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Environmental Protection
Agency

Office of Solid Waste
and Emergency Response
Washington, DC 20460

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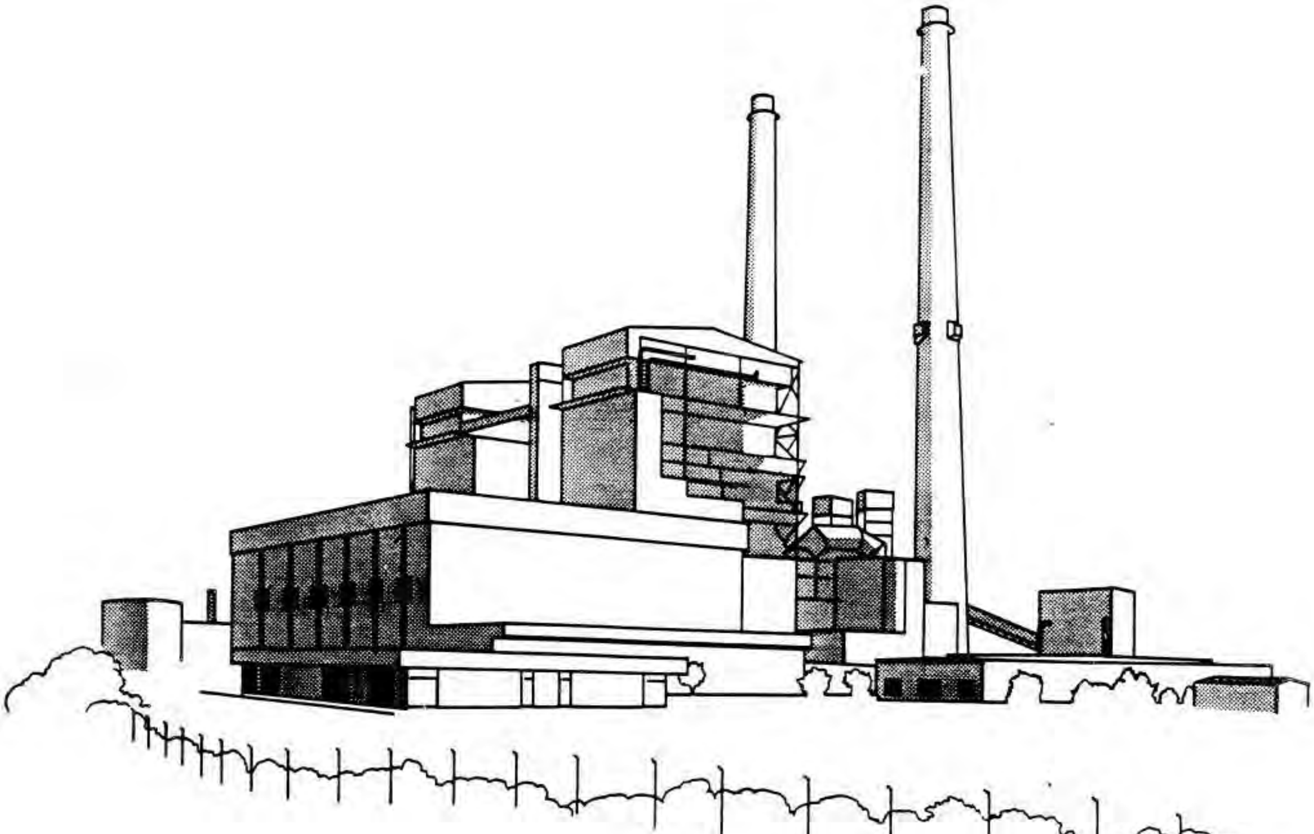
February 1988

Solid Waste

Report to Congress

Wastes from the Combustion of Coal by Electric Utility Power Plants



UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable George Bush
President of the Senate
Washington, D.C. 20510

Dear Mr. President:

I am pleased to transmit the Report to Congress on Wastes from the Combustion of Coal by Electric Utility Power Plants. The report presents the results of studies carried out pursuant to Section 8002(n) of the Resource Conservation and Recovery Act of 1976 as amended (42 U.S.C. Section 6982(n)).

The report provides a comprehensive assessment of the management of solid wastes generated by the combustion of coal from electric utility power plants. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. The principal waste categories covered include fly ash, bottom ash, boiler slag and flue gas emission control waste.

The report and appendices are transmitted in two separate volumes.

Sincerely,

Lee M. Thomas

Enclosure

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

MAR 8 1988

THE ADMINISTRATOR

Honorable James C. Wright
Speaker of the House
of Representatives
Washington, D.C. 20515

Dear Mr. Speaker:

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EXECUTIVE SUMMARY

The Environmental Protection Agency (EPA) has prepared this report on fossil fuel combustion wastes pursuant to the requirements of Section 8002(n) of the Resource Conservation and Recovery Act (RCRA), as amended in 1980. These amendments to the Act added Section 8002(n), which directed the Administrator of EPA to

> conduct a detailed and comprehensive study and submit a report on the adverse effects on human health and the environment, if any, of the disposal and utilization of fly ash waste, bottom ash waste, slag waste, flue gas emission control waste, and other by-product materials generated primarily from the combustion of coal or other fossil fuels.

Pending the completion of this study, fossil fuel combustion wastes were exempted from the hazardous waste requirements established under RCRA. Under Section 3001(b)(3)(A), EPA is prohibited from regulating these wastes until at least six months after this report is submitted to Congress.

If EPA determines that fossil fuel combustion wastes are hazardous under RCRA, and therefore subject to regulation under Subtitle C, EPA has some flexibility to promulgate regulations that take into account the unique characteristics of these wastes. Section 3004(x) states ...

> If ... fly ash waste, bottom ash waste, slag waste and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels ... is subject to regulation under this subtitle, the Administrator is authorized to modify the requirements of subsections (c), (d), (e), (f), (g), (o) and (u) and section 3005(j) ... to take into account the special characteristics of such wastes, the practical difficulties associated with implementation of such requirements, and site-specific characteristics ... so long as such modified requirements assure protection of human health and the environment.

This report examines only those wastes generated from the combustion of coal by the electric utility industry. These wastes account for approximately 90 percent of all wastes generated from the combustion of fossil fuels. EPA has deferred study of the disposal of wastes generated by the combustion of other fossil fuels and from coal combustion in industries other than the electric utility industry until a later date.

Coal-fired power plants produce substantial quantities of wastes. In 1984 about 69 million tons of ash and 16 million tons of flue gas desulfurization wastes were generated. Because of increasing reliance on coal for producing electricity, by the year 2000 the amount of ash waste is expected to increase by about 75 percent to about 120 million tons annually; production of FGD wastes is expected to triple to about 50 million tons annually.[1] In addition to the high-volume ash and flue gas desulfurization wastes, coal-fired power plants also generate several lower-volume waste streams as a result of equipment maintenance and cleaning activities.

About one-fifth of all waste generated at coal-fired electric utility power plants is currently reused; the remaining four-fifths are typically disposed in surface impoundments or landfills. The recycled wastes, usually fly ash, bottom ash, or boiler slag, have been used primarily as cement additives, high-volume road construction material, and blasting grit. There is some potential for increased use of these wastes in such applications. However, barring the

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[1] It is possible that advances in coal combustion technology will alter the amount and types of coal-combustion wastes produced in the future. An analysis of these technological advances is beyond the scope of this report.

development of new utilization techniques, or major changes in combustion and environmental control technologies, the proportion of coal combustion wastes that are reused is unlikely to change significantly.

While utility waste management sites are currently exempt from RCRA hazardous waste requirements, they are subject to state and local level solid waste laws and regulations. There is substantial variation in the state-mandated disposal requirements.

Most utility waste management facilities were not designed to provide a high level of protection against leaching. Only about 25 percent of all facilities have liners to reduce off-site migration of leachate, although 40 percent of the generating units built since 1975 have liners. Additionally, only about 15 percent have leachate collection systems; about one-third of all facilities have ground-water monitoring systems to detect potential leachate problems. Both leachate collection and ground-water monitoring systems are more common at newer facilities.

The primary concern regarding the disposal of wastes from coal-fired power plants is the potential for waste leachate to cause ground-water contamination. Although most of the materials found in these wastes do not cause much concern (for example, over 95 percent of ash is composed of oxides of silicon, aluminum, iron, and calcium), small quantities of other constituents that could potentially damage human health and the environment may also be present. These constituents include arsenic, barium, cadmium, chromium, lead, mercury, and selenium. At certain concentrations, these elements have toxic effects.

To assess the potential threat to health and the environment posed by these wastes and to document any specific damage cases, EPA, other agencies, and various private organizations sponsored several studies. The main research efforts cited in this Report to Congress are a 1985 study by Arthur D. Little, Inc. for EPA, which characterized the environmental effects of waste disposal at several utility disposal sites, and a series of reports submitted to the Agency in 1982 by the Utility Solid Waste Activities Group, the Edison Electric Institute, and the National Rural Electric Cooperative Association.

The findings of these various research efforts indicate that most coal combustion wastes do not exhibit any of the four hazardous characteristics defined in RCRA Subpart C. The results of a substantial number of extraction procedure tests were examined; these tests indicated that metals do not generally leach out of coal combustion wastes at levels classified as hazardous under RCRA. The only metals which were found in any ash or sludge samples at "hazardous" levels were cadmium and arsenic. For boiler cleaning wastes, chromium and lead were sometimes found at levels classified as hazardous under RCRA. This waste stream was also found to be corrosive in a number of samples. Results of EP Tests performed on co-disposed high and low volume wastes indicate, however, that boiler cleaning wastes do not exhibit hazardous characteristics when co-disposed with ash.

While most of the laboratory results indicated that coal combustion wastes do not possess RCRA hazardous characteristics, in some instances, data on actual field observations indicate that migration of potentially hazardous constituents from utility waste disposal sites has occurred. For example, observed concentrations of contaminants found in ground water downgradient from the sites exceed the Primary Drinking Water Standards about 5 percent of the time. Although the magnitude of the PDWS exceedances are typically not many times greater than the standard, a large number of disposal facilities report at least one PDWS exceedance at some time.

While a causal connection cannot always be made between the utility waste disposal site and the presence of contaminants at concentrations in excess of these standards, the available information indicates that some ground-water contamination from utility disposal sites is indeed occurring. The actual potential for exposure of human and ecological populations is likely to be limited, however, since ground water in the vicinity of utility waste disposal sites is not typically used for drinking water; the concentrations of contaminants in the ground water also tend to be diluted in nearby surface water bodies. These surface water bodies are typically used by electric utilities in the power plants for cooling and other purposes.

The electric utility industry currently spends about $800 million annually to dispose of its coal-fired combustion wastes. Under current practices, costs for waste management at most basic facilities range from as little as $2 per ton to as much as $31 per ton. Mitigative measures to control potential leaching include installation of liners, leachate collection systems, and ground-water monitoring systems and corrective action to clean up ground-water contamination. These mitigative measures, which are currently used at some utility waste disposal sites, may reduce the likelihood of ground-water contamination, but may also substantially increase disposal costs. For example, the incremental cost of new waste disposal practices, excluding corrective action costs or higher recycling costs, could range up to $70 per ton, or $3.7 billion annually if all wastes were listed as hazardous. While substantial on a total cost basis, these increases would be unlikely to significantly affect the rate at which existing power plants consume coal. Due to the competitiveness of alternative fuels for electricity generation at future power plants, however, any increase in disposal costs could potentially slow the growth in electric utility coal consumption in future years. Moreover, if new disposal standards require corrective action measures as set forth in 40 CFR 264.100, the costs to utilities could be extremely high and could have a substantial effect on the utility industry.

Based on the findings from this Report to Congress, the Agency presents three preliminary recommendations for those wastes included in the scope of this study. The recommendations are subject to change based on continuing consultations with other government agencies and new information submitted through the public hearings and comments on this report. Pursuant to the process outlined in RCRA 3001(b)(3)(C), EPA will announce its regulatory determination within six months after submitting this report to Congress.

First, EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics under current RCRA regulations. EPA does not intend to regulate under Subtitle C fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes. EPA's tentative conclusion is that current waste management practices appear to be adequate for protecting human health and the environment. The Agency prefers that these wastes remain under Subtitle D authority. EPA will use section 7003 of RCRA and sections 104 and 106 of CERCLA to seek relief in any cases where wastes from coal combustion waste disposal sites pose substantial threats or imminent hazards to human health and the environment. Coal combustion waste problems can also be addressed under RCRA Section 7002, which authorizes citizen lawsuits for violations of Subtitle D requirements in 40 CFR Part 257.

Second, EPA is concerned that several other wastes from coal-fired utilities may exhibit the hazardous characteristics of corrosivity or EP toxicity and merit regulation under Subtitle C. EPA intends to consider whether these waste streams should be regulated under Subtitle C of RCRA based on further study and information obtained during the public comment period. The waste streams of most concern appear to be those produced during equipment maintenance and water purification, such as metal and boiler cleaning wastes. The information available to the Agency at this time does not allow EPA to determine the exact quantity of coal combustion wastes that may exhibit RCRA Subtitle C characteristics. However, sufficient information does exist to indicate that some equipment maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics, and therefore, may pose a danger to human health and the environment. These wastes are similar to wastes produced by other industries that are subject to Subtitle C regulation, and waste management practices for coal combustion wastes are often similar to waste management practices employed by other industries. EPA is considering removing the exemption for all coal-fired utility wastes other than those identified in the first recommendation. The effect would be to apply Subtitle C regulation to any of those wastes that are hazardous by the RCRA characteristic tests. EPA believes there are various treatment options available for these wastes that would render them nonhazardous without major costs or disruptions to the utilities.

Third, EPA encourages the utilization of coal combustion wastes as one method for reducing the amount of these wastes that need to be disposed to the extent such utilization can be done in an environmentally safe manner. From the information available to the Agency at this time, current waste utilization practices appear to be done in an environmentally safe manner. The Agency supports voluntary efforts by industry to investigate additional possibilities for utilizing coal combustion wastes.

Through its own analysis, evaluation of public comments, and consultation with other agencies, the Agency will reach a regulatory determination within six months of submission of this Report to Congress. In so doing, it will consider and evaluate a broad range of management control options consistent with protecting human health and the environment. Moreover, if the Agency determines that Subtitle C regulation is warranted, in accordance with Section 3004(x) EPA will take into account the "special characteristics of such waste, the practical difficulties associated with implementation of such requirements, and site-specific characteristics . . . ," and will comply with the requirements of Executive Orders 12291 and 12498 and the Regulatory Flexibility Act.

CHAPTER ONE

INTRODUCTION

This is the Environmental Protection Agency's Report to Congress on wastes from fossil fuel combustion, as required by section 8002(n) of the Resource Conservation and Recovery Act. It describes sources and quantities of utility waste, current utilization and disposal practices and alternatives to these practices, potential dangers to human health and the environment, and the costs of current and alternative waste management practices. This report is based on numerous literature reviews and contractor studies; EPA's RCRA Docket contains copies of the source materials that the Agency used in preparing this report.

1.1 Legislative History

Because Congress has amended the Resource Conservation and Recovery Act several times and EPA's regulatory program continues to evolve in response to these Congressional mandates and other additional information, a brief legislative and regulatory history is provided below.

The Resource Conservation and Recovery Act (RCRA, or the Act) of 1976 (Public Law 94-580) substantially amended the Solid Waste Disposal Act of 1965 and authorized the U.S. Environmental Protection Agency (EPA) to establish and enforce regulations concerning the identification, generation, transportation, and management of hazardous waste. These regulations would accomplish the Act's objectives of "...promote[ing] the protection of health and the environment ... and conserve[ing] valuable material and energy resources...."[1] RCRA comprises several subtitles, including Subtitle C-- Hazardous Waste

Management, and Subtitle D-- State or Regional Solid Waste Plans. The intent of the regulations promulgated under Subtitle C of the Act is that wastes identified as hazardous be properly managed from "cradle to grave," that is, from the time they are generated, during transport, throughout their use in various applications, and during disposal. As provided under RCRA Subtitle D, other wastes not considered hazardous as defined under Subtitle C are subject to State regulations.

On December 18, 1978, EPA proposed the first regulations to implement Subtitle C. In the course of preparing these regulations, EPA recognized that certain very large-volume wastes (e.g., wastes generated by utility power plants) could require special treatment:

> ... The Agency has very little information on the composition, characteristics, and the degree of hazard posed by these wastes, nor does the Agency yet have data on the effectiveness of current or potential waste management technologies or the technical or economic practicability of imposing the Subpart D standards [current RCRA section 3004--Standards applicable to owners and operators of hazardous waste treatment, storage, and disposal facilities] on facilities managing such waste.
>
> The limited information the Agency does have indicates that such waste occurs in very large volumes, that the potential hazards posed by the waste are relatively low, and that the waste generally is not amenable to the control techniques developed in Subpart D.[2]

Thus, the Agency proposed a limited set of regulations for managing large-volume wastes, pending an additional rulemaking. Until that rulemaking was completed, EPA proposed exempting utility wastes from storage and disposal regulations.

On May 19, 1980, EPA promulgated the first regulations implementing Subtitle C of RCRA. By then, Congress was debating RCRA reauthorization, and both Houses had passed bills restricting EPA's ability to regulate utility wastes. Anticipating the enactment of legislation amending RCRA Section 3001, EPA excluded utility wastes from the promulgated regulations, writing in the preamble:

> The United States Senate and House of Representatives have each recently passed a bill to reauthorize and amend RCRA (S.1156 and H.R.3994). Both bills contain amendments to Section 3001 which, if enacted, would repeal or temporarily suspend EPA's authority to regulate certain utility and energy development wastes as hazardous wastes under Subtitle C. These bills are now awaiting action by a conference committee. Because it appears likely that Congress will act before November 19, 1980 [the end of the six month comment period on the promulgated interim final regulations and the date on which they would take effect] to exempt these wastes, EPA has temporarily excluded them from this regulation (see section 261.4(b)). This exclusion will be revised, if necessary, to conform to the legislation which is ultimately enacted.[3]

In fact, Congress did act before November 19, 1980; the Solid Waste Disposal Act Amendments (Public Law 96-482) were passed in October 1980.

As anticipated, the amendments temporarily exempted from regulation fly ash waste, bottom ash waste, boiler slag waste, and flue gas emission control waste generated primarily from the combustion of coal or other fossil fuels. In section 8002(n), Congress directed EPA to produce a report on the kinds of waste generated by the combustion of coal and other fossil fuels, which would include an analysis of eight topics:

1. the source and volumes of such material generated per year;

2. present disposal and utilization practices;
3. potential danger, if any, to human health and the environment from the disposal and reuse of such material;
4. documented cases in which danger to human health or the environment from surface runoff or leachate has been proved;
5. alternatives to current disposal methods;
6. the costs of such alternatives;
7. the impact of those alternatives on the use of coal and other natural resources; and
8. the current and potential utilization of such materials.[4]

Finally, in section 3001(b)(3)(C), Congress directed that within six months after submitting this report, EPA must conduct public hearings and decide whether regulating the management of coal combustion wastes under Subtitle C is warranted. Once the decision is made, the Administrator must publish the Agency's regulatory determination in the Federal Register.

In a January 1981 letter,[5] Gary Dietrich, then Associate Deputy Assistant Administrator for Solid Waste, provided an interpretation of RCRA regulations concerning the exemption from regulation of fossil fuel combustion waste.[6] (This letter, as well as a February 18, 1981 memorandum that enclosed it as part of a mailing to EPA Regional Directors, is included as Appendix A.) The letter noted that the beneficial use of hazardous waste as a fuel was not subject to regulation, though it might well be subject to regulation in the future. This meant that utilities could burn as fuel a combination of hazardous waste and coal, as long as more than 50 percent of the mixture was comprised of coal. The letter also addressed disposal, noting that wastes produced in conjunction with the burning of fossil fuels (e.g., cleaning and other maintenance-related wastes) may be exempt from Subtitle C regulations provided they are mixed and co-disposed or co-treated with fossil fuel wastes and provided "there is no evidence of any substantial environmental danger from these mixtures."[7] The letter concluded:

> ...Pending the completion of [further study on the hazards posed by waste from coal-fired utility plants and the collection of relevant data from the utility industry], EPA will interpret 40 CFR 261.4(b)(4) to mean that the following solid wastes are not hazardous wastes:
>
> (a) Fly ash, bottom ash, boiler slag, and flue gas emission control wastes resulting from (1) the combustion solely of coal, oil, or natural gas, (2) the combustion of any mixture of these fossil fuels, or (3) the combustion of any mixture of coal and other fuels, where coal makes up more than 50 percent of the mixture.
>
> (b) Wastes produced in conjunction with the combustion of fossil fuels, which are necessarily associated with the production of energy, and which traditionally have been, and which actually are, mixed with and co-disposed or co-treated with fly ash, bottom ash, boiler slag, or flue gas emission control wastes from coal combustion.

This provision includes, but is not limited to, boiler cleaning solutions, boiler blowdown, demineralizer reagent, pyrites, and cooling tower blowdown.

In November 1984, Congress reauthorized RCRA by passing the Hazardous and Solid Waste Amendments (HSWA). These amendments restricted the land disposal of certain hazardous wastes without treatment, established minimum technology requirements for landfills and surface impoundments, issued corrective action requirements for continuing releases at permitted facilities, and established interim status requirements for surface impoundments. Under this new legislation, EPA was granted some flexibility to promulgate regulations that take into consideration the unique characteristics of several types of large-volume wastes, including wastes generated by utility power plants. Specifically, if EPA determined that some or all of the wastes from fossil fuel combustion were subject to regulation under Subtitle C, EPA was empowered to modify the standards imposed by HSWA "...to take into account the special characteristics of such wastes, the practical difficulties associated with implementation of such requirements, and site-specific characteristics ... so long as such modified requirements assure protection of human health and the environment."[8]

The HSWA Conference Report accompanying H.R. 2867 (which in its final amended form was passed by both Houses of Congress as Public Law 98-616) provides clarification:

> This Amendment recognizes that even if some of the special study wastes [which include utility wastes as specified in Section 8002(n)] are determined to be hazardous it may not be necessary or appropriate because of their special characteristics and other factors, to subject such waste to the same requirements that are applicable to other hazardous wastes, and that protection of human health and the environment does not necessarily imply the uniform application of requirements developed for disposal of other hazardous wastes. The authority delegated to the Administrator under this section is both waste-specific and requirement-specific. The Administrator could also exercise the authority to modify requirements for different classes of wastes. Should these wastes become subject to the requirements of Section 3005(j), relating to the retrofit of surface impoundments, the Administrator could

> modify such requirements so that they are not identical to the requirements that are applied to new surface impoundments containing such wastes. It is expected that before any of these wastes become subject to regulation under Subtitle C, the Administrator will determine whether the requirements of Section 3004(c), (d), (e), (f), (g), (o), and (u), and Section 3005(j) should be modified.[9]

1.2. Scope and Sources

This report addresses only the wastes generated by coal-fired electric utility power plants. Because this industry generates the vast majority of all fossil fuel combustion waste (nearly 90 percent),[10] EPA decided to focus its study in this area. This study does not address oil- and gas-fired electric utility power plants or coal, oil and gas-fired industrial boilers.

A number of research projects were undertaken to provide data for this report. EPA sponsored a major study of current coal ash and flue gas desulfurization waste management practices at coal-fired electric utility power plants.[11] In this study comprehensive environmental monitoring was conducted, which included characterizing the wastes, soils, ground water, and surface water at six disposal sites. The contractor (Arthur D. Little, Inc.) evaluated the environmental effects of the disposal practices used at these six sites and, by inference, what effects may be present at other utility waste disposal sites. They also performed extensive engineering and cost evaluations of disposal practices at the six sites.

EPA also sponsored a separate study effort to develop information on the incidences of ground water contamination resulting from utility waste management practices.[12] In this study, contamination was defined as the presence of hazardous constituents at levels above primary drinking water standards. The main source of information for this phase of the research was a review of case files at the state offices having responsibility for such matters.

In addition, the Agency also reviewed reports submitted by the Utility Solid Waste Activities Group (USWAG), the Edison Electric Institute (EEI), and the National Rural Electric Cooperative Association (NRECA).[13] The reports present information on the sources, volumes, and physical and chemical characteristics of waste streams; ground-water monitoring results assembled from various utility plants; damage case information from various sources; costs of complying with hazardous waste regulations; and resource recovery opportunities using utility wastes.

EPA also has incorporated findings from several documents prepared by the Department of Energy (DOE) and the Electric Power Research Institute (EPRI).[14] These reports examined the chemical composition of utility wastes, technologies for disposal and the costs associated with disposal, as well as results of leaching tests performed on utility wastes.

Finally, EPA gathered information from the Utility Data Institute's Power Statistics Database.[15] This database contains information concerning the size of utility power plants, location of power plants, the types of disposal technologies employed by each power plant, and the amount of waste produced by site and by region. The information on location of power plants was combined with hydrogeologic, population, and ecological profiles of these locations to analyze the potential for exposure to coal combustion wastes.

1.3 Organization

The following chapters of this report address the eight issues (enumerated earlier in this chapter) as required by Section 8002(n) as they apply to coal-fired combustion wastes generated by electric utilities. Chapter Two of this report provides an overview of the U.S. electric utility industry. Chapter Three examines the amount and types of wastes that are generated. Chapter Four discusses current waste management and disposal practices used by the electric utility industry, as well as alternatives to these practices; a review of applicable State regulations is included in this chapter. Chapter Five reviews the potential and documented impact of these wastes on human health and the environment, and Chapter Six evaluates costs associated with current waste disposal practices and additional costs that could be incurred under a variety of alternative waste management practices. Finally, Chapter Seven summarizes the conclusions contained in the previous chapters and presents recommendations.

CHAPTER ONE

NOTES

[1] Resource Conservation and Recovery Act of 1976 (RCRA), Section 1003(a).

[2] Federal Register, Volume 43, No. 243, December 18, 1978, pp. 58991-58992.

[3] Federal Register, Volume 45, No. 98, May 19, 1980, p. 33089.

[4] RCRA, Section 8002(n).

[5] Letter of January 13, 1981, from Gary N. Dietrich, Associate Deputy Assistant Administrator for Solid Waste, to Paul Elmer, Jr., Chairman of the Utility Solid Waste Activities Group.

[6] See 40 CFR 261.4.

[7] Gary N. Dietrich, January 13, 1981, op. cit.; for further information, see Congressional Record, February 20, 1980, p. H 1102, remarks of Congressman Bevill; also see remarks of Congressional Record, February 20, 1980, p. H 1104, remarks of Congressman Rahall.

[8] RCRA, Section 3004(x)

[9] H.R. Report 98-1133, pp. 93-94, October 3, 1984.

[10] Most fossil fuel combustion wastes are generated from coal. For example, as indicated in Physical-Chemical Characteristics of Utility Solid Wastes (by Tetratech, Inc. for EPRI, September 1983), only about one percent of utility wastes are generated from oil; the remaining 99 percent is largely attributable to coal-fired electricity production. Of the coal consumed in the U.S., electric utilities burn nearly 90 percent (excluding metallurgical coal, which is not burned but is instead converted into coke primarily for making steel).

[11] Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants. Prepared for EPA's Office of Research and Development, EPA Contract #68-02-3167; June 1985.

[12] Franklin Associates, Ltd., Survey of Groundwater Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for U.S. Environmental Protection Agency, March 1984.

[13] USWAG is an informal consortium of approximately 65 electric utility operating companies, EEI, and NRECA. The primary source used in the preparation of this report was Report and Technical Studies On The Disposal and Utilization of Fossil-Fuel Combustion By-Products, USWAG, EEI, and NRECA, October 26, 1982.

[14] For example, see Impacts of Proposed RCRA Regulations and Other Related Federal Environmental Regulations on Utility Fossil Fuel-Fired Facilities; Prepared by Engineering-Science for DOE, DOE Contract Number DE-AC-01-79ET-13543, May 1983; Physical-Chemical Characteristics of Utility Solid Wastes, EPRI, September 1983; Analytical Aspects of the Fossil Energy Waste Sampling and Characterization Project, Prepared by Western Research Institute, DOE Order Number DE-AP20-84LC00022, March 1984; and Environmental Settings and Solid Residues Disposal in the Electric Utility Industry, EPRI, July 1984. More sources are included in the Bibliography.

[15] Utility Data Institute's Power Statistics Database was developed under the auspices of the Edison Electric Institute to assist in their analysis of issues affecting the electric utility industry.

CHAPTER TWO

OVERVIEW OF THE ELECTRIC UTILITY INDUSTRY

This chapter provides a general overview of the U.S. electric utility industry. Section 2.1 summarizes electricity demand and discusses the overall structure of the electric utility industry. Section 2.2 focuses the discussion on the role that coal plays in generating electricity. Section 2.3 provides details of coal-fired electric generating technologies and the regional characteristics of coal-fired plants. The chapter concludes with a discussion in Section 2.4 of the waste streams that are produced during coal combustion.

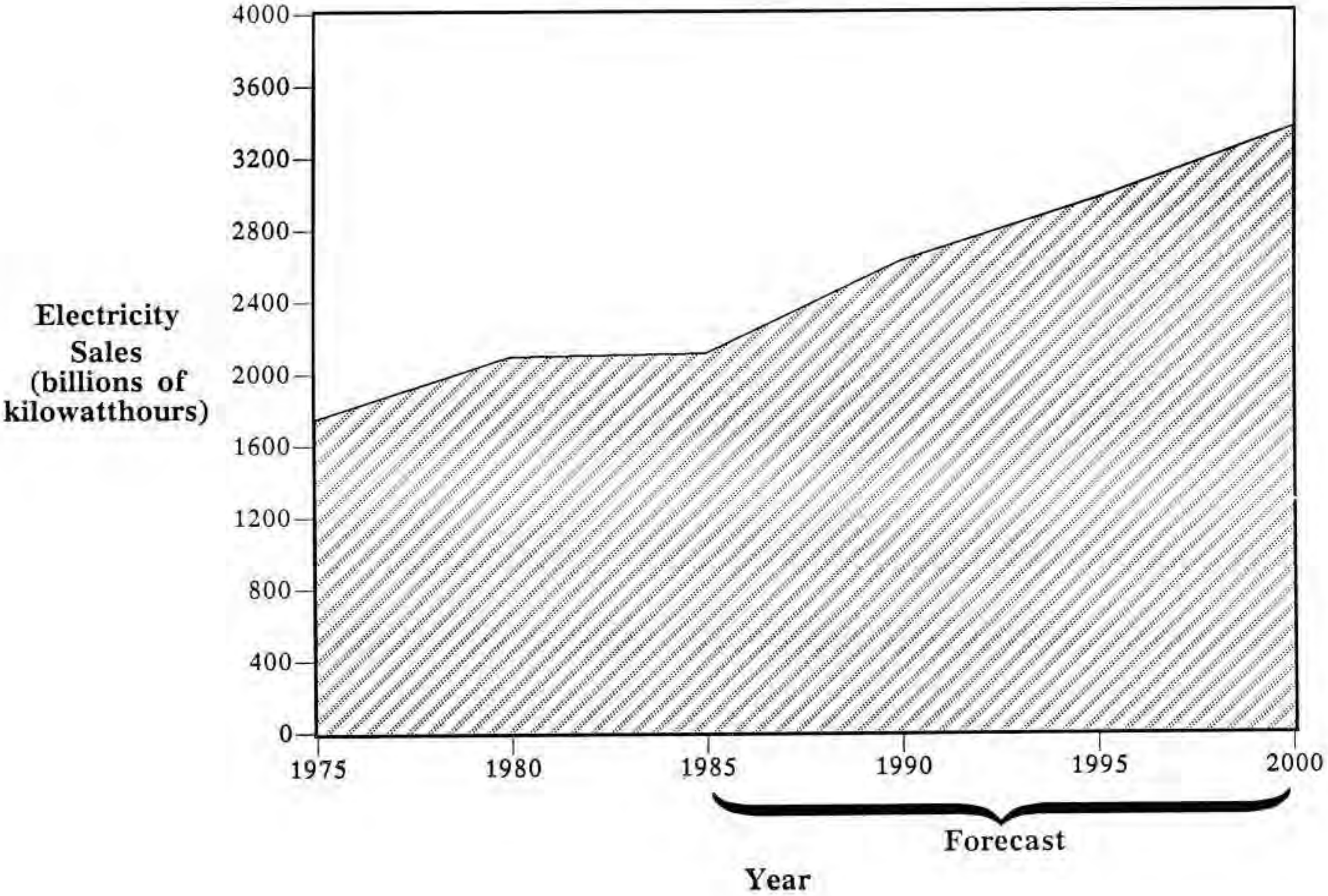
2.1 THE DEMAND FOR ELECTRICITY

The generation, transmission, and distribution of electricity is one of our nation's largest industries. With annual revenues in excess of $140 billion and assets of about $500 billion, the electric utility industry provides vital services to nearly every person in the U.S.[1]

Total demand for electricity in the U.S. has increased substantially in recent decades and will likely continue to grow in coming years (see Exhibit 2-1). From the 1940's through the early 1970's, electricity demand grew at about 7 percent per year, doubling approximately every ten years. This growth slowed beginning with the 1973 OPEC oil embargo and subsequent changes in the energy markets such as fuel price increases, shifts in the economy to markets that require less electricity to meet their power needs, and energy conservation measures. Since 1973, growth in electricity demand has averaged

EXHIBIT 2-1

GROWTH IN ELECTRICITY DEMAND - 1975-2000



Sources: 1975-1985: Energy Information Administration, Electric Power Monthly, DOE/EIA-0226 (85/12), December 1985, p. 39.

