Kentucky's plan to reduce NOx emissions included a limit on the amount of NOx that electric generating units may emit. NOx allowances were issued, which allow the holder of the allowance to emit one ton of NOx.

In August 2001, the Kentucky Division of Air Quality revised Kentucky's SIP to adopt the EPA's final rule. There were two principal components in the rule: a budget ceiling and a trading system. The SIP incorporates the federally imposed NOx budget ceiling for EGUs, which restricts the amount of NOx emission in Kentucky to 36,045 tons. Combined with the NOx reductions required from non-EGU sources such as industrial boilers and cement kilns, the EPA-imposed emissions ceiling is projected to reduce Kentucky's NOx emissions by 59 percent from the level that it was projected to reach by 2005 without the restrictions (Leonardo Academy). Each ton of NOx that may be emitted is represented as a credit or a "trading allowance." One allowance gives its holder the right to emit one ton of NOx. For every ton of NOx emitted by a generator during the ozone season, the owner of the generator must hold an equal number of emission allowances. If the owner does not have a sufficient number of allowances, allowances from the next year will be reduced. The restrictions on NOx emissions will be enforced beginning in 2004.

NOx allowances may be sold to others or saved for use in later years.

The SIP also incorporates a flexible banking and trading system, which permits EGUs to use allowances, bank them for future use, or sell them to other sources. The banking and trading system gives EGUs greater control over how and when they use allowances. If an EGU does not have enough allowances, then it must purchase additional allowances on the open market or cut production. NOx allowance prices fluctuated in 2003. J.D. Energy reported that some July trades for 2004 NOx allowances were as high as $4,750 per ton (J.D. Energy, Monthly). November prices for the same 2004 allowances dropped to $2,600 per ton, but are expected to rise to $3,000 per ton in the summer of 2004.[1] If allowances from other states are purchased by the owners of EGUs located in Kentucky, total NOx emissions for the state may exceed the limit of 36,045 tons. If EGUs in Kentucky purchased allowances from other states, EGUs in those states would have to reduce their emissions.

[1] While most EGUs are regulated utilities and will be able to pass on the cost of purchasing allowances to the ratepayer, these companies are constrained by the statutory requirement to maintain the lowest rates possible by containing costs and maximizing efficiency. Therefore, the PSC may not allow an EGU to purchase NOx credits if there are less expensive ways of delivering electricity and meeting the NOx restrictions.

NOx allowances are allocated to electric generating units (EGUs).

Allocation of NOx Allowances to Electric Generators. An accounting system to track the allowances was established at the EPA, the Kentucky Division of Air Quality, and within each EGU. The EPA transfers the allowances to a state account so the state can allocate them to the individual EGUs. The basic requirement imposed by the EPA is that the state remain under the NOx budget ceiling and that reductions be achieved by limiting emissions, primarily from electric generating units. The EPA does not, however, stipulate the number of allowances each EGU is to receive. The EPA offered a methodology in the model rule, which Kentucky incorporated, with some modifications, into its SIP.

Existing source EGUs are EGUs in operation on or prior to May 1, 2001. New source EGUs commenced operations after May 1, 2001.

In the SIP, EGUs are subdivided into existing and new sources. Existing sources are those in commercial operation on or prior to May 1, 2001. These sources tend to be comprised of traditional, rate-regulated electric utilities; have three years of data available on past heat values for fuel burned at the plant; and have, as a group, made significant investments in NOx reduction technologies.[2] New sources are those that commenced operations after May 1, 2001. New sources will not have sufficient heat data to determine NOx emissions and are mainly comprised of merchant electric generators (those that sell <u>all</u> electric energy on the wholesale market).

Existing sources receive 95 percent or the NOx allowances at no charge. New sources may purchase the remaining 5 percent.

According to the Kentucky SIP, existing sources will receive 95 percent of the allowances (34,242 tons) for the 2004-2007 period at no charge. Five percent of the allowances (1,803 tons) for the 2004-2007 period will be set aside for new sources, but new sources will not actually be given any allowances. New sources will be able to purchase allowances at market rates from a brokerage firm. The Kentucky Finance Cabinet has issued a request for proposals to hire a brokerage firm to sell the allowances. For the 2007-2010 period, existing sources will receive 98 percent of the allowances and 2 percent will be available for new sources. It is not known at this time whether the allowances for the 2007-2010 period that will be set aside for new sources will continue to be sold on the open market or whether the Kentucky Division of Air Quality will revise administrative regulations to allocate those allowances to the new source EGUs.

NOx allowances are distributed to existing-source EGUs based on their past emission rates.

The Division of Air Quality uses a formula to determine the number of allowances each existing source EGU is to receive. The formula uses data on how hot the fuel burns in the boiler to

[2] Enforcement of the NOx restrictions will not begin until the summer of 2004. By this point, electric utilities that were in existence before May 1, 2001, should have three years of data.

estimate NOx emissions for each generator during the ozone season if the emissions rate was restricted to a federally imposed rate of 0.15 lbs/mbtu. Then, allowances are distributed to each unit proportionally, but are constrained by the 34,242 limit. The allowances will be issued periodically and will be useable for a period of three years. After the three-year period, the allowance expires. A generator can expend the allowance immediately, bank them for near-future use, or sell them to another generator.

NOx restrictions may have an indirect effect on the competitiveness of Kentucky coal.

The Effect of NOx Regulations on the Competitiveness of Kentucky Coal. The regulations aimed at reducing the amount of NOx emitted may have an indirect effect on the competitiveness of Kentucky coal. It is unlikely that these regulations will cause utilities and other purchasers of coal to switch from Kentucky coal to coal from other areas. It is possible, however, that the NOx regulations will cause utilities to switch from coal to other types of fuel that produce less NOx emissions.

According to the EIA, the formation of NOx is a function of the nitrogen content in the fuel, the flame structure, the flame temperature, and the amount and distribution of air during combustion (U.S., EIA, Reducing). In short, for fuels containing relatively the same amount of nitrogen, the hotter the burn, the more NOx is produced. Some benefits might be obtained by switching to different types of coal such as coal mined from western states. Changing coal types, however, will not achieve significant reductions. The difference in emissions between different qualities of coal is so slight that EPA's emissions manual does not list a difference between different types of coal. Because switching to non-Kentucky coal will not significantly reduce NOx emissions, a utility's decision to purchase non-Kentucky coal likely is predicated on prices rather than emission values.

While switching to different types of coal may not significantly affect NOx emissions, some utilities have switched from coal-fired electric plants to plants that burn other types of fuel. Switching from coal to natural gas has occurred because natural gas produces considerably less NOx, and the cost of adding new gas-fired generation has been less expensive than operating existing coal baseload plants or building new coal-fired plants. The EIA reported that 91 percent of planned generation additions forecast by utilities for the 2001-2005 period will be gas-fired. Actual capacity additions in Kentucky from 1990 to 1999 were mostly gas-fired. Coal-fired capacity for that same period decreased by 1.4 percent (U.S., EIA. Inventory). According to the Kentucky Public Service Commission, until predictions were made for increases in the price of natural gas for the 2003-04 winter heating season, requests for new capacity additions by electric utilities have been gas-fired. The new gas-fired capacity, intended for use during the summer peak, was in anticipation of the summer NOx cap.

New-source EGUs that burn coal will have to purchase NOx allowances in order to meet NOx limits. The additional expense will make them relatively less profitable.

