2000

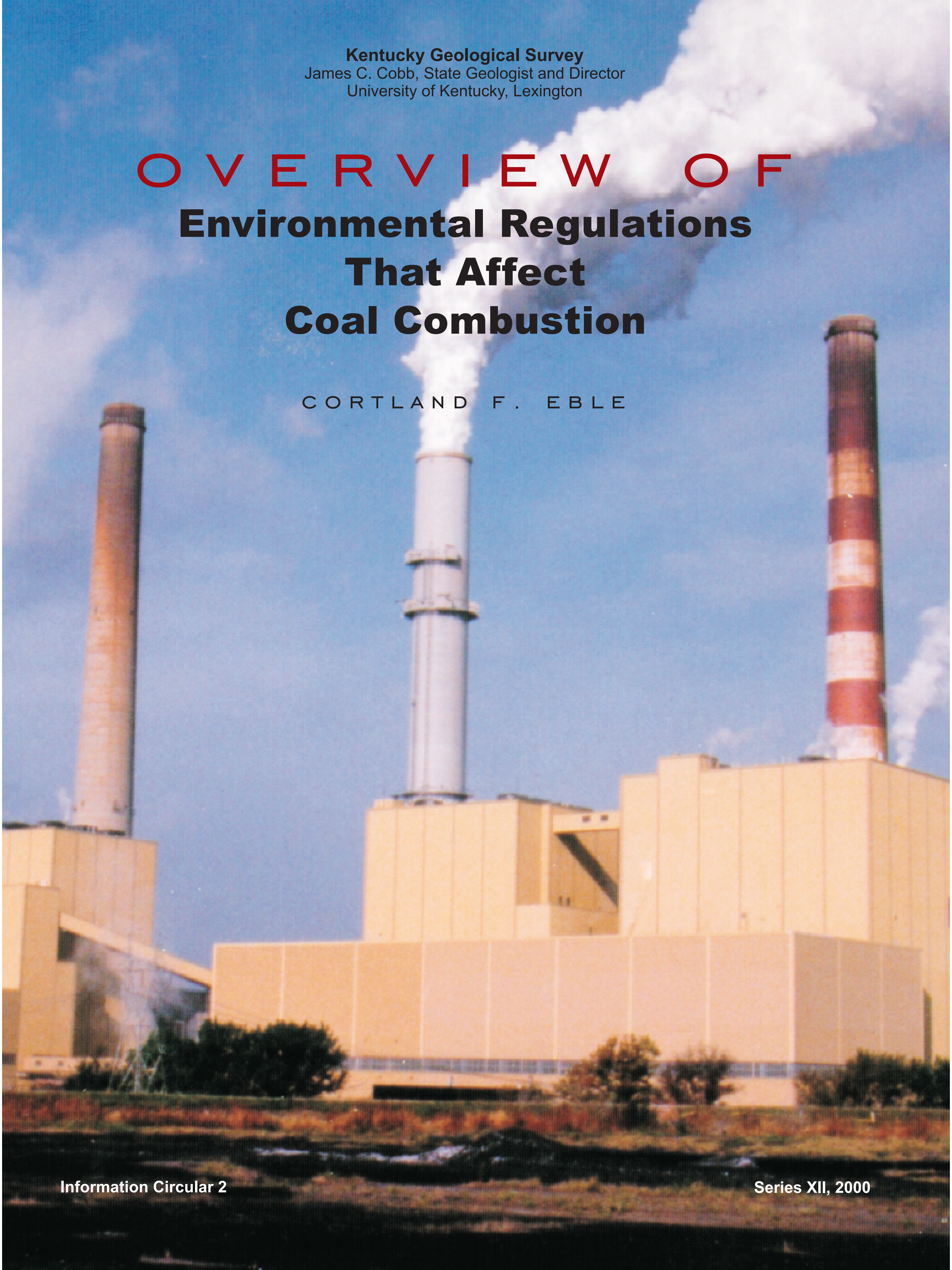
Overview of Environmental Regulations That Affect Coal Combustion

Cortland F. Eble
University of Kentucky, eble@uky.edu

Kentucky Geological Survey
James C. Cobb, State Geologist and Director
University of Kentucky, Lexington