1985-2000: ICF Incorporated, Analysis of 6 and 8 Million ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

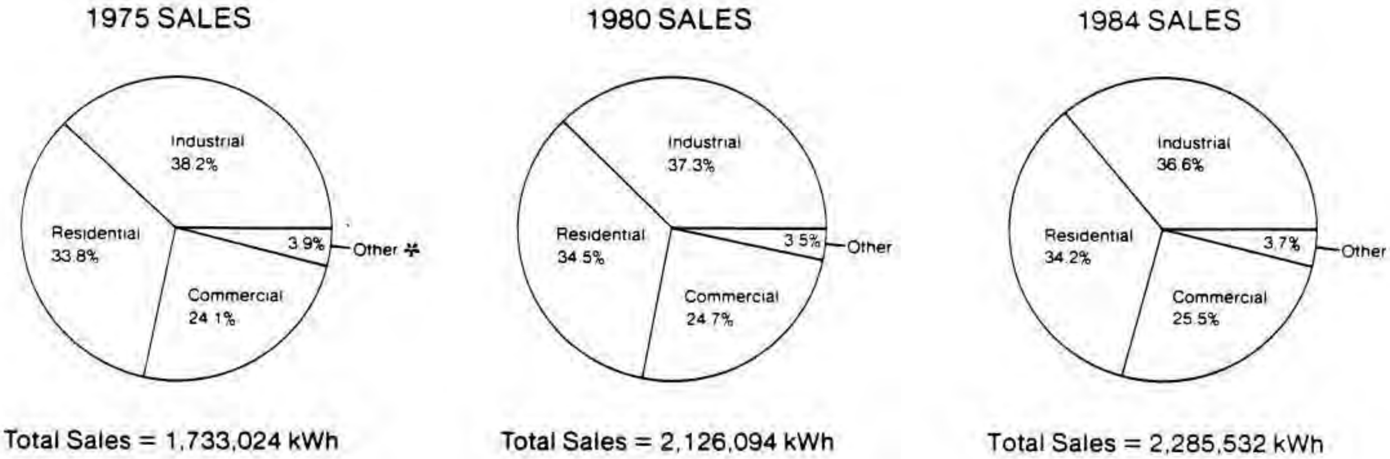
about three percent per year. Expectations are that electricity demand will continue to grow at an average rate of about 2 to 3 percent per year over the next several years.[2]

Every major segment of the U.S. economy relies on electricity to meet a portion of its energy needs. As shown in Exhibit 2-2, the demand for electricity is divided almost evenly between the industrial, commercial, and residential sectors. This demand for electricity has continued to increase over the last decade with total sales increasing from 1.7 million gigawatt-hours (Gwh) in 1975 to 2.3 million Gwh in 1985.[3] As demand has increased, electricity sales patterns have remained relatively consistent. Industry continues to be the largest consuming sector, although industry's fraction of total sales has decreased by about 2.7 percent from 1975 to 1985, primarily due to an increased market share for the commercial sector (i.e., stores, office buildings, restaurants, etc.). Residential customers consume about one-third of all electricity for basic necessities such as lighting, heating, and electrical appliances.

Virtually every geographic area in the U.S. relies on electricity supplied by the electric utility industry. As shown in Exhibit 2-3, electricity demand is highest in the eastern half of the U.S., particularly in EPA Regions 3-6 (see Exhibit 2-4 for a map of these EPA Regions). This level of demand is not surprising considering that these areas are the most heavily industrialized and densely populated areas of the country.

EXHIBIT 2-2

ELECTRICITY SALES BY YEAR AND CLASS OF SERVICE (gigawatt-hours)



1975 SALES

Total Sales = 1,733,024 kWh

1980 SALES

Total Sales = 2,126,094 kWh

1984 SALES

Total Sales = 2,285,532 kWh

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1985, December 1986.

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*Includes street lighting, other public authorities, railroads and interdepartmental transfers within utilities (i.e., use of electricity by the utility itself).

EXHIBIT 2-3

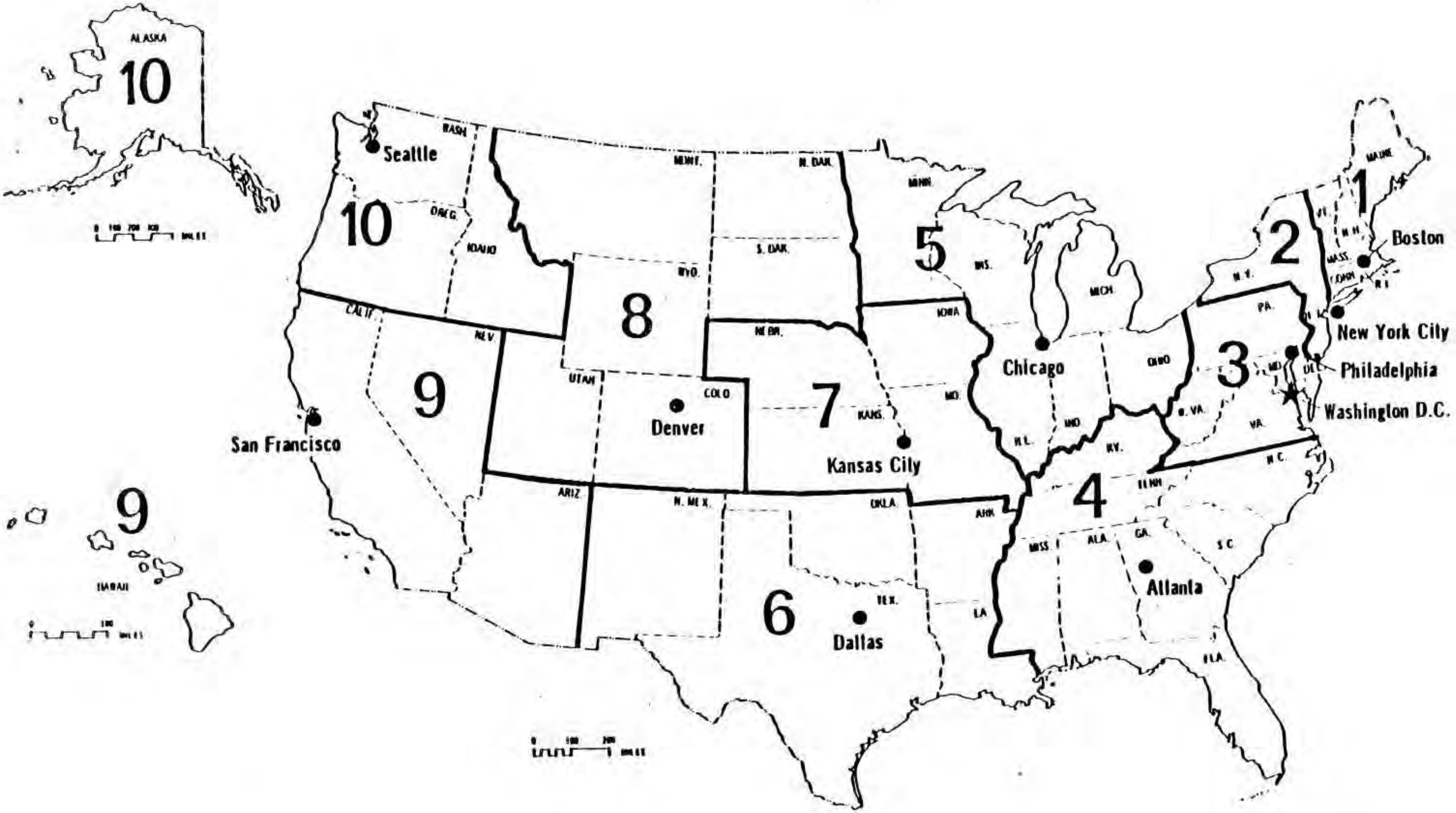
ELECTRICITY DEMAND by EPA REGION
1985

EPA Region	Millions of Kilowatt Hours	Percent of Total
1	86,397	3.8
2	164,780	7.2
3	230,055	10.1
4	483,248	21.2
5	428,873	18.8
6	340,198	14.8
7	112,076	4.9
8	72,458	3.2
9	227,006	10.0
10	135,716	6.0
Total U.S.	2,280,585	100.0

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry/1985, December 1986.

EXHIBIT 2-4

EPA FEDERAL REGIONS



2.1.1 Structure of the U.S. Electric Utility Industry

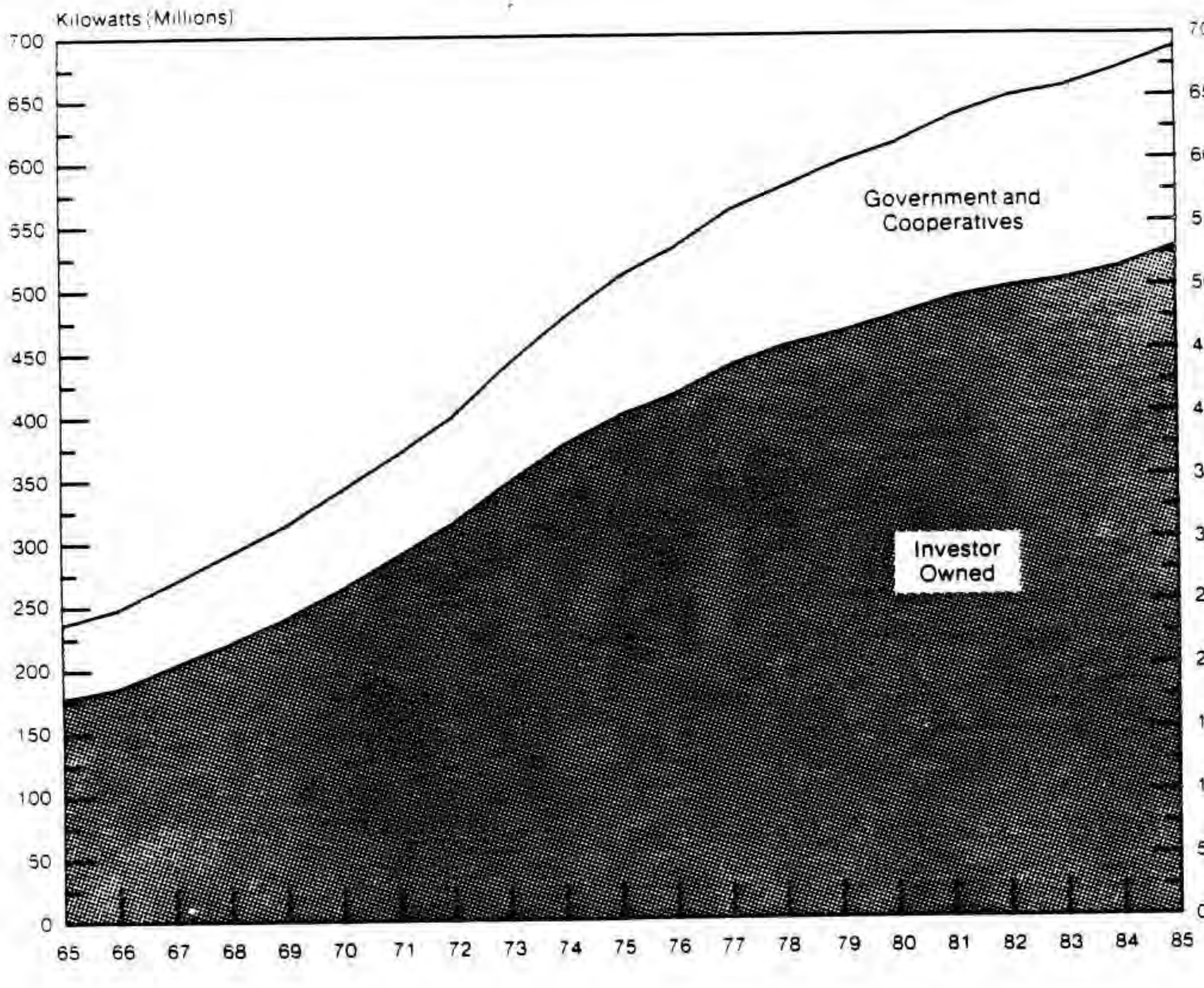
The U.S. electric power industry is a combination of private, Federal, and public nonprofit organizations. The distribution of capacity, generation, revenue, and sales differs widely among these ownership groups since each group has different objectives, organizational characteristics, and financing methods. Private investor-owned utilities dominate the U.S. electric utility industry as shown in Exhibit 2-5. Investor-owned utilities have historically served large consolidated markets to take advantage of economies of scale. Federal, municipal, cooperative, and other publicly-owned utilities have generally served smaller markets where local governments or nonprofit organizations have had access to limited supplies of less expensive Federal power or to government-supplied capital for power plant construction. These circumstances have allowed municipal, cooperative, or other publicly-owned utilities to predominate in areas not traditionally served by investor-owned utilities.[4] A brief discussion of each type of organization is provided below.

2.1.1.1 Investor-Owned Utilities

Investor-owned utilities account for about three-quarters of all U.S. electric utility generating capacity, generation, sales, and revenue. Investor-owned utilities are privately owned, profit-oriented businesses granted service monopolies in certain geographic areas. As franchised monopolies, they are obligated to provide service to all customers within their geographic area. In providing this service, investor-owned utilities are required to charge reasonable prices, to charge similar prices to similar

EXHIBIT 2-5

GENERATING CAPACITY IN THE UNITED STATES



Source: Edison Electric Institute, Statistical Yearbook for the Electric Utility Industry/1985, December 1986.

customers, and to give customers access to services under similar conditions.[5] Investor-owned utilities operate in all states except Nebraska (which depends primarily on public power districts and rural electric cooperatives for electricity). In 1984, consumers paid an average of 6.5 cents per kilowatt-hour (kwh) for privately-produced power compared to the industry average from all ownership groups of 6.3 cents per kilowatt-hour (an average customer consumed 23,150 kwh in 1984).[6]

2.1.1.2 Federal Power

The U.S. Government is the second largest producer of electricity in the United States with roughly 10 percent of total U.S. generation and generating capacity. Consumers of Federal power paid the lowest rate among the different ownership groups -- only 3.5 cents per kwh on average in 1984, (compared to an industry average of 6.3 cents per kwh).[7] Federal power production is designed to provide power at the lowest possible rate, with preference in the sale of electricity given to public entities and cooperatives.[8] In this role the Federal Government is primarily a generator and wholesaler of electricity to other organizations, rather than a direct distributor to electricity consumers.[9]

2.1.1.3 Municipal Utilities

Municipal utilities are nonprofit local government agencies designed to serve their customers at the lowest possible cost. Most municipal utilities simply distribute power obtained from one of the other ownership groups (e.g., Federal facilities), although some larger ones also generate and transmit power. Municipally-owned electric utilities rank third in the amount of installed capacity (5.5 percent of total generating capacity), but comprise the single most numerous ownership group (1,811 utilities in 1984).[10] Average revenue per kwh sold in 1984 was 5.69 cents compared to an industry average of 6.3 cents per kwh. Municipal utilities are exempt from local, state, and Federal taxes and have access to less expensive capital via public financing and less expensive Federal power. As a result, municipal utilities can generally afford to charge less than investor-owned utilities for the power they produce.[11]

2.1.1.4 Cooperatives

Rural electric cooperatives are owned by and provide electricity to their members and currently operate in 46 states. They have the lowest amount of installed capacity among all ownership categories (24.7 gigawatts in 1984 or less than 4 percent of all capacity).[12]

In 1984, average revenue for cooperatives from sales to consumers was 6.7 cents per kwh, the highest of all ownership types (the industry average was 6.3 cents per kwh). Large construction programs in the 1970's usually account for the high rates.[13]

2.1.1.5 Other Public Entities

There are a variety of other public organizations that provide electric power, including public power districts, state authorities, irrigation districts, and various other State organizations. These other public entities operated a combined total of 32.8 gigawatts in 1984, or about 5 percent of all generating capacity in the U.S.[14] The public power districts are concentrated in five states -- Nebraska, Washington, Oregon, Arizona, and California. The average price paid for electricity from all of these entities was 4.37 cents per kwh in 1984, compared to an industry average of 6.3 cents per kwh.[15]

2.1.2 Economic and Environmental Regulation of the Electric Utility Industry[16]

The electric utility industry is regulated by several different regulatory bodies at both the Federal and State levels. According to the U.S. Department of Energy: "The basic purpose of public utility regulation is to assure adequate service to all public utility patrons, without discrimination and at the lowest reasonable rates consistent with the interests both of the public and the electric utilities."[17] This regulation involves both economic and environmental objectives. As natural monopolies, electric utilities are regulated to ensure that adequate, reliable supplies of electric power are available to the public at a reasonable cost. Additionally, since the operations of electric utilities can affect environmental quality, they are regulated to ensure the protection of the nation's air and water resources. This section briefly reviews the main regulatory bodies that affect the electric utility industry.

2.1.2.1 Federal Regulation

There are five major organizations at the Federal level that regulate some aspect of the electric utility industry -- the Federal Energy Regulatory Commission (FERC), the Economic Regulatory Administration (ERA), the

Securities and Exchange Commission (SEC), the Nuclear Regulatory Commission (NRC), and the Environmental Protection Agency (EPA).

- The Federal Energy Regulatory Commission (FERC) oversees various aspects of the electric utility, natural gas, hydroelectric, and oil pipeline industries. FERC approves the rates and standards for wholesale interstate electricity sales between investor-owned utilities and other investor-owned utilities, municipals, or cooperatives (these sales are about 15 percent of total U.S. electricity sales).[18] It determines whether these rates are reasonable and non-discriminatory. FERC also oversees utility mergers and the issuance of certain stock and debt securities, approves the rates of Federal Power Marketing Administrations, and administers agreements between utilities concerning electricity transmission.
- The Economic Regulatory Administration (ERA) has several responsibilities, including administering a program to ensure that all future power plants have the potential to burn coal, regulating international electricity transmission connections, and licensing exports of power.
- The Securities and Exchange Commission (SEC) is an independent regulatory agency established to regulate interstate transactions in corporate securities and stock exchanges. With respect to the electric utility industry, the SEC regulates the purchase and sale of securities, utility properties, and other assets.
- The Nuclear Regulatory Commission (NRC) is involved only in the regulation of nuclear facilities owned and operated by the utility industry. Its main responsibilities include licensing the construction and operation of nuclear facilities, licensing the possession, use, transportation, handling, and disposal of nuclear materials, licensing the export of nuclear reactors and the import and export of uranium and plutonium, and regulating activities affecting the protection of nuclear facilities and materials.

In addition to these regulatory bodies, the Environmental Protection Agency (EPA) is the main Federal regulatory authority for protecting the nation's air and water quality. As part of its overall authority, EPA sets limits on the level of air pollutants emitted from electric power plants and develops regulations to control discharges of specific water pollutants.

Throughout this Report to Congress key regulations that affect the electric utility industry are discussed. While EPA often takes the Federal lead when these regulations are developed, the Agency also works closely with the States since they often retain primary authority for implementing and enforcing standards (for example, see Section 4.1 on state regulation of coal combustion wastes).

2.1.2.2 State Regulation

States are also involved in the environmental and economic regulation of the electric utility industry. As mentioned above, the States often share regulatory authority with the various Federal organizations. For environmental regulation the States often have their own environmental protection agencies to implement and enforce State and Federal environmental regulations. For example, they are responsible for drafting State Implementation Plans (SIP) that must be approved by the U.S. EPA to attain National Ambient Air Quality Standards (NAAQS). Similarly, as will be discussed in greater detail in Chapter Four, the States have authority for implementing and enforcing regulations concerning the disposal of solid wastes under Subtitle D of RCRA. Environmental regulations for which the States exercise regulatory authority are discussed throughout this Report to Congress.

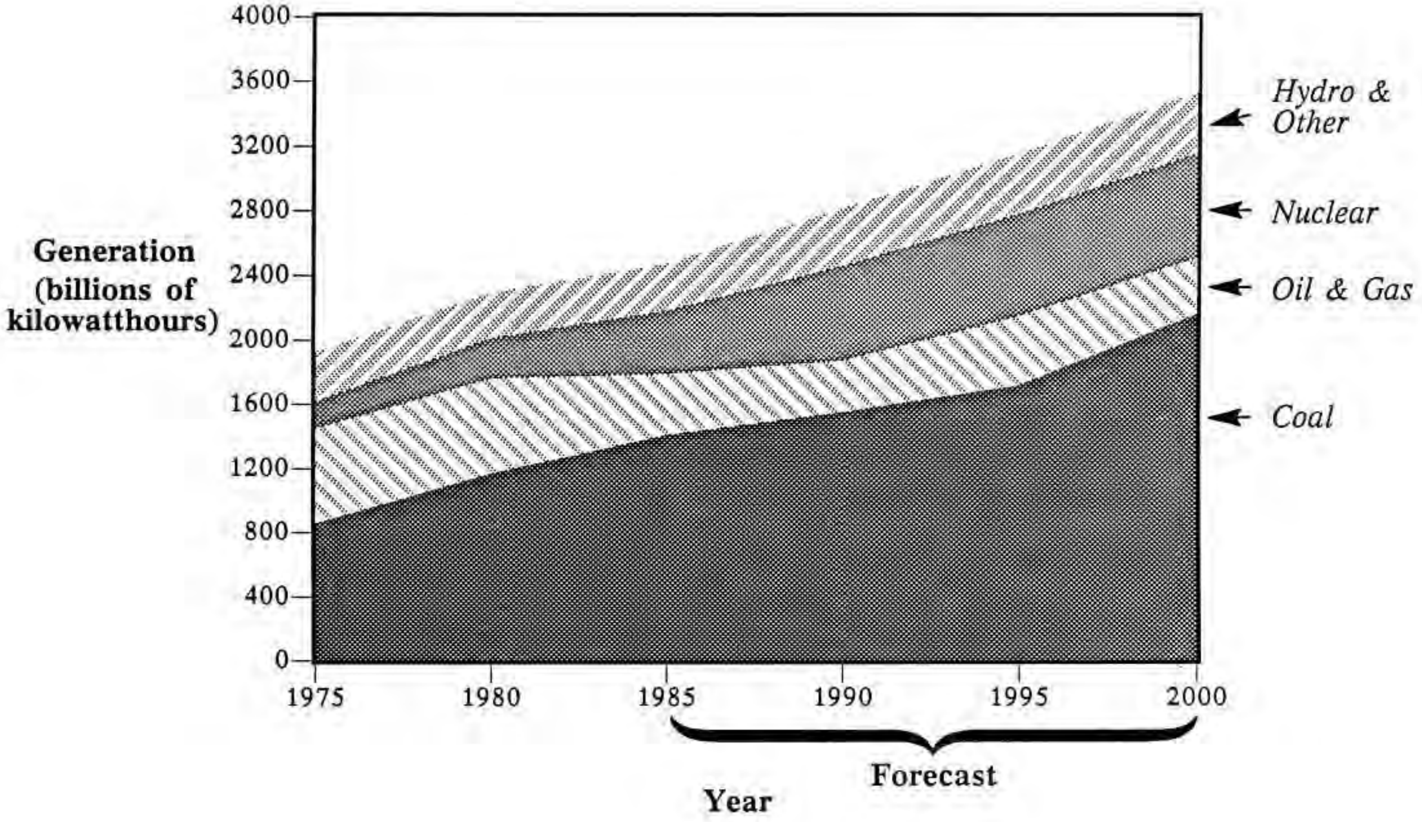
States are also very involved in the economic regulation of the electric utility industry. The primary goals of state economic regulation is usually to provide adequate nondiscriminatory service to electricity consumers at reasonable prices.[19] This is usually accomplished by state regulatory agencies such as public utility commissions. The amount of authority these state regulatory agencies have can differ widely from state to state. However, these agencies usually have the authority to approve electricity price levels and the rates of return allowed for utility stockholders. State regulators also approve the franchise under which the utility operates. Licensing for construction and operation and approval of the sites at which power plants will be built are also important functions of some state regulatory commissions. Other areas into which some commissions have entered to ensure that utility activities protect the public interest include setting rules about when competitive bids are required, promulgating company performance standards, deriving methods for allocating power during shortages, establishing billing and safety rules, and promoting conservation.[20]

2.2 IMPORTANCE OF COAL TO ELECTRIC UTILITIES

Electric utilities use many different technologies and energy sources to generate electricity. At present, as shown in Exhibit 2-6, over 70 percent of electricity in the U.S. is generated by the combustion of fossil fuels (coal, oil and natural gas); most of the remaining 30 percent is generated by hydroelectric plants and nuclear power plants. A small portion of electricity demand is satisfied by alternative sources such as geothermal energy, renewable resource technologies (e.g., wood, solar energy, wind), purchased power from industrial and commercial cogeneration (cogeneration is the simultaneous production of electricity and process steam; the electricity is typically used by the cogenerator or sold to another industry while the steam is used for various production processes), and power imports (primarily from Canada).

EXHIBIT 2-6

ELECTRICITY GENERATION BY PRIMARY ENERGY SOURCE
1975-2000



Source: 1975-1985: Energy Information Administration, Electric Power Monthly DOE/EIA-0226 (85/12), December 1985, p. 10.

1985-2000: ICF Incorporated, Analysis of 6 and 8 million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

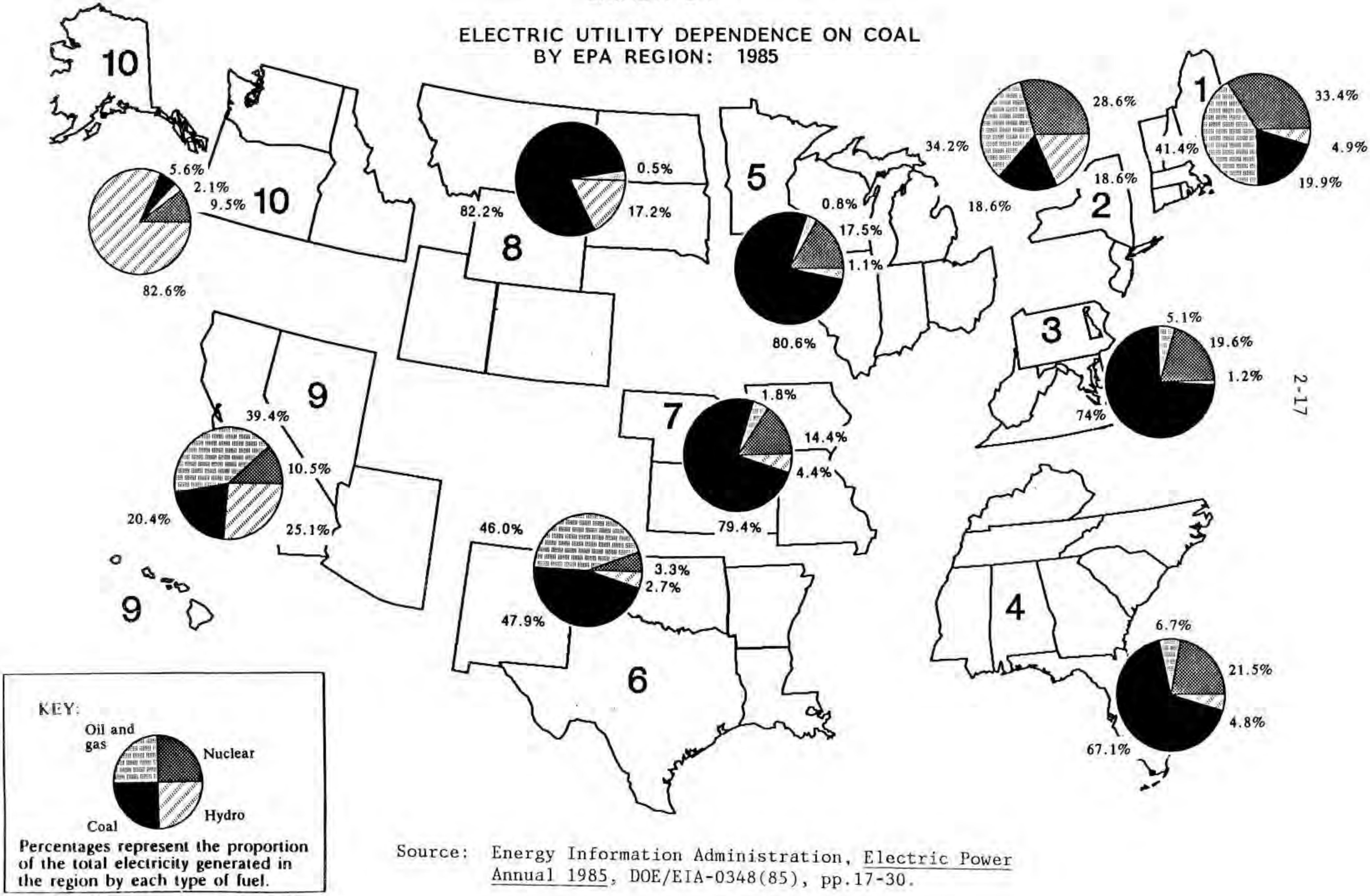
In 1984, coal accounted for more than half of all the electricity generated in the U.S.[21] The portion of electricity generated from coal is expected to remain at about this level throughout the rest of the century since coal-fired generation is expected to remain economically attractive. The relative contribution to total generation made by other fossil fuels and by hydroelectric power will likely continue to decline, while the contribution made by nuclear power plants will likely increase for the next few years as several new units come on-line. However, the addition of nuclear plants beyond those now under construction will be minimal, leading to an eventual decline in nuclear's relative contribution. Cogeneration, power imports, and emerging technologies are expected to continue to grow, but their share of total generation will remain small. As a result, coal will continue to be the major fuel source for electricity generation.

The extent of the electric utility industry's dependence on coal varies geographically. Exhibit 2-7 shows that coal accounts for over three-quarters of electricity generation in some regions, but less than half in others. For example, in the far West and southern Plains states, the local availability of oil, gas, and hydroelectric power has limited regional dependence on coal. In many of the eastern regions, where coal is relatively more accessible and less costly than oil or gas, coal is significantly more dominant. Despite these regional variations, however, coal-fired electricity generation is an important source of electricity in most regions of the United States.