The distribution of allowances to new and existing EGUs and the requirement that new EGUs purchase allowances could affect the demand for Kentucky coal. New EGUs that planned to purchase Kentucky coal will have to purchase allowances in order to operate. Representatives from existing EGUs indicated that they have a sufficient amount of allowances so that operations will not be constrained. These utilities expect to be able to meet their requirements for the 2004 ozone season using existing allowances, switching to gas-fired capacity during summer peaks, and purchasing and transferring allowances. Representatives from new EGUs, however, stated that allowances will be insufficient for operations and that the larger coal-fired operations will have to purchase additional allowances. As the cost of these allowances increases, or access to these allowances decreases, these EGUs will be relatively less profitable.

At the December 2001 meeting of the Administrative Regulations Subcommittee, Martin Huelsmann, chairman of the Kentucky Board on Electric Generation and Transmission Siting, reported that five plants had filed notices of intent to construct electric generation plants, two of which have been completed. Of the five projects for which construction certificates were requested, four are coal-fired or fired with a blend of waste and coal. Most of these projects are expected to utilize on-site waste coal or will be located at or near an active Kentucky mine. Two of the electric utilities, American Electric Power and LG&E, have indicated that the boiler configuration and proximity to the mine have made it unfeasible for them to switch to a non-Kentucky coal. The owners of some of these generators have made public commitments to using Kentucky coal for their projects.

An increase in the price of NOx allowances may reduce the demand for coal.

Coal purchases from these plants could become a significant source of demand for Kentucky coal. These plants are estimated to need approximately 7.3 million tons of coal per year. If the price of NOx allowances increases, these types of plants would become relatively less profitable and could cause utilities to look for alternative sources to provide electricity. It is not clear, however, whether the price of NOx allowances will increase, or whether the price will increase sufficiently to cause substantial changes in the demand for Kentucky coal. It is possible that there will be a sufficient number of allowances and that the price will be low.

Price increases, however, would tend make these plants, which expect to use Kentucky coal, relatively less competitive, and therefore, reduce the demand for Kentucky coal.

Regulation of Electric Utilities by the Kentucky Public Service Commission

The Kentucky Public Service Commission is charged with regulating the delivery of electricity in Kentucky and can potentially affect the demand for Kentucky coal.

The Kentucky Public Service Commission (PSC) is charged with regulating the delivery of electricity in Kentucky. It is the PSC's responsibility to evaluate the prices that utilities in Kentucky charge and to ensure that reliable electrical service is provided. As part of its regulatory activities the PSC can potentially affect the demand for Kentucky coal by utilities in Kentucky.

In theory, regulation is a method of mimicking a competitive market to achieve low prices and reliable service. A producer of a good in a competitive market is unable to charge prices that are substantially higher than the cost of producing the good because it will lose customers to other producers. Regulation is imposed when the good or service is "essential" to economic and physical well-being and when the market fails to deliver the quality, supply, or price of the good or service that would be obtained in a competitive market.

The retail electricity market is not a fully competitive market and there are two primary reasons for this. First, it is typically cheaper for one company to deliver electricity to an area than it is for multiple companies. The electricity market requires capital investments that few companies can make. Multiple competitors would have duplication of the infrastructure such as lines and poles needed to deliver electricity. This duplication is inefficient and can be obtrusive to the public. A second reason this market is not considered competitive is that companies are required to cooperate in order to distribute electricity to customers. The lines used by various electrical utilities to transmit electricity are interconnected, and the actions of one utility can have serious consequences for other utilities. These consequences were demonstrated recently when a power line failure in Ohio caused a black out across much of the eastern United States and portions of Canada (Hebert). The interconnection of companies requires a degree of cooperation that does not exist in typical competitive markets.

The PSC regulates electric utilities' activity to protect customers from high prices or unreliable service.

Due to these market characteristics, the electricity market has been considered a "natural monopoly." That is, it is cheaper for one company to provide the product than for several companies. The disadvantage of only one company providing the product is that the company could set prices substantially higher than its costs. Therefore, government regulation has been adopted as a method of protecting consumers. Government regulators provide the utility with a monopoly market and a rate of return on the utility's investment in exchange for the right to approve or disapprove the utility's expenses and rates.[3] This is the type of regulatory arrangement established in Kentucky.

Under KRS Chapter 278.010, the PSC is granted exclusive jurisdiction to regulate those entities that furnish "retail electric service" and are not municipal utilities or regulated by the Tennessee Valley Authority. Utilities under the PSC jurisdiction that own generation and would be making fuel purchases include Louisville Gas & Electric, Kentucky Utilities, American Electric Power-Kentucky Power, Big Rivers, and East Kentucky Power Cooperative.

The PSC may review a utility's expenses and determine if these expenses may be passed on the utility's customers. This review can potentially affect the demand for Kentucky coal.

The Public Service Commission's Regulatory Activities. As part of its regulatory activities, the PSC periodically reviews electric utilities' operations, including expenses incurred and rates charged. By examining a utility's expenses, the PSC is able to determine if rates are appropriate. In some instances, the PSC may determine that certain expenses were not appropriate or could have been lower. If some expenses are deemed inappropriate, the PSC may not allow the utility to include those expenses when setting the rates charged to its customers. In its oversight role, the PSC can potentially affect utilities' decisions and in turn the utilities' demand for Kentucky coal. There are four primary activities that the PSC engages in that may affect a utility's demand for Kentucky coal.

1) <u>Review of Purchased Fuel Contracts</u>

The PSC may review and approve fuel purchases.

The commission reviews and approves purchased fuel contracts. This activity is a separate, ancillary function from ratemaking. To determine the reasonableness of the price a utility pays for fuel, the PSC reviews comparable prices for similar types and quantities of coal, reviews similar purchases by other companies in different states, and assesses market conditions.

[3] In Kentucky, KRS 278.017 establishes these monopoly markets as "certified territories" for electric utilities and KRS 278.040 gives the Public Service Commission the "exclusive jurisdiction over the regulation of rates and service of utilities."

2) Review of Fuel Adjustment Surcharges

The PSC determines whether increases in the cost of fuel may be passed on to a utility's customers.

The PSC also reviews fuel adjustment surcharges that are applied to customers' electricity bills. Generally, the rates charged to customers reflect expectations of the cost of fuel. If the cost of fuel is higher or lower than expected, a utility may apply a surcharge or refund to its customers' bills. The fuel adjustment surcharge is provided for under the Fuel Adjustment Clause and allows utilities to immediately pass along a cost increase rather than wait for a formal rate case.

While a utility may immediately pass the cost on to its customers, the PSC may review the surcharge or refund. Both individual changes to the surcharge and changes in the fuel component of the base rate may be reviewed by the PSC. In its reviews, the PSC may consider the utility's long-term contract and spot market purchases. The PSC can make a determination as to whether the base rate for electricity needs to be reset or whether surcharges were erroneously applied and need to be refunded to customers.

3) Integrated Resource Planning

The PSC monitors and works with utilities to determine whether utilities have sufficient resources to meet the demand for electricity.

The PSC both monitors and works with the utility in the capital planning and investment decisions through a process called Integrated Resource Planning (IRP). The IRP process is designed to ensure that a utility's resources are sufficient to meet the projected electricity demand of the utility's customers. Utilities file IRPs with the PSC at six-month intervals. The IRP will contain a Resource Assessment and Acquisition Plan, which identifies improvements, expansion to existing facilities, and capacity additions and retirements. The plans look ahead 15 years to identify whether resource additions or changes in usage patterns must change in order to meet demand at the lowest possible cost.