OVERVIEW OF
Environmental Regulations That Affect Coal Combustion

CORTLAND F. EBLE



Information Circular 2

Series XII, 2000

Kentucky Geological Survey
James C. Cobb, State Geologist and Director
University of Kentucky, Lexington

Overview of Environmental Regulations That Affect Coal Combustion

Cortland F. Eble

Information Circular 2 https://doi.org/10.13023/kgs.ic02.12 Series XII, 2000

Contents

Overview 1

What Is the Clean Air Act? 1

Title IV of the Clean Air Act Amendment of 1990 1

How Have Electric Utilities Responded to Phase I SO_2 Reduction Mandates? 1

How Are Electric Utilities Responding to Phase II SO_2 Reduction Mandates? 3

How Have Electric Utilities Reduced Nitrogen Oxide Emissions? 4

Title III of the Clean Air Act Amendments of 1990 4

Toxics Release Inventory (TRI) 4

Electric Utility Deregulation 5

Carbon Dioxide Emissions Limitations 5

Summary 5

Recommended Reading 6

Figures

1. Options for complying with Phase I Clean Air Act mandates at 261 affected units 2
2. Increased use of low- to medium-sulfur coal in response to Phase I Clean Air Act mandates 2

Table

1. Title III elements that naturally occur in coal 4

Mission Statement

The Kentucky Geological Survey at the University of Kentucky is a State-mandated organization whose mission is the collection, preservation, and dissemination of information about mineral and water resources and the geology of the Commonwealth. KGS has conducted research on the geology and mineral resources of Kentucky for more than 150 years, and has developed extensive public databases for oil and natural gas, coal, water, and industrial minerals that are used by thousands of citizens each year. The Survey's efforts have resulted in topographic and geologic map coverage for Kentucky that has not been matched by any other state in the Nation.

One of the major goals of the Kentucky Geological Survey is to make the results of basic and applied research easily accessible to the public. This is accomplished through the publication of both technical and nontechnical reports and maps, as well as providing information through open-file reports and public databases.

Earth Resources—Our Common Wealth

Acknowledgments
Edited by—Margaret Luther Smath
Cover design and drafting—Collie Rulo

For further information contact:
Manager, Communications and Technology Transfer
Kentucky Geological Survey
228 Mining and Mineral Resources Building
University of Kentucky
Lexington, KY 40506-0107

ISSN 0075-5583

Overview of Environmental Regulations That Affect Coal Combustion

Cortland F. Eble

Overview

Environmental regulations have had, and continue to have, an effect on the combustion of coal. These regulations largely affect the electric utility industry, the largest consumer of domestic coal, but they ultimately affect everyone, because we all use electricity, and the cost of compliance is usually passed on to the consumer, resulting in higher electric bills.

The information in this summary was largely obtained from reports by the U.S. Environmental Protection Agency (EPA) and the Energy Information Administration (EIA). If you would like to learn more about environmental regulations and the effect they have on coal combustion, a list of more detailed publications is included in the "Recommended Reading" section of this report.

What Is the Clean Air Act?

The first Federal initiatives to address air pollution in the United States date back to 1955, when legislation was enacted to provide research and technical assistance relating to air-pollution control. The Federal government had no direct regulatory role in this initial effort. Rather, it sought to remedy a growing air-pollution problem by supporting research and providing information and financial aid at the state level. In 1963 the first Clean Air Act was implemented, which, along with the subsequent Air Quality Act of 1967, began to expand the role of the Federal government in curbing air pollution by direct regulation.

In response to limited action taken by state and local governments to control air pollution, Congress passed the first of a series of amendments to the Clean Air Act in 1970. That year also saw the creation of the Environmental Protection Agency (EPA), which was given responsibility for setting and monitoring pollution standards. Additional amendments were passed by Congress in 1977 and 1990. To date, the Clean Air Act Amendments of 1990 (CAAA90) are the most stringent set of regulations to limit gaseous emissions from fossil-fuel combustion.