The use of coal by electric utilities has also made the coal and electric utility industries highly interdependent; not only does coal-fired electricity generation account for over half of the electricity produced in the U.S., but

EXHIBIT 2-7

ELECTRIC UTILITY DEPENDENCE ON COAL BY EPA REGION: 1985



Source: Energy Information Administration, Electric Power Annual 1985, DOE/EIA-0348(85), pp.17-30.

the electric utility industry is the largest customer of the coal industry, purchasing approximately three-quarters of all coal mined, as shown in Exhibit 2-8. This interdependence has increased as electric utility coal consumption has grown from 406 million tons in 1975 to over 600 million tons in 1985.[22] Moreover, electric utility coal consumption is expected to continue to increase to about 1 billion tons by the year 2000.

2.3 OVERVIEW OF COAL-FIRED POWER PLANTS

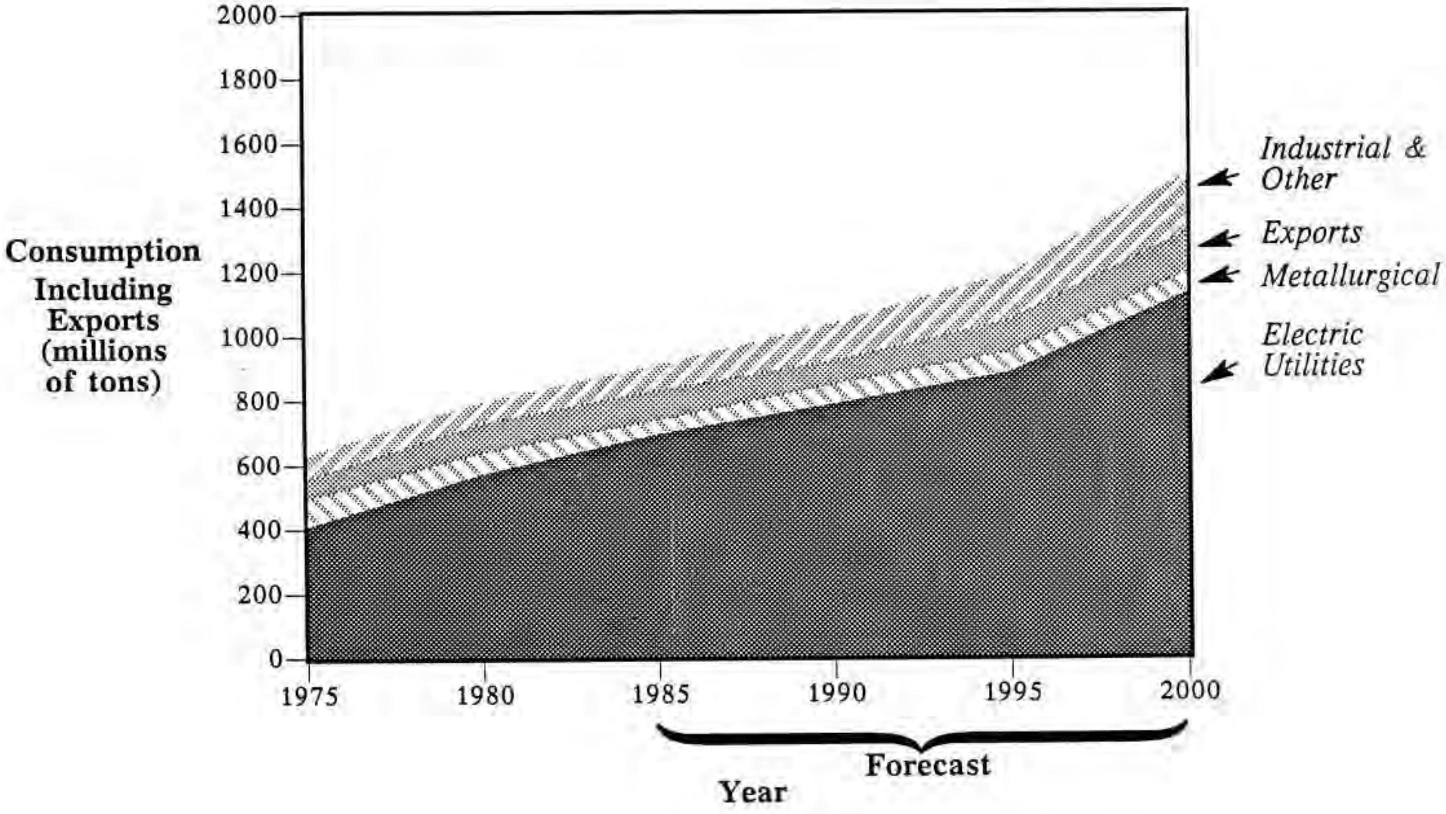
Coal-fired power plants can vary greatly in terms of their generating capacity and the type of boiler technology they employ which, in turn, can affect the amount and type of combustion wastes produced. This section discusses the geographic differences in the size of plants and generating units and describes the three main boiler types along with the regional importance of each.

2.3.1 Regional Characteristics of Coal-Fired Electric Generating Plants

Coal-fired power plants can range in size from less than 50 MW to larger than 3000 MW. In many cases, particularly at the larger power plants, one power plant site may be the location for more than one generating unit (a generating unit is usually one combination of a boiler, turbine, and generator for producing electricity). Exhibit 2-9 shows the number of coal-fired power plants and number of units in each EPA region and their average size in megawatts. On average, each power plant site is comprised of about three generating units. The average generating capacity of coal-fired power plants in the U.S. is approximately 584 MW, with an average unit size of 257 MW.

EXHIBIT 2-8

U.S COAL CONSUMPTION BY SECTOR
1975-2000



Sources: 1975-1985: Energy Information Administration, Annual Energy Review 1985, DOE/EIA-0384 (85), April 1985, pp. 167, 169.

1985-2000: ICF Incorporated, Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 lb. Sulfur Dioxide Emission Reduction Cases, Prepared for Environmental Protection Agency, February 1986.

EXHIBIT 2-9

TOTAL NUMBER AND AVERAGE SIZE OF COAL-FIRED PLANTS AND UNITS

EPA Region	Number of Plants	Average Size (MW)	Number of Units a/	Average Size a/ (MW)
1	6	374	18	158
2	17	297	39	138
3	57	753	144	308
4	93	799	295	301
5	171	492	492	185
6	39	852	87	580
7	66	400	149	186
8	48	454	109	250
9	13	603	34	383
10	4	479	11	382
U.S. Total	514	584	1378	257

Source: Utility Data Institute Power Statistics Database.

a/ The total amount of generating capacity indicated by multiplying the number of units by their average size (e.g., 1378 units X 257 Mw = 354,146 Mw) is greater than the amount indicated by multiplying the number of power plants by their average (e.g., 514 plants X 584 Mw = 300,176 Mw) because the information in the UDI Power Statistics Database by generating units includes units planned, currently under construction, etc. while the information by power plants refers only to power plants currently operating.

Regional averages for power plant size range from 297 MW in Region 2 to 852 MW in Region 6. Unit sizes range from an average of 138 Mw in Region 2 to 580 Mw in Region 6. Individual power plants and units can be larger or smaller than these averages indicate.

The majority of coal-fired plants (60%) are smaller than 500 MW, while only about 4 percent of U.S. coal-fired power plants have a generating capacity exceeding 2000 MW. Exhibit 2-10 shows the distribution of coal-fired plant sizes across EPA regions.

2.3.2 Electricity Generating Technologies

The basic process by which electricity is produced with coal is shown in Exhibit 2-11. When coal is burned to produce electricity, there are three key components that are critical to the operation of the power plant: the boiler, turbine, and generator. As coal is fed into the boiler, it is burned in the boiler's furnace. In the boiler there are a series of water-filled pipes. As heat is released during combustion, the water is converted to steam until it reaches temperatures that can exceed 1000°F and pressures that approach 4000 pounds per square inch. This high pressure, high temperature steam is then injected into a turbine, causing the turbine blades to rotate. The turbine, in turn, is connected to a generator, so the mechanical energy available from the rotating turbine blades is transformed into electrical energy. The electricity produced by this process is distributed via transmission lines to residential, commercial, and industrial end-users who rely on the power to meet their electrical requirements. Although each step of this process is critical to the production of electricity, this study focuses on boilers only

EXHIBIT 2-10

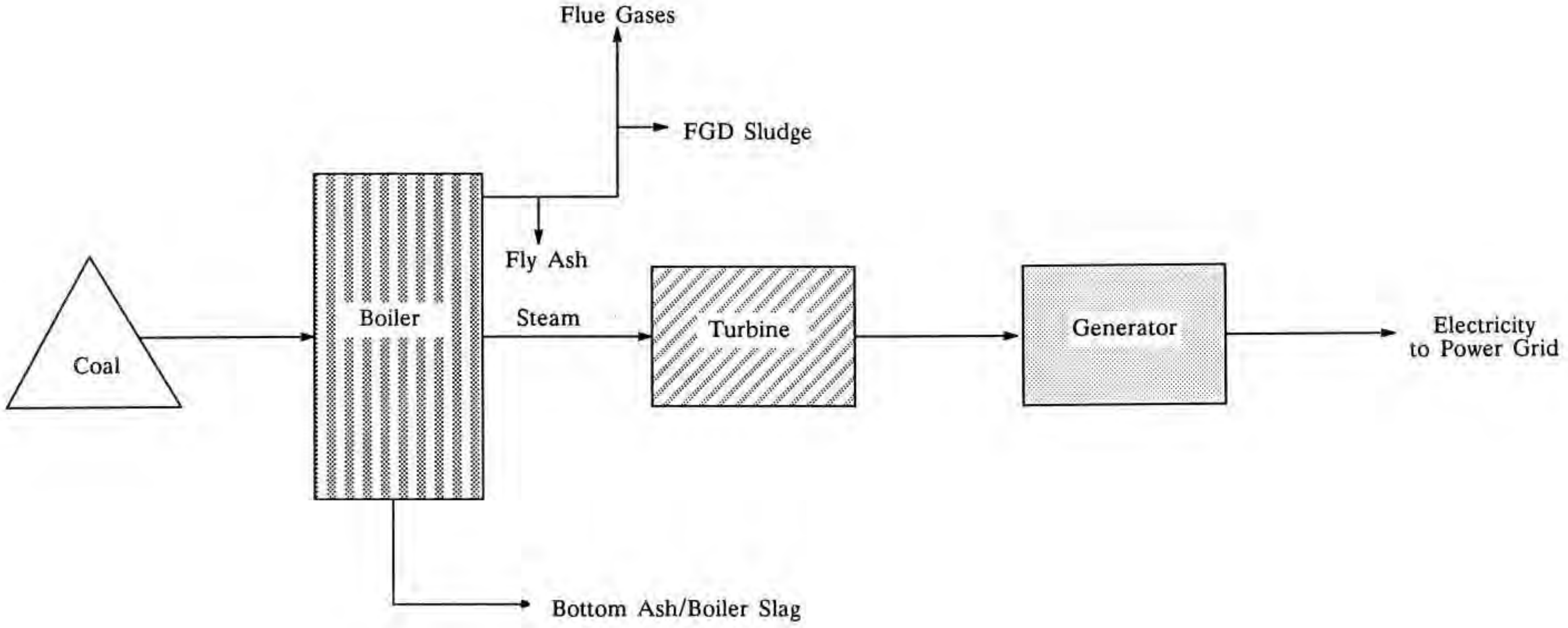
RANGE OF COAL-FIRED POWER PLANT SIZES
(number of plants)

	Power Plant Size					
EPA Region	<100 MW	101-500 MW	501-1000 MW	1001-2000 MW	≥2000 MW	Total
1	1	4	0	1	0	6
2	6	6	5	0	0	17
3	6	23	11	14	3	57
4	15	31	17	23	7	93
5	63	51	23	29	5	171
6	10	4	10	12	3	39
7	25	24	8	7	2	66
8	18	14	10	4	2	48
9	5	2	4	1	1	13
10	2	0	1	1	0	4
U.S. Total	151	159	89	92	23	514

Source: Utility Data Institute Power Statistics Database.

EXHIBIT 2-11

PROCESS FOR GENERATING ELECTRICITY AT COAL-FIRED POWER PLANTS



Source: ICF Incorporated

since it is in the boiler where the combustion wastes are produced as the coal is burned.

There are three main types of boilers: (1) pulverizers, (2) cyclones, and (3) stokers. As discussed below in greater detail, the key differences between these boiler types are operating size and the procedures used for handling and burning the coal. Pulverized coal boilers are so-named because the coal is finely pulverized prior to combustion; most utility boilers are this type. Cyclones have been used in past utility applications, but have not been built recently. They are called cyclones because of the cyclone-like vortex created by the coal particles in the furnace during combustion. Stoker boilers are usually used when smaller capacities are required (e.g., 20-30 MW) and burn coal in a variety of sizes.

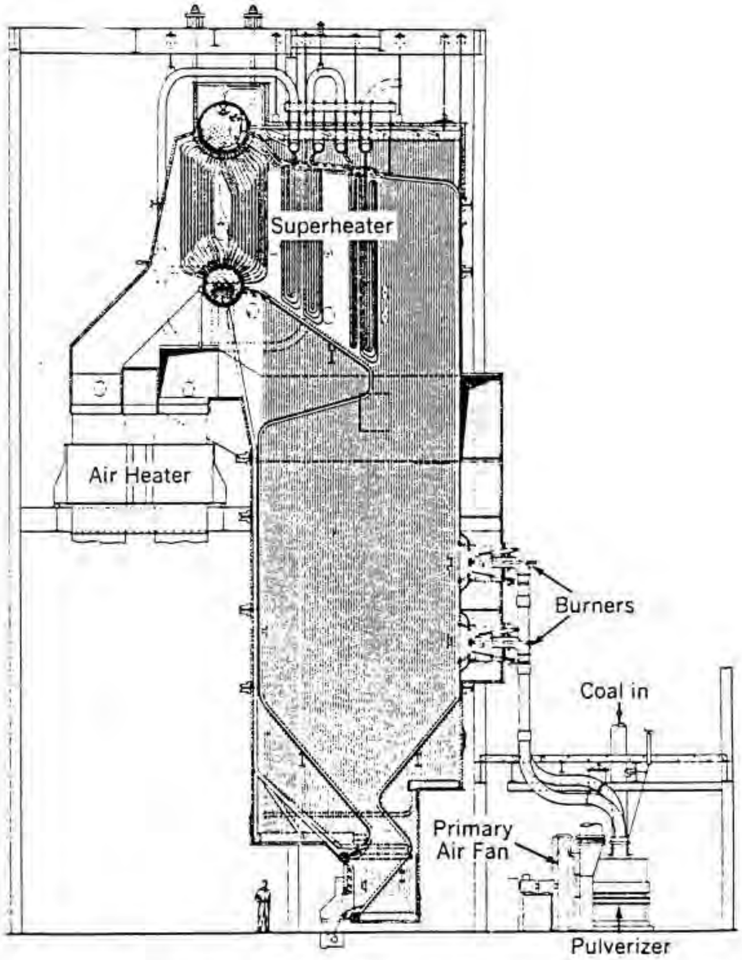
A brief description of each of these coal combustion technologies follows.[23]

2.3.2.1 Pulverized-Coal Boiler

Exhibit 2-12 shows a typical pulverized-coal boiler setup. In a pulverized coal boiler, coal is ground to a fine size (about 200 mesh, which is powder-like) in a pulverizer or mill. The pulverized fuel is then carried to the burners by forced air injection and blown into the furnace, where it is burned in suspension. Much of the ash remaining after combustion remains airborne and is carried from the furnace by the flue gas stream (i.e., it becomes fly ash; see Chapter Three for a more detailed discussion of types of waste and how they are produced). Some ash is deposited on the furnace walls,

EXHIBIT 2-12

DIAGRAM OF A PULVERIZED COAL BOILER



Two-drum boiler direct-fired with pulverized coal.

Source: Babcock and Wilcox Co., Steam: Its Generation and Use, New York, NY 1978.

where it agglomerates and may sinter or fuse. Ash that falls to the bottom of the furnace is removed via an ash hopper. Ash deposits and slagging are more of a problem in pulverized coal boilers than in stoker boilers.

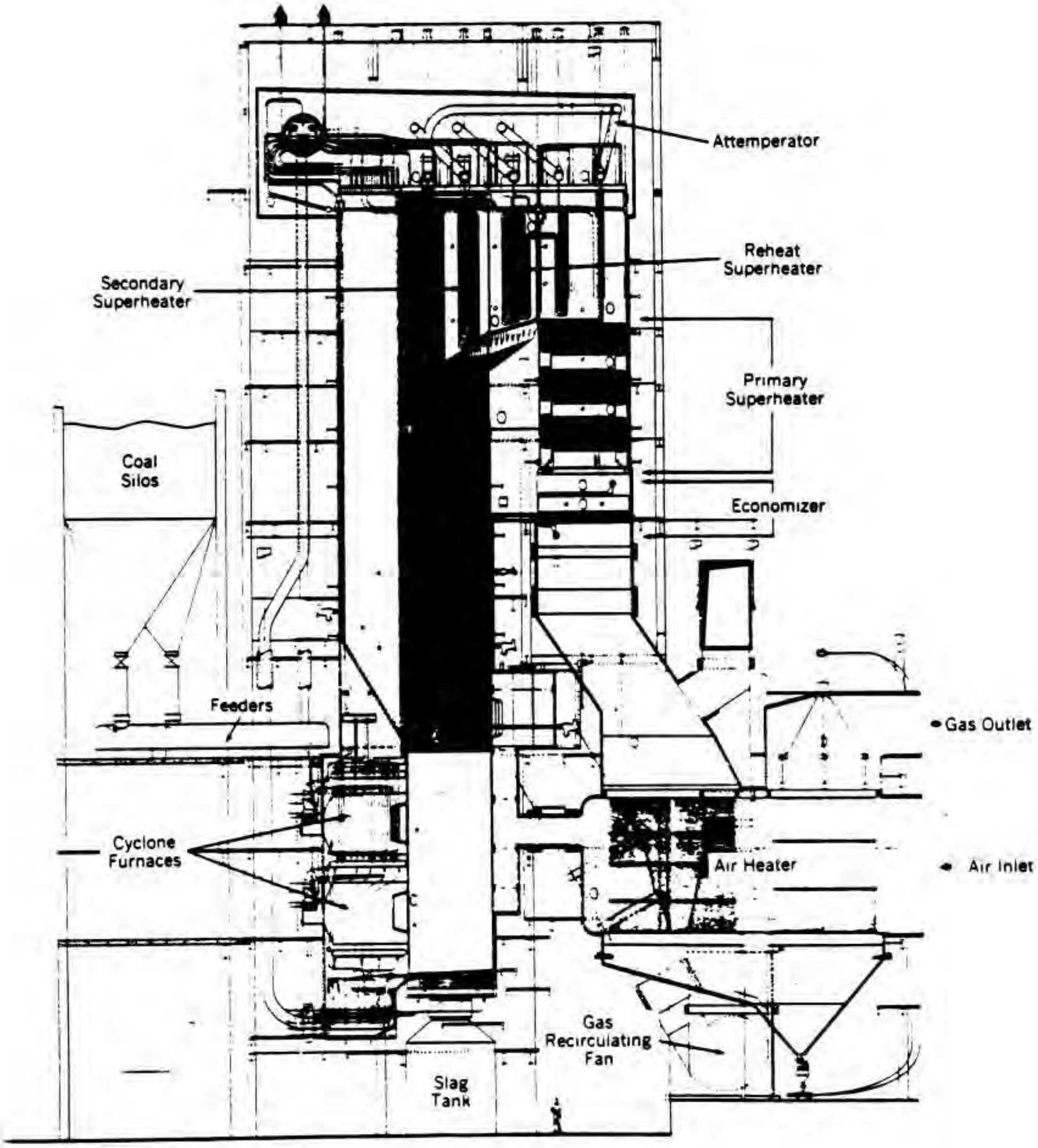
Most modern pulverized-coal boilers have dry-bottom furnaces; that is, the ash is intended to be removed as a dry solid before complete melting occurs. As a result, for dry-bottom boilers, the ash-fusion temperature (the melting point) of the coal must be high enough to prevent the ash from becoming a running slag (i.e., a liquid form). Wet-bottom, or slag-tap, pulverized-coal boilers are designed to remove the ash as a flowing slag. These boilers depend on lower ash-fusion temperature coals so that the ash will melt to form slag for easier removal.

2.3.2.2 Cyclones

The cyclone furnace consists of a water-cooled horizontal furnace in which crushed coal is fired and heat is released at high rates, as shown in Exhibit 2-13. The temperature inside the furnace may reach 3000°F, which is sufficient to melt the ash into a liquid slag that forms on the walls of the furnace. Air circulation within the furnace typically creates a cyclone-like vortex that not only helps the coal to burn in suspension but also causes many coal particles to impinge upon the slag-covered walls of the furnace. This tendency for coal particles to adhere to the walls of the cyclone boiler aids the combustion process because the coal particles will burn more thoroughly before reaching the bottom of the boiler. Most of the ash is retained in the slag layer, thus minimizing the amount of fly ash that is carried out of the boiler. The slag,

EXHIBIT 2-13

DIAGRAM OF A CYCLONE BOILER



Source: Babcock and Wilcox Co., Steam: Its Generation and Use, New York, NY, 1978.

or melted ash particles, is typically removed at the bottom of the furnace.

The cyclone offers the advantage of being able to burn low ash-fusion coals that create problems when burned in most conventional pulverized-coal burners. The cyclone design also helps to minimize erosion and fouling problems in the boiler. The smaller amounts of fly ash created compared to other boiler types reduces the costs associated with particulate collection.

2.3.2.3 Stokers

Stokers are designed to mechanically feed coal uniformly onto a grate within a furnace. Because most of the combustion takes place in the fuel bed, not in suspension within the furnace, the heat release rate of this type of boiler is lower than it is for pulverizers or cyclones. As a result, stokers are generally designed for smaller-sized applications. In fact, this boiler type is used by many manufacturing industries, but has seen only limited use by electric utilities.

Stokers are classified by the method of feeding fuel to the furnace and by the type of grate. The three most important stoker types include:

1) the spreader stoker, the most popular type of overfeed stoker,

2) other overfeed stokers, such as the chain-grate, travelling-grate stoker, or the vibrating-grate stoker, and

3) the underfeed stoker.

The major features of each are summarized in Exhibit 2-14. An illustration of a spreader stoker is provided in Exhibit 2-15.

Use of the different boiler types varies by geographic region. As shown in Exhibit 2-16, about three-fourths of all boiler capacity in the U.S. uses pulverizers, with most of these dry-bottom pulverizers. Cyclones are the next most prevalent boiler type, representing only about 8 percent of all boilers. Stokers represent less than one-half of one percent of the total; due to their size limitations stokers are used primarily in other industrial applications for the production of steam.

Exhibit 2-17 shows the distribution of average capacity for each boiler type by EPA region. The range in average sizes is most pronounced in dry bottom boilers (127.8-610.0 MW), which reflects their substantial flexibility in terms of size and dominance in electric utility applications. Stokers tend to have the smallest capacities (an average of 14 MW nationwide), limiting their usefulness in utility applications compared to all of the other boiler types.

2.4 COAL CONSTITUENTS AND BY-PRODUCTS

Despite its attractiveness as a power plant fuel, coal has its drawbacks. As a solid fuel, coal is often more difficult and more costly to transport, store, and burn than oil or gas. Also, coal's many impurities require environmental control at various stages of the fuel cycle.

EXHIBIT 2-14

CHARACTERISTICS OF VARIOUS TYPES OF STOKERS

Stoker Type & Subclass	Typical Maximum Capacity Range (pph steam) a/	Burning Rate (Btu/hr/ft^2) b/	Characteristics
1. Spreader			Capable of burning a wide range of coals, best ability to follow fluctuating loads, high fly ash carry over, low load smoke.
- Stationary and dumping grate	20,000-80,000	450,000	
- Travelling grate	100,000-400,000	750,000	
- Vibrating grate	20,000-100,000	400,000	
2. Overfeed			Characteristics similar to vibrating-grate stokers except these stokers experience difficulty in burning strongly caking coals
- Chain grate and travelling grate	20,000-100,000	600,000	
- Vibrating grate	30,000-150,000	400,000	Low maintenance, low fly ash carry over, capable of burning wide variety of weakly caking coals, smokeless operation over entire range.
3. Underfeed			Capable of burning caking coals and a wide range of coals (including anthracite), high maintenance, low fly ash carry over, suitable for continuous-load operation.
- Single or double retort	20,000-30,000	400,000	
- Multiple retort			

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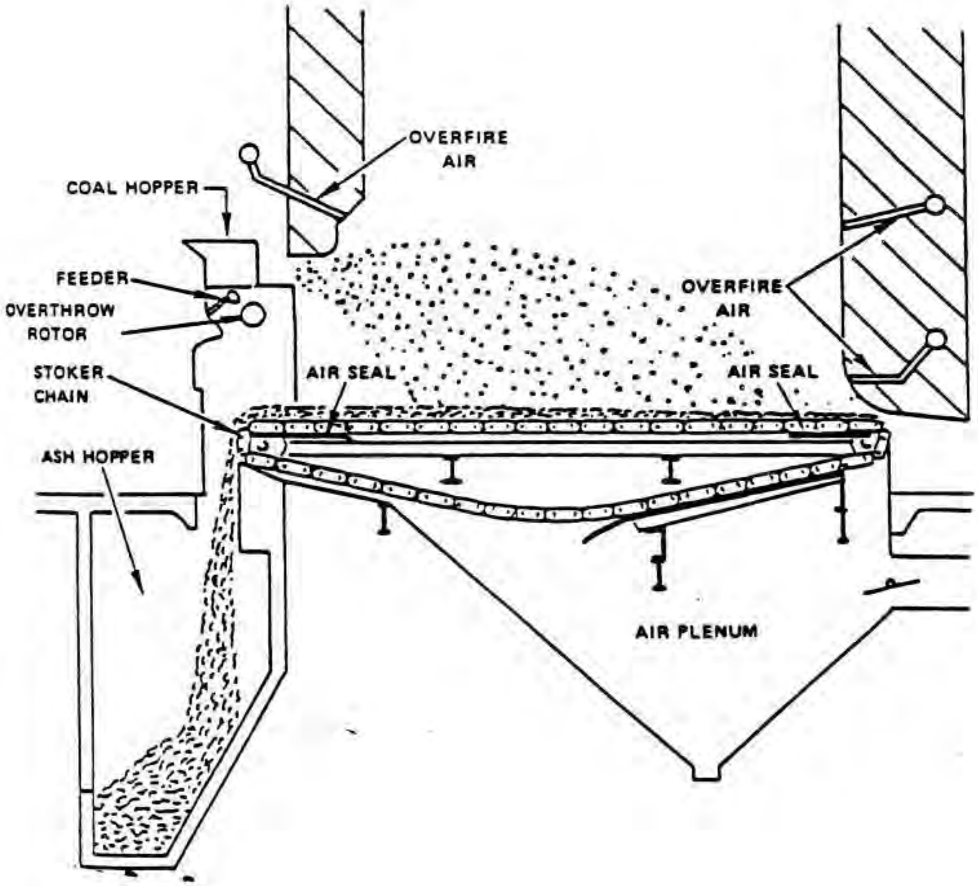
a/ pph = pounds steam/hr; 1 pph = 1000 Btu/hr.

b/ Maximum amount of Btus consumed per hour for each square foot of grate in the stoker.

Source: Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, NY, 1981.

EXHIBIT 2-15

DIAGRAM OF A SPREADER STOKER



Source: Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, NY, 1981.

EXHIBIT 2-16

TOTAL COAL BOILER CAPACITY BY EPA REGION (%)

	Pulverizers					
EPA Region	Dry Bottom	Wet Bottom	Cyclone	Stoker	Other a/	Total
1	69.2	11.3	16.7	0.0	2.8	100.0
2	60.6	19.4	5.0	2.7	12.2	100.0
3	87.6	0.3	2.8	0.0	9.2	100.0
4	71.6	5.3	5.2	0.1	17.7	100.0
5	70.4	4.9	14.0	0.5	10.1	100.0
6	48.6	12.5	0.0	0.0	38.9	100.0
7	58.3	3.5	19.2	1.0	18.0	100.0
8	60.3	5.4	10.6	1.1	22.5	100.0
9	77.5	0.0	0.0	0.0	22.5	100.0
10	100.0	0.0	0.0	0.0	0.0	100.0
U.S. Total	69.3	5.3	8.3	0.4	16.7	100.0

---

a/ Includes unknown, or other boiler types.

Source: ICF Coal and Utilities Information System Database.

EXHIBIT 2-17

AVERAGE COAL BOILER SIZE BY TYPE OF BOILER AND BY EPA REGION (MW)

	Pulverizers			
EPA Region	Dry Bottom	Wet Bottom	Cyclone	Stoker
1	210.2	102.7	228.0	N/A
2	127.8	137.7	143.5	39.0
3	297.6	136.0	195.3	N/A
4	249.3	147.4	342.6	14.6
5	185.0	117.0	222.6	11.2
6	522.7	489.0	N/A	N/A
7	162.5	148.3	243.2	12.3
8	234.2	141.7	322.8	17.9
9	388.3	N/A	N/A	N/A
10	610.0	N/A	N/A	N/A
U.S. Total	231.8	162.9	243.2	14.0

N/A = Not applicable.

Source: ICF Coal and Utilities Information System Database.

These impurities are typically referred to as "ash", whether the reference is to some of the constituents that compose the coal itself prior to combustion or the waste products that result from its combustion. Some coal ash is inherent to the coal seam, while other ash comes from non-coal strata near the coal seam which are intermixed during mining. The coal consumed by electric utilities is generally over 10 percent ash.[24] At current rates of coal consumption, about 70 million tons of ash pass through coal-fired power plants each year.[25]

The ash generated at utility power plants is produced inside the boiler furnace from the inorganic components as the organic components of the coal combust. The types of ash produced can vary -- some ash is swept through the furnace with the hot flue gases to form fly ash, while some settles to the bottom of the boiler as bottom ash or slag. The amount of each type of ash produced depends upon the boiler configuration as described in Section 2.3 and the characteristics of the coal (see Chapter Three for further discussion of ash types).

Air quality regulations have long restricted the amount of fly ash that may be released through a power plant's stacks. Primarily through the use of electrostatic precipitators or bag houses, power plants collect fly ash particles, leaving the flue gases nearly particulate-free as they are emitted from the stack. As a result, the fly ash, bottom ash, and slag that is collected during and after combustion is approximately equal to the amount of ash in the coal prior to combustion.

For many power plants constructed since the 1970's, additional environmental controls also require that a portion of the sulfur oxides be removed from the flue gases. The dominant technology for removing sulfur oxides is known as flue gas desulfurization (FGD), in which alkaline agents, usually in liquid slurry form, are mixed with the flue gases to convert the sulfur into non-gaseous compounds. The resulting waste product is generally referred to as FGD sludge and can amount to 25 percent or more of the volume of coal consumed at a given plant.[26] In total, U.S. coal-fired power plants produce about 85 million tons of ash and FGD sludge per year. By the end of the century, this volume is expected to approximately double.

Exhibit 2-18 shows the number of coal-fired utility power plants and units that produce FGD wastes in each EPA region as of 1985. Regions 6, 8, and 9 have the highest proportion of both plants and units producing FGD wastes. For example, more than half of the coal-fired units in region 9 produce FGD wastes. The high proportion of FGD-producing plants in these regions is in part attributable to the fact that many of the coal-fired plants in these regions are relatively new and were required to incorporate scrubbers to meet air emission regulations.

Plants and units producing FGD waste represent a smaller percentage in other regions, primarily because these regions relied on coal-fired capacity for a major portion of their generation before units with FGD technology were installed. For example, the absolute number of both plants and units producing FGD waste is greatest in Region 4, reflecting this area's reliance on coal for generating electricity.