4) Ratemaking Process

The PSC examines utilities' expenses in developing rates and may determine that utilities cannot pass some expenses on to customers.

During the ratemaking process, the PSC examines all costs of providing electricity service to customers with the exception of fuel costs. While the price of fuel and emissions requirements might affect from which supplier a utility purchases coal, the way a utility's electric generating units are operated will affect how much coal is needed. It is during the ratemaking proceeding that the PSC considers how units are operated and whether generation is sufficient to meet demand during peak and off-peak periods. During the ratemaking proceeding, the commission will consider such things as which units to run, the availability of units, the need for additional generation from wholesale markets or from installation of new units, and the demand for electricity. It is through this process that utilities make decisions on what type of electric generators should be used or what type should be built. This process can affect choices between generators that burn coal or other types of fuel, and therefore, affect the demand for coal.

To ensure that rates accurately reflect the actual cost of service, the commission performs a "cost of service" study for a utility during a rate case. The cost of service study will determine the "embedded cost" of producing electricity. The embedded cost reflects all relevant and prudently incurred costs of producing and delivering electricity to the customer. In the ratemaking proceeding, the commission develops a customer rate based on a portion of fixed capital costs from plant and assets; a reasonable return on capital investment; a portion of fixed operations, maintenance, and administrative costs; and a portion of the variable operations and maintenance costs. There is a fuel cost in the base rate, but this cost is charged to the base rate when the PSC considers fuel adjustment surcharges rather than during the general ratemaking proceeding.

The PSC's regulatory activities can potentially affect the competitiveness of Kentucky coal, but these activities are under-taken to achieve reliable service and reasonable rates.

PSC Regulatory Activities' Effect on Competitiveness of Kentucky Coal. Each of the regulatory activities discussed above can potentially affect the competitiveness of Kentucky coal. By reviewing the costs incurred by utilities and determining whether these costs may be passed on to customers, the PSC might affect the choices utilities make, which can affect these utilities' demand for Kentucky coal. For example, the PSC may not allow a utility to pass on the cost of a new coal-fired plant if there are cheaper alternatives. This decision could result in the utility selecting one of these alternatives rather than building a plant that would require coal. Each of the PSC's regulatory activities discussed above can potentially affect the demand for Kentucky coal in a similar way. While the PSC does not specifically encourage or discourage the use of Kentucky coal, it can constrain the decisions of utilities in such a way as to indirectly affect the competitiveness of Kentucky coal. The regulatory activities may improve or worsen the competitiveness of Kentucky coal but are undertaken in an effort to achieve the PSC's statutory charge to ensure reliable service and reasonable rates (KRS 278.030).

The PSC has no authority to set the price utilities pay for coal or stipulate that utilities purchase coal from out-of-state suppliers.

While the PSC can potentially influence the decisions of utilities, it has no authority to stipulate the price paid for coal by utilities or that utilities purchase coal from out-of-state suppliers. The PSC may review the price paid and which suppliers provided coal. In its review, the PSC may determine that a utility paid too high a price. In this situation, the PSC may not allow the utility to pass the full price on to its customers. The PSC does not, however, set the price to be paid for coal, nor does it mandate that coal be purchased from certain suppliers.

The effect that the PSC can have on the competitiveness of Kentucky coal is determined by the level of scrutiny the PSC chooses to place on utilities.

It should be noted that the effects discussed above are potential effects. The actual effect is determined by the level of scrutiny that the PSC chooses to place on utilities. If oversight is minimal, the PSC will likely have little effect on utilities' choices. If the PSC closely scrutinizes utilities' decisions, there may be a greater effect. The PSC's impacts are also subject to the types of decisions utilities make. It is not clear that in the absence of the PSC's oversight, utilities would make decisions that would tend to increase or decrease demand for Kentucky coal.

Nonregulatory Factors Affecting the Competitiveness of Kentucky Coal

Mine Productivity

Productivity differences can result in differences in the cost of coal between regions, making some regions relatively less competitive.

A key determinant of the price of coal is the cost to mine the coal. Mines that are able to produce coal at a lower cost will have a competitive advantage over more costly mines. Fixed costs, such as the cost of mining equipment, vary only slightly across coal producers within a given region. Economies of scale, however, allow larger mines to produce coal less expensively than smaller mines by spreading out those fixed costs over larger volumes of coal. Other factors, such as mine characteristics, can also contribute to differences in productivity within and across regions (U.S., EIA. Issue). Productivity differences can affect the cost of coal between regions, making some regions relatively less competitive than others.

Kentucky coal mines are generally smaller than coal mines in the western United States.

Kentucky has a large number of coal mines. However, according to the Energy Information Administration, almost all, 92 percent, are small mines that produce less than 100,000 tons annually. These small mines produce 57 percent of Kentucky's total production while 43 percent of the state's coal production is from a small number of larger mines. Coal production in the western United States, however, comes from a small number of large mines. Wyoming, for example, the leading producer of coal in the United States, has a total of only 21 mines and 17 of those mines produce over 100,000 tons a year. Almost all of the coal produced in Wyoming comes from these 17 larger mines (U.S., EIA. Coal Industry Annual 2000).

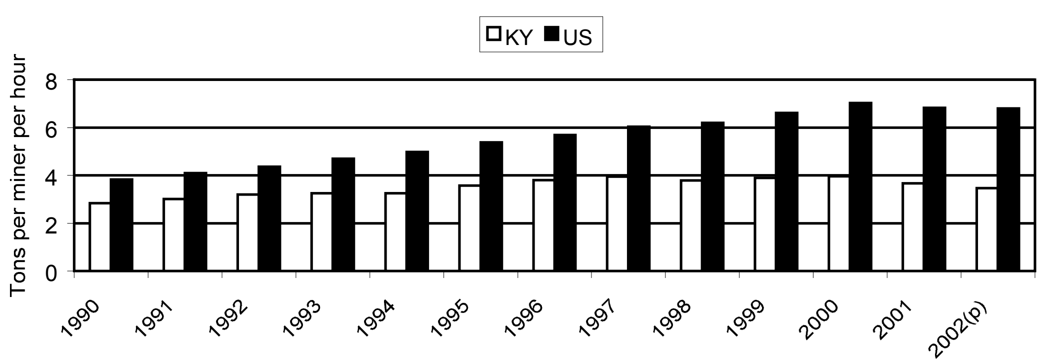
Kentucky coal is typically in thin seams, which are difficult to mine.

According to the Kentucky Geological Survey at the University of Kentucky, the eastern Kentucky coal field contains approximately 40 minable coal seams. The majority of these seams are thin seams estimated to be less than 28 inches thick. Western Kentucky has 10 coal seams, with approximately 70 percent of those seams being thicker than 42 inches. Approximately 80 percent of eastern Kentucky's recoverable coal reserves and 95 percent of western Kentucky's recoverable coal reserves are in underground mines (U.S., EIA. Coal Industry Annual 2000). The thickness of the coal seam and the depth of the seam are important because these characteristics determine the type of mining process that must be used to extract the coal, with thin seams and underground seams being more difficult to mine (Flynn).

Productivity has improved both in Kentucky mines and mines in the rest of the nation, but productivity has improved at a faster rate in the rest of the nation.