Title IV of the Clean Air Act Amendment of 1990

Title IV of the CAAA90, which is called "Acid Deposition Control," was implemented to reduce so-called acid rain. Acid rain is caused by the emission of sulfur dioxide (SO_2) and nitrogen oxides (NO_x, mainly in the form of NO_2) during the combustion of fossil fuels (for example, coal and gasoline). Both of these gases react with atmospheric moisture to form sulfuric acid (H_2SO_4) and nitric acid (HNO_3), which returns to the earth's surface primarily as rain or snow. Title IV of the CAAA90 affects 261 individual coal-fired units across the United States, and was implemented in two phases. Phase I took effect in 1995 and required coal-fired utilities to reduce SO_2 emissions by 5 million tons annually from 1995 to 2000, with a final emissions cap of 2.5 pounds of SO_2 emitted for every million Btu generated (lb SO_2/MM Btu). Phase I also mandated a 2 million ton decrease in nitrogen oxide emissions, to a level not exceeding 0.5 lb NO_x/MM Btu for wall-fired units and 0.45 lb NO_x/MM Btu for tangentially fired boilers. Phase II, which became effective January 1, 2000, required a further reduction of SO_2 emissions from coal-fired power plants (by 10 million tons annually), and a new emissions cap of 1.2 lb SO_2/MM Btu. The original nitrogen oxide emissions cap for Phase II was set at 0.46 lb NO_x/MM Btu for wall-fired units and 0.40 lb NO_x/MM Btu for tangentially fired boilers. A proposal has been submitted to lower this ceiling to 0.15 lb NO_x/MM Btu for coal-burning power plants in the Ohio River Valley.

How Have Electric Utilities Responded to Phase I SO_2 Reduction Mandates?

Electric utilities have complied with Phase I SO_2 reduction mandates in a number of ways:

- *Switching from high- to low-sulfur coal, or blending coals to achieve a lower sulfur content.* This has been the most popular reduction option: 52 percent of the affected units switched to, or blended in, low-sulfur coal to lower the total sulfur content (Fig. 1). This is also the least expensive option. Modifying a high-sulfur, bituminous coal–fired power plant to burn low-sulfur coal has been estimated to cost between $113 and $167 per ton of SO_2 removal (EIA, 1997), which is one-third to one-half the cost of installing SO_2 reduction equipment (such as flue-gas desulfurization, see below).

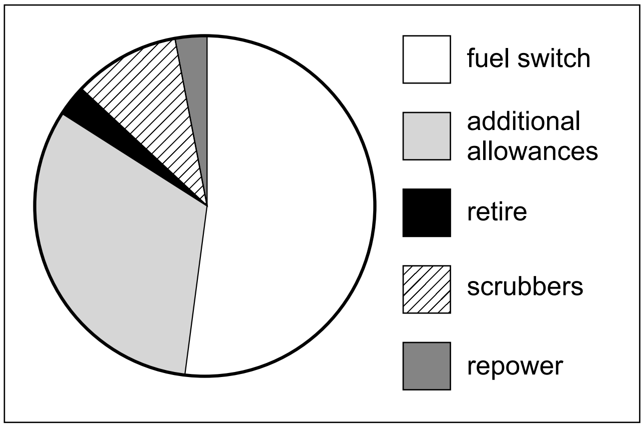


Figure 1. Options for complying with Phase I Clean Air Act mandates at 261 affected units (EIA, 1997).

This switch to lower-sulfur coal has drastically affected regional coal production patterns. Between 1990 and 1995, sales of low- to medium-sulfur coal from the Powder River Basin of Wyoming and Montana increased by 78 million tons. Following this trend, sales of low-sulfur coal from the central Appalachian region (Virginia, eastern Kentucky, and southern West Virginia) increased by 15 million tons, and sales of low-sulfur coal from the Rocky Mountains (Colorado and Utah) increased by 10 million tons (Fig. 2).

In contrast, for the same period sales of higher-sulfur coal from the northern Appalachian region (Maryland, Pennsylvania, Ohio, and northern West Virginia) decreased by 29 million tons; and sales from the Illinois Basin (Illinois, Indiana, and western Kentucky) decreased by 40 million tons (EIA, 1997).

❖ *Repowering, or switching to a fuel other than coal (such as fuel oil or natural gas)*. Repowering has not been an attractive compliance option (only 2 percent of the affected Phase I units chose this option), because it requires a substantial capital investment to retrofit existing infrastructure. Obtaining sufficient quantities of the new fuel in a cost-effective manner is also problematic. Utilities in a number of different states have built, or are planning to build, several small (typically less than 250-megawatt generating capacity) "peak generating" facilities, usually powered by natural gas. These units are designed to be operated during times of heavy consumer demand for electricity. Peak generating stations have an advantage over coal-fired units in that their capital construction costs are much lower, and they have fewer visible emissions (smoke). Lack of smoke and their relatively small size make them attractive options for heavily populated areas.