EXHIBIT 2-18

ELECTRIC UTILITY PRODUCTION OF FGD WASTES: 1985

EPA Region	# of Plants Producing FGD waste	Percent of Plants Producing FGD Wastes	# of Units Producing FGD Wastes	Percent of Units Producing FGD Wastes
1	0	0.0	0	0.0
2	3	17.6	3	7.9
3	5	8.8	13	9.4
4	11	12.0	26	9.8
5	10	5.8	16	3.6
6	8	20.5	23	35.9
7	6	9.1	11	7.9
8	9	18.8	25	29.4
9	3	23.1	12	57.1
10	0	0.0	0	0.0
Total U.S.	55	12.0	129	14.4

Source: Utility Data Institute Power Statistics Database.

Regions 1 and 10, at the other extreme, have no plants or units producing FGD wastes. These regions (New England and the Pacific Northwest) are not highly dependent upon coal and consequently, have relatively few coal-fired plants.

Numerous other types of wastes are produced during normal operation and maintenance at coal-fired power plants. These include, among others, boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerants and rinses, metal and boiler cleaning wastes, pyrites, and sump effluents. These wastes are usually small in volume relative to ash and FGD sludge, but because they may have higher concentrations of certain constituents that may cause environmental concern, they also require care in handling and disposal. All of these wastes are discussed in greater detail in Chapter Three.

CHAPTER TWO

NOTES

[1] Edison Electric Institute, 1985 Statistical Yearbook.

[2] Energy Information Administration, Annual Energy Outlook 1985, DOE/EIA-0383(85), p. 50.

[3] A gigwatt-hour (Gwh) is one million kilowatt-hours; a kilowatt-hour is the amount of electricity generated by 1 kilowatt of electric generating capacity operating for one hour.

[4] Energy Information Administration, Annual Outlook for U.S. Electric Power, DOE/EIA-0474(86), 1986.

[5] Ibid.

[6] Ibid.

[7] Ibid.

[8] Ibid.

[9] Ibid.

[10] Ibid.

[11] Ibid.

[12] Ibid.

[13] Ibid.

[14] Ibid.

[15] Ibid.

[16] The major portion of this discussion is taken from Annual Outlook for U.S. Electric Power, DOE/EIA, 1986. See this document for further information.

[17] Ibid., page 5.

[18] Ibid.

[19] Ibid.

[20] Ibid.

[21] Energy Information Administration, Electric Power Annual 1984, DOE/EIA-0348(84), p. 24.

[22] Energy Information Administration, Electric Power Monthly, DOE/EIA-0226(85/12), December 1985, p. 21.

[23] For more detail, see Meyers, Robert A. (Ed.), Coal Handbook, Marcel Dekker, Inc., New York, New York, 1981, pp. 378-431.

[24] Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1984, DOE/EIA-0191(84), July 1985, p. 6.

[25] American Coal Ash Association.

[26] For example, a coal with 2 percent sulfur would produce approximately 80 pounds sulfur dioxide per ton of coal consumed. A limestone scrubber capturing 90 percent of the sulfur dioxide, assuming a stoichiometric ratio of 1.4 and a sludge moisture content of 50 percent, would product almost 500 pounds of FGD sludge per ton of coal consumed. See Appendix B for a detailed discussion of the methodologies used to determine this calculation.

CHAPTER THREE

WASTES GENERATED FROM COAL-FIRED ELECTRIC UTILITY POWER PLANTS

As part of EPA's responsibility under Section 8002(n) of RCRA, Congress directed that the study of wastes from the combustion of fossil fuels should include an analysis of "the source and volumes of such material generated per year." In response to this directive, this chapter examines the physical and chemical characteristics of the types and quantities of wastes that are generated currently and likely to be generated in the future.

3.1 OVERVIEW OF ELECTRIC UTILITY WASTES

As discussed initially in Chapter Two, the noncombustible material that remains after coal is burned is called ash. The proportion of noncombustible material in coal is referred to as the ash content. There are four basic types of wastes that can be produced directly from coal combustion: fly ash, bottom ash, boiler slag, and flue gas desulfurization (FGD) sludge. The smaller ash particles entrained by the flue (exhaust) gas are referred to as fly ash and are produced in varying degrees by all plants. Larger ash particles that settle on the bottom of the boiler will form either bottom ash (if the particles have never completely melted) or boiler slag (if the ash particles have melted), depending on the furnace design. Another waste product, called FGD sludge, is generated when some of the sulfur dioxide (formed when the sulfur present in the coal combines with oxygen during combustion) is removed from other flue gases. This removal process is required by the Clean Air Act Amendments of 1979, which revised the New Source

Performance Standards for any electric utility boiler constructed after September 1978. These plants are required to remove 90 percent of the sulfur dioxide, which is usually accomplished with a flue gas desulfurization (FGD, or scrubber) system. Because they are generated in very large quantities, these four waste materials -- fly ash, bottom ash, boiler slag, and FGD sludge -- are referred to by the industry as high-volume wastes. This term will be used throughout this study to be consistent with the terminology that is commonly used for these wastes.

Electric utility power plants also generate waste streams that the industry typically calls low-volume wastes, which are formed during equipment maintenance and water purification processes. Types of low-volume wastes generated by coal-fired power plants include boiler blowdown, coal pile runoff, cooling tower blowdown, demineralizer regenerants and rinses, metal and boiler cleaning wastes, pyrites, and sump effluents. Because it is common industry terminology, the term "low-volume wastes" will be used throughout this report; however, some of these wastes (such as cooling tower blowdown) can be generated in substantial quantities, although generally in smaller quantities than high-volume wastes.

The remainder of this chapter describes each type of high-volume and low-volume waste stream, the various methods of collection used for each, the volumes produced, and the physical and chemical characteristics that determine the waste's behavior during disposal and its potential to leach.

3.2 HIGH-VOLUME WASTES

High-volume coal combustion utility wastes are those waste streams generated in the boiler furnace -- fly ash, bottom ash, and boiler slag -- and in the cleaning of coal combustion flue gas. The following sections describe the volumes and the physical and chemical characteristics of these high-volume waste streams.

3.2.1 Ash

The noncombustible waste material that remains after coal is burned is referred to as ash. Some noncombustible materials are characteristic of the coal itself, originating from the chemical elements in the plants from which the coal was formed. These materials generally account for no more than two percent of the ash content of the coal. Other noncombustible materials extraneous to the coal, such as minerals lodged in the coal seam during or after its geologic formation and rocks near the coal seam that are carried away with the coal during mining, are burned during the fuel combustion process along with the coal itself. These materials account for most of the ash content.

3.2.1.1 How Ash is Generated

The type of ash produced from a boiler is determined by the type of coal that is burned and the design of the boiler furnace. As discussed in Chapter Two, the major types of boilers used by electric utilities are wet-bottom pulverizers, dry-bottom pulverizers, cyclone-fired boilers, and stokers.

Pulverizers are the most widely used boilers in the electric utility industry because they can burn many different types of coal. Due to the very fine consistency of the coal after it is pulverized, the ash particles are easily carried out of the boiler along with the flue gases, resulting in a relatively large proportion of fly ash.

The amount of fly ash that accumulates in a pulverizer depends on whether it is dry-bottom or wet-bottom.[1] In dry-bottom pulverizers, which constitute the majority of electric utility boilers, ash particles in the coal generally do not melt during the combustion process because the ash fusion temperature (i.e., the melting point) is higher than the operating temperature in the boiler. In dry-bottom pulverizers, therefore, about 80 percent of the fine ash remains in the flue gas as fly ash. The remaining ash settles to the bottom of the boiler (hence the term bottom ash) where it is collected at a later time. In wet-bottom pulverizers, about 50 percent of the ash exits the boiler as fly ash, while the other 50 percent remains in the furnace. However, ash particles that remain in wet-bottom pulverizers become molten; this boiler slag remains in a molten state until it is drained from the boiler bottom.

Cyclone-fired boilers burn larger-sized coal particles than do pulverizers, since partial crushing is the only preparation required prior to injection into the furnace. The amount of fly ash that is generated in a cyclone boiler is less than that generated in a pulverizer because of the larger-sized coal particles and the design of the cyclone boiler. Because the air circulation within the boiler furnace is designed to create a cyclone-like vortex, the coal particles have a tendency to contact the boiler walls. The operating temperature is high enough to melt the ash so that it adheres to the furnace walls as liquid slag. Excess slag continually drains to the bottom of the furnace, where it is removed for disposal. Only 20 to 30 percent of the ash formed in a cyclone boiler leaves the boiler as fly ash.

A few older and smaller power plants have stoker-type boilers, in which coal is burned on or immediately over a grate in the furnace. Stokers are designed to burn coals that do not contain too many small particles (fines), which can tend to smother the fire. Because there are fewer small particles, the amount of fly ash is reduced. For example, in a spreader stoker, the most common type of stoker boiler, the coal is uniformly fed over the fire in a manner that enables suspension burning of the finer pieces, while heavier pieces of coal fall onto the grate for further combustion. The large amount of coal that is burned on the grate reduces the amount of fly ash; the ash produced in a spreader stoker is generally about 50 percent fly ash and 50 percent bottom ash.

3.2.1.2 Methods of Ash Collection

As the flue gas leaves the boiler, it is passed through a mechanical ash collector to remove some of the fly ash particles. A mechanical ash collector operates by exerting centrifugal force on the fly ash particles, throwing them to the outside wall of the collector where they can be removed. These collectors are effective mainly for capturing the larger fly ash particles. To remove the smaller particles, the flue gas must then pass through some other type of particulate control device, such as an electrostatic precipitator, a baghouse, or a wet scrubber.

The electrostatic precipitator (ESP) is the most common device for fine ash collection. ESPs operate by applying an electrical charge to the fly ash particles. In the presence of an intense electrical field, the charged particles are attracted to a grounded collection electrode. The collected dust is then discharged to a storage hopper by a process called rapping that dislodges the collected particles. ESPs are most efficient when coal with high sulfur content is used because the sulfur dioxide in the flue gas helps retain the electrical charge. When properly designed and maintained, an ESP is capable of collecting over 99 percent of the ash present in the flue gas.[2]

When coal with lower sulfur content is burned, baghouses (also called fabric filters) are often more appropriate to use as fly ash collection devices. If operated efficiently, they also can remove over 99 percent of the ash from the flue gas.[3] In this system, the flue gas passes through a filter that traps the ash particles. The ash builds up on the filter, forming a filter cake. As this process continues, the ash collection efficiency tends to increase as it becomes more difficult for particles to pass through the filter material. Periodically, the cake is dislodged from the filters, which reduces efficiency until buildup occurs again.

Some power plants remove fly ash by the wet scrubbing method, in which liquids are used to collect the ash. In one method, the ash particles are removed from the flue gas stream by contacting them with a scrubbing liquid in a spray tower. This process forms an ash slurry, which is then discharged.

Alternatively, fly ash particles may be dislodged from the walls of the scrubber by a liquid flushing of the scrubber. Because the operation of a scrubber is very plant-specific, the collection efficiency of wet scrubbers varies, though wet scrubbers are generally not as efficient as ESPs and baghouses. The advantage of wet scrubbers, however, is that they can also be used simultaneously to collect sulfur oxides from the flue gas system.

Ash particles that do not escape as fly ash become bottom ash or boiler slag. In dry-bottom pulverizers and stokers, the temperatures are low enough to allow the molten ash to cool and reform into dry, solid ash particles, or bottom ash. In smaller boilers of this type, the ash falls onto a grate, which then is opened, allowing the ash to drop into a flat-bottom hopper. The large quantities of bottom ash produced in larger boilers often require hoppers with sloped sides for self-feeding. Some hoppers may contain water to quench the ash and to facilitate disposal.

In cyclone-fired boilers and wet-bottom pulverizers, the liquified ash particles that fall to the bottom of the boiler during combustion remain in a molten state and coalesce into large masses (called slag), which then drop onto the boiler floor. The slag is tapped into a water-filled hopper, or slag tank, which is periodically emptied and the slag disposed. Slag tanks for cyclone-fired boilers are similar to those used for pulverizers but have a higher relative capacity because a greater percentage of the ash in cyclones becomes boiler slag.

3.2.1.3 Quantities of Ash Generated

Nearly all of the noncombustible material in coal ends up as fly ash, bottom ash, or boiler slag. As mentioned earlier, the coal industry and the electric utility industry refer to this material as a coal's ash content. As a result, the volume of ash generated is directly related to the amount of coal consumed and the ash content of the coal. The ash content of coal will vary according to several factors, including coal-producing region, coal rank (i.e., bituminous, subbituminous, anthracite, or lignite), mine, seam, and production method. Although the proportion of ash in coal may range from 3 to 30 percent, the industry-wide average for electric utility power plants is 10.1 percent.[4] Exhibit 3-1 shows the average ash content of coal that was delivered to coal-fired power plants in 1985 for some of the major coal-producing regions.

In 1984, electric utilities generated about 69 million tons of coal ash. Ash generation is expected to increase considerably, to about 120 million tons in the year 2000, an increase of about 72 percent over 1984 levels. This increase can primarily be attributed to the increase in the demand for coal by electric utilities. While there is some uncertainty over the amount of coal that will be consumed by electric utility power plants, coal-fired electricity generation is likely to increase significantly. For example, one estimate indicates that by the year 2000 electric utility power plants will burn over one billion tons of coal to meet 61 percent of total electricity demand,[5] an increase of 70 percent over the 664 million tons consumed in 1984.[6] Exhibit 3-2 shows historical and forecasted future ash generation by coal-fired electric power plants.

EXHIBIT 3-1

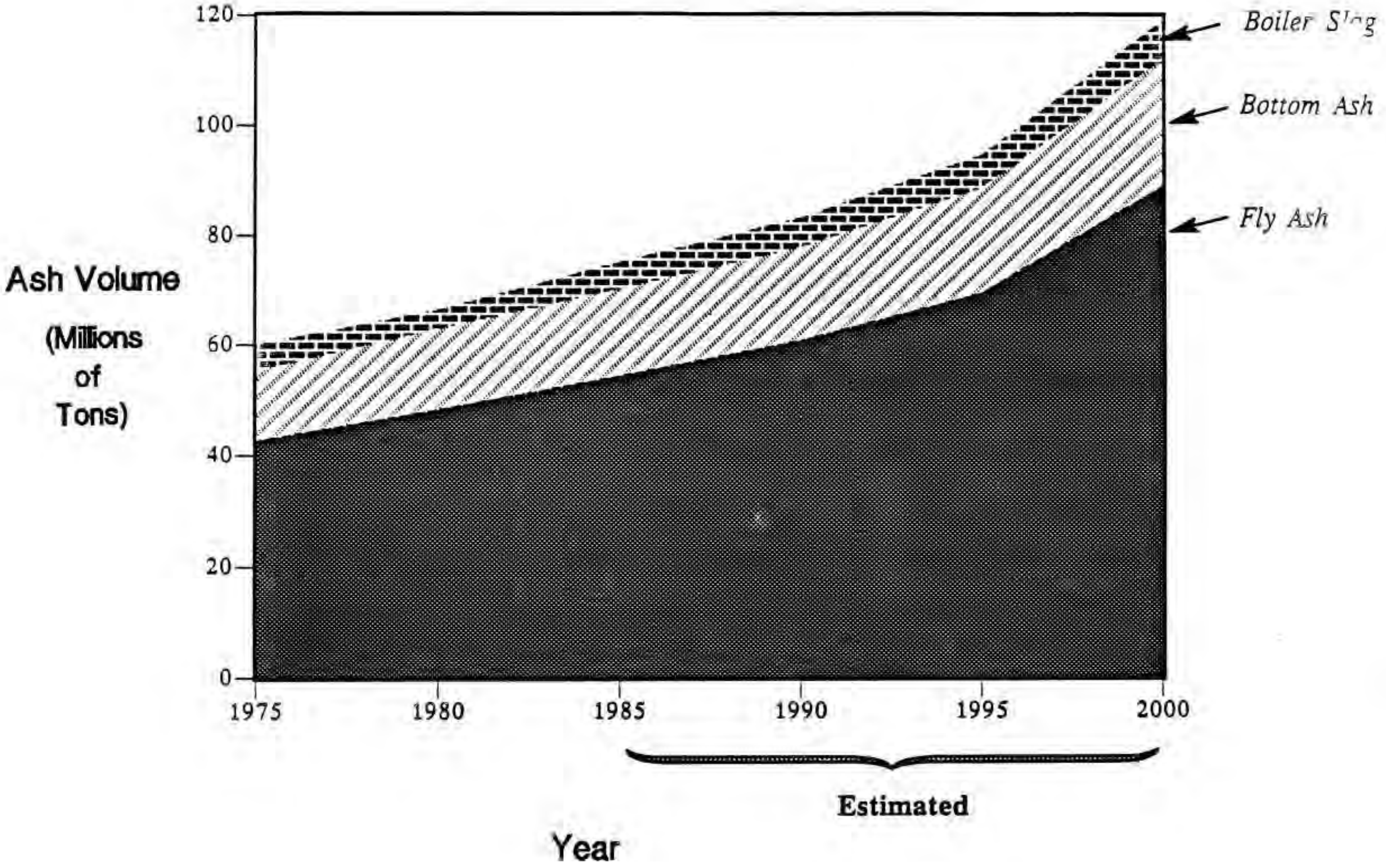
REPRESENTATIVE ASH CONTENTS BY PRODUCING REGION AND COAL RANK: 1985

Coal Rank and Region	Percent Ash
Anthracite	
Northeastern Pennsylvania	29.4
Bituminous	
Western Pennsylvania	10.9
Northern West Virginia	10.4
Ohio	11.3
Eastern Kentucky	9.9
Alabama	12.2
Illinois	9.7
Colorado	6.2
Utah	9.4
Arizona	8.9
Subbituminous	
Wyoming	5.9
New Mexico	18.8
Lignite	
Texas	15.8
North Dakota	9.0
U.S. Average	10.1

Source: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants 1985, DOE/EIA-0191(85), July 1986.

EXHIBIT 3-2

VOLUME OF ASH GENERATED BY COAL-FIRED ELECTRIC UTILITY POWER PLANTS 1975 - 2000



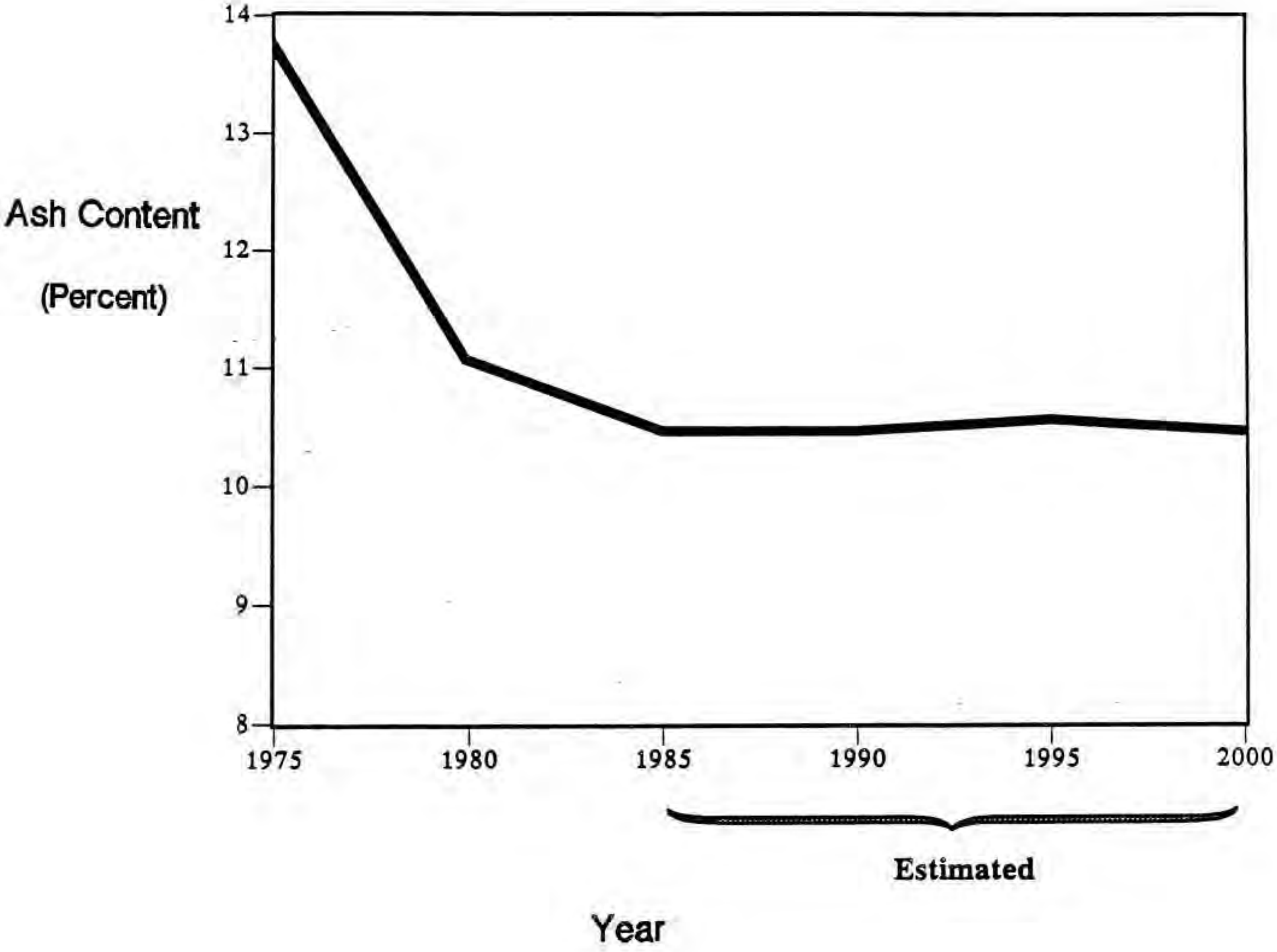
Sources: 1975-1984: American Coal Ash Association.
1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

The average ash content of coal burned by electric utilities has declined from about 14 percent to slightly more than 10 percent over the past decade (see Exhibit 3-3). To meet particulate emission standards and to lower certain operating and maintenance costs, more electric utilities are now choosing to burn coal with lower ash contents. Although some coals are naturally low in ash, producers and/or utilities can also reduce ash content by cleaning the coal.[7] In some cases, cleaning can reduce ash content by as much as 50 to 70 percent. At present, utilities clean about 35 percent of all the coal they consume; most of the coal that is cleaned comes from eastern and midwestern underground bituminous coal-mining operations. Another reason for the increased use of coal with lower average ash content is the growth in Western coal production, particularly in the Powder River Basin area of Montana and Wyoming. These coals are naturally low in ash content, and little ash is extracted during the mining process.

The quantity of fly ash and bottom ash produced is likely to increase faster over time than the quantity of boiler slag because most new coal-fired plants will employ dry-bottom pulverizer boilers, which generate fly ash and bottom ash rather than boiler slag. Because dry-bottom pulverizers are capable of burning coal with a wide range of ash fusion temperatures,[8] they are able to burn a greater variety of coals compared with cyclone boilers and wet-bottom pulverizers. Another advantage of dry-bottom pulverizers is that they produce less nitrogen oxide emissions than do other boiler types, which enables electric utilities to meet requirements for nitrogen oxide emissions control more easily.

EXHIBIT 3-3

AVERAGE ASH CONTENT OF COAL BURNED BY ELECTRIC UTILITY POWER PLANTS IN THE U.S. 1975 - 2000



Source: 1975-1984: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants.

1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

3.2.1.4 Physical Characteristics of Ash

The physical characteristics of coal combustion ash of interest are particle size and distribution, compaction behavior, permeability, and shear strength. Exhibit 3-4 provides representative ranges of values for these characteristics of fly ash, bottom ash, and boiler slag.

The greater the assortment of particle sizes in the material, the more it can be compacted to achieve greater density and shear strength and lower permeability. Generally, fly ash is similar in size to silt. Most fly ash particles are between 5 and 100 microns in diameter; within a single sample, the largest particles may be 200 times larger than the smallest particles.[9] The size of bottom ash and boiler slag particles can range from that of fine sand to fine gravel, or about 0.1 to 10 millimeters.[10]

Compaction behavior refers to the amount of settling that takes place after disposal and the rate at which such settling occurs. Compressibility, density, and moisture content are factors affecting compaction behavior.[11] When compacted and dry, most fly ash and bottom ash behave very similarly to cohesive soil.

Permeability reflects the rate at which water will seep through the waste material in a given period of time and provides a good first estimate of the rate and quantity of leachate migration. A number of factors can influence the degree of permeability, such as the size and shape of the waste particles, the degree of compaction, and the viscosity of the water. Properly compacted fly ash often has low permeability, similar to that of clay, while the

EXHIBIT 3-4

REPRESENTATIVE RANGES OF VALUES FOR THE PHYSICAL CHARACTERISTICS OF FLY ASH, BOTTOM ASH, AND BOILER SLAG

	Fly Ash	Bottom Ash/ Boiler Slag
Particle Size (mm)	0.001-0.1	0.1-10
Compaction Behavior:		
Compressibility (%)	1.8	1.4
Dry Density (lbs/ft^3)	80-90	80-90
Permeability (cm/sec)	10^{-6}-10^{-4}	10^{-3}-10^{-1}
Shear Strength		
Cohesion (psi)	0-170	0
Angle of Internal Friction (°)	25-45	25-45

Sources: For compressibility values, Arthur D. Little, Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, Volume I, Prepared for U.S. Environmental Protection Agency, June 1985, p. 3-29. For other values, Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, p. 3-3 - 3-8.

permeability of bottom ash is usually slightly higher. Boiler slag is higher still, having a permeability comparable to that of fine gravel.

Shear strength is an important determinant of the shape and structural stability of wastes disposed in landfills; a strong material (i.e., one with high shear strength) can form steep slopes and support heavy loads from above. Two indicators of shear strength are cohesion, a measure of the attraction between particles due to electrostatic forces, and the angle of internal friction, an indicator of the friction between particles. Dry, nonalkaline ash has no cohesion. Dry ash that is alkaline demonstrates some cohesion and, when compacted, increases in strength over time. The angle of internal friction associated with ash varies with the degree of compaction, although it is similar to that for clean, graded sand.

3.2.1.5 Chemical Characteristics of Ash

The chemical composition of ash is a function of the type of coal that is burned, the extent to which the coal is prepared before it is burned, and the operating conditions of the boiler. These factors are very plant- and coal-specific.

In general, over 95 percent of ash is made up of silicon, aluminum, iron, and calcium in their oxide forms. Magnesium, potassium, sodium, and titanium are also present to a lesser degree. Exhibit 3-5 shows the concentration of these major elements typically found in fly ash, bottom ash, and boiler slag.

Ash also contains many other elements in much smaller quantities. The types and proportions of these trace elements are highly variable and not

EXHIBIT 3-5

LOW AND HIGH CONCENTRATIONS OF MAJOR CHEMICAL CONSTITUENTS FOUND IN ASH GENERATED BY COAL-FIRED POWER PLANTS (parts per million)

	Fly Ash		Bottom Ash/Boiler Slag	
	Low	High	Low	High
Aluminum	11,500	144,000	88,000	135,000
Calcium	5,400	177,100	8,400	50,600
Iron	7,800	289,000	27,000	203,000
Magnesium	4,900	60,800	4,500	32,500
Potassium	1,534	34,700	7,300	15,800
Silicon	196,000	271,000	180,000	273,000
Sodium	1,180	20,300	1,800	13,100
Titanium	400	15,900	3,300	7,210

Source: Utility Solid Waste Activities Group, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, Appendix A, Submitted to the U.S. Environmental Protection Agency, October 26, 1982, p. 31.

readily categorized. Concentrations for various trace elements in coal ash are shown in Exhibit 3-6, which indicates the potential range of values and median concentration for such trace elements for coals from different regions of the U.S. A summary of how the concentration of elements in ash varies according to coal source is shown in Exhibit 3-7. For example, Eastern and Midwestern coal ashes usually contain greater amounts of arsenic, selenium, chromium, and vanadium than do Western coal ashes, while Western coals have larger proportions of barium and strontium. Coal mining and cleaning techniques can reduce the amount of trace elements that are ultimately found in the ash after combustion. For example, in some cases, coal cleaning can remove more than half of the sulfur, arsenic, lead, manganese, mercury, and selenium that is contained in the coal prior to combustion.

The proportions of elements contained in fly ash, bottom ash, and boiler slag can vary. Exhibit 3-8 provides ranges and median values for element concentrations in different types of ash -- bottom ash and/or boiler slag, and fly ash. The concentrations of elements formed in fly ash are shown for two types -- the larger particles removed from the flue gas by mechanical collection and the smaller particles removed with an electrostatic precipitator or a baghouse (see Section 3.2.1.2 for more detail on methods of ash collection). For example, much higher quantities of arsenic, copper, and selenium are found in fly ash than are found in bottom ash or boiler slag. The distribution of elements among the different types of ash is largely determined by the firing temperature of the boiler relative to the coal's ash fusion temperature, which in turn affects the proportions of volatile elements that end up in fly ash and bottom ash. Some elements, such as sulfur, mercury, and chlorine, are almost completely volatilized and leave the boiler

EXHIBIT 3-6

ELEMENT CONCENTRATIONS IN ASH FROM THREE GEOGRAPHIC SOURCES
(milligrams per kilogram)*

	Eastern Coal		Midwestern Coal		Western Coal	
Element	Range	Median	Range	Median	Range	Median
Arsenic	2.0-279	75	0.50-179	54	1.3-129	18
Barium	52-2200	892	300-4300	905	300-5789	2700
Boron	10.0-580	121	10-1300	870	41.9-1040	311
Cadmium	0.10-8.24	1.59	0.50-18	2.6	0.10-14.3	1.01
Chromium	34-437	165	70-395	172	3.4-265	45
Cobalt	6.22-79	40.6	19-70	35.7	4.9-69	13.0
Copper	3.7-349	136	20-330	125	29-340	74.8
Fluorine	0.40-89	8.8	3.2-300	75	0.40-320	50.1
Lead	1.3-222	18.0	3.0-252	149	0.40-250	26.1
Manganese	79-430	190	194-700	410	56.7-769	194
Mercury	0.02-4.2	0.192	0.005-0.30	0.044	0.005-2.5	0.067
Molybdenum	0.84-51	15.0	7.0-70	43	1.4-100	12.0
Nickel	6.6-258	78	26-253	121	1.8-229	38.0
Selenium	0.36-19.0	8.05	0.08-19	7.0	0.13-19.0	4.1
Silver	0.25-8.0	0.695	0.10-1.20	0.39	0.040-6.0	0.26
Strontium	59-2901	801	30-2240	423	931-3855	2300
Thallium	7.0-28.0	25.0	2.0-42	16.0	0.10-3.50	1.06
Vanadium	110-551	269	100-570	270	11.9-340	94
Zinc	16-1420	163	20-2300	600	4.0-854	71

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* Values shown are for all types of ash combined.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983.

EXHIBIT 3-7

EFFECT OF GEOGRAPHIC COAL SOURCE ON ASH ELEMENT CONCENTRATION

Element	Concentration Pattern
Arsenic	low in western coal ash; eastern and midwestern coal ashes indistinguishable
Barium	highest in western coal ash
Cadmium	most concentrated in midwestern coal ash
Chromium	low in western coal ash; eastern and midwestern coal ashes indistinguishable
Mercury	highest in eastern coal ash; all distributions highly skewed toward high concentrations
Lead	highest in midwestern coal ash
Selenium	similar in eastern and midwestern coal ash; lower in western coal ash
Strontium	greater in eastern than in midwestern coal ash; greater still in western coal ash
Vanadium	similar in eastern and midwestern coal ash; lower in western coal ash
Zinc	greater in eastern than in western coal ash; greater still in midwestern coal ash

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Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983, p. 3-30.