The EIA measures coal mine productivity as the amount of coal produced per miner per hour during a period. Figure 2.A shows coal productivity for the United States and Kentucky. Coal mining productivity in the United States increased by approximately 77 percent from 3.83 tons per miner per hour in 1990 to 6.8 in 2002. Total productivity in Kentucky increased 22 percent from 2.83 tons per miner per hour in 1990 to 3.47 in 2002.

Figure 2.A
Coal Mine Productivity
United States and Kentucky

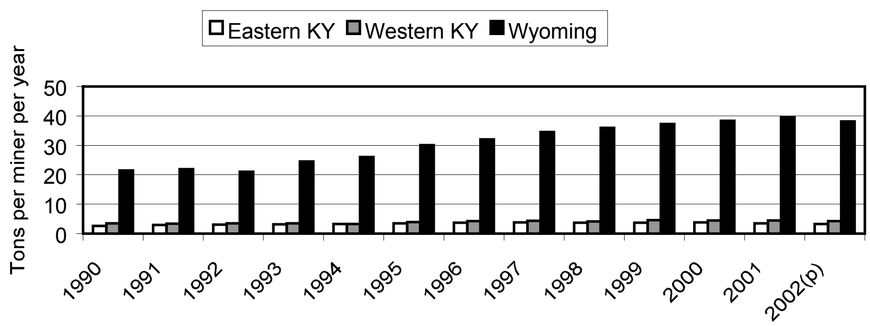


Source: United States. Department of Energy. Energy Information Administration. *Coal Industry Annual 1990-2000 and Annual Coal Report 2001-2002.* Numbers for 2002 are preliminary.

Productivity is lower in Kentucky coal mines than coal mines in the rest of the nation.

Productivity gains were made in Kentucky in both underground and surface mining. Compared to other coal producing regions like the western United States, however, Kentucky's productivity is well behind. The level of productivity at low-sulfur, western United States surface mines has not been attainable in Kentucky, primarily because of the characteristics of Kentucky's coal fields. Coal fields in the western United States tend to be surface beds that are thicker and lie under thin, easily mined surfaces. Western mining is at least four to five times as productive as mining in Kentucky (Figure 2.B). The ease of mining coal from the western United States makes it less expensive to mine compared to Kentucky coal and contributes to differences in the price of coal.

Figure 2.B
Coal Mine Productivity for Eastern Kentucky, Western Kentucky, and Wyoming Coal Fields



Source: United States. Department of Energy. Energy Information Administration. *Coal Industry Annual,* 1990-2000 *and Annual Coal Report,* 2001-2002. Numbers for 2002 are preliminary.

Transportation Costs

Rail transportation is the primary mode for shipping coal.

According to the Kentucky Coal Association's Kentucky Coal Facts 2001-2002 Pocket Guide, rail transportation is the primary mode of delivery for Kentucky coal. More than three-fourths of mined coal is initially transported by truck from the mine site to either preparation or loading facilities; however, transportation from these sites to customers typically relies on rail transportation. Nearly 72 percent of all Kentucky coal delivered to electric utility customers in 2000 used rail as the primary mode of transportation. Of the remaining shipments, an estimated 19 percent were made by barge, and 9 percent were made by truck.

Approximately half of the rail-delivered price of low-sulfur coal, typically from the western United States, is the cost to transport it (U.S., EIA. Energy Policy). By comparison, transportation costs of medium-sulfur and high-sulfur coal, typically from the eastern

United States, make up only approximately one-fourth to one-fifth of the rail-delivered cost.

In the past, high rail rates provided some protection to Kentucky coal from competition from the western United States.

Prior to deregulation of the railroad industry, the relatively high cost of shipping coal made it impractical for electric utilities in the eastern United States to purchase coal from the west. After deregulation, rail rates began to decrease. In a 2000 report, the EIA concluded that the decrease in rail rates was a disadvantage for coal producers in the eastern United States. In the past, transportation costs may have acted as a competitive barrier. The cost of shipping coal from western states to eastern states may have made it cheaper to purchase Kentucky coal. As the cost of transportation decreased, this barrier was eroded and may have reduced the competitiveness of Kentucky coal.

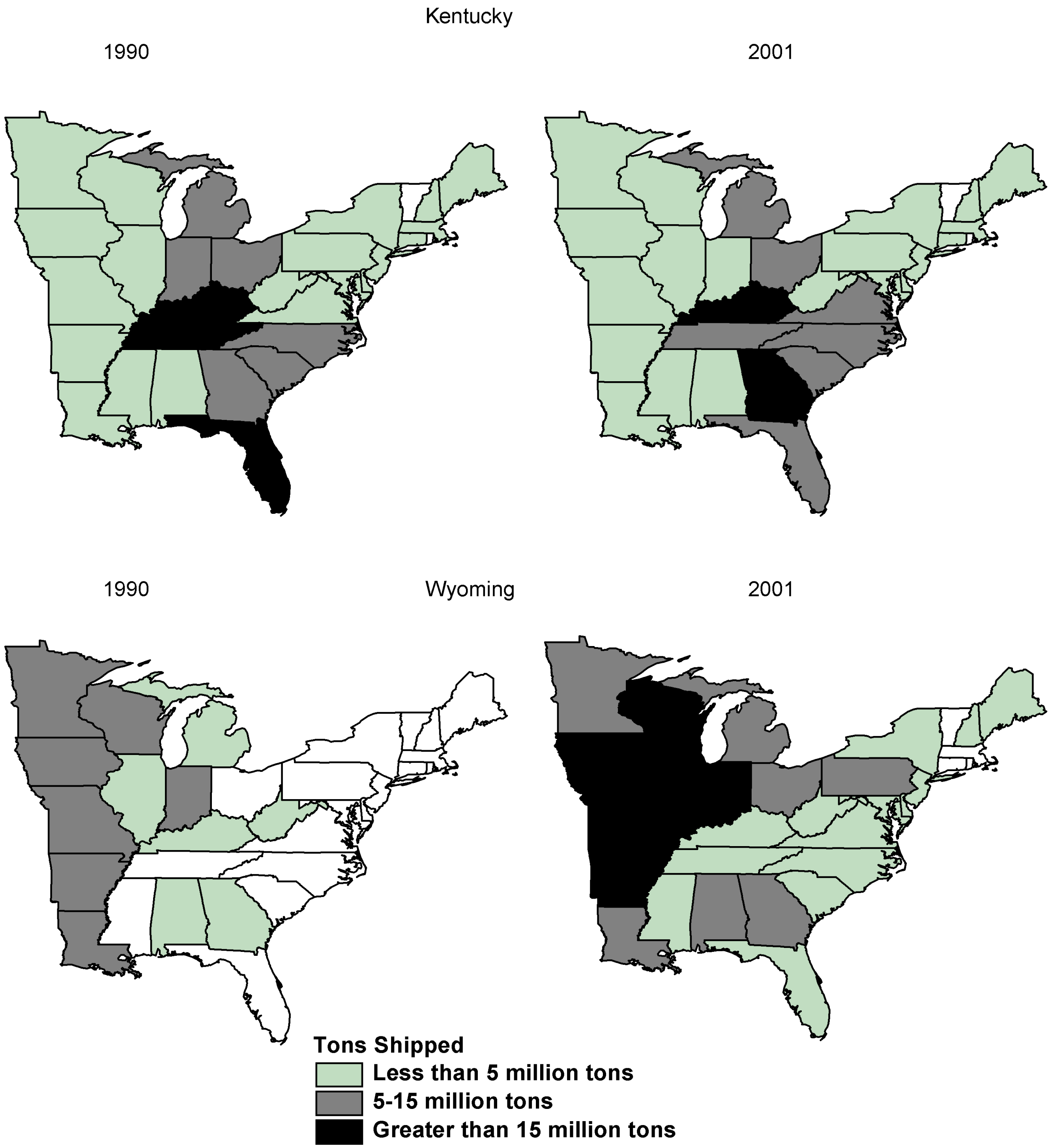
Rail rates for coal declined 27 percent from 1984 to 1999.