Although peak generating units are cheaper to build, and are more environmentally friendly than their coal-fired counterparts, they are hampered by higher overall operating costs and, for many areas of the country, limited fuel availability. Ultimately, the expanded use of natural gas may be determined by a potential "carbon tax" on fossil-fuel use that is being considered as part of an effort to reduce carbon dioxide (CO_2) emissions in the United States. Coal is currently a much less expensive fuel than natural gas, but it also emits roughly twice as much CO_2 as natural gas, on the basis of pounds of CO_2 emitted per kilowatt-hour generated (EIA and EPA, 1999). A tax on CO_2 emissions could conceivably make the cost of coal and

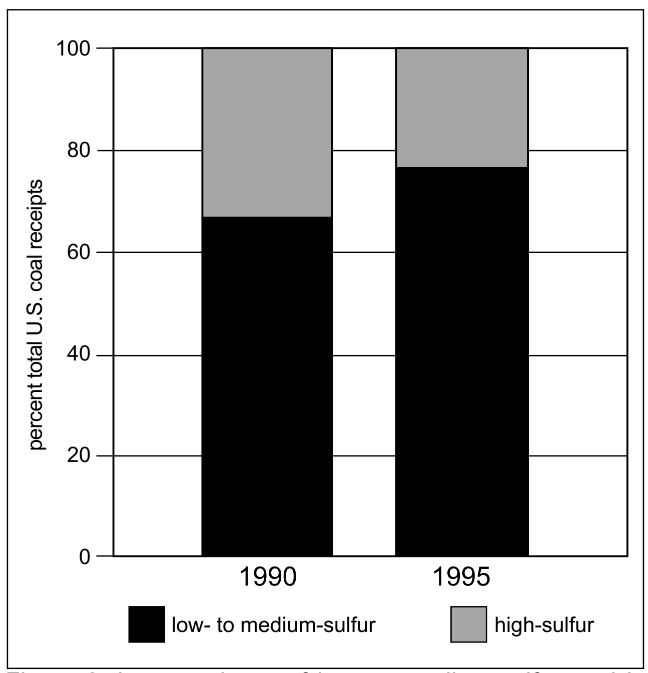


Figure 2. Increased use of low- to medium-sulfur coal in response to Phase I Clean Air Act mandates. Low- to medium-sulfur coal is classified as coal emitting no more than 2.5 lb SO_2/MM Btu (EIA, 1997).

natural gas less disparate, making natural gas more attractive.

- *Installing SO_2 emission-control equipment (flue-gas desulfurization, fluidized-bed combustion).* This has been one of the least attractive compliance methods (only 10 percent of the affected Phase I units chose this option), primarily because of its high cost, estimated at $322/ton of SO_2 removal. Compare this with switching to low-sulfur coal, which costs an estimated $113 to $167 per ton of SO_2 removal (EIA, 1997).
- *Purchasing or transferring emissions allowances.* An emissions allowance is simply the permission to emit 1 ton of SO_2. The number of allowances granted for individual units is calculated using a formula that takes into account the amount of fuel consumed and SO_2 emitted from 1985 to 1987 (baseline years). Electric utilities may choose to purchase additional allowances, which are available on the open market, to offset a unit that emits more SO_2 than it has been granted credits for. Alternatively, a utility can transfer allowances within its system, from an overcompliant unit (one that does not use all of its emissions allowances) to another unit that is undercompliant (emits more SO_2 than it has emissions allowances for). During Phase I, the electric utility industry largely overcomplied—they reduced emissions below their mandated limits—which created a large surplus of emissions credits. Thus, the price of emissions allowances has been much lower than was originally projected, making the purchase or transfer of additional allowance credits a very cost-effective compliance option. In fact, it is the second most popular Phase I compliance strategy (32 percent of the affected units opted for this) (EIA, 1997).
- *Unit retirement.* Only 3 percent of the 261 affected Phase I units were taken out of service as a compliance option. In fact, deregulation of the electric utility industry, which places utilities in competition with one another, has extended the projected operating lives of several older units in order to keep generating rates as low as possible. By extending the lives of older units, utilities also avoid the large capital expenditure of constructing new units.