EXHIBIT 3-8

ELEMENT CONCENTRATIONS IN THREE TYPES OF ASH

(milligrams per kilogram)

			Fly Ash			
	Bottom Ash/Boiler Slag		Mechanical Hopper Ash		Fine Fly Ash	
Element	Range	Median	Range	Median	Range	Median
Silver	0.1-.51	0.20	0.08-4.0	0.70	0.04-8.0	0.501
Arsenic	.50-168	4.45	3.3-160	25.2	2.3-279	56.7
Boron	41.9-513	161	205-714	258	10.0-1300	371
Barium	300-5789	1600	52-1152	872	110-5400	991
Cadmium	0.1-4.7	0.86	0.40-14.3	4.27	0.10-18.0	1.60
Cobalt	7.1-60.4	24	6.22-76.9	48.3	4.90-79.0	35.9
Chromium	3.4-350	120	83.3-305	172	3.6-437	136
Copper	3.7-250	68.1	42.0-326	130	33.0-349	116
Fluorine	2.5-104	50.0	2.50-83.3	41.8	0.40-320	29.0
Mercury	0.005-4.2	0.023	0.008-3.00	0.073	0.005-2.50	0.10
Manganese	56.7-769	297	123-430	191	24.5-750	250
Lead	0.4-90.6	7.1	5.2-101	13.0	3.10-252	66.5
Selenium	.08-14	0.601	0.13-11.8	5.52	0.60-19.0	9.97
Strontium	170-1800	800	396-2430	931	30.0-3855	775
Vanadium	12.0-377	141	100-377	251	11.9-570	248
Zinc	4.0-798	99.6	56.7-215	155	14.0-2300	210

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, September 1983, p. 3-24.

in the flue gas rather than remaining in the bottom ash or boiler slag. Some of these more volatile elements may condense on the surface of the fly ash particles as the flue gas cools.

3.2.2 FGD Sludge

Another waste stream often generated in large volumes by coal-fired utility power plants is FGD sludge, which is created when utilities remove sulfur oxides from the flue gases. Emissions of sulfur oxides in the flue gases are due to the oxidation of sulfur during coal combustion. State and Federal regulations require power plants to control the amount of sulfur oxides released through the stack. To meet the applicable requirements most power plants use coals whose inherent sulfur content is low. If the sulfur content is so low that additional sulfur dioxide removal is not needed, then FGD sludge is not produced.

Present requirements for all new coal-fired plants, however, not only limit the amount of sulfur oxides that can be emitted, but also mandate a percentage reduction in the amount of sulfur dioxide emissions.[12] This requirement will substantially increase the number of sulfur dioxide control systems in use. The primary method of sulfur dioxide control currently available is a flue gas desulfurization (FGD) system through which the flue gases pass before being emitted from the stack. The wastes produced by this system are called FGD (scrubber) sludge. Other methods of control include newer technologies such as fluidized bed combustion (FBC) and limestone injection multistage burners (LIMB).[13] The technical and economic feasibility of the latter two technologies are currently under evaluation by private industry and the U.S.

Department of Energy. If these technologies do become more widely available, they also will produce substantial volumes of wastes.

3.2.2.1 Methods of FGD Sludge Collection

There are two major types of FGD (scrubber) systems. Non-recovery systems produce a waste material for disposal. Recovery systems produce recyclable by-products. Exhibit 3-9 illustrates the different types of FGD systems currently in use. Non-recovery systems, which account for 95 percent of the scrubber systems now in use by electric utilities, are further classified as wet or dry systems. In wet non-recovery scrubber systems, the flue gas contacts an aqueous solution of absorbents, thereby producing waste in a slurry form. The wastes generated by dry non-recovery systems contain no liquids.

Direct lime and limestone FGD systems are the most common wet non-recovery processes. With these systems, flue gases pass through a fly ash collection device and into a contact chamber where they react with a solution of lime or crushed limestone in the form of a slurry. The slurry circulates between the contact chamber and a separate reaction tank, where the reagents are added. From the reaction tank, the slurry is fed to a thickening and dewatering device to be prepared for disposal. After dewatering, the resulting liquid is recycled back to the reaction tank and the sludge solids are removed for disposal. Under certain conditions, direct lime and limestone scrubbers have been able to remove over 95 percent of the sulfur dioxide in the flue gas.[14]

EXHIBIT 3-9

MAJOR TYPES OF FLUE GAS DESULFURIZATION SYSTEMS

Non-Recovery		Recovery	
Wet	Dry	Wet	Dry
Direct Lime	Spray Drying	Wellman-Lord	Alumina/Copper* Sorbent
Direct Limestone	Dry Sorbent Injection*	Magnesium Oxide	Activated Carbon* Sorbent
Alkaline Fly Ash			
Dual-Alkali			

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*Systems are currently in development and testing phases, and are not as yet being used commercially.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, pp. 4-1 - 4-4.

A variation on the direct lime and limestone systems is the alkaline fly ash scrubber. Several western power plants that burn coal containing high-alkaline ash use these systems, which can improve sulfur dioxide removal. Rather than being collected by a separate upstream device (such as an ESP or baghouse), fly ash particles remain in the gas stream as it passes through the scrubber. In the scrubber, the alkaline fly ash, augmented with an alkaline lime/limestone slurry, acts to remove sulfur oxides. Alkaline fly ash scrubbers are not as efficient as direct lime and limestone systems, removing on average only about 40 percent of the sulfur dioxide.[15]

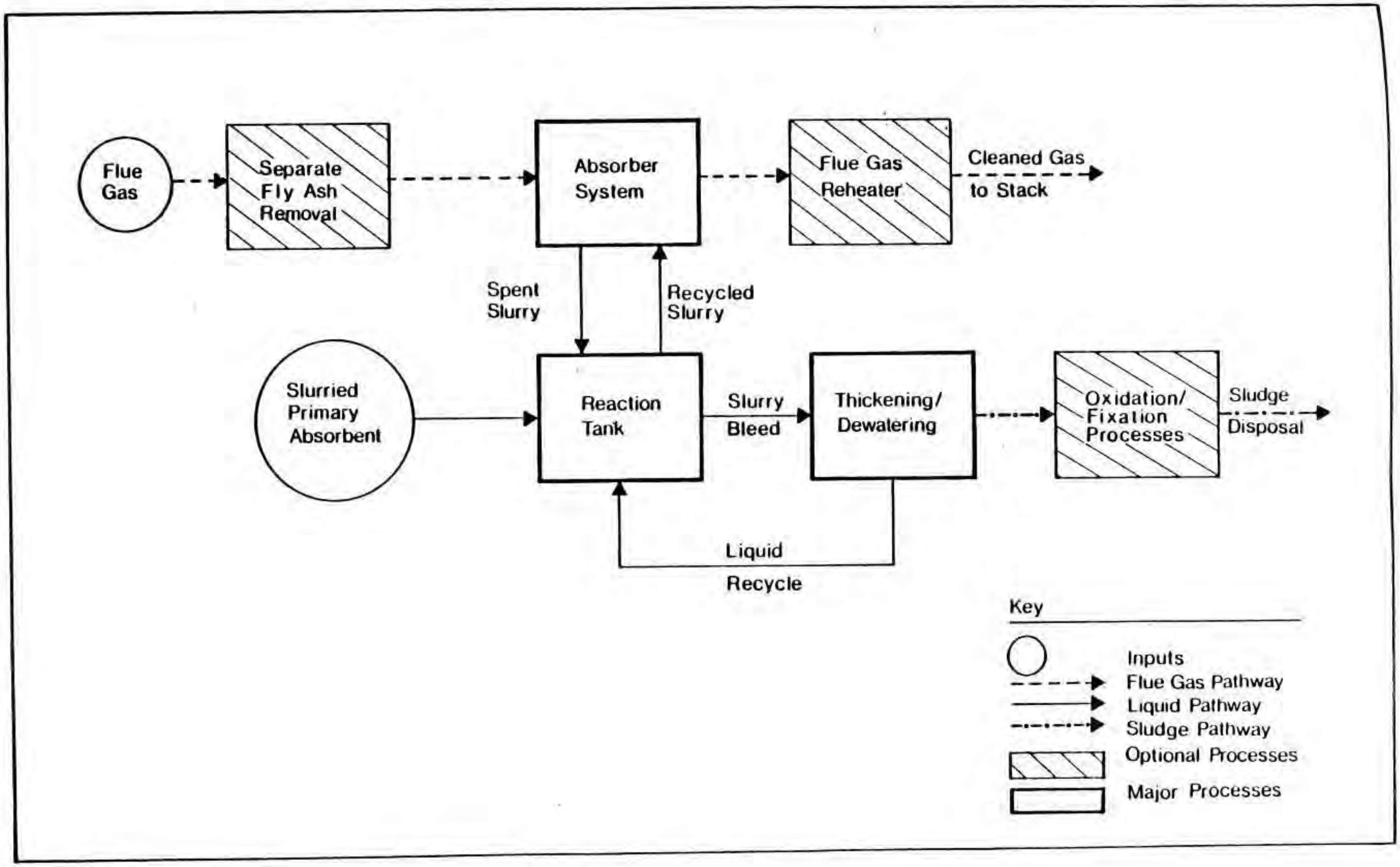
Another wet non-recovery system is the dual-alkali process. These scrubbers operate in much the same manner as the direct lime and limestone scrubbers. However, dual-alkali systems use a solution of sodium salts as the primary reagent to which lime is added for additional absorption. The soluble sodium salts are then recycled to the scrubber system and the insoluble portion of the slurry is left to settle so that it can be collected and disposed. Like direct lime and limestone systems, dual-alkali scrubbers remove up to 95 percent of the sulfur dioxide.[16]

Exhibit 3-10 presents a diagram of the operations of a wet FGD system. The flows shown for the flue gas, absorbent, slurry, and sludge are essentially the same for direct lime, direct limestone, alkaline fly ash, and dual-alkali systems.

At present, the two most popular methods of dry scrubbing under investigation are spray-drying and dry sorbent injection, although only the spray-drying process is now in commercial use at electric utility power plants.

EXHIBIT 3-10

FLOW DIAGRAM OF WET FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-3.

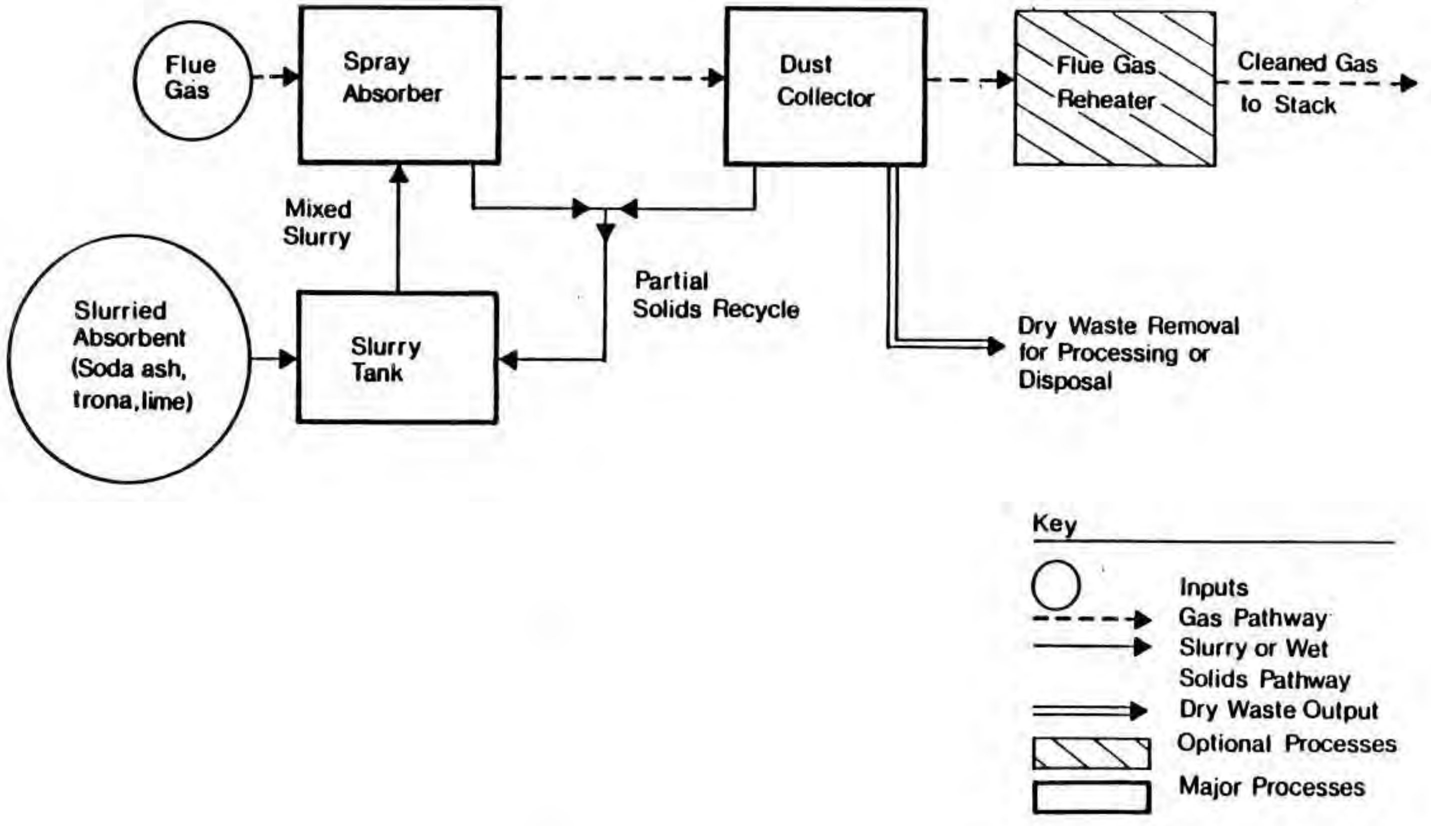
A flow diagram of a spray-drying system is presented in Exhibit 3-11. With this system, a fine spray of an alkaline solution is injected into the flue gas as it passes through a contact chamber, where the reaction with the sulfur oxides occurs. The heat of the flue gas evaporates the water from the absorbent solution, leaving a dry powder. This powder is then collected downstream of the contact chamber by a particulate collector, usually a baghouse. Spray-drying typically removes about 70 percent of the sulfur dioxide from the flue gas.[17] Because of the relatively low percentage reduction in sulfur dioxide achieved by spray-drying scrubbers compared with other scrubber technologies, this dry-scrubbing method is most commonly used for furnaces that burn lower sulfur coals.

Dry sorbent injection, illustrated schematically in Exhibit 3-12, is not yet used commercially by electric utilities, although one utility is designing a generating unit that will use this type of scrubber and which is due to begin operation by 1990.[18] This system involves the injection of a powdered sorbent, either nacholite or trona, into the flue gas upstream of a baghouse. Sulfur dioxide reacts with the reagent in the flue gas and on the surface of the filter in the baghouse. The dry wastes, which form a filter cake, are then removed during normal filter cleaning.

Dry injection offers several advantages over traditional wet scrubbing and spray-drying techniques: the required equipment is smaller and less expensive, no water is needed, flue gas reheating is not necessary, and sulfur dioxide and fly ash are removed simultaneously. Potential drawbacks of this process are the limited geographic availability of the sorbents and problems associated with waste disposal. For example, the waste tends to be very water soluble,

EXHIBIT 3-11

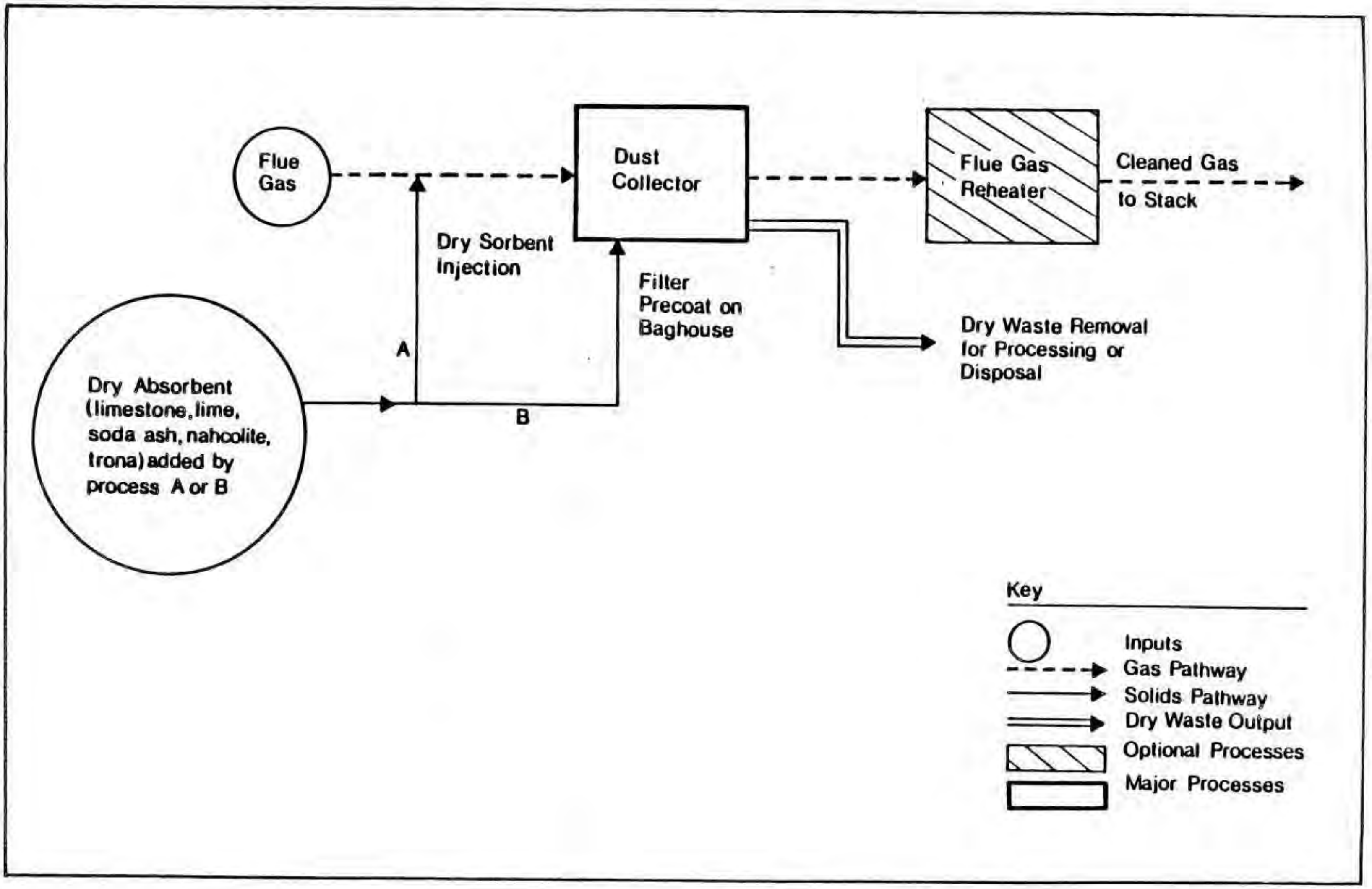
FLOW DIAGRAM OF SPRAY-DRYING FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, Prepared for Electric Power Research Institute, September 1983, p. 4-5.

EXHIBIT 3-12

FLOW DIAGRAM OF DRY INJECTION FLUE GAS DESULFURIZATION SYSTEM



Source: Tetra Tech Inc., <u>Physical-Chemical Characteristics of Utility Solid Wastes</u>, Prepared for Electric Power Research Institute, September 1983, p. 4-6.

and could potentially affect ground-water quality. Also, dry injection is most effective when used for low-sulfur coals, achieving only 70 to 80 percent sulfur dioxide removal in most cases, compared with up to 95 percent removal by wet scrubbing systems.[19]

Recovery systems are designed to produce a salable by-product such as sulfur, sulfuric acid, or liquid sulfur dioxide; however, small amounts of waste are still produced. A prescrubber is usually required upstream of the main scrubber to filter out such contaminants as fly ash and chlorides. Secondary waste streams formed by the oxidation of the absorbent are sometimes present and, along with the prescrubber by-products, are the materials that need to be disposed. Two recovery FGD systems presently used commercially, the Wellman-Lord and Magnesium Oxide processes, are both based on wet scrubbing. Diagrams of these systems are shown in Exhibit 3-13. Other recovery systems, both wet and dry, have been developed, but are still in the testing phase.

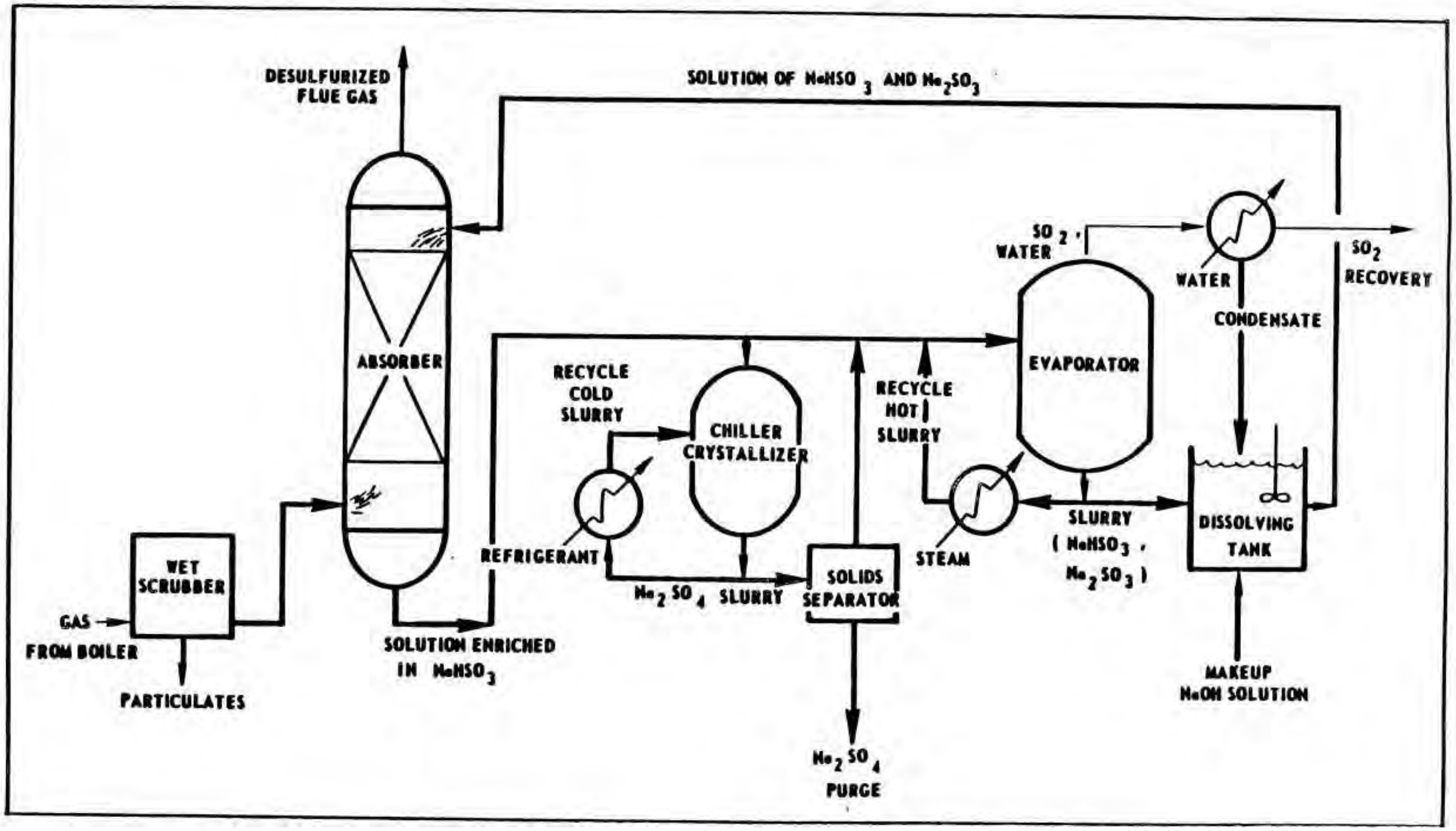
3.2.2.2 Quantities of FGD Sludge Generated

There has been a large increase in the quantity of FGD sludge generated over the past decade, as shown in Exhibit 3-14. This increase is due to the more widespread use of scrubbers brought about by tightened state limits on sulfur dioxide emissions, the Federal New Source Performance Standards (NSPS) of the Clean Air Act of 1971, and the revisions to the NSPS in 1979. This trend will continue as new power plants are equipped with scrubbers as required under the NSPS. By the year 2000, scrubber capacity is likely to be several times greater than at present.

EXHIBIT 3-13

FLOW DIAGRAMS OF RECOVERY FLUE GAS DESULFURIZATION SYSTEMS

WELLMAN-LORD PROCESS

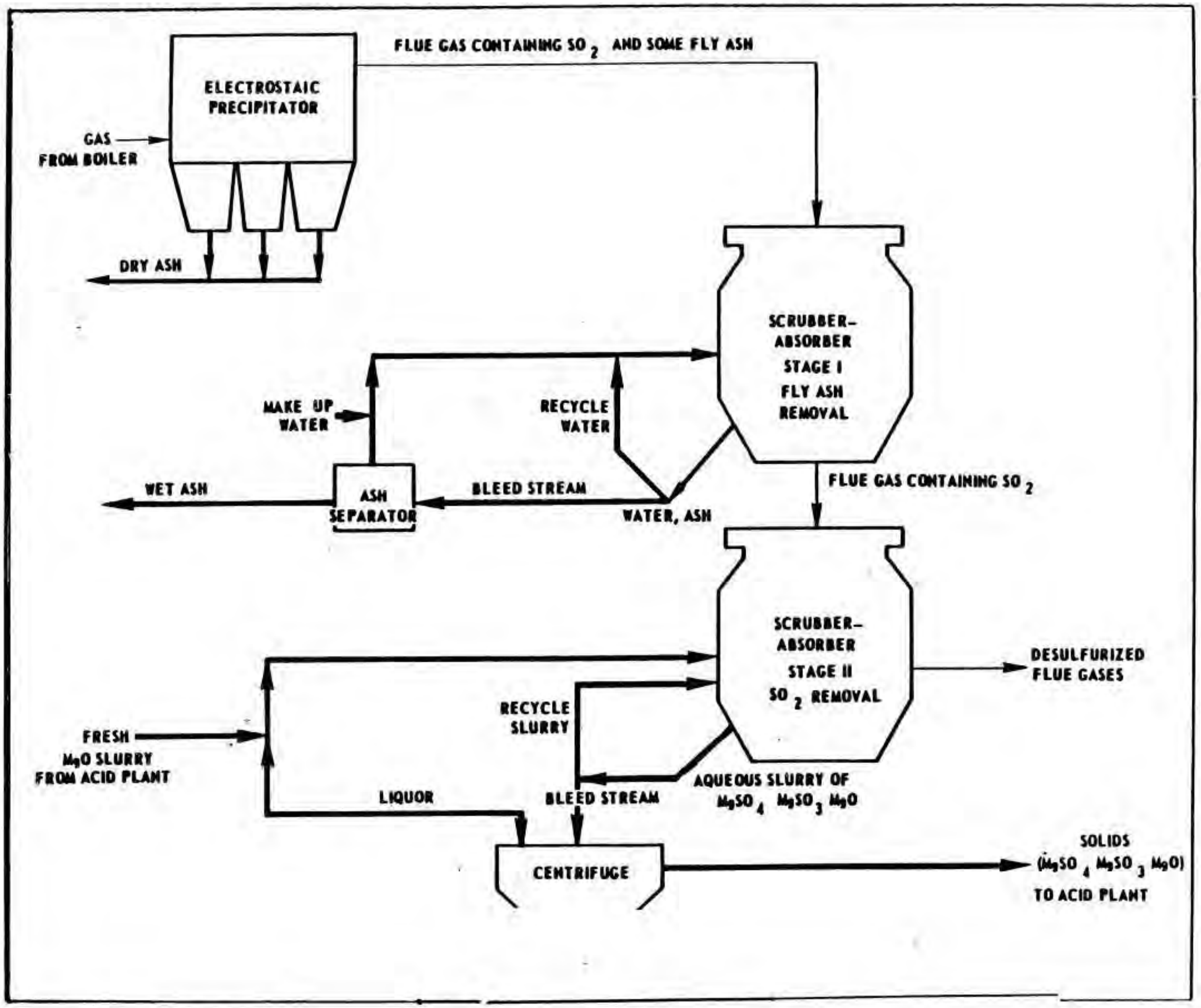


Source: Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, pp. VII-27, VII-30.

EXHIBIT 3-13 (Continued)

FLOW DIAGRAMS OF RECOVERY FLUE GAS DESULFURIZATION SYSTEMS

MAGNESIUM OXIDE PROCESS

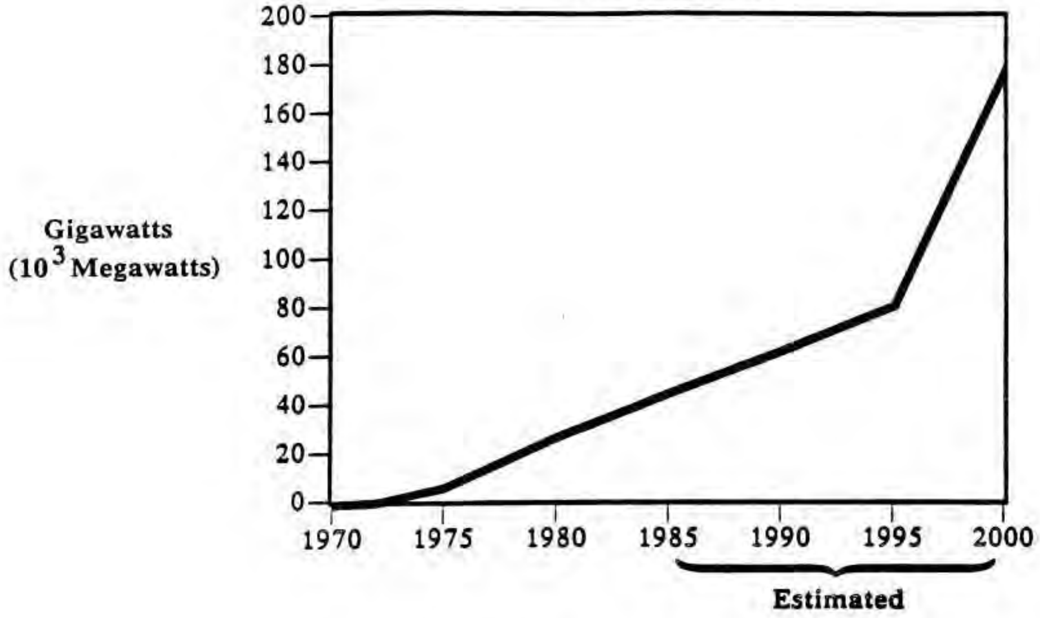


Source: Federal Power Commission, The Status of Fluc Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, pp. VII-27, VII-30.