Rail shipment rates for coal in the United States declined approximately 27 percent from 1984 to 1999 (U.S., Office of Economics, Environmental Analysis, and Administration). Rail rates fell in both the eastern and western United States, however, the west experienced a reduction in rates at twice the level as the east. During this time frame, the rate per ton mile for coal rail shipments in the east decreased by approximately 20 percent while rates in the west decreased by almost 40 percent.

Lower rail rates have allowed coal from the western United States to move into Kentucky coal's primary market.

The steady reduction in rail shipping rates following deregulation, coupled with already lower production costs, allowed coal from the western United States, particularly low-sulfur coal from Wyoming, to become more cost competitive with coal from the east. The amount of coal shipped to the eastern United States from Wyoming has not only increased, but has been shipped farther east than in the past. Figure 2.C shows that in 1990, Wyoming only had coal shipments greater than 5 million tons in four eastern states. By 2001, the number of eastern states receiving more than 5 million tons from Wyoming had increased to 10. During the same period, the number of eastern states receiving shipments of Kentucky coal in amounts greater than 5 million tons decreased from eight to six. If the cost to ship coal continues to drop, it is likely that Kentucky coal producers will lose additional market share. If shipping costs rise, however, Kentucky coal will likely become more competitive.

Figure 2.C
Coal Shipments from Kentucky and Wyoming
to the Eastern United States



Source: United States. Department of Energy. Energy Information Administration. *Coal Distribution Report.*

Tax Credit for Synfuel

A federal tax credit for synfuel, a type of fuel produced by crushing coal into small pieces and spraying it with an oil-based product, has increased the demand for Kentucky coal.

A federal tax credit for synfuel, based on the heat content of coal used to produce synfuel, has recently increased the demand for Kentucky coal. Synfuel is made by crushing large pieces of coal into smaller pieces that are then sprayed with an oil-based product such as petroleum. The final product is a fuel of a specific size and consistent quality. Synfuel producers have found the high heat content of Kentucky coal particularly attractive because the higher the heat content of the coal used, the higher the tax credit. Production at synfuel plants in the U.S. has increased from 49.3 million tons in 2001 to 83.1 million tons in 2002 (Freme).

The tax credit allows synfuel producers to sell synfuel at a cost that is lower than the cost of the coal used in the synfuel's production.

Synfuel qualifies for a federal tax credit through Section 29 of the Crude Oil Windfall Profit Tax Act of 1980. The tax credit is based on the heat content of the synfuel, which has caused producers to migrate to high-Btu coal areas such as Kentucky. The tax credit averages approximately $27 per ton for eastern Appalachia coal, compared to a delivered price for coal to Kentucky of approximately $25 per ton (Morey).[4] The tax credit allows the synfuel producer to sell the synfuel at a price that is typically lower than the cost of coal. This is illustrated in the following example. Synfuel producers might pay $25 per ton of coal and incur $12 in additional cost to turn the coal into synfuel. The total cost of producing the synfuel is then $37. The producer may obtain a tax credit of $27 making the net cost of production just $10 per ton.

Example

Cost of Coal (per ton)	$25
Production Costs	+$12
After production cost of Synfuel	$37
Tax Credit	-$27
Cost of Synfuel after Tax Credit	$10

The synfuel tax credit will expire in 2007.

The growth of the synfuel market has increased the marketability of coal from Kentucky's smaller coal producers that are unable to meet the prices of larger coal producers or that cannot produce large amounts of coal of a consistent quality or size. It has also helped make high-sulfur, lower-cost, western Kentucky coal more competitive with low-sulfur coal from other regions because it can be mixed with other coal to produce a quality of synfuel that can be burned at plants that have not installed scrubbers. While the

[4] The delivered price of coal is the cost that electric utilities in Kentucky paid for a ton of coal, regardless of its origin. It includes the mine price plus any costs for transportation, loading, and handling.

credit has improved demand for Kentucky coal, it will expire in 2007.

Representatives from each of the utilities that are regulated by the Kentucky Public Service Commission indicated that their plants receive a portion of synfuel. Representatives from Eastern Kentucky Power Cooperative, Kentucky Utilities, and Louisville Gas and Electric indicated that 30 to 40 percent of their companies' coal purchases are from synfuel producers. Representatives from American Electric Power (AEP) indicated that their company currently purchases two-thirds of its coal as synfuel because it is the right size and of a consistent quality. They explained that AEP typically cannot buy coal from small producers because this coal does not meet the size specifications for AEP's plants, and small coal producers typically do not have the equipment to crush the coal into a smaller size.

Natural Gas

Natural gas is a fossil fuel, consisting primarily of methane, used to produce energy. It is different from coal because, when it is used to produce energy, there are few pollutants released into the air. Electric utilities that utilize natural gas are able to remain in compliance with federal environmental regulations. In 1999, the National Petroleum Council estimated that demand in the U.S. for natural gas will grow approximately 40 percent by 2015 and that electricity generation will account for almost half of that growth.

Some utilities may choose to substitute natural gas for coal when the price of natural gas is relatively high.

The extent to which electric utilities substitute natural gas for coal in their electric generation affects the competitiveness of coal. Many electric utilities have the ability to switch between coal and natural gas to take advantage of changes in fuel prices. In the short run, as the price of gas increases, the demand for gas will decrease and electric utilities will rely more heavily on coal (International Energy Agency). In the future, according to the Energy Information Administration, natural gas is expected to provide most of the electricity generation at new plants built in the United States because of federal environmental regulations. The consumption of natural gas at existing electric utilities is also expected to grow. The extent to which existing coal-fired electric utilities switch to burning natural gas will depend on the price of using natural gas compared to implementing other environmental compliance strategies. Although the cost of natural gas has been increasing over the past few years and coal prices have been decreasing, natural gas-fired generators may have some advantages over coal-fired plants such as lower capital costs, higher fuel efficiency, shorter construction times, and lower emissions (U.S., EIA. Annual Energy Outlook 2003).

Summary

There are several issues that have been identified in this chapter that have caused Kentucky coal to become less competitive than coal produced in other parts of the nation. The Clean Air Act Amendments of 1990 reduced Kentucky coal competitiveness by increasing the cost of using higher-sulfur coal. To meet sulfur emission restrictions, many electric utilities have switched to burning lower-sulfur coal from the western United States. Restrictions on the amount of NOx may cause utilities to switch from coal to other types of fuel. The reduction in rail transportation rates has also allowed western United States coal to be shipped longer distances and begin supplying areas that have traditionally used Kentucky coal. Lower national transportation costs, increased federal regulations, and lower productivity for Kentucky coal have all contributed to the decreased competitiveness of Kentucky coal.

CHAPTER 3
THE ROLE COAL PLAYS IN KENTUCKY'S ECONOMY

The level of coal production affects state and local economies.