Recently, however, the Environmental Protection Agency has intervened, and filed a number of lawsuits against several utilities that continue to keep older units in service. The EPA is claiming that the targeted units have violated New Source Review (NSR) initiatives, a program put in place by the Clean Air Act Amendments. The NSR program requires utilities to undergo a review process if they propose to construct new electricity-generating units, primarily to ensure that new facilities install the best available technology for reducing emissions from a given source. The program also applies to units that are modified to the point that the physical or operational changes result in an increase in emissions of a regulated pollutant. The principal issue at the root of lawsuits is whether older units that are kept in service should be subjected to NSR review. The electric utilities claim they need to keep the older units operational to keep generating costs down, and to meet increased consumer demand. The EPA claims they should be subject to review, and either retrofitted with modern pollution-control equipment, or retired outright. Basically, it is a difference of opinion.

How Are Electric Utilities Responding to Phase II SO_2 Reduction Mandates?

Electric utilities have complied with Phase II SO_2 reduction mandates by:

- *Fuel switching to lower-sulfur coal, or blending in lower-sulfur coal.* This is still the predominant strategy used by utilities to comply with Phase II of the CAAA90, just as it was for Phase I. Compared to scrubbing, the fuel switching/blending strategy is lower cost, takes less time to implement, and offers flexibility in meeting future emission requirements.
- *SO_2 allowance acquisition.* This is currently the second most popular choice for Phase II compliance. Purchasing allowance credits is a much less expensive option than installing pollution-control equipment. Also, many utilities that overcomplied during Phase I are saving their extra allowances for Phase II. Allowance prices are much lower than expected, primarily because of the reduction in low-sulfur coal prices.
- *Flue-gas desulfurization.* New units planned for Phase II implementation have largely been deferred. For the most part, utilities that are overcomplying with Phase I have allowance credits they can use to delay their own Phase II scrubbing. They can also sell their credits to other utilities that want to delay Phase II actions. This creates the possibility of running a pollution-control system as a revenue source, at least in the short term.
- *Repowering.* Although converting a coal-fired power plant to one that uses natural gas or fuel oil

has several advantages, including decreased SO_2, NO_x, and CO_2 emissions, very few utilities have opted for this compliance method, in part because of the high cost of retrofitting existing infrastructure. Repowering older coal-fired units that would otherwise be retired, as well as expanding the use of peak generating units that use natural gas, may become more attractive if limitations are imposed on CO_2 emissions from fossil-fuel combustion, however.

How Have Electric Utilities Reduced Nitrogen Oxide Emissions?

Two hundred thirty-nine coal-fired units were required to meet the NO_x emissions limitations of the first phase of Title IV of CAAA90. Control of nitrogen oxide emissions has largely been achieved by installing low-NO_x burners, the burner being the mechanism that regulates the fuel-air mixture that is injected into the furnace. Overall, the utilities that operate the affected units achieved a 40 percent reduction in NO_x emissions between 1990 and 1996. Most utilities have also met Phase II NO_x emissions limitations by using low-NO_x burner technology.

Recently, however, the EPA has proposed additional restrictions for coal-burning utilities in the Ohio Valley, citing them as a cause of ozone non-attainment (ground-level smog) in the northeastern United States. The proposed ceiling of 0.15 lb NO_x/MM Btu has prompted several utilities in Kentucky to begin installing selective catalytic reduction (SCR) at their facilities. SCR works by injecting ammonia into the flue-gas stream, which then passes over a special catalyst that reduces the NO_x in the flue-gas stream to elemental nitrogen and water. Although highly effective, SCR is also very expensive.

Title III of the Clean Air Act Amendments of 1990

Title III of the CAAA90, entitled "Hazardous Air Pollutants," lists 189 substances (mainly chemical compounds) that have the potential to be regulated. Among these 189 substances are 15 elements that naturally occur in bituminous coal. They are listed in Table 1.

Three of these elements, chlorine, mercury, and selenium, remain largely volatile during the combustion process and escape with flue gases. The other 12 elements, though initially volatilized in the fire box, adhere to the ash by-product, which is collected as furnace slag (coarse ash) or downstream fly ash (fine ash). Both types of ash can either be reused in a variety of applications or disposed of in landfills (which is what occurs most of the time). Currently, the EPA is collecting data for two Title III elements, mercury and chlorine (two of the three "volatile" elements), in an effort to determine the amounts and range of values of these two elements in utility feed coal.