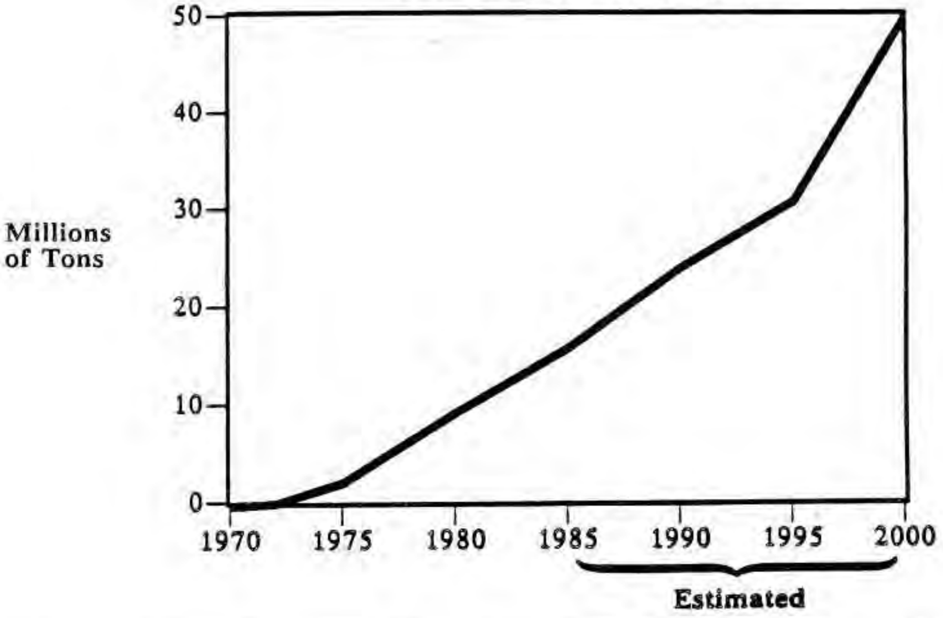
EXHIBIT 3-14

FGD CAPACITY AND FGD SLUDGE GENERATION
1970-2000

FGD Capacity



FGD Sludge Generation



Source: 1970-1984: Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants, and Arthur D. Little, Inc., Full Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, Vol. 1, June 1985.

1985-2000: ICF Incorporated. See Appendix B for in-depth discussion of the methodologies used to develop these estimates.

The dramatic increase in scrubber capacity has a direct effect on the amount of scrubber sludge produced. In 1984, about 16 million tons of scrubber sludge were generated. By 2000, the annual amount of sludge produced is estimated to be about 50 million tons, over three times the sludge generated at present.[20]

All FGD sludge is comprised of spent reagent, which is made up of the chemicals that result from the reaction of the absorbent with the sulfur oxides in the flue gas, plus any unreacted portion of the absorbent. The sludge may also contain water and fly ash. Several factors determine how much spent reagent, water, and ash are present in the FGD sludge. These factors include the type of scrubber system used, the characteristics of the coal, and the sulfur dioxide emission limit that the power plant is required to meet by state or Federal law.

The type of FGD system is an important determinant of the amount of spent reagent, amount of water, and amount of ash present in the sludge. Reagents used in different systems vary as to their absorbent utilization, or "stoichiometry," which is the percentage of the reagent that reacts with the sulfur oxides. A lower percentage implies more reagent is needed to remove a given percentage of sulfur dioxide. Direct limestone systems have an average absorbent utilization of 80 percent, while the direct lime and dual-alkali processes both achieve higher utilization of 90 and 95 percent, respectively. This results in the generation of about six percent more sludge by direct limestone scrubbers compared to direct lime and dual-alkali processes.[21]

Wet systems, both non-recovery and recovery, employ aqueous solutions to remove the sulfur oxides from the flue gas. Dry FGD systems use no water for sulfur oxide removal, although dry FGD wastes may be mixed with water prior to disposal, which increases the volume of sludge. Because of their dependency on water, wet FGD systems generally produce larger volumes of wastes than do dry systems.

Wet FGD systems can also be used as fly ash removal devices. The amount of ash in the sludge depends on how much fly ash is generated by the boiler and whether any other particulate control device is upstream of the scrubber. In particular, alkaline fly ash scrubbers rely on the entrapment of ash to act as their primary absorbent, and therefore their sludge contains large amounts of ash. The collection of fly ash and wastes in a spray-drying system occurs simultaneously by a baghouse; therefore, the wastes from these systems also contain large proportions of ash. Recovery FGD systems often require prescrubbers to remove fly ash. Although recovery systems produce only about half the wastes of non-recovery systems, these wastes are predominantly made up of ash.

Specific characteristics of the coal can have a large effect on the quantity of sludge generated. For example, the higher the sulfur content, the more reagent that must be used to achieve a certain level of sulfur dioxide removal and, consequently, the more spent reagent in the sludge. The ash content of the coal affects the amount of ash caught up in the sludge. Just as using low-sulfur coal will reduce the amount of spent reagent, reducing the ash content prior to combustion will greatly reduce the amount of fly ash that is absorbed by wet scrubbers and thus the amount of sludge that must be disposed.

The amount by which a power plant must reduce sulfur dioxide emissions also affects the volume of sludge produced. To achieve a higher reduction, the amount of reagent used in the scrubber needs to be increased, which will, in turn, produce greater quantities of sludge.

3.2.2.3 Physical Characteristics of FGD Sludge

In general, the same physical properties important in determining the disposal behavior of ash are also important determinants of the disposal characteristics of FGD sludge. These physical characteristics -- particle size, compaction behavior, permeability, and shear strength -- vary considerably depending on the type of scrubber system and what (if any) preparation is done prior to disposal. Exhibit 3-15 presents representative ranges of values for these characteristics of FGD sludge.

Depending on the type of FGD system used, the particle size distribution of FGD sludge can vary substantially. For example, sludge from wet scrubbers tends to have a narrow range of particle sizes. The particles produced by dual-alkali systems are finer than those produced by direct lime or limestone scrubbers, while dry scrubbers generally produce sludge containing larger particles.

The density of FGD sludge depends directly on the method of handling. Wet sludge mixed with ash will have a higher density than untreated sludge, while chemical fixation increases the density even more.[22] The density of the particles in dry sludge varies widely.

EXHIBIT 3-15

REPRESENTATIVE RANGES OF VALUES FOR THE PHYSICAL CHARACTERISTICS OF FGD SLUDGE

	Wet	Dry
Particle Size (mm)	.001-.05	.002-.074
Density (g/cm3)	0.9-1.7	Variable
Optimum Moisture Content (%)	16-43	0
Permeability (cm/sec)	10^{-6}-10^{-4}	10^{-7}-10^{-6}
Unconfined Compressive Strength (psi)	0-1600	41-2250

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, pp. 4-8 - 4-15.

The solids content of scrubber sludge is a function of many things, including whether the sludge is treated prior to disposal, the size of the particles in the sludge, the sulfur content of the coal, the amount of ash present in the sludge, and the desulfurization process used. The percentage of solids in untreated sludges usually ranges from 20 to 40 percent, although it can be as high as 60 percent.[23] Depending on the method of treatment used before disposal (if any), the percentage of solids could be much higher. In fact, some chemical fixation processes are designed to transform the sludge into a cement-like product.

The permeabilities of untreated FGD sludges from wet scrubber systems generally are very similar. Mixing the sludge with fly ash does not necessarily change the degree of permeability, although if fly ash acts as a fixative when added to the sludge, the mixed waste product will have a reduced permeability. Chemical fixation also can decrease permeability. Sludge from dry scrubber systems has low permeability relative to sludge from wet systems.

The shear strength of FGD sludge is referred to as "unconfined compressive strength," which reflects the load-bearing capacity of the sludge. The unconfined compressive strength of sludge is sensitive to the moisture content and age of the sludge. Untreated wet sludge has no compressive strength and is similar to toothpaste in this respect. Mixing with ash or lime increases compressive strength, as does chemical fixation. Also, as the treated sludge ages, its compressive strength becomes greater.

3.2.2.4 Chemical Characteristics of FGD Sludge

The major constituents found in wet FGD sludge are determined by the absorbent reagent used, the quantity of fly ash present, the sulfur content of the coal, and whether or not forced oxidation is used.

Most wet FGD systems operate by causing the sulfur dioxide in the flue gas to react with an absorbent reagent, such as lime or limestone, to form a calcium compound, such as calcium sulfite ($CaSO3$), calcium sulfate or gypsum ($CaSO4$), or calcium sulfite-sulfate ($CaSO3 \cdot CaSO4$), which can then be removed from the system in the sludge. The ratio of calcium sulfate to calcium sulfite is generally greater in sludge generated by direct limestone scrubber systems than in that produced by direct lime systems.

Dual-alkali scrubber systems differ slightly in that they use absorbent solutions containing sodium hydroxide ($NaOH$) or sodium sulfite ($Na2SO3$) as well as lime; sludges from these processes tend to have high levels of calcium sulfite and sodium salts. Because these compounds are highly soluble and apt to leach, they may pose problems as major components in a landfilled sludge.[24]

Spray-drying scrubber systems produce particulates containing either sodium sulfate ($Na2SO4$) and sodium sulfite ($Na2SO3$) or calcium sulfate ($CaSO4$) and calcium sulfite ($CaSO3$), depending on whether the reagents are sodium- or calcium-based.

Exhibits 3-16 and 3-17 show the major chemical constituents found in sludge solids and sludge liquors. Oxides of calcium, silicon, magnesium, aluminum, iron, sodium, and potassium can be found in most FGD sludge. The presence of

EXHIBIT 3-16

CONCENTRATION OF MAJOR CHEMICAL CONSTITUENTS OF WET FGD SLUDGE SOLIDS BY SCRUBBER SYSTEM AND SOURCE OF COAL *
(percent of total)

	Direct Lime		Direct Limestone		Dual-Alkali		Alkaline Fly Ash
	East	West	East	West	East	West	West
Calcium Sulfate ($CaSO_4$)	15-19	17-95	5-23	85	15-68	82	20
$CaSO_3 \cdot 1/2\ H_2O$	13-69	2-11	17-50	8	13-68	1	15
Calcium Sulfite ($CaSO_3$)	1-22	0-3	15-74	6	8-10	11	--
Sodium Sulfate ($Na_2SO_4 \cdot 7H_2O$)	--	--	--	--	4-7	4	--
Fly Ash	16-60	3-59	1-45	3	0-7	8	65

---

* Source of coal is categorized by Eastern producing regions (Northern Appalachia, Central Appalachia, Southern Appalachia, Midwest, Central West, and Gulf; i.e., Bureau of Mine (BOM) Districts #1-15, 24) and Western producing regions (Eastern Northern Great Plains, Western Northern Great Plains, Rockies, Southwest, and Northwest; i.e., BOM Districts #16-23).

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3236, September 1983, p. 4-18.

EXHIBIT 3-17

CONCENTRATION OF MAJOR CHEMICAL CONSTITUENTS OF WET FGD SLUDGE LIQUORS BY SCRUBBER SYSTEM AND SOURCE OF COAL a/

	Direct Lime	Direct Limestone		Dual-Alkali
Constituent b/	East	East	West	East
pH (units)	8-9.4	5.5-8.4	6.6-6.8	12.1
Total Dissolved Solids	2,800 - 10,260	5400	3300- 14,000	155,700
Chloride	1050-4900	1000	620-4200	4900-5600
Potassium	11-28	24	8-28	320-380
Sodium	36-137	12	370-2250	53,600-55,300
Calcium	660-2520	1600	390-770	7-12
Magnesium	24-420	53	3-9	0.1
Sulfate	800-4500	2500	1360-4000	80,000-84,000
Sulfite	0.9-2.7	160	1-3900	--

---

a/ Source of coal is categorized by Eastern producing regions (Northern Appalachia, Central Appalachia, Southern Appalachia, Midwest, Central West, and Gulf; i.e., BOM Districts #1-15, 24) and Western producing regions (Eastern Northern Great Plains, Western Northern Great Plains, Rockies, Southwest, and Northwest; i.e., BOM Districts #16-23).

b/ All constituent concentrations, unless noted, in milligrams per liter.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3226, September 1983, p. 4-20.

these compounds results from the presence of fly ash in the sludge, and they are unreactive in FGD systems. In wet scrubbers that also serve as fly ash collection devices, more than 50 percent of the sludge solids may be ash. However, when an ESP or baghouse precedes the scrubber, ash may make up less than 10 percent of the sludge solids.[25]

The calcium sulfate/calcium sulfite ratio of the sludge solids is important because sludge containing a greater proportion of sulfates has better disposal properties due to its lower solubility. This ratio is usually higher in systems scrubbing lower sulfur coals and in direct limestone systems. Many scrubber systems add a forced oxidation step to lower the calcium sulfite content of the sludge, thereby lowering its solubility.

The concentration of trace elements in FGD sludge reflects the levels of trace elements in the ash, the efficiency of the scrubber in capturing trace elements in the flue gas, and the trace elements present in the reagent and in the process makeup waters. Fly ash is the primary source of most of the trace elements found in scrubber sludge. Some elements, such as mercury and selenium, may be scrubbed directly from the flue gases and then captured in the scrubber sludge. Exhibit 3-18 illustrates the concentrations at which major trace elements are found in sludge from wet scrubber systems.

3.3 LOW-VOLUME WASTES

Low-volume utility wastes are those waste streams generated in the routine cleaning of plant equipment and in purifying of water used in the combustion process. The types and volumes of low-volume wastes vary among different power

EXHIBIT 3-18

CONCENTRATION OF TRACE ELEMENTS FOUND IN WET-FGD SLUDGES
(Solids and Liquors)

	Sludge Solids a/			Sludge Liquors b/		
	Range			Range		
	Low	High	Median	Low	High	Median
Arsenic	0.8	52.0	12	0.0004	0.1	0.03
Boron	42.0	530.0	14.0	2.1	76.0	14.9
Cadmium	0.1	25.0	10.6	0.002	0.1	0.02
Chromium	1.6	180.0	15.0	0.0002	0.3	0.02
Copper	6.0	340.0	17.5	0.0045	0.5	0.03
Fluoride	266.0	1017.0	625.0	0.2	63.0	2.3
Mercury	0.01	6.0	0.4	0.00006	0.1	0.005
Lead	0.2	290.0	2.4	0.005	0.5	0.03
Selenium	2.0	60.0	5.0	0.003	1.9	0.18

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a/ Sludge solid concentrations in milligrams per kilogram.

b/ Sludge liquor concentrations in milligrams per liter.

Source: Tetra Tech Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EPRI EA-3226, September 1983, p. 4-24.

plants, depending on plant-specific factors such as the size of the plant, the type of equipment, and the age of the equipment. Some low-volume wastes commonly produced are:

- boiler blowdown,
- coal pile runoff,
- cooling tower blowdown,
- demineralizer regenerants and rinses,
- metal and boiler cleaning wastes,
- pyrites, and
- sump effluents.

Estimates of the total amount of low-volume wastes generated each year by coal-fired power plants are not available. The frequency of generation and the quantities generated vary widely from power plant to power plant, depending on the maintenance requirements of the plant and operating conditions. Variations also occur within the same power plant, according to its maintenance schedule and operations. Exhibit 3-19 gives representative annual production figures for low-volume wastes generated by a typical power plant.

This section presents for each type of low-volume waste a brief description of how the waste is generated, typical quantities produced, and the physical and chemical composition of the waste.

3.3.1 Boiler Blowdown

Boiler systems can be either a once-through (supercritical) type or a

EXHIBIT 3-19

ANNUAL LOW-VOLUME WASTE GENERATION AT A REPRESENTATIVE COAL-FIRED POWER PLANT *

Type of Waste	Average Annual Production
Boiler Blowdown	11 million gallons/year
Coal Pile Runoff	20 inches/year
Cooling Tower Blowdown	2.6 billion gallons/year
Demineralizer Regenerant	5 million gallons/year
Gas-side Boiler Cleaning	700,000 gallons/year
Water-Side Boiler Cleaning	180,000 gallons/year
Pyrites	65,000 tons/year

---

* Assuming a 500 megawatt power plant, operating at 70 percent capacity.

Sources: Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

U.S. Environmental Protection Agency, Waste and Water Management for Conventional Coal Combustion Assessment Report - 1979; Volume II: Water Management, EPA-600/7-80-012b, March 1980.

drum-type. In drum-type boiler systems, after steam passes through the turbines, it is converted back to water in the condenser and is recirculated through the boiler to produce steam again. In this process, impurities that become concentrated in the feedwater periodically must be purged from the system. This waste stream is known as boiler blowdown. A once-through system, however, maintains pressurized steam throughout the cycle, and thus does not require the recirculation of water. These boiler types, therefore, do not generate boiler blowdown.

Boiler blowdown is produced either in a continuous stream or intermittently during the day. The flow is adjusted in order to maintain the desired water quality in the boiler and is dependent on the quality of the feedwater and the size and condition of the boiler. The average blowdown rate for a 500 megawatt unit can range from 20 to 60 gallons per minute, or about 2 to 7 gallons per megawatt-hour.[26]

Boiler blowdown is generally fairly alkaline with a low level of total dissolved solids. The waste stream usually contains certain chemical additives used to control scale and corrosion. Trace elements commonly found in boiler blowdown are copper, iron, and nickel. The components and characteristics of boiler blowdown are presented in Exhibit 3-20.

3.3.2 Coal Pile Runoff

Power plants typically maintain two types of coal storage piles in their coal yards: an active pile to supply their immediate needs and an inactive or long-term pile, which generally stores a 60- to 90-day supply of coal. Coal

EXHIBIT 3-20

CHARACTERISTICS OF BOILER BLOWDOWN

Parameter	Range[a/] Low	High
pH (units)	8.3	12.0
Total Solids	125.0	1,407.0
Total Suspended Solids	2.7	31.0
Total Dissolved Solids	11.0	1,405.0
BOD5	10.8	11.7
COD	2.0	157.0
Hydroxide Alkalinity	10.0	100.0
Oil and Grease	1.0	14.8
Phosphate (total)	1.5	50.0
Ammonia	0.0	2.0
Cyanide (total)	0.005	0.014
Chromium (total)	0.02	b/
Chromium (Hexavalent)	0.005	0.009
Copper	0.02	0.2
Iron	0.03	1.4
Nickel	0.03	b/
Zinc	0.01	0.05

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a/ All concentrations, unless noted, in milligrams per liter.

b/ Data on these elements were limited.

Source: Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

piles are usually 25-40 feet high and can cover an area of up to 75 acres, depending on the size and demands of the power plant.[27] Inactive coal piles are generally sealed with a tar spray to protect the coal against the weather; active piles are usually open and exposed. Coal pile runoff is formed when water comes into contact with the piles, whether from rainfall or snowfall, during spraying for dust control, or from underground streams that surface under the piles.

The quantity of coal pile runoff depends primarily on rainfall and, to a lesser extent, the permeability of the soil. It has been estimated that, on average, 73 percent of the total rainfall on coal piles becomes coal pile runoff.[28]

The composition of coal pile runoff is influenced by the composition of the coal, the drainage patterns of the coal pile, and the amount of water that has seeped through. Bituminous coals generate runoff that is usually acidic, with the level of acidity depending on the availability of neutralizing materials in the coal, while subbituminous coals tend to produce neutral to alkaline runoff. Elements commonly found in high concentrations in coal pile runoff are copper, zinc, magnesium, aluminum, chloride, iron, sodium, and sulfate. Exhibit 3-21 displays ranges of concentrations for these and other characteristics.

3.3.3 Cooling Tower Blowdown

Power plants need cooling systems to dissipate the heat energy that remains after the production of electricity.[29] The two major types of cooling systems are once-through and recirculating. Cooling tower blowdown generally refers to

EXHIBIT 3-21

CHARACTERISTICS OF COAL PILE RUNOFF

Parameter	Range a/ Low	High
pH (units)	2.1	9.3 b/
Acidity (as CACO3)	300.0	7,100.0
Total Dissolved Solids	270.0	28,970.0
Total Suspended Solids	8.0	2,500.0
Aluminum	20.0	1,200.0
Ammonia	0.0	1.8
Arsenic	0.005	0.6
Beryllium	0.01	0.07
Cadmium	0.001	0.003
Chloride	3.6	481.0
Chromium	0.005	16.0
Cobalt	0.025	--
Copper	0.01	6.1
Iron	0.1	5,250.0
Magnesium	0.0	174.0
Manganese	0.9	180.0
Mercury	0.0002	0.007
Nickel	0.1	4.5
Nitrate	0.3	1.9
Phosphorus	0.2	1.2
Selenium	0.001	0.03
Sodium	160.0	1,260.0
Sulfate	130.0	20,000.0
Zinc	0.006	26.0

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a/ All concentrations, unless noted, in milligrams per liter.

b/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All information, unless noted otherwise, is from Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

the water withdrawn from a recirculating cooling system to control the concentration of impurities in the cooling water; although once-through systems also discharge water from the cooling system, this discharge is not typically referred to as cooling tower blowdown. At present, about two-thirds of electric utility power plants use a once-through cooling system. This percentage may decrease, however, due to concern over water availability and potential environmental concern over thermal discharges; consequently, future plants may be built with recirculating systems that use cooling towers or cooling ponds.[30]

Once-through cooling systems are primarily used by power plants located next to large bodies of water. After passing through the condenser, the cooling water is discharged, usually into a river, lake, or pond. The quantity discharged ranges from 26,000 to 93,000 gallons per megawatt-hour. For a 500 megawatt plant, this roughly equals 70-300 billion gallons per year.[31] In most instances, the chemical composition of the water remains the same after passing through the condenser, but some changes may occur as the result of the formation of corrosion products or the addition of biocides.

Recirculating cooling systems can use either cooling ponds or cooling towers. In a cooling pond system, water is drawn from a large body of water, such as a pond or canal. After it passes through the condenser to absorb waste heat, the water is recycled back into the pond or canal. Cooling tower systems operate by spraying the water through a cooling tower. About 80 percent of the waste heat contained in the water is then released through evaporation. The remainder of the water is recycled back through the cooling tower system. Cooling tower blowdown is a waste stream bled off to control the concentrations of impurities and contaminants in the cooling system that could lead to scale formation in the condenser.[32]

The cooling tower blowdown rate is adjusted to maintain water quality in the recirculating cooling system in order to prevent scale formation in the condenser. The quantity of blowdown generated is a function of the quality of the makeup water (the water added to the system to replace that which is lost by evaporation and blowdown), the condition of the cooling system, and the amount of water evaporated by the cooling tower. For a representative 500 megawatt unit, the blowdown rate varies between 2 and 30 cubic feet (15 to 225 gallons) per second.[33]

The composition and quantity of cooling tower blowdown varies greatly from plant to plant. It generally reflects the characteristics of the makeup waters (e.g., fresh water versus brackish or saline water) and the chemicals added to prevent the growth of fungi, algae, and bacteria in the cooling towers and to prevent corrosion in the condensers. Some of these chemical additives are chlorine, chromate, zinc, phosphate, and silicate. Ranges of concentration for some of the characteristics and components of cooling tower blowdown are shown in Exhibit 3-22.

3.3.4 Demineralizer Regenerant and Rinses

A power plant must treat water prior to its use as makeup water. The use of demineralizers is the most common method of purification. During the demineralization process, which may entail several rinses, high-purity process water is provided for the boiler through an ion exchange process. The wastes

EXHIBIT 3-22

CHARACTERISTICS OF COOLING TOWER BLOWDOWN

	Range a/	
Parameter	Low	High
Alkalinity (as CaCO3)	8.0	556.0
BOD	--	94.0
COD	--	436.0
Total Solids	750.0	32,678.0
Total Dissolved Solids	4.1	32,676.0
Total Suspended Solids	0.2	220.0
Ammonia (as N)	0.01	11.6
Nitrate (as N)	0.1	711.0
Phosphorus (as P)	0.1	17.7
Total Hardness (as CaCO3)	84.0	2,580.0
Sulfate	7.2	20,658.0
Chloride	5.0	16,300.0
Fluoride b/	0.3	33.0
Aluminum b/	1,100.0	1,700.0
Boron b/	0.5	1.0
Chromium (ug/l)	0.02	120.0
Copper (ug/l)	0.01	1,740.0
Iron (ug/l))	0.1	1,160.0
Lead (ug/l) b/	4.0	--
Magnesium (ug/l)	0.1	1,580.0
Manganese (ug/l) b/	24.0	220.0
Mercury (ug/l) b/	1.5	--
Nickel (ug/l)	0.03	150.0
Zinc (ug/l)	0.02	3,000.0
Oil & Grease	1.0	7.4
Phenols (ug/l)	--	72.0
Surfactants	0.2	--
Sodium	3.4	11,578.0

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a/ All concentrations, unless noted, in milligrams per liter.

b/ Data on these elements were limited.

Source: Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

produced in this process can be either acidic or alkaline. When sulfuric acid is employed as the regenerant, calcium sulfate is precipitated in the waste stream. Exhibit 3-23 presents ranges for the components of demineralizer regenerants and rinses.

Regeneration of boiler makeup water by demineralizers is done on a batch basis. The frequency with which the process occurs depends on the quality of the incoming water, although for a 500 megawatt unit, regeneration usually occurs every one to four days. A single regeneration requires approximately 30,000 gallons of water, which amounts to about 3-10 million gallons per year.[34]

3.3.5 Metal and Boiler Cleaning Wastes

This category of low-volume waste streams can be divided into two basic types: gas-side cleaning wastes and water-side cleaning wastes. Gas-side wastes are produced during maintenance of the gas-side of the boiler, which includes the air preheater, economizer, superheater, stack, and ancillary equipment. Residues from coal combustion (such as soot and fly ash), which build up on these surfaces, must be removed periodically -- usually with plain water containing no chemical additives.

Water-side wastes are produced during cleaning of the boiler tubes, the superheater, and the condenser, which are located on the water-side or steam-side of the boiler. The scale and corrosion products that build up on these boiler parts must be removed with cleaning solutions containing chemical additives.

EXHIBIT 3-23

CHARACTERISTICS OF SPENT DEMINERALIZER REGENERANTS

Parameter	Range a/ Low	High
Alkalinity (as CaCO3)	0.0	3,831.0
BOD	0.0	344.0
COD	0.0	440.0
Total Solids	284.0	36,237.0
Total Dissolved Solids	283.0	25,235.0
Total Suspended Solids	0.0	300.0 c/
Ammonia (as N)	0.0	435.0
Phosphorus (as P)	0.0	87.2
Turbidity (JTU)	2.5	100.0
Total Hardness (as CaCO3)	0.0	8,000.0
Sulfate	4.5	9,947.0
Chloride	0.0	20,500.0
Boron	0.0	0.1
Chromium	0.0	2,168.0
Copper (ug/l)	0.0	3,091.0
Iron (ug/l)	0.0	2,250.0
Lead (ug/l) b/	160.0	37,500.0
Magnesium (ug/l)	0.0	753.0
Manganese (ug/l)	0.0	3,100.0
Mercury (ug/l)	0.05	--
Nickel (ug/l)	0.0	560.0
Zinc (ug/l)	0.0	4,500.0
Oil & Grease b/	0.0	24.5
Phenols (ug/l)	0.0	303,000.0
Surfactants b/	1.7	--
Nitrate as N	0.0	118.0
Algicides b/	0.003	--
Sodium	4.9	30,000.0

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a/ All concentrations, unless noted, in milligrams per liter.

b/ Data on these components were limited.

c/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All data, unless noted otherwise, are from Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

The boiler and auxiliary equipment are cleaned intermittently, creating large quantities of wastes in a short time. Gas-side boiler cleaning is done approximately twice a year. The volume of the waste stream produced depends on the size of the boiler and the number of rinses. For a typical plant, gas-side cleanings can produce between 24,000 and 700,000 gallons of wastes. Water-side equipment is cleaned less frequently, approximately once every three years. As is true of gas-side cleaning, the volume of waste produced varies with the number of rinses. A representative 500 megawatt unit generates about 120,000-240,000 gallons of wastewater per treatment.[35]

Because no chemicals are used, the composition of the waste streams associated with gas-side cleaning directly reflects the composition of the soot and fly ash residues and, therefore, of the coal that is burned. Exhibit 3-24 shows two reported values for components and characteristics of gas-side cleaning waste streams.

The particular solution used for the cleaning of the water-side of the boiler varies depending on the equipment being cleaned and the type of scale that needs to be removed. When the scale contains high levels of metallic copper, an alkaline solution that contains ammonium salts, an oxidizing agent such as potassium or sodium bromate or chlorate, and nitrates or nitrites is used. Exhibit 3-25 presents some of the major characteristics associated with these types of solutions and representative ranges of concentrations in which they are found.

For the removal of scale caused by water hardness, iron oxides, and copper oxide, an acid cleaning solution is needed. Usually hydrochloric acid acts as

EXHIBIT 3-24

REPORTED CHARACTERISTICS OF GAS-SIDE CLEANING WASTES

Parameter	Quantities Produced per Cleaning (in lbs. except as noted) a/	
	Source A	Source B
Cleaning Frequency (cycles/yr)	2.0	8.0
Batch Volume (1000 gallons)	720.0	24.0
Alkalinity	0.0	6.0
COD	1,134.0	19.0
Total Solids	40,861.0	4,002.0
Total Dissolved Solids	35,127.0	3,002.0
Total Suspended Solids	3,823.0	119.1
Turbidity (JTU)	476.0	98.0
Hardness	35,409.0	791.4
Ammonia	1.5	0.4
Chloride	0.0	18.0
Chromium (total)	0.03	1.0
Copper	--	0.3
Iron	900.0	30.0
Lead	--	--
Magnesium	11,949.0	190.3
Nickel	30.0	--
Nitrate	14.7	0.7
Phosphorus	11.1	0.3
Sodium	0.0	9.0
Sulfate	11,949.0	299.4
Vanadium	--	--
Zinc	28.7	2.0

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a/ Quantities produced are shown for two different reported values.

Source: Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

EXHIBIT 3-25

CHARACTERISTICS OF SPENT WATER-SIDE ALKALINE CLEANING WASTES

Parameter	Range a/ Low	Range a/ High
Alkalinity (as CaCO3)	20,200.0	25,700.0
NH3-N	4,280.0	6,360.0
Kjeldahl-N	5,190.0	7,850.0
Nitrate-N	1.0	193.0
Oil & Grease	7.9	10.3
BOD5	5,820.0	8,060.0
COD	14,600.0	20,900.0
Total Suspended Solids	5,580.0	6,720.0
Total Dissolved Solids	10.0	400.0
TDS	22,100.0	32,300.0
Total Iron	180.0	10,800.0
Silica	1.0	40.0
Chromium	0.2	7.7 b/
Copper	8.0	1,912.0
Lead	0.004 b/	23.0 b/
Manganese	0.1	14.3
Nickel	2.5	130.0
Tin	2.0	20.7
Zinc	3.1	390.0
pH (units)	8.4 b/	10.3 b/

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a/ All concentrations, unless noted, in milligrams per liter.

b/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All data, unless noted otherwise, are from Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

the solvent in these solutions, although sulfuric, phosphoric, and nitric acids can also be used. Organic acids have been used increasingly as substitutes for hydrochloric acid because of their lower toxicity. For the removal of silica deposits, hydrofluoric acid or fluoride salts are added to the cleaning solution. Exhibit 3-26 presents the various characteristics of acid boiler cleaning solutions.

Alkaline chelating rinses and alkaline passivating rinses are often used to remove iron and copper compounds and silica and to neutralize any residual acidity left over from acid cleaning. These solutions may contain phosphates, chromates, nitrates, nitrites, ammonia, EDTA, citrates, gluconates, caustic soda, or soda ash. Exhibit 3-27 gives representative ranges for these components and others present in these rinses.

3.3.6 Pyrites

Pyrites are the solid mineral compounds, such as iron sulfides or other rock-like substances, present in raw coal. Most pyrites are generally separated out before coal is burned, usually at a preparation plant prior to shipment to the power plant. Smaller quantities of pyrites are often removed at the power plant just before the coal is pulverized. The size of the deposits depends on the method by which they are separated from the coal.

The volume of pyrites collected at a power plant depends on the amount and quality of the coal that is burned, which is determined by the source of the coal and the preparation process, as well as by the coal pulverization process.