Kentucky coal production impacts the state and local economies in a number of different ways. Coal produced within the state is primarily sold to electric utilities and industrial customers, both in and outside the state. The revenues received from coal sales go toward paying the wages, salaries, and benefits of the mine employees and are used to pay the firms that supply inputs to mines. As these coal miners earn wages and mining supply firms pay their employees, these employees in turn spend their wages on consumer goods such as groceries, clothes, and appliances, and at restaurants and entertainment facilities, which help to support these businesses and their employees.

The coal industry's contribution to the state's economy consists of employment within the industry, businesses that supply the industry, and businesses that provide goods and services to employees of the industry.

Simply put, the coal industry's contribution to the state economy is composed of three effects: direct effect, indirect effect, and induced effect. The *direct effect* consists of jobs created and income paid to workers employed in the coal industry. The direct effect of coal on Kentucky's economy in terms of production, employment, and income are summarized in Table 3.1. Kentucky coal mines produced 134 million tons of coal in 2001, which is valued at approximately $3.58 million. The Kentucky coal industry in 2001 accounted for 17,500 jobs in the state with total earnings of over $1 billion.

The *indirect effect* of coal production includes employment and income in the economic sectors that supply or support the coal mining industry. Finally, the *induced effec*t occurs as people employed in the coal mining and support sectors spend their earnings, creating additional employment and income. The total of these three effects is referred to as an economic multiplier and represents the total economic impact that the coal industry has within the economy.

Changes in the coal industry affect other businesses as well.

Because the coal industry is linked to other sectors of the state's economy, changes in the coal industry affect more than just those employed by the coal mines. This chapter discusses the role the coal industry plays in Kentucky's economy and how changes in Kentucky's coal industry have affected the state's economy.

Table 3.1
Direct Economic Effect of
Coal Mining in Kentucky
(2001)

Coal Mining Output*	133.8 million tons
Value of Output	$3.58 billion
Employment*	17,538 Jobs
Earnings**	$1.035 billion
Average Wage per Job**	$46,212
Average Earnings per Job**	$55,819

Sources: *United States. Department of Energy. Energy Information Administration. *Annual Coal Report 2001* .
**United States. Bereau of Economic Analysis. Regional Economic Accounts, www.bea.doc.gov.

Note: Earnings are made up of wages and salaries, other labor income (i.e. primarily health and retirement benefits), and proprietor's income.

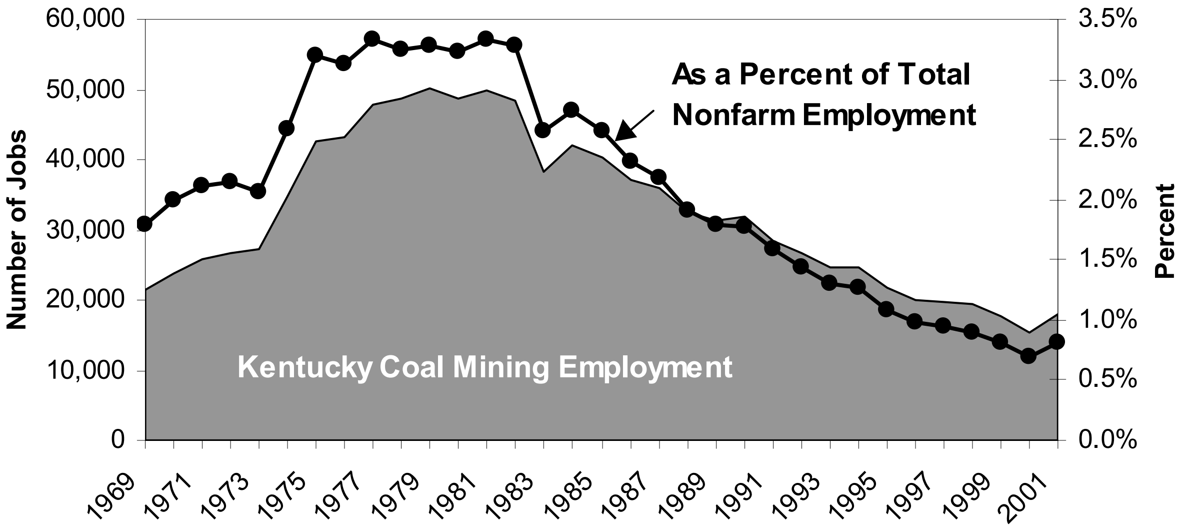
Coal Mining Employment

The number of jobs in the Kentucky coal mining industry has steadily declined since 1979.

Coal mining employment in Kentucky peaked in 1979, at just over 50,000 mining jobs (Figure 3.A). The most recent data, from 2001, indicate that Kentucky's coal mining industry recorded 17,500 jobs. Overall, Kentucky has experienced a 65 percent reduction in the number of coal mining jobs since 1979.

While coal mining employment has been decreasing, total employment in Kentucky has generally grown. This has resulted in the coal mining sector accounting for a smaller share of total employment in the state. In 1979, when coal mining employment was at its peak, coal mining jobs comprised 3.27 percent of the total nonfarm jobs in Kentucky. For 2001, the mining industry accounted for less than 1 percent (0.8 percent) of the nonfarm jobs in Kentucky. Similar trends have occurred for the United States: coal employment has fallen, while total employment has risen.

Figure 3.A
Kentucky Coal Mining Employment

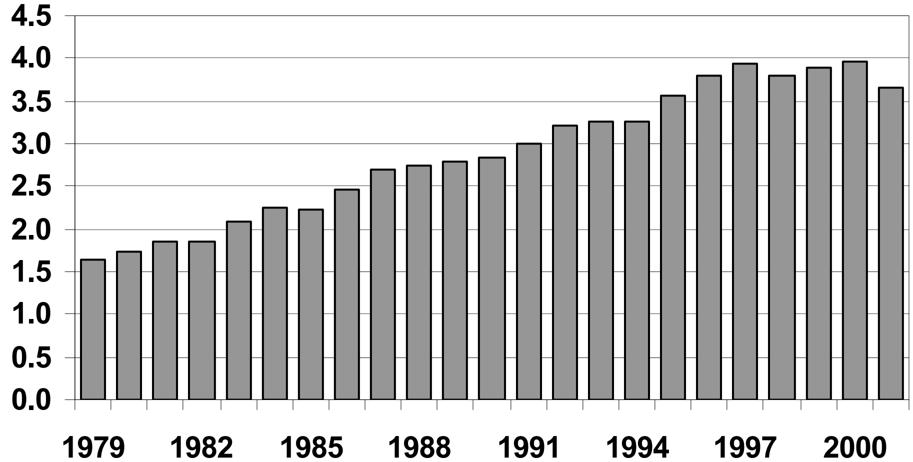


Source: United States. Bureau of Economic Analysis. Regional Economic Accounts.

Increases in productivity and decreases in production have contributed to the decline in jobs.

Two primary factors have contributed to the decrease in coal mining employment in Kentucky. The first factor is the decline in Kentucky's coal production. As discussed in Chapter 1, production from Kentucky coal mines peaked in 1990 and has generally decreased since. The second, and more important, factor contributing to the decrease in coal mining employment was increased productivity. Figure 3.B displays changes in coal mining productivity since 1979. Productivity, which is measured as output per miner per hour, increased by 123 percent from 1979 to 2001, or more than 3.5 percent annually. The rate of productivity growth outpaced the decrease in production. While both contributed to fewer coal mining jobs in Kentucky, the majority of the lost employment was due to the increase in productivity. In 2002, coal output was 23.2 tons less than 1979 output, the year of peak employment. Using estimates of production in 1979, this decrease in output was equal to 6,800 mining jobs. The remaining decrease in mining jobs was attributable to productivity increases (19,900 mining jobs). By decomposing these two effects, it is estimated that since 1979, 75 percent of the decline in mining jobs can be attributed to technological change and 25 percent to the decline in production.