Table 1. Title III elements that naturally occur in coal.

antimony	arsenic	beryllium	cadmium	chlorine
cobalt	chromium	lead	manganese	mercury
nickel	phosphorus	selenium	thorium	uranium

Although the implementation of flue-gas desulfurization is largely on hold for now by most utilities, limitations placed on any of the elements listed above may accelerate scrubber implementation. Scrubbers effectively control fly-ash particles that are not entrained by particulate control devices, such as electrostatic precipitators or baghouses. Because many of the elements listed above adhere to fly-ash particles during the combustion process, they are effectively controlled as well. In addition, scrubbing has been shown to be highly effective in preventing the atmospheric liberation of hydrogen chloride and hydrogen fluoride aerosols, and partially effective in controlling mercury emissions (EIA, 1997).

Toxics Release Inventory (TRI)

The Toxics Release Inventory (TRI) is part of the Emergency Planning and Community Right-to-Know Act of 1986. Users of chemicals that fall under certain Standard Industrial Classification codes are required to report to the EPA the levels of listed chemicals that they release into the environment. Currently, over 600 chemicals are on the TRI list, or about twice as many as were listed in the first TRI report published in 1987. Keep in mind that TRI is just a reporting mechanism. It does not contain any information on levels of toxicity or health risks posed by exposure to a reported substance. It is simply a tracking system.

In 1997, several new industries were added to the TRI. Among them were electric utilities, metal mining, and coal mining. Although the full impact of these industries being added to TRI is unclear, there are concerns about the use and potential misuse of the reported data. For example, the ash by-product of coal combustion contains most of the elements that must be reported to TRI. Most of this ash is transferred directly from a power plant to a nearby landfill. Thus, electric utilities are required to report, in many instances, the release of large amounts (greater than 100,000 lb) of elements such as arsenic, cobalt, chromium, and lead into the environment. On the surface, this is disturbing news, to say the least. What TRI does *not* tell you, however, is that coal ash is primarily a glass-like material, and as such is an essentially inert substance. This property immobilizes the elements contained within the ash to the point that the EPA classifies coal ash as a nonhazardous material.

Electric Utility Deregulation

The U.S. electric utility industry has traditionally been made up of regulated monopolies serving prescribed state service areas. In effect, a consumer was able to obtain electricity from only one company. This changed in 1996 when the Federal Energy Regulatory Commission recommended that the industry be deregulated in an effort to promote a competitive marketplace for electricity. Currently, 22 states have passed deregulation legislation, and six more states have pending legislation in place. Kentucky is not one of these states, although an electricity restructuring task force has been looking at this issue since 1998.

A competitive marketplace has made low-cost power generation a top priority for electric utilities. The effects utility deregulation will have on coal as the fuel of choice for electric utility generation are mixed. On the one hand, utilities will want to keep using coal-based generating infrastructure as long as possible, extending the demand for coal. Utilities want to avoid any large capital investment, such as the construction of new units, to keep generating costs as low (and competitive) as possible. They will, however, be seeking *low-cost* coal, which will affect the profit margin of the coal producer. Utilities will also want Phase II–compliant low-sulfur coal, since the construction of additional scrubbing capacity, which would allow the use of higher-sulfur coal, has largely been put on hold.

Carbon Dioxide Emissions Limitations

Because coal produces the most CO_2 emissions of any fossil fuel currently used for large-scale electricity generation, any emissions limitations would have a serious impact on coal utilization. Carbon dioxide is a greenhouse gas that has been blamed by some for a general rise in the world's temperature during the last decade. Efforts in this country to curtail CO_2 emissions include the increased use of natural gas and accelerated efforts to introduce new, emissions-free energy technologies, such as advanced coal combustion/conversion technologies and hydrogen fuel cells, into the power-generation mix as quickly as possible. Research into the sequestration of post-combustion CO_2, by a variety of methods, is rapidly expanding as well.