EXHIBIT 3-26

CHARACTERISTICS OF SPENT WATER-SIDE HYDROCHLORIC ACID CLEANING WASTES

Parameter	Range [a/] Low	High
pH (units)	0.5	3.3
Total Suspended Solids	8.0	2375.0
Silica	19.0	280.0
NH3-N	80.0	325.0
Nitrogen	1.0	870.0
Phosphorus	1.0	300.0
Sulfate	1.0	10.0
Aluminum	6.5	8.2
Arsenic	0.01	0.1
Barium	0.1	0.4
Beryllium	0.0	0.1
Cadmium	0.001	0.13 b/
Calcium	16.0	980.0
Chromium	0.005	16.8
Copper	2.2	960.0
Iron	1125.0	6470.0
Lead	0.01	5.2
Magnesium	5.7	8.8
Manganese	6.9	29.0
Mercury	0.0	0.002
Nickel	3.0	500.0
Potassium	1.4	2.3
Selenium	0.002	0.004
Silver	0.02	0.2 b/
Sodium	9.2	74.0
Tin	1.0	7.3
Zinc	0.9	840.0

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a/ All concentrations, unless noted, in milligrams per liter.

b/ Electric Power Research Institute, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

Source: All data, unless noted otherwise, are from Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

EXHIBIT 3-27

CHARACTERISTICS OF SPENT WATER-SIDE ALKALINE PASSIVATING WASTES

Parameter	Range*	
	Low	High
pH (units)	9.2	10.0
Total Suspended Solids	13.0	45.0
NH3-N	15.0	232.0
Kjeldahl-N	97.0	351.0
Nitrite-N	7.0	12.9
BOD5	40.0	127.0
COD	98.0	543.0
TOC	16.0	23.0
Iron	7.5	28.0
Chromium	0.0	0.4
Copper	0.1	1.2

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* All concentrations, unless noted, in milligrams per liter.

Source: Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

The amount of pyrites to be disposed at a power plant can vary considerably, although coal typically contains up to 5 percent pyrites.[36] A 500 megawatt plant, depending on how often it operates and the quality of its coal, will generate, on average, between 30,000 and 100,000 tons of pyrites per year. The characteristics of pyrites and pyrite slurry transport water are shown in Exhibit 3-28.

3.3.7 Sump Effluents

Floor and yard drains collect waste streams from a variety of sources at power plants, such as rainfall, seepage from ground-water sources, leakage, small equipment cleaning operations, and process spills and leaks. As a result, the composition of drain effluents is highly variable. Depending on the particular circumstances at the power plant, these waste streams may contain coal dust, fly ash, oil, and detergents.

The frequency of sump effluent generation and quantities generated are very plant-specific. The more efficient a plant's operating procedures, the smaller this waste stream will be. Also, power plants located in dry areas of the country will have relatively small amounts of wastes collected in yard drains.

3.4 SUMMARY

In the process of generating electricity, coal-fired utility power plants produce a number of waste products. These wastes are produced in large quantities and have widely varying physical and chemical characteristics.

EXHIBIT 3-28

CHARACTERISTICS OF PYRITES AND PYRITE TRANSPORT WATER

Parameter	Pyrite Slurry Water a/	Pyrites b/ Solid Form
Total Suspended Solids	1,700.0	--
Total Aluminum	93.3	--
Total Calcium	134.0	--
Total Iron	220.0	--
Total Magnesium	13.6	--
Sulfate	177.0	--
pH (units)	7.7	--
Arsenic	--	500-5000
Chromium	0.1	--
Copper	0.1	10-10,000
Lead	0.1	200-1000
Zinc	0.3	500-10,000
Manganese	--	10-5000
Selenium	--	10-100
Silica	212.0	--
Silver	--	10-50
Cobalt	--	100-5000
Nickel	--	10-1000
Vanadium	--	100-200

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a/ All concentrations, unless noted, in milligrams per liter.

b/ All concentrations in parts per million.

Source: Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981.

- Coal-fired electric utility power plants produce three major forms of wastes:

  1) Ash, formed from the noncombustible material present in coal. There are three types of ash -- fly ash, bottom ash, and boiler slag;

  2) FGD sludge, produced by flue gas desulfurization systems designed to remove sulfur oxides from flue gas; and

  3) Low-volume wastes, generated primarily from equipment maintenance and cleaning operations.

- In 1984, about 69 million tons of ash and about 16 million tons of FGD sludge were produced by coal-fired electric utilities. By the year 2000, these wastes are expected to increase to about 120 million and 50 million tons, respectively.

- Several physical characteristics of utility waste determine the waste's behavior during disposal and the potential for leachate problems. These characteristics vary a great deal among the different types of ash and FGD sludge.

- The chemical constituents of ash and FGD sludge largely depend on the chemical components in the coal. Other chemical compounds present in FGD sludge, primarily calcium and sodium salts, are the result of the reactions between the absorbent reagent used and the sulfur oxides in the flue gas.

- Compared with ash and FGD sludge, low-volume wastes are generally produced in much smaller quantities. Many of these wastes contain various chemicals from the cleaning solutions used for power plant operations and maintenance; potentially-hazardous elements in these chemicals may be found at high concentrations in the low-volume waste.

CHAPTER THREE

NOTES

[1] See Appendix B for a more in-depth discussion of boiler types and how the type of boiler affects the types of waste that are generated.

[2] Babcock & Wilcox, Steam: Its Generation and Use, New York: The Babcock & Wilcox Company, 1978, p. 18-3.

[3] Ibid.

[4] Energy Information Administration, Cost and Quality of Fuels for Electric Utility Plants-1985, DOE/EIA-0191(85), July 1986.

[5] ICF Incorporated, Analysis of 6 and 8 Million Ton and 30 Year/NSPS and 30 Year/1.2 Pound Sulfur Dioxide Emission Reduction Cases, prepared for EPA, February 1986. There are many factors that can affect the amount of coal consumed, including electricity growth rates, oil and gas prices, types of technology available, etc. Nevertheless, utilities will continue to burn substantial amounts of coal in the foreseeable future.

[6] Energy Information Administration, Electric Power Annual 1984, DOE/EIA-0348(84), p. 45.

[7] There are presently over 500 coal cleaning plants in the U.S., the majority of which are operated by coal companies and located at the mouth of the mine. The type of cleaning method employed depends upon the size of the coal pieces to be cleaned, a factor that can be controlled at the cleaning plant.

The most widely used methods of coal cleaning are those that use specific gravity, relying on the principle that heavier particles (i.e., impurities) separate from lighter ones (i.e., coal) when settling in fluid. A common method of cleaning coarse coal pieces is to pulse currents of water through a bed of coal in a jig; impurities, such as shale and pyrite, sink, while the coal floats on top. The heavy, or dense, media process is used for cleaning coarse and intermediate-sized pieces. A mixture of water and ground magnetite, having a specific gravity between that of coal and its impurities, acts as a separating fluid. An inclined vibrating platform with diagonal grooves, known as a concentrating table, also is used to clean intermediate-sized coal pieces. Raw coal slurry is fed onto the high end of the table. As the slurry flows down, the vibrations separate the coal from the refuse, allowing the lighter coal to be carried along in the water, while the heavier impurities are trapped in the grooves.

Because of their small size, fine coal particles are very difficult to clean. Their recovery is important, however, because these particles can provide up to 25 percent of the energy derived from raw coal. A popular method of fine coal cleaning is froth flotation. The coal pieces are coated with oil and then agitated in a controlled mixture of water, air, and reagents until froth is formed on the surface. Bubbles tend to attach to the coal pieces, keeping them buoyant, while heavier particles such as pyrite, shale, and slate remain dispersed in the water. The coal can then be removed from the surface. For more information, see Coal Preparation, 4th edition, Joseph Leonard, editor, American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., 1979.

[8] Ash melts when heated to a sufficiently high temperature. The temperatures at which the ash changes forms -- e.g., melting from a cone shape to a spherical shape to a hemispherical shape to a flat layer -- are referred to as ash fusion temperatures.

[9] Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, prepared for Electric Power Research Institute, September 1983, p. 3-4. A micron is 0.001 millimeters.

[10] Ibid.

[11] The compressibility of a material is measured as the ratio of its height at 50 psi to its original height at atmospheric pressure. The dry density, the ratio of weight to unit volume of the material containing no water, affects permeability and strength, which in turn determine the structural stability of a landfill and the extent of leachate mobility. The optimum moisture content is the moisture content, in percentage terms, at which the material attains its maximum density.

[12] In 1979 the New Source Performance Standards, part of the Clean Air Act of 1971, were revised. The new regulations required that all coal-fired electric utility units with capacity greater than 73 megawatts, whose construction commenced after September 18, 1978, would not only have to meet a 1.2 pound sulfur dioxide per million Btu emission limit, but would have to do so by a continuous system of emissions reduction. New power plants must reduce sulfur dioxide emissions between 70 and 90 percent, depending on the type of coal burned.

[13] During fluidized bed combustion the sulfur oxides react with limestone or dolomite to form calcium sulfate. In LIMB technology, limestone is injected into the boiler, also forming calcium compounds.

[14] Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, p. VII-15.

[15] Ibid., p. VII-18.

[16] Ibid., p. VII-23.

[17] Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, EPRI EA-3236, prepared for Electric Power Research Institute, September 1983, p. 4-4.

[18] "Dry Capture of SO2," EPRI Journal, March 1984, p. 21.

[19] Ibid., p. 15.

[20] ICF, op. cit. See Appendix B for a detailed explanation of how future FGD sludge estimates were derived.

[21] U.S. Environmental Protection Agency, Controlling SO2 Emissions from Coal-Fired Steam-Electric Generators: Solid Waste Impact, Volume I, EPA-600/7-78-044a, March 1978, p. 23.

[22] See Chapter Four for a detailed discussion of the methods of sludge fixation.

[23] Michael Baker, Jr., Inc., State-of-the-Art of FGD Sludge Fixation, prepared for Electric Power Research Institute, January 1978, p. 2-25.

[24] Tetra Tech, Inc., op. cit., p. 4-17.

[25] Ibid.

[26] Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981, p. 26.

[27] U.S. Environmental Protection Agency, Waste and Water Management for Conventional Coal Combustion Assessment Report - 1979; Volume II: Water Management, EPA-600/7-80-012b, March 1980, p. 3-146.

[28] Ibid., p. 3-147.

[29] Ibid., p. 3-16. About 35 to 40 percent of the total heat input of a power plant is converted to electricity, about 5 percent is lost in the stack gases, and the remaining 55 to 60 percent is rejected in the condenser.

[30] Ibid., p. 3-17.

[31] Ibid.

[32] The term "cooling tower blowdown" refers to the waste waters produced by all recirculating cooling systems, whether they use a cooling pond or a cooling tower.

[33] U.S. EPA, Waste and Water Management, p. 3-19.

[34] Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated at Fossil Fuel Fired Electric Generating Stations, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, August 1981, p. 27.

[35] Ibid., p. 27.

[36] Ibid., p. 28. The term "pyrites" is used to refer to a variety of rock-like substances that may be found in raw coal; it does not just refer to pyritic sulfur that is found in all raw coal, although pyritic sulfur is typically part of the pyrites generated at a power plant.

CHAPTER FOUR

COAL COMBUSTION WASTE MANAGEMENT PRACTICES

Under Section 8002(n) of RCRA, EPA is to analyze "present disposal and utilization practices" and "alternatives to current disposal methods." This chapter addresses these issues by first examining the various state regulations that affect coal combustion disposal since these regulations set the context for current practices. The following section describes coal combustion waste management practices. First, three commonly employed types of land management practices are described in detail. Next, this chapter describes additional measures currently employed by some utilities; more widespread use of these technologies could be employed as an alternative to current practices. Ocean disposal, an alternative that is in the research and development stage, is also addressed in this chapter. Finally, the extent of coal combustion waste recycling as an alternative to disposal is described.

4.1 STATE REGULATION OF COAL COMBUSTION WASTE DISPOSAL

Since coal combustion wastes are currently exempt from Federal hazardous waste regulation under RCRA, their regulation is primarily carried out under the authority of state hazardous and solid waste laws. State solid waste laws establish programs to provide for the safe management of non-hazardous solid wastes. If solid wastes are considered hazardous, state hazardous waste laws establish programs to provide for their safe management. To implement these laws, state health or environmental protection agencies promulgate solid and hazardous waste regulations. A 1983 report for the Utility Solid Waste Activities Group (USWAG) surveyed these regulations; the USWAG report provided summaries of state regulations based on applicable state laws, regulations, and interviews with state environmental officials.[1] EPA updated the information provided in the USWAG summaries for the purposes of this report.

Exhibit 4-1 lists the disposal requirements promulgated under each state's solid waste (non-hazardous) regulations. (As will be discussed below, it is very rare for coal combustion wastes to be regulated as hazardous under state regulations.) The list of states is arranged in descending order according to each state's share of national coal-fired generating capacity (Column 1 of Exhibit 4-1). The information shown in the Exhibit is discussed in detail in Sections 4.1.1 and 4.1.2.

4.1.1 State Classification of Coal Combustion Wastes

Forty-three states have exempted coal combustion wastes from hazardous waste regulation.[2] As a result, in these states the state solid waste laws, which apply to non-hazardous wastes, regulate the disposal of these coal combustion wastes. Column 2 of Exhibit 4-1 shows that: (1) in seven states, coal combustion wastes are not exempt from hazardous waste regulation (indicated by an entry of CH), which means that they are tested to determine whether they will be regulated as solid or hazardous wastes; (2) in all but one of the remaining states wastes are regulated by solid waste regulations (indicated by an entry of SW); and (3) in the one remaining state, wastes are exempt from both the hazardous waste and solid waste regulations (indicated by an entry of EX).

EXHIBIT 4-1

STATE REGULATIONS GOVERNING COAL COMBUSTION WASTE DISPOSAL

STATE	(1) % NATIONAL COAL-FIRED CAPACITY	(2) CLASSIFICATION	(3) PERMITS	(4) SITE RESTRICTIONS	(5) LINER	(6) LEACHATE CONTROL	(7) GROUND-WATER MONITORING	(8) CLOSURE CONDITIONS	(9) FINANCIAL ASSURANCE
Texas	8.40%	SW	OFF SITE	NO	NO	NO	MAY	YES	YES
Indiana	6.44%	SW	ON & OFF SITE	NO	NO	NO	MAY	NO	NO
Kentucky	6.43%	CH	ON & OFF SITE	YES	MAY	YES	MAY	YES	NO
Ohio	6.02%	EX							
Pennsylvania	5.71%	SW	ON & OFF SITE	YES	NO	NO	MAY	YES	YES
Illinois	5.46%	SW	ON & OFF SITE	NO	NO	NO	NO	YES	YES
West Virginia	3.87%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
North Carolina	3.41%	SW	ON & OFF SITE	YES	NO	NO	YES	YES	NO
Michigan	3.37%	SW	ON & OFF SITE	YES	NO	NO	YES	NO	NO
Georgia	3.35%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Florida	3.26%	SW	OFF SITE	YES	YES	YES	YES	YES	YES
Missouri	3.16%	SW	ON & OFF SITE	YES	NO	MAY	NO	YES	NO
Alabama	3.08%	SW	ON & OFF SITE	YES	MAY	NO	YES	YES	NO
Tennessee	2.54%	CH	ON & OFF SITE	YES	MAY	NO	MAY	YES	NO
Nevada	2.49%	SW	ON & OFF SITE	YES	NO	NO	NO	NO	NO
South Carolina	2.24%	SW	ON & OFF SITE	YES	NO	YES	NO	YES	NO
Wisconsin	2.19%	SW	ON & OFF SITE	YES	MAY	MAY	MAY	YES	YES
Louisiana	1.98%	SW	ON & OFF SITE	YES	YES	YES	YES	YES	YES
Colorado	1.97%	SW	OFF SITE	YES	YES	YES	YES	NO	NO
Iowa	1.83%	SW	OFF SITE	NO	NO	MAY	NO	NO	NO
Wyoming	1.82%	SW	ON & OFF SITE	YES	NO	NO	NO	NO	NO
Kansas	1.69%	SW	ON & OFF SITE	YES	NO	NO	MAY	YES	YES
Arizona	1.67%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
New Mexico	1.58%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Utah	1.57%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Minnesota	1.54%	SW	ON & OFF SITE	YES	NO	MAY	YES	YES	NO
Arkansas	1.48%	SW	ON & OFF SITE	YES	NO	NO	NO	YES	YES
Maryland	1.48%	SW	OFF SITE	NO	NO	YES	YES	NO	NO
North Dakota	1.39%	SW	ON & OFF SITE	NO	NO	MAY	YES	YES	YES
Oklahoma	1.34%	CH	ON & OFF SITE	YES	NO	NO	YES	YES	YES
New York	1.24%	SW	ON & OFF SITE	YES	MAY	MAY	YES	YES	NO
Virginia	0.94%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Washington	0.93%	CH	OFF SITE	YES	YES	YES	YES	YES	NO
Nebraska	0.85%	SW	ON & OFF SITE	NO	NO	MAY	NO	NO	NO
Montana	0.74%	SW	OFF SITE	YES	NO	NO	NO	NO	NO
Mississippi	0.62%	SW	OFF SITE	NO	MAY	NO	NO	YES	NO
New Jersey	0.51%	CH	ON & OFF SITE	YES	NO	NO	YES	YES	YES
Massachusetts	0.41%	SW	ON & OFF SITE	YES	NO	NO	NO	NO	NO
Oregon	0.31%	SW	ON & OFF SITE	YES	NO	NO	MAY	NO	YES
Delaware	0.27%	SW	ON & OFF SITE	YES	NO	YES	YES	YES	NO
Maine	0.15%	CH	ON & OFF SITE	YES	YES	YES	MAY	YES	NO
South Dakota	0.13%	SW	ON & OFF SITE	NO	NO	NO	NO	YES	NO

EXHIBIT 4-1 (continued)

STATE REGULATIONS GOVERNING COAL COMBUSTION WASTE DISPOSAL

STATE	(1) % NATIONAL COAL-FIRED CAPACITY	(2) CLASSIFICATION	(3) PERMITS	(4) SITE RESTRICTIONS	(5) LINER	(6) LEACHATE CONTROL	(7) GROUND-WATER MONITORING	(8) CLOSURE CONDITIONS	(9) FINANCIAL ASSURANCE
New Hampshire	0.12%	SW	ON & OFF SITE	NO	NO	NO	YES	NO	NO
Alaska	0.01%	SW	ON & OFF SITE	YES	NO	NO	MAY	NO	NO
California	0.00%	CH	ON & OFF SITE	YES	NO	YES	MAY	YES	YES
Connecticut	0.00%	SW	ON & OFF SITE	YES	NO	YES	YES	YES	NO
Vermont	0.00%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Rhode Island	0.00%	SW	ON & OFF SITE	YES	NO	YES	YES	NO	NO
Hawaii	0.00%	SW	ON & OFF SITE	NO	NO	NO	NO	NO	NO
Idaho	0.00%	SW	ON & OFF SITE	NO	NO	MAY	NO	NO	NO

NOTES

Column (1) Percent national coal-fired capacity: i.e., each state's share of total U.S. coal-fired generating capacity.

Column (2) Classification: SW - coal combustion waste is exempted from hazardous waste regulation and regulated as a solid waste.

CH - coal combustion waste is not exempted from hazardous waste regulation and is tested for hazardous characteristics (In practice, coal combustion wastes are rarely considered hazardous, therefore columns 3-8 reflect solid, not hazardous, waste regulations).

EX - coal combustion waste is exempted from both solid and hazardous waste regulation.

Column (3) Permits: Permits are required for off-site facilities only, or for both on-site and off-site facilities.

Columns (4), (5), (6), (7), (8), (9): YES - the disposal standard is imposed by state regulations.

NO - the disposal standard is not imposed by state regulations.

MAY - the regulation states that a case-by-case investigation will determine whether the disposal standard will be imposed.

Source: Wald, Harkrader & Ross, Survey of State Laws and Regulations Governing Disposal of Utility Coal-Combustion Byproducts, prepared for the Utility Solid Waste Activities Group, September, 1983.

Of the seven states that do not exempt coal combustion wastes from hazardous waste regulation (indicated by a CH classification in Exhibit 4-1), California burns little coal to produce electricity. The hazardous waste regulations of the six remaining states -- Kentucky, Tennessee, New Jersey, Oklahoma, Maine, and Washington -- regard coal combustion wastes as "characteristic" waste; that is, the wastes are tested for Extraction Procedure (EP) toxicity (see Chapter Five for further discussion), and if the waste proves to be toxic, some or all sections of state hazardous waste regulations apply. In Kentucky, for example, hazardous waste standards concerning lining and leachate control are enforced for coal combustion wastes that are found to be toxic, but utilities are not required to participate in the hazardous waste management fund established to ensure the long-term viability of disposal facilities. Similarly, according to the hazardous waste regulations of Tennessee and Oklahoma, if a waste is determined to be toxic, strict analysis and monitoring requirements must be followed, but compliance with state hazardous waste design and operating standards is not required. Officials from these five states have indicated that it is very rare for a coal-burning utility's waste to be classified as hazardous.[3] Therefore, state solid waste regulations, with only isolated exceptions, establish the standards applicable to most coal combustion waste disposal activities.

Although solid waste regulations in most states do not differentiate between coal combustion wastes and other solid wastes, solid waste regulations in three states make specific reference to coal combustion waste disposal:

- Ohio's solid waste regulations list "non-toxic fly ash ... and slag ... that are not harmful or inimical to public health" as wastes that are exempt from solid waste regulation. Ash is typically determined to be non-toxic, according to the USWAG report.

- Maine's solid waste regulations provide a separate, more stringent set of design and operating requirements for the disposal of coal combustion wastes. The requirements call for lining, leachate control, and ground-water monitoring at coal combustion waste sites. These standards do not apply to other solid waste disposal facilities.[4]

- Pennsylvania has established industry-specific waste disposal standards. Pennsylvania's regulations for coal combustion waste disposal exclude the leachate control systems and liner requirements that apply to general solid waste disposal facilities.

4.1.2 Requirements for Coal Combustion Waste Disposal

The solid waste regulations of every state require that off-site solid waste disposal facilities be permitted or have some form of official approval. In order to obtain a permit, the operator of a facility must meet the requirements that are outlined in the regulations. These regulations are listed in Exhibit 4-1 and described below:

- The regulations in 41 states require permits for both on-site and off-site facilities. Eight states' regulations explicitly exempt on-site disposal from the permit requirement (Ohio, which exempts coal combustion wastes from solid waste regulation, is not included among the eight states). Column 3 of Exhibit 4-1 shows whether a permit is required for the operation of on-site and off-site solid waste disposal facilities.[5]

- Site restrictions are included in the solid waste regulations of 30 states. Examples of site restrictions are prohibiting solid waste disposal facilities from violating local zoning laws, banning placement of a new facility in a 100-year floodplain, and prohibiting waste placement unless there is a minimum depth to ground water. Column 4, "site restrictions," shows whether a state's regulations include restrictions on a disposal facility's location.

- Five states' regulations (Florida, Louisiana, Colorado, Washington, and Maine) call for all solid waste facilities to have a clay or synthetic liner. In addition, six states' regulations (Kentucky, Alabama, Tennessee, Wisconsin, New York, and Mississippi) call for the state permitting authority to determine, on a case-by-case basis, whether a liner is required. Column 5, "liners," shows whether the state's regulations include a requirement for liners at solid waste disposal facilities.

- Leachate control systems are collection devices placed under wastes in landfills or impoundments to collect waste leachate. Regulations in 12 states call for leachate control systems in all solid waste disposal facilities; the regulations of an additional 8 states allow leachate control systems to be required on a case-by-case basis. Column 6, "leachate control systems," shows whether a state's regulations include a requirement for leachate control systems at solid waste disposal facilities.

- The solid waste regulations of 17 states call for ground-water monitoring systems at all solid waste disposal facilities. The regulations of an additional 11 states specify that ground-water monitoring may be required on a case-by-case basis. Column 7, "ground-water monitoring," shows whether a state's regulations include requirements for ground-water monitoring wells at solid waste disposal facilities.

- Twenty-six states have solid waste regulations that call for closure and post-closure care. Column 8, "closure conditions," shows whether a state's regulations include requirements for closure and post-closure care for disposal facilities that have ceased operating.

- Thirteen states have solid waste regulations that include a financial assurance requirement. Column 9, "financial assurance," shows whether a state's regulations include a requirement that a solid waste facility operator post a bond or participate in a waste management fund to ensure the long-term viability of safe disposal facilities.

The management of waste in surface impoundments, a common practice for coal-burning utility plants, is often only indirectly addressed by state solid waste regulations. Only six states -- Louisiana, Colorado, New York, Washington, Oregon, and New Hampshire -- have solid waste regulations that include requirements exclusively for surface impoundments. The solid waste regulations of Indiana, Tennessee, Kentucky, North Carolina, Georgia, and Missouri exclude surface impoundments and defer to state water laws for regulatory authority. The water regulations in these states do not include any design and operating requirements for surface impoundments. However, according to the USWAG report, the water agencies in Missouri do regulate the design and operation of impoundments -- requiring lining and ground-water monitoring. According to the same report, state water agencies in Pennsylvania also regulate the design and operation of surface impoundments.

The regulatory requirements discussed above refer to regulations explicitly promulgated by the states for waste disposal facilities. However, state solid and hazardous waste regulations generally allow state authorities a large degree of discretion in designing site-by-site disposal standards that are more strict than those specified in the solid waste regulations. Many states' regulations allow local governments to design their own waste disposal regulations, provided that the standards set forth in the state solid waste regulations are enforced. Interviews with several state environmental officials and the summaries in the USWAG report indicate that in some states coal combustion utility wastes are regulated more stringently than what is required by the solid waste regulations. For example, the solid waste regulations in Texas have few design and operating requirements and exempt on-site disposal from the permit requirement. It is, however, the policy of the state environmental agency to provide guidelines for on-site facilities as well as off-site facilities, and to require ground-water monitoring. (For more information on individual state regulations, see Appendix C.)

4.1.3 Summary

The regulation of coal combustion waste is generally carried out under state solid, not hazardous, waste regulations. These solid waste regulations vary from state to state. Based on the requirements included under each state's solid waste regulations (as shown in Exhibit 4-1), it is difficult to generalize about the extent of state regulation of coal combustion wastes; some states have very stringent regulations and/or policies, such as those that impose design and operating standards and on-site and off-site permit requirements, whereas other states have few requirements or exempt on-site disposal from regulation. For a number of states, requirements are determined on a case-by-case basis. This allows the states to take climatic, geologic, and other site-specific characteristics into account for each waste management facility.

4.2 AVAILABLE WASTE MANAGEMENT METHODS AND CURRENT PRACTICES

There are a variety of methods available for managing coal combustion wastes. Wastes may be land managed in impoundments, landfills, mines, and quarries or may be reused for various purposes. This section describes types of land management of coal combustion wastes and their prevalence within the ten EPA-designated regions of the United States. The second part of the section reviews available waste management technology alternatives (such as lining, leachate collection, and pre-disposal treatment), and explores how these different technologies are currently used in different parts of the U.S. and how these technologies have changed over time. The third part of this section describes the potential for ocean disposal to be used to manage coal combustion wastes. The final section describes coal combustion waste recycling. The waste management methods discussed in this section apply to high-volume and low-volume utility waste streams since these wastes are often co-disposed in the same facility.[6]

4.2.1 Land Management of Coal Combustion Wastes

80 percent of coal combustion waste is treated, stored, and/or disposed by means of land management, with the remaining 20 percent recycled (see Section 4.2.4). This section describes three common methods of land management currently used for coal combustion wastes. It also presents data on use of these management methods geographically and how land management practices have changed over time.

4.2.1.1 Types of Coal Combustion Waste Land Management

Three types of utility waste land management facilities are commonly used today:[7]

- **Surface Impoundments** -- often called wet ponds, in which coal combustion wastes are disposed as a slurry or sludge, allowing solids to settle and accumulate at the bottom of the pond.
- **Landfills** -- facilities used for disposing of dry or dewatered coal combustion wastes; landfills are typically managed like an earth-moving operation in which the wastes are disposed in the excavated area.
- **Mines and Quarries** -- abandoned pits in which wet or dry wastes are disposed.

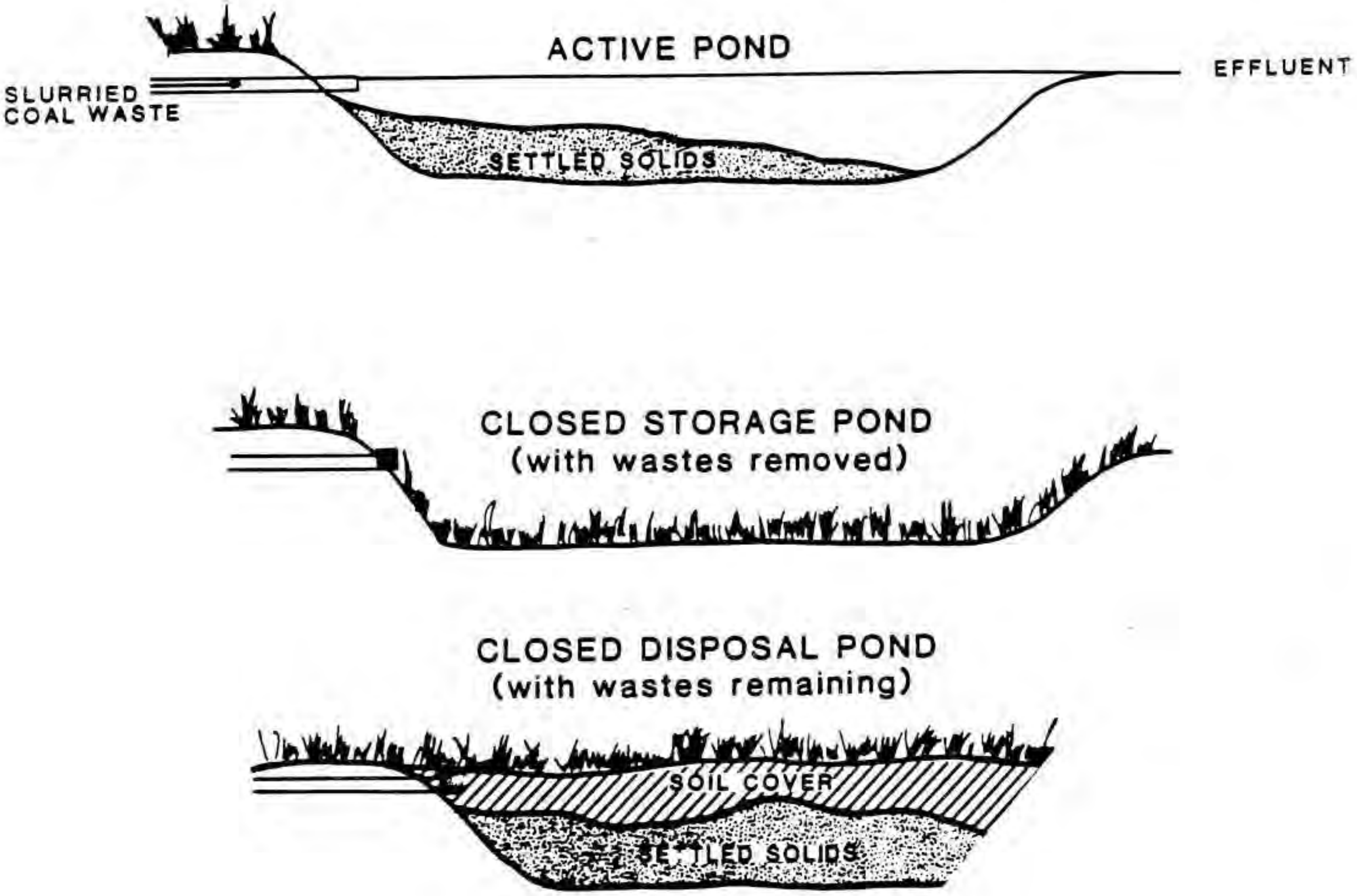
Surface Impoundments

Surface impoundments are used to treat, store, and dispose of coal combustion wastes. Slurried coal ash and other wastes are introduced into the impoundment; the solids settle out and gradually accumulate at the bottom of the pond, leaving relatively clear water at the surface, which is often discharged to surface water. By using this method, certain types of waste treatment, such as neutralization of acids, can be accomplished concurrently with disposal. Exhibit 4-2 illustrates the different stages in the life of a typical impoundment.