Figure 3.B
Kentucky Coal Mining Productivity
(tons/miner/hour)



Source: United States. Department of Energy. Energy Information Administration. *Coal Industry Annual, 1979 - 2000* and *Annual Coal Report 2001 - 2002*.

Compensation paid to coal miners have improved over time.

While employment within Kentucky's coal mines has fallen over the past two decades, compensation paid to coal miners in the form of wages, salaries, and benefits has displayed strong improvements. Beginning in 1969—when data was first collected on earnings by industry—average earnings per job for the coal industry increased by more than 6 percent annually. Growth during the 1990s, however, was slower at approximately one-half of the historical trend. Compared to other industries within the state, coal mining is very competitive in terms of average earnings per job. Table 3.2 shows that compensation paid to Kentucky miners exceeded the average earnings per job for most other industries and was comparable to the average earnings for a number of high-paying industries such as motor vehicle manufacturing. Not only do mining jobs pay relatively high wages, but these jobs pay particularly high wages for individuals with a high school education or less. According to data from the 2000 Census, 96 percent of the workers employed as miners in Kentucky had a high school education or less. This figure is higher than the general employed population in which only 72 percent of employed workers had a high school education or less. The wages paid to Kentucky miners were 62 percent higher than wages paid to other Kentuckians with a similar level of education.

Table 3.2
Average Earnings Per Job 2001

Utilities	$70,117
Motor vehicle manufacturing	$56,202
Mining (except oil and gas)	**$55,819**
Durable goods manufacturing	$45,474
Wholesale trade	$43,652
Manufacturing	$43,548
Information	$41,517
Transportation and warehousing	$41,144
Professional and technical services	$39,797
Finance and insurance	$36,543
Health care and social assistance	$34,547
State and local government	$34,281
Construction	$31,178
Retail trade	$18,987
Educational services	$17,858
Accommodation and food services	$16,198
Other services	$16,140
Arts, entertainment, and recreation	$15,029
Real estate and rental and leasing	$12,792

Source: U.S., Department of Commerce. Bureau of Economic Analysis.

Economic Effects of Decreasing Market Share in Kentucky

Kentucky coal producers' lost market share results in lower employment and earnings in other sectors of the state economy and lower tax revenues for state and local governments.

As discussed in Chapter 1, the market for Kentucky coal can be segmented into three primary markets: the Kentucky market, the national market, and the foreign market. In all three of these markets, Kentucky coal has lost market share. In the national and foreign markets, the loss in market share was accompanied by a decline in the amount of coal shipped to these markets. A larger amount of Kentucky coal is shipped to the Kentucky market, but the amount of coal shipped from other states has increased at a faster rate, resulting in Kentucky coal losing market share. The lost market share in each of these markets represents a lost opportunity for Kentucky coal producers and an economic loss for the state relative to what would have existed if Kentucky coal had been able to maintain its market share. The economic loss includes fewer jobs and lost earnings associated with these jobs. Businesses that supply the coal industry would also experience a loss in output, as coal mines would require fewer supplies. Lost earnings result in less spending in other Kentucky businesses where coal employees would spend their earnings. Finally, the economic loss affects state and local governments by reducing the tax base and, therefore, tax revenues.

Examining how changes in inter- and intrastate shipments of coal affect Kentucky's economy can be accomplished in various ways. One way is to quantify the impact that a 1 percentage point loss in market share has on employment, income, and taxes in Kentucky. The economic impact of a 1 percentage point decrease in market share is useful for understanding how any future declines in market share would affect the state's economy. Another option would be to estimate what Kentucky production might have been if the state had maintained its historical market share, and then estimate the related impacts on employment, income, and taxes. This option represents a hypothetical situation in which Kentucky coal producers were able to maintain their share of the market while the market was growing.

Economic Impact of a 1 Percentage Point Decrease in the Kentucky Market Share

A 1 percentage point decrease in Kentucky coal's share of the Kentucky market over the past 10 years amounts to 380,000 tons of coal annually.

Purchasers of coal that are located in Kentucky receive coal mined from various states. Over the past decade, total coal shipments to Kentucky averaged 38 million tons annually. Coal mined in Kentucky accounts for 71 percent of this total. A 1 percentage point decrease in Kentucky coal's market share implies that Kentucky's market share drops from 71 percent to 70 percent. This decrease represents 380,000 tons of coal that would be produced by out-of-state coal mines rather than Kentucky coal mines. At an average price of $25 per ton, the value of these lost shipments would be $9.5 million.

This decrease in coal shipments would result in lower employment levels in the state. Many of the lost jobs would occur in the coal sector, but employment by businesses that support the coal mines or employees of the coal mines would also decrease. The total economic effect of the decrease can be estimated using an economic model of Kentucky's economy. The model, which was developed by REMI, Inc., summarizes various aspects of the state's economy and how industries within the state interact. The model can be used to evaluate the extent to which an economic change, such as building a plant, closing a plant, and other economic shocks, affects the total state economy. In this case, the model can be used to measure the effect that a decrease in coal production has on employment and earning in Kentucky, including both the coal industry and other industries.

A 1 percentage point decrease in the Kentucky market results in a loss of 135 jobs and $5.3 million in earnings.

Estimates of the impacts on Kentucky's economy from a 1 percentage point decrease in market share are shown in Table 3.3. In total, the value of lost output to the Kentucky economy is approximately $19.9 million. Accompanied with the output loss is a loss of 135 jobs and $5.3 million in earnings. The employment loss demonstrates the interaction between Kentucky's coal industry and other businesses in the state. While a percentage point loss in market share results in a loss of 53 coal mining jobs, the majority of lost jobs (82 jobs) would be in other industries.

Fiscal Impact of a 1 Percentage Point Decrease in Kentucky Market Share

The economic impacts discussed above do not include the impacts on the public or governmental sectors. While a large part of the total state economy comes from private sector activity, federal, state, and local government activities represent the remaining portion. As economic activity fluctuates in the private sector, the public sector is also affected, as many taxes, fees, and other sources of government revenues are based on private sector economic activity.

Declines in the Kentucky coal industry would also reduce the amount of revenue collected through the income, sales, and coal severance taxes.

State government's fiscal impacts would primarily involve the income, sales, and coal severance taxes. As out-of-state coal displaces Kentucky coal, income and sales tax receipts will decline. These impacts will result from employment and income reductions within the coal industry and for the input suppliers to the coal industry and for sectors of the economy where these employees spend their dollars. Coal severance tax receipts would also decrease as the amount of coal produced falls.

A 1 percentage point market share decrease in the Kentucky market would result in a decrease of $171,000 in the state's sales tax.

Fiscal impacts can be estimated by applying Kentucky's tax rates to the losses estimated above. The fiscal impacts are also summarized in Table 3.3. Kentucky's sales tax rate is 6 percent on purchases made in the state. A number of items, however, are exempt from the sales tax, making the effective sales tax rate less than 6 percent. It is estimated that approximately 54 percent of the average person's income is spent on taxable items. The earnings loss of $5.3 million would therefore result in lost sales tax revenue of $171,000.