Summary

Although our nation continues to rely on coal for the generation of electricity, environmental regulations have made its combustion more and more of a challenge. The Clean Air Act Amendments of 1990 impose strict limitations on the amounts of sulfur dioxide and nitrogen oxides that can be emitted into the atmosphere. These amendments also identify 15 elements that naturally occur in coal for possible emissions regulation. Electric utilities, the primary consumers of domestic coal, have largely complied with CAAA90 mandates by switching to, or blending in, low-sulfur coal to reduce SO_2 emissions. Purchasing or transferring emissions allowances has also been an effective option. Compliance with NO_x emissions limits has mainly been achieved through the implementation of low-NO_x burner technology. Stricter limitations being considered for power plants in the Ohio Valley region has prompted many utilities to install selective catalytic reduction units in several power plants in this area. Currently, no limitations have been placed on any of the elements in coal that are included in Title III of the CAAA90, but the EPA is collecting data to determine the amount of mercury and chlorine in utility feed coal, suggesting that emissions limits for these two elements may be pending.

In 1998, electric utilities were required to start reporting to the Toxics Release Inventory. TRI is a tracking mechanism, and does not report any information about the relative mobility of a substance released to the environment (that is, very mobile versus essentially inert), nor does it contain any information about levels of toxicity or health risks posed by exposure to a reported substance.

The electric utility industry, which has historically consisted of regulated monopolies, each providing electric power to prescribed service areas, was deregulated in 1996 by the Federal Energy Regulatory Commission. The response to this mandate has been swift: 22 states have passed deregulation legislation, and six more have legislation pending. Deregulation has forced utilities to keep electric-power production costs as low and competitive as possible. Competition has forced several companies to delay, or even abandon, plans to build new units or retrofit older units with more modern technology; instead, they have chosen to prolong the working life of existing generating facilities.

Perhaps the greatest challenge coal will face in the new millennium is a proposal to limit CO_2 emissions from fossil-fuel combustion. Because coal emits more CO_2, on an energy-equivalent basis, than other fossil fuels such as petroleum or natural gas, any limitation would have serious impacts. Currently in the United States, research is being conducted to develop new technologies that limit or trap the CO_2 produced from coal utilization. These new technologies will doubtless play a vital role in the future of coal as a principal energy resource.

Recommended Reading

These articles can be downloaded from the Internet

Clean Air Act Amendments of 1990, http://www.epa.gov/oar/caa [accessed June 29, 2000].

Cobb, J.C., Currens, J.C., and Enoch, H.G., 1982, Compliance coal resources in Kentucky: Kentucky Geological Survey, ser. 11, Information Circular 9, 52 p.

Cobb, J.C., Currens, J.C., and Teoh, K.W., 1989, Predicting the impact of changes in the EPA compliance standard for sulfur emissions on the coal resources of eastern Kentucky: Kentucky Geological Survey, ser. 11, Information Circular 29, 9 p.

Cobb, J.C., and Eble, C.F., 1992, Sulfur in Kentucky coal and the Clean Air Act Amendments of 1990: Kentucky Geological Survey, ser. 11, Information Circular 38, 14 p.

Eble, C.F., and Cobb, J.C., 1994, Trace elements in coal: The next challenge: Kentucky Geological Survey, ser. 11, Information Circular 48, 4 p.

Energy Information Administration, 1994, Electric utility Phase I acid rain compliance strategies for the Clean Air Act Amendments of 1990: DOE/EIA-0578, 118 p.

Energy Information Administration, 1996, The changing structure of the electric power industry: An update: DOE/EIA-0562(96), 175 p.

Energy Information Administration, 1997, The effects of Title IV of the Clean Air Act Amendments of 1990 on electric utilities: An update: DOE/EIA-0582(97), 116 p.

Energy Information Administration, 1998, Reducing nitrogen oxide emissions: 1996 compliance with Title IV limits: Electric Power Monthly, May 1998, 9 p.

Energy Information Administration and the Environmental Protection Agency, 1999, Carbon dioxide emissions from the generation of electric power in the United States: 18 p.

Kentucky Geological Survey, 1995, Impact of hazardous air pollutants on mineral producers and coal-burning plants in the Ohio Valley (Title III, Clean Air Act Amendments of 1990): Abstracts for conference, March 19–21, 1995, Hyatt Regency Lexington, Lexington, Ky.: Kentucky Geological Survey, ser. 11, Special Publication 21, 25 p.

Selected Coal Publications Available from the Kentucky Geological Survey

KGS Bulletin 2 (ser. 11): Geology and stratigraphy of the Western Kentucky Coal Field, by S.F. Greb and others, 1992, 77 p.

KGS Bulletin 3 (ser. 11): Stratigraphic and structural framework of the Carboniferous rocks of the central Appalachian Basin in Kentucky, by D.R. Chesnut Jr., 1992, 42 p., 8 plates.

KGS Information Circular 23 (ser. 10): Coal production in Kentucky, 1790–1975, by J.C. Currens and G.E. Smith, 1977, 66 p.

KGS Information Circular 8 (ser. 11): Stratigraphic framework of coal-bearing rocks in the Western Kentucky Coal Field, by D.A. Williams and others, 1982, 201 p.

KGS Information Circular 12 (ser. 11): Geologic descriptions and coal analyses for 1982 coal drilling in the Daniel Boone National Forest, eastern Kentucky, by R.R. Bergeron and others, 1983, 243 p.

KGS Information Circular 13 (ser. 11): General coal reflectance and rank study of the Eastern Kentucky Coal Field, by D.A. Williams, 1984, 47 p.

KGS Information Circulars 18–23 (ser. 11): Analyses of coal samples from the Princess, Hazard, Big Sandy, Southwestern, Upper Cumberland, and Licking River Districts

KGS Information Circular 29 (ser. 11): Predicting the impact of changes in the EPA compliance standard for sulfur emissions on the coal resources of eastern Kentucky, by J.C. Cobb and others, 1989, 9 p.

KGS Information Circular 38 (ser. 11): Sulfur in Kentucky coal and the Clean Air Act Amendments of 1990, by J.C. Cobb and C.F. Eble, 1992, 14 p.

KGS Information Circulars 42, 43, 47 (ser. 11): Available coal resources of the Booneville, Handshoe, and Salyersville South 7.5-minute quadrangles

KGS Information Circular 48 (ser. 11): Trace elements in coal: The next challenge, by C.F. Eble and J.C. Cobb, 1994, 4 p.

KGS Information Circular 59 (ser. 11): Kentucky's coal industry: Historical trends and future opportunities, by G.A. Weisenfluh and others, 1998, 9 p.

KGS Map and Chart Series 20 (ser. 11): Total coal thickness of the Lower Elkhorn coal in eastern Kentucky, by E.E. Thacker and others, 1998, 1 sheet

KGS Report of Investigations 6 (ser. 10): Pennsylvanian cross sections in western Kentucky—Coals of the lower Carbondale Formation, part 1, by G.E. Smith, 1967, 14 p.

KGS Report of Investigations 5 (ser. 11): Amos and Foster coals: Low-ash and low-sulfur coals of western Kentucky, by D.A. Williams and others, 1990, 34 p.

KGS Report of Investigations 14 (ser. 11): Compositional variations in the Fire Clay coal bed of eastern Kentucky: Geochemistry, petrography, palynology, and paleoecology, by C.F. Eble and others, 1999, 18 p.

KGS Report of Investigations 2 (ser. 12): Geology of the Fire Clay coal in part of the Eastern Kentucky Coal field, by S.F. Greb and others, 1999, 37 p.

KGS Report of Investigations 3 (ser. 12): Available resources of the Fire Clay coal in part of the Eastern Kentucky Coal Field, by S.F. Greb and others, 1999, 18 p.

KGS Reprint 7 (ser. 11): Coal in Kentucky, by R.A. Brant and N.C. Hester, 1980, 11 p.

KGS Reprint 20 (ser. 11): Kentucky coal, by J.C. Cobb and others, 1985, 20 p.

KGS Reprint 36 (ser. 11): Determination of fluorine in coal and coal fly ash by proton-induced gamma-ray emission analysis, by A.S. Wong and others, 1993, 7 p.

KGS Special Publication 21 (ser. 11): Impact of hazardous air pollutants on mineral producers and coal-burning plants in the Ohio Valley, 1995, 25 p.

UK Institute for Mining and Mineral Resources publications: Coal resources of the Big Sandy, Hazard, Licking River, Princess, Southwestern, and Upper Cumberland Districts

USGS Miscellaneous Field Studies Map MF-2275: Revised correlation chart of coal beds, coal zones, and key stratigraphic units, Pennsylvanian rocks of eastern Kentucky, by C.L. Rice and J.K. Hiett, 1994, 1 sheet.