A 1 percentage point market share decrease in the Kentucky market would result in a decrease of $299,000 in the state's income tax.

Kentucky's income tax rate is 6 percent for income over $8,000. Kentucky's income tax code, however, also allows for certain income tax deductions and has lower tax rates on the first $8,000 in income; thus the effective income tax rate is slightly less than 6 percent. It is estimated that the effective income tax rate is 5.64

percent. The lost earnings of $5.3 million would result in $299,000 in lost income tax receipts.

A 1 percentage point market share decrease in the Kentucky market would result in a decrease of $427,500 in the state's coal severance tax.

Kentucky's coal severance tax is 4.5 percent of the gross value of severed coal. Applying this rate to the decrease in coal produced results in lost coal severance receipts of $427,500. The largest fiscal impact is associated with reduced coal severance tax receipts. This result is not surprising since the coal severance tax is based on gross receipts, whereas wages represent only a portion of the total receipts from coal and many items are not subject to the sales and use tax.[5] In terms of fiscal impacts, the reductions in income, sales, and coal severance tax receipts from a 1 percentage point shift in Kentucky market share to out-of-state coal (equivalent to 380,000 tons) are estimated to total $897,500.

Economic and Fiscal Impact Attributable to Market Share Loss

The economic effects estimated above are based on Kentucky coal losing 1 percentage point of the Kentucky market share. Over time, however, Kentucky has lost more than 1 percentage point. At its peak in 1992, Kentucky coal supplied 82 percent of the coal shipped to Kentucky. The percentage of coal shipments coming from Kentucky suppliers has slipped over the past decade, falling to 60 percent in 2001 for a 22 percentage point decrease.

Table 3.3
Economic & Fisal Impact from a 1 Percentage Point Decrease in Kentucky Coal's Share of the Kentucky Market

Economic Effect	
Output Loss Across All Sectors of the Economy	$19.9 Million
Total Employment Loss	135 jobs
Mining Employment Loss	53 jobs
Total Earnings Loss	$5.3 Million
Fiscal Effect	
Reduced Income Tax Receipts	$299,000
Reduced Sales Tax Receipts	$171,000
Reduced Coal Severance Tax Receipts	$427,500
Total Reduced Receipts	$897,500

Source: Staff analysis.

[5] The term "fiscal impact" in this context represents the amount of tax receipts related to the loss in coal production. Since Kentucky has been losing market share for some time, this effect is already reflected in base tax receipts; therefore a fiscal impact—as defined in an LRC Fiscal Note—has not occurred.

If Kentucky coal producers had been able to maintain their market share in other states, Kentucky would have shipped 11.4 million more tons of coal than it did.

A 22 percentage point drop in shipment volume from Kentucky suppliers is equal to a loss of 11.4 million tons of coal. The direct loss in coal sales would be $285.7 million. The resulting economic and fiscal impacts are shown in Table 3.4.

Table 3.4
Economic & Fisal Impact from a 22 Percentage Point Decrease in Kentucky Coal's Share of the Kentucky Market

Economic Effect	
Output Loss Across All Sectors of the Economy	$600 Million
Total Employment Loss	4,054 Jobs
Mining Employment Loss	1,560 Jobs
Total Earnings Loss	$159 Million
Fiscal Effect	
Reduced Income Tax Receipts	$8.9 Million
Reduced Sales Tax Receipts	$5.2 Million
Reduced Coal Severance Tax Receipts	$12.86 Million
Total Reduded Receipts	$26.96 Million

Source: Staff analysis.

Economic Effects of Decreasing Market Share in the National Market

Kentucky's share of the market in other states decreased from 48 percent in 1993 to 33 percent in 2001.

In Chapter 1, it was shown that Kentucky coal has lost market share in other states as well as Kentucky. In addition to Kentucky, 10 other states make up the bulk of Kentucky coal's market. Kentucky coal's market share in these 10 states has decreased from 48 percent in 1993 to 33 percent in 2001. This slide in market share represents a lost opportunity for the Kentucky coal industry.

A 1 percentage point market share decrease amounts to approximately 2.5 million tons of coal.

Economic and Fiscal Impact of Percentage Point Shift in Market Share

The economic and fiscal impacts of lost market share in these 10 states were estimated in the same manner described above. A 1 percentage point market share loss amounts to 2.5 million tons of coal. Assuming coal prices of $25 per ton, the direct loss represented by the value of coal shipments would be $62.5 million. The economic and fiscal impacts are shown in Table 3.5. These figures represent the losses that would occur if Kentucky lost 1 percentage point of the market share in the 10 primary states to which Kentucky coal is shipped.

Table 3.5
Economic & Fisal Impact from a 1 Percentage Point Decrease in Kentucky Coal's Share of the Other States' Market*

Economic Effect	
Output Loss Across All Sectors of the Economy	$131 Million
Total Employment Loss	885 Jobs
Mining Employment Loss	345 Jobs
Total Earnings Loss	$35 Million
Fiscal Effect	
Reduced Income Tax Receipts	$1.96 Million
Reduced Sales Tax Receipts	$1.12 Million
Reduced Coal Severance Tax Receipts	$2.81 Million
Total Reduded Receipts	$5.89 Million

Source: Staff analysis.

*These states are Alabama, Florida, Georgia, Indiana, North Carolina, Ohio, South Carolina, Tennessee, Michigan, and Virginia

Table 3.6
Economic & Fisal Impact from a 15 Percentage Point Decrease in Kentucky Coal's Share of Other States' Market*

Economic Effect	
Output Loss Across All Sectors of the Economy	$2.18 Billion
Total Employment Loss	14,734 Jobs
Mining Employment Loss	5,670 Jobs
Total Earnings Loss	$578 Million
Fiscal Effect	
Reduced Income Tax Receipts	$32.6 Million
Reduced Sales Tax Receipts	$18.7 Million
Reduced Coal Severance Tax Receipts	$46.7 Million
Total Reduded Receipts	$98 Million

Source: Staff analysis.

*These states are Alabama, Florida, Georgia, Indiana, North Carolina, Ohio, South Carolina, Tennessee, Michigan, and Virginia

If Kentucky coal had been able to maintain its market share in other states, Kentucky would have shipped 41.5 million more tons of coal than it did.

Economic and Fiscal Impact Attributable to Market Share Loss

Since its peak in 1993, Kentucky coal's market share in the 10-state market has decreased from 48 percent to 33 percent, for a decrease of 15 percentage points. A 15 percentage point loss in domestic market share is equivalent to 41.5 million tons of coal. By not maintaining market share in the domestic export market, Kentucky's coal industry lost potential sales of $1.04 billion. The related economic and fiscal impacts are highlighted below.

Summary

While U.S. coal production expanded during the 1990s, Kentucky coal production contracted. As a result, Kentucky's share of the nation's coal production has been steadily declining. Expansion at the national level was primarily driven by output increases in the western U.S. coal fields. Conversely, Kentucky's contraction was tied to market share losses both within Kentucky and in other states. Since most of Kentucky's coal is shipped to other states, the market share loss in these states has had a larger impact on Kentucky's coal market than the market share loss within the state.

Declining coal production translates into output, employment, and income reductions in the coal industry, industries that supply coal firms, and sectors of the economy where employees of these firms spend their income. Employment losses in the mining sector, however, have been ongoing, even without production decreases, due to advances in mining technology that have improved productivity.

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