Historically, wet ponding has been one of the most widely used disposal methods for coal ash and FGD wastes because it is simple and easily implemented. In 1983, about 80 percent of the waste management facilities used

EXHIBIT 4-2

TYPICAL SURFACE IMPOUNDMENT (POND) STAGES



by utilities employed some type of sedimentation treatment pond; most of these treatment ponds were used directly as final disposal impoundments (about 45 percent of all facilities; see section 4.2.1.2). The remainder of the impoundments were used only for treatment and temporary storage of waste, in part to comply with the National Pollutant Discharge Elimination System established in Section 402 of the Clean Water Act.[8] In recent years, some state and local regulations concerning wet ponds have become more restrictive, requiring liners and ground-water monitoring at these facilities. These types of restrictions will tend to increase wet ponding costs, making it less attractive as a disposal option.[9]

Utilities may use a single pond or a series of ponds to facilitate the settling of solids. Chemicals or different wastes can be added at different points in the ponding system to produce desired chemical reactions, such as metals precipitation or neutralization. Fly ash, bottom ash, and FGD wastes are usually sluiced with water to the impoundments. The ash solids may be allowed to accumulate in a pond until it is full, or the pond may be drained and the solids dredged periodically and taken to an alternative disposal site, such as a landfill.

Pond designs vary widely depending upon local site conditions, the regulations that govern design of the impoundment, and whether bottom ash, fly ash, FGD wastes, or a combination of wastes are to be disposed and/or treated in the ponds. Because utility wastes are generated in large volumes, a pond's total surface area may cover up to several hundred acres, and the initial depth of a pond may be anywhere between 10 and 100 feet.[10] The total volume of an impoundment system depends on several factors, including the total quantity of ash to be disposed (both dry and slurried volumes), the liquid and solid retention times, the type and degree of treatment performed, and the desired quality of the discharge or effluent. The number of ponds in a system and the specific uses to which each is put can also influence the total volume required for wet ponding.

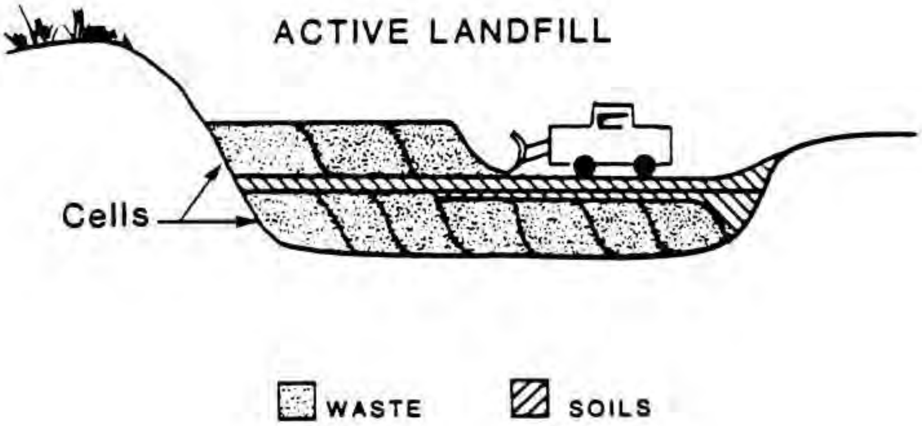
Landfills

Landfills are used to dispose of coal combustion wastes such as fly ash, bottom ash, and FGD sludges when they are produced or after they are dredged from surface impoundments that are used as interim treatment facilities. The typical design of a landfill during its active stage and after closure is depicted in Exhibit 4-3.

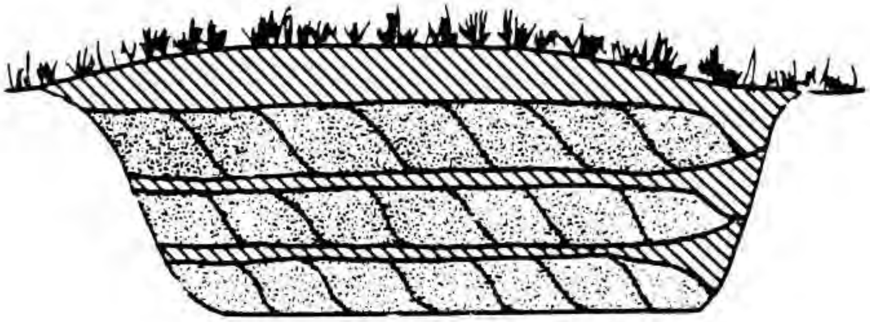
Landfills are constructed in a somewhat similar fashion to surface impoundments. Excavation is required in both cases, but may be ongoing throughout a landfill's active life because most large landfills are divided into sections, or cells, of which only one or two may be active at any given time. A landfill cell is defined as the area (up to several hundred square feet) over which waste is placed to a depth ranging from one to ten feet (industry practice refers to each layer of cells as a lift). Several lifts may be stacked atop one another in the landfill. A cell may be open for periods ranging from a day to a few weeks, after which it is usually covered with six inches to several feet of soil. The waste and soils are often sprinkled with water throughout the fill operation to mitigate potential dust problems.

EXHIBIT 4-3

DIAGRAMS OF ACTIVE AND CLOSED LANDFILLS


ACTIVE LANDFILL

CLOSED LANDFILL



Excavation may be initiated in phases; for example, as one cell is filled, another is prepared for waste placement, while yet another is being excavated. Roads are built in to provide access for waste-hauling equipment as well as for the earth-moving and earth-compacting equipment that prepares the waste after it has been placed in the landfill cell. After a cell is filled, the access road frequently becomes part of the containment system as a wall separating one cell from the next.

Landfilling of coal ash and FGD sludges has increased over the past few years as the costs of wet ponding have increased (see section 4.2.1.2). Most electric utilities that use landfills currently dispose their high-volume wastes in Subtitle D (non-hazardous waste) landfills. Landfills in compliance with RCRA Subtitle C standards may be used occasionally for disposal of small quantities of hazardous waste.[11]

Mine and Quarry Disposal

Some utilities use abandoned mines or quarries as ash and FGD sludge disposal sites. Abandoned mine disposal includes the use of mine shafts as well as strip-mined areas. Wastes disposed to abandoned mine shafts can be dumped into the shaft or carefully placed within the mine to fill the areas remaining after the coal or other material has been removed. Strip-mined areas may be filled like a landfill. Regulatory agencies may consider wastes disposed in this manner to pose less of a threat than the runoff and potential contamination from the abandoned mine itself.[12] In some cases, a chemical reaction between the waste and the mine runoff and leachate might actually reduce the toxicity of the runoff (for example, an alkaline sludge could neutralize acid mine drainage). However, the likelihood of such a mitigative effect is very site-specific and would not necessarily occur uniformly throughout any given mine disposal site.

In a few cases, utility wastes, particularly acidic wastes, have been disposed in quarries. Limestone quarries are considered the best setting for this type of disposal because they provide a natural acid buffering capacity and the capacity for the metals present in the waste to be attenuated by chemically combining with materials in the quarry.[13] Quarry disposal of wastes works well for lime or limestone slurry wastes, which harden to form a concrete-type floor at the bottom of the quarry, thereby plugging any potential leakage paths. The probability of achieving success with this method must be evaluated on a case-by-case basis prior to its use.

4.2.1.2 Prevalence of Various Land Management Methods

Use of the waste management methods described above can vary from plant to plant and, in some cases, among individual generating units at a single power plant. This section presents information on how these utility waste management methods are employed nationwide and within EPA regions. It also discusses how these utility waste management methods have changed over time. The emphasis is on surface impoundments and landfills because these two waste management methods are the most commonly-used utility waste management practices in the United States.

The information presented in this section was derived from the Edison Electric Institute Power Statistics Database, currently maintained by the Utility Data Institute. This database contains information on power plant characteristics for all electric utility generating plants in the U.S. These data include number of power plants, number of generating units at each power plant site, type of fuel, plant capacity, as well as other information. It also contains information on the type of waste management methods currently used by power plants throughout the country, including type of disposal facility and whether the wastes were disposed at the power plant or in off-site facilities. Because each generating unit at a power plant may have its own waste management practice, the database gives waste disposal information for all generating units.

Data were not available for all generating units in the database. When information is not available, the extent of data coverage is indicated. In some instances the number of generating units on which no information was available was quite high. Although EPA recognizes the possibility of some statistical bias due to lack of data on some generating units, this database is the most comprehensive source available on utility waste management practices. EPA has no reason to believe that such bias is serious enough to call into question conclusions drawn in this analysis.

Exhibit 4-4 displays, for each of the ten EPA regions of the U.S. (see Exhibit 2-4 for a map of these regions), the number of generating units whose waste is managed in surface impoundments, in landfills, or mines. The most

EXHIBIT 4-4

UTILITY WASTE MANAGEMENT FACILITIES BY EPA REGION (number of generating units) a/

EPA Region	Surface Impoundments	Landfills	Minefills	Other/ Unknown	Total
1	1	10	0	7	18
2	0	22	0	17	39
3	33	103	1	7	144
4	195	55	0	45	295
5	160	198	4	130	492
6	19	48	2	18	87
7	55	61	1	32	149
8	9	56	23	21	109
9	11	16	0	7	34
10	0	9	2	0	11
U.S. Total	483	578	33	284	1378

Source: Utility Data Institute Power Statistics Database

a/ The data are provided by generating unit because each generating unit at a power plant may have its own management facility. A generating unit typically refers to a single boiler, turbine, and generator set at a power plant. A power plant may have more than one generating unit at the site. For the database used here, data were available for 1,378 generating units located at 514 power plants.

common types of facilities used by the electric utility industry are surface impoundments and landfills:

- Landfills are the most common type of disposal facility used. Of the 1,094 generating units for which data were available (for 284 units, type of waste disposal method was unknown), 578 units (about 53 percent) used landfills for waste disposal. Landfills are used throughout the United States, with the largest number (over one-half of all landfills) located in the high coal-consuming, industrialized areas of the East and Midwest (Regions 3 and 5).
- Surface impoundments are also commonly used; approximately 44 percent of the generating units (483 out of 1,094) used this type of management facility. Of the 483 generating units that place wastes in surface impoundments, nearly 75 percent are located in Regions 4 and 5. (In the past, access to abundant, inexpensive supplies of water in these Regions often made it economical to use this management option.)
- Mine disposal is used for about three percent of all generating units (33 units out of 1,094). This disposal technique is used most frequently in the western U.S., particularly Region 8. Power plants in this area are often located at or near the coal mine that is supplying the plant. Since the coal mine is located nearby, disposal of waste in the mine is often economic.

When managing coal combustion wastes, electric utilities may treat, store, or dispose of the wastes at the power plant or at facilities located off-site. EPA could not determine from the data available how far the wastes are transported when managed off-site, although the cost of transporting the wastes would tend to encourage disposal near the power plant. A summary of industry practices is provided in Exhibit 4-5, which shows for each EPA region, by type of facility, whether the wastes are managed on-site or off-site.

EXHIBIT 4-5

LOCATION OF UTILITY WASTE MANAGEMENT FACILITIES: ON-SITE VERSUS OFF-SITE (number of generating units)*

EPA Region	On-Site	Off-Site	Unknown	Total
1				
Surface Impoundments	1	0	0	1
Landfills	0	8	2	10
Other/Unknown	0	0	7	7
Total	1	8	9	18
2				
Surface Impoundments	0	0	0	0
Landfills	3	18	1	22
Other/Unknown	0	0	17	17
Total	3	18	18	39
3				
Surface Impoundments	25	3	5	33
Landfills	62	37	4	103
Other/Unknown	0	1	7	8
Total	87	41	16	144
4				
Surface Impoundments	186	4	5	195
Landfills	26	8	21	55
Other/Unknown	0	0	45	45
Total	212	12	71	295
5				
Surface Impoundments	141	5	14	160
Landfills	41	140	17	198
Other/Unknown	0	6	128	134
Total	182	151	159	492
6				
Surface Impoundments	18	0	1	19
Landfills	36	3	9	48
Other/Unknown	0	6	14	20
Total	54	9	24	87

EXHIBIT 4-5 (continued)

LOCATION OF UTILITY WASTE MANAGEMENT FACILITIES: ON-SITE VERSUS OFF-SITE (number of generating units)*

EPA Region	On-Site	Off-Site	Unknown	Total
7				
Surface Impoundments	42	0	13	55
Landfills	20	26	15	61
Other/Unknown	7	1	25	33
Total	69	27	53	149
8				
Surface Impoundments	6	2	1	9
Landfills	28	11	17	56
Other/Unknown	2	23	19	44
Total	36	36	37	109
9				
Surface Impoundments	9	2	0	11
Landfills	16	0	0	16
Other/Unknown	0	0	7	7
Total	25	2	7	34
10				
Surface Impoundments	0	0	0	0
Landfills	5	4	0	9
Other/Unknown	0	2	0	2
Total	5	6	0	11
Total U.S.				
Surface Impoundments	428	16	39	483
Landfills	237	255	86	578
Other/Unknown	9	39	269	317
Total	674	310	394	1378

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* The data are provided by generating unit because each generating unit at a power plant may have its own management facility. A generating unit typically refers to a single boiler, turbine, and generator set at a power plant. A power plant may have more than one generating unit at the site. For the database used here, data were available for 1,378 generating units located at 514 power plants.

- Nearly 70 percent of all generating units in the U.S. manage their coal combustion wastes on-site (based on information for 984 units, 674 units dispose on-site). About two-thirds of the on-site facilities are surface impoundments; most of the other on-site facilities are landfills.

- Landfills are used for about 95 percent of all off-site disposal in the U.S. This is not surprising considering that surface impoundments are typically used when wastes are transported as a wet slurry; the cost of disposal could become prohibitive if a utility transported the slurry off-site.

- Coal combustion waste management practices also differ by region:

    - In the Northeast (Regions 1 and 2), where few coal-fired generating units are located, management tends to occur off-site in landfills.

    - The highest percentage of on-site management is found in the South (Region 4), where about 95 percent of all units manage their waste on-site (212 units, based on information from 224 units). On-site management is common because utilities in this region often use surface impoundments, which are typically located at the power plant.

    - In the Rockies and northern Great Plains area (Region 8), most of the off-site disposal (23 of 36 units) occurs in mines that are generally adjacent to the power plant.

These trends in utility waste management methods have been changing in recent years, with a shift towards greater use of disposal in landfills located on-site. For example, for generating units built since 1975, nearly 65 percent currently dispose of coal combustion wastes in landfills, compared with just over 50 percent for units constructed before 1975. Similarly, over 80 percent of all units built since 1975 use on-site management facilities, compared with just under 65 percent of all units built before 1975 that manage wastes on-site.

4.2.2 Alternative Waste Management Technologies

Section 4.2.1 described the types of land management facilities used by utilities and patterns of use. This section describes the additional technologies that utilities may employ at the facilities described above in order to reduce potential environmental risk associated with waste management. For example, some utilities use liner systems for impoundments and landfills, leachate collection systems, and ground-water monitoring systems to control and monitor waste constituent migration. Pre-treatment technologies, by altering physical and chemical properties, can also render wastes more amenable for certain disposal methods. This section also presents data on the prevalence of these various technologies. The alternative technologies discussed in this section, although not necessarily the same as technologies required for RCRA Subtitle C facilities, may be required by current state regulations (described in Section 4.1) and could be more widely used in the future to further mitigate potential environmental impacts at utility waste disposal sites not currently employing these technologies.

4.2.2.1 Installation of Liners

Until recently, most surface impoundments and landfills used for utility waste management have been simple, unlined systems. Lining is becoming a more common practice, however, as concern over potential ground-water contamination from "leaky ponds" and, to a lesser extent, from landfills has increased. Some waste management facilities use one or more impermeable synthetic liners; some are lined with one or more layers of low-permeable clay[14]; and some use a combination of clay and synthetic liners.

Synthetic Liners

Several dozen manufacturers and distributors supply impermeable synthetic liners. The most common materials of construction for these liners include polyvinyl chloride (PVC) and high-density polyethylene (HDPE), although several other impermeable synthetics have also been used. Liners may be reinforced with fibers to increase strength and decrease the likelihood of punctures. The liners can be purchased in standard thicknesses that range from 10 mils to 100 mils,[15] or can be made to order. Most liner installations will include protective geotextile fabric above and/or below the impermeable synthetic liner to minimize further the potential for puncture.

Preparation of the site prior to installation of a synthetic liner is similar to that which occurs before clay liner construction. However, more care must be taken to smooth out the surfaces to eliminate any peaks and cavities on the disposal facility floor that could cause a puncture of the liner material. Consequently, surface preparation costs are greater than those for clay liners. Excavation costs are usually less, however, because the thinner synthetic liners allow shallower excavation (i.e., the additional excavation required to install a clay liner that is several feet thick can be avoided if a much thinner synthetic liner is installed).

The liner itself, which comes rolled or folded in large pieces, is laid in the field and sealed along the seams by heat or solvent fusion techniques; the seams may be field tested at spot checkpoints. The liner is usually covered with a foot or more of soil to protect it from puncture and to keep it in place during construction of the disposal facility. The edges of the liner at the tops of the dikes or landfill cell walls must be well secured to prevent the liner from pulling out and shifting due to the mass of the wastes placed in the impoundment or landfill. Some facilities are double lined and often contain a leachate collection system located in a soil or sand layer between the two liners.

Among the limitations to the use of synthetic liners is their susceptibility to tear and puncture. This is of particular concern in a single-lined impoundment because of the opportunity for liquids to seep through a single tear. Synthetic liners are also susceptible to degradation by certain waste materials. Acidic wastes, for example, can degrade some synthetic liner materials. As with clay liners, waste/liner compatibility testing should be performed to ensure that the disposed wastes will not weaken or permeate the liner. Additionally, because the seams of a synthetic liner are frequently weaker than the liner itself, they may pull apart under stress (e.g., large mass loadings or wave action). Finally, dredging of synthetically-lined impoundments must be done cautiously, sometimes at very significant expense.

Synthetic liners, unlike clay liners (described below), are impermeable. Another advantage is the ease of repairing an exposed, damaged impoundment liner. A tear or puncture can be patched and seamed, and an impoundment put back into service, relatively quickly. (To repair subsurface damage, however, the impoundment must be wholly or partially drained.) Another advantage to using synthetic liners is that because of manufacturer quality control, a facility owner can be fairly certain that each liner sheet is as impermeable as the next. Clay is expensive to transport and in areas of the country where clay soils are scarce, a synthetic liner system may prove to be the less expensive option.

Clay Liners

The installation of a clay liner in a surface impoundment or landfill entails several steps. First, the site must be excavated or graded to a level below the design elevation of the facility floor. Many facilities take advantage of natural low areas or abandoned ponds to minimize excavation costs. The excavated earth can be used to build up the dike walls for the impoundment or to build containing berms within the landfill. Occasionally, soil must be brought to the construction site to raise the dikes to the design height.

Once the floor and dikes or berms have been prepared, the clay liner is laid in 6- to 9-inch lifts; its final thickness will be between 1 foot and 8 feet. Each lift is individually compacted before the next one is laid, thereby providing effective compaction and minimizing leakage potential. Field testing of the clay for permeability and other pertinent characteristics is sometimes performed during construction to provide quality assurance. Before the impoundment or landfill can be used, the liner is visually inspected for flaws; non-contaminated water may also be piped to the pond to assure that the liner is sufficiently impermeable.

One of the primary concerns about the use of clay liners is whether the entire clay liner meets thickness and permeability requirements. If weather conditions during liner construction are arid and hot, the liner may dry out and crack, causing localized areas of leakage. If conditions are wet or the clay is too moist, clay compaction may never be sufficient to achieve the necessary low permeability. The clays used as liner materials vary in the degree to which they are compatible with the wastes placed in the facility. Laboratory tests, in which the proposed liner material is exposed to the wastes intended for management, should be conducted for each facility to ensure that components of the waste material will not unduly alter the permeability of the clay used as liner material. If the chemical characteristics of the generated waste were to change over time, then the tests would need to be repeated to determine what effect the altered waste stream would have on the clay liner.

An advantage of clay liners is their potential for chemical, particularly cation, attenuation. The chemical structure of clay allows its use as an exchange site for metallic cations and other ions that might gradually seep out of the facility. Such exchange further reduces the opportunities for migration of waste constituents to the ground water. For facilities with fairly ready access to clays, the capital and construction costs associated with the use of a clay liner, even one that is several feet thick, may be substantially lower than those associated with the use of a synthetic liner.

Composite Liners

Many waste management facilities in industries currently subject to RCRA Subtitle C requirements are installing liner systems that combine both clay liner and synthetic liner technologies. Most commonly, an impoundment or landfill will be lined with 2-4 feet of impermeable clay, which is then prepared for placement of a synthetic liner. The synthetic liner may be covered with 1-2 feet of sand to serve as drainage for a leak detection system. Some facilities may then add another 1- to 2-foot layer of clay, which is again prepared for placement of the upper synthetic liner. In landfills, another leachate collection system is usually placed above this upper liner.

The composite synthetic/clay liner system offers a combination of advantages over single-material liners. A composite liner has some of the advantages provided by synthetic liners, such as factory quality control and ease of repair (for the upper liner), as well as the advantage of clay's propensity for attenuating escaped ions. Furthermore, use of multiple-liner materials reduces the likelihood that waste material will leak into the ground water because of chemical incompatibility between a waste and a single liner material. In general, the more layers of impermeable liner material that are used, the more efficient containment of liquids will be, thus reducing the likelihood of a release of waste material.

The biggest drawback of the composite synthetic/clay liner system is the cost of installation. Utility waste landfills are very large (up to 100 acres or more), and a liner large enough to cover such a area could be very expensive. In areas where labor costs are high and clay is unavailable locally and must be transported long distances, these costs would be magnified.

Frequency of Liner Use

Some electric utilities have installed liners to retard the flow of leachate from the waste disposal facility to the surrounding area. Exhibit 4-6 shows the extent to which electric utilities are currently using this technology.

- About 25 percent of all generating units in the U.S. for which data were available (139 of 580 units) have installed some type of liner. There are no available data on the material used to construct these liners or if more than one liner has been installed at the disposal facility.

EXHIBIT 4-6

INSTALLATION OF LINERS FOR LEACHATE CONTROL AT UTILITY WASTE MANAGEMENT FACILITIES (number of generating units)*

EPA Region	Unlined	Lined	Unknown	Total
1				
Surface Impoundments	0	0	1	1
Landfills	0	0	10	10
Other/Unknown	0	0	7	7
Total	0	0	18	18
2				
Surface Impoundments	0	0	0	0
Landfills	1	14	7	22
Other/Unknown	0	0	17	17
Total	1	14	24	39
3				
Surface Impoundments	17	2	14	33
Landfills	17	7	79	103
Other/Unknown	0	0	8	8
Total	34	9	101	144
4				
Surface Impoundments	153	3	39	195
Landfills	14	7	34	55
Other/Unknown	0	0	45	45
Total	167	10	118	295
5				
Surface Impoundments	90	20	50	160
Landfills	64	31	103	198
Other/Unknown	0	4	130	134
Total	154	55	283	492
6				
Surface Impoundments	7	7	5	19
Landfills	11	17	20	48
Other/Unknown	0	0	20	20
Total	18	24	45	87

EXHIBIT 4-6 (continued)

INSTALLATION OF LINERS FOR LEACHATE CONTROL AT UTILITY WASTE MANAGEMENT FACILITIES (number of generating units)*

EPA Region	Unlined	Lined	Unknown	Total
7				
Surface Impoundments	30	4	21	55
Landfills	7	4	50	61
Other/Unknown	6	0	27	33
Total	43	8	98	149
8				
Surface Impoundments	4	0	5	9
Landfills	12	6	38	56
Other/Unknown	0	0	44	44
Total	16	6	87	109
9				
Surface Impoundments	2	9	0	11
Landfills	2	4	10	16
Other/Unknown	0	0	7	7
Total	4	13	17	34
10				
Surface Impoundments	0	0	0	0
Landfills	4	0	5	9
Other/Unknown	0	0	2	2
Total	4	0	7	11
Total U.S.				
Surface Impoundments	303	45	135	483
Landfills	132	90	356	578
Other/Unknown	6	4	307	317
Total	441	139	798	1378

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* The data are provided by generating unit because each generating unit at a power plant may have its own waste management facility. A generating unit typically refers to a single boiler, turbine, and generator set at a power plant. A power plant may have more than one generating unit at the site. For the database used here, data were available for 1378 generating units located at 514 power plants.

- Based on the information available, landfills are more likely to be lined than surface impoundments. Of the 222 generating units that use landfills and that indicated whether the disposal facility was lined or not, about 40 percent (90 units) have lined disposal facilities. Only 13 percent of surface impoundments have liners installed (based on information from 348 of the 483 units).

The information in Exhibit 4-6 should be interpreted cautiously since data were available for only 42 percent of the population (580 units of 1,378 units). One of the reasons this information is unavailable is due to the number of electric utilities that dispose of coal combustion wastes off-site. In many of these cases, the utility does not know whether the off-site disposal facility is lined or not since the utility does not run the disposal operation.

Liner use has been increasing in recent years. Before 1975, less than 20 percent of all generating units managed their coal combustion wastes in lined facilities. For units constructed since 1975, however, this percentage has increased to over 40 percent. The proportion of lined management facilities is particularly high at generating units that produce FGD sludge; since 1975 about 60 percent of management facilities containing these wastes have been lined.

4.2.2.2 Leachate Collection and Ground-Water Monitoring

Any lined management facility may have a leachate collection system and any facility (lined or unlined) may be equipped with a ground-water monitoring system. Leachate collection systems are used to prevent the migration of contamination from a landfill or impoundment. Both systems can be used to monitor the rate and extent of contaminant migration. The design and placement of ground-water monitoring and leachate collection systems should take into account the manner in which a landfill or impoundment might potentially interfere with natural ground-water flow and usage patterns.

In surface impoundments, the leachate collection system(s) can be placed below the entire liner system or it can be placed between any two liners. Leachate collection systems typically consist of a drainage media (coarse sand and/or gravel) and perforated pipes (called riser pipes) that slope toward a collection sump. The collected leachate is pumped out via these riser pipes to the surface for treatment and/or disposal. If the riser pipes through which the leachate is pumped perforate the synthetic or clay liner, tight seals are necessary to ensure that the leachate does not escape through the perforation.

In landfills, leachate control systems can be installed below all liners (this is usually called a pressure relief system), between liners (the inter-liner leachate control system), and/or above the upper liner. The floors of a landfill cell are designed to slope to the leachate collection sumps and are usually covered with a drainage media such as sand or gravel. Each leachate control system has its own collection sump, which is emptied through riser pipes so that the leachate can be treated or disposed appropriately. As with impoundment liner systems, riser pipes, if they pierce the liners, must be sealed to prevent leakage.

Ground-water monitoring wells are placed at strategic locations to facilitate early detection of any contaminants that escape the facility and migrate to the ground water. The design and placement of the monitoring wells is based on site-specific hydrogeological assessments, soil chemistry, specific regulatory directives, and other physical and chemical factors. Downgradient wells typically are used to monitor the extent of contamination arising from a facility, and upgradient "background" wells are installed to serve as controls.

Most newer utility waste management facilities have ground-water monitoring systems, and many also have leachate collection systems. In other industries, permitted facilities subject to Subtitle C regulations are required by law to have both ground-water monitoring and leachate collection systems.[16] For utility waste disposal sites, it is estimated that about 15 percent of all facilities have leachate collection systems and about 35 percent have ground-water monitoring systems.[17]

4.2.2.3 Pre-disposal Treatment

Facilities employ a variety of waste treatment processes to alter the physical or chemical characteristics of wastes so that they will be compatible with the disposal method used. Treatment methods may also be employed to comply with the effluent limitations established under the Clean Water Act.

Sludge Dewatering

The most commonly used pre-disposal treatment process is sludge dewatering. This process is often necessary so that the sludge can be more easily handled and of a consistency suitable for landfill disposal. This procedure can also be used for any wet coal ash or combined coal ash/FGD sludge wastes. Most frequently, sludge dewatering is accomplished by sedimentation of the suspended solids in surface impoundments or, in some cases, in clarification tanks. This type of dewatering is carried out at 80 percent of the utilities.[18]

After the waste solids have had sufficient time to settle, the water layer is drawn off the tank or impoundment and is either discharged subject to National Pollutant Discharge Elimination System (NPDES) permits or recycled back to the plant as sluice or cooling water. The sludge layer containing the solid ash and other particles is allowed to accumulate for several months (or longer), and is finally dredged after the pond is drained. With this process, the solids content (initially between 5 and 15 percent by weight) can be increased to between 30 and 60 percent. The final solids content in the sludge is affected by the sedimentation impoundment or tank design, the initial solids content, the liquid and solids retention times, and the physical and chemical characteristics of the solid particles.

Even after dewatering, the settled sludges often have a mud-like consistency and still contain so much free liquid that they are inappropriate for landfill disposal. In this case, the sludge may be further dewatered by natural or mechanical processes. In arid and semi-arid areas, the sludges may be retained in the impoundments until natural evaporation removes still more water. Sludges may also be placed on drying beds made of screens, sand, or other drainage media designed to allow water to percolate out by gravity, while the solids are retained. In mechanical sludge dewatering, belt or vacuum filters, filter presses, thermal dryers, or other processes are used. Ten percent of the utilities use some sort of filtration to dewater sludges.[19] For high-volume sludges, however, mechanical dewatering equipment may be expensive and inconvenient to operate.

Reagent Addition

Most FGD sludges and some other wet sludges can be rendered less chemically reactive and/or more structurally stable by adding solidification, stabilization, or fixation reagents. This practice is not widespread; less than 10 percent of the utilities report using these processes.[20] Solidification agents, such as sawdust or soil, absorb the liquid in a sludge but do not chemically react with the sludge. Stabilization and fixation reagents chemically react with some portion of the sludge -- either the water, the dissolved solids, the particulate solids, or some combination of the three-- and, in some cases, may render potentially hazardous material non-hazardous as a result. All of these processes result in an increased volume of waste that contains less free water and is easier to handle than the original waste stream. An additional benefit is an increase in the structural integrity (shear stress and load-bearing potential; see Chapter Three for discussion of these characteristics) of the waste material so that it may be placed in deeper disposal facilities and covered with more material.

Low-volume Waste Treatment

The major methods available for low-volume waste management and treatment include:

- co-disposal;
- contract disposal;
- evaporation;
- incineration;
- neutralization;
- physical/chemical treatment; and
- recycle/reuse.

The type of waste management method used most often depends on the type of low-volume waste stream. Exhibit 4-7 shows the treatment process commonly used for each low volume waste stream. Each of these treatment processes is discussed briefly below.

EXHIBIT 4-7

SUMMARY OF CURRENT HANDLING, TREATMENT AND DISPOSAL OF LOW VOLUME WASTES

Low Volume Waste	Treatment	Predominant Disposal Method
Waterside Cleaning Waste	If organic chelating agents are used, this stream can be incinerated. If acids are used, the stream is often neutralized and precipitated with lime and flocculants.	1. Co-disposal with high volume wastes in pond or landfill following treatment. 2. Disposal by paid contractor.
Fireside Cleaning Waste	Sometimes neutralized and precipitated. For coal-fired plants most often diverted to ash ponds without treatment. If metals content is high, chemical coagulation and settling is used.	1. Co-disposal with high volume wastes in pond without treatment. 2. Ponding following treatment.
Air Preheater Cleaning Waste	Settling in ash pond; neutralized and coagulated if combined with other streams before treatment.	1. Co-disposal in pond without treatment. 2. Ponding with treatment.
Coal Pile Runoff	Neutralized by diverting to alkaline ash pond. Fine coal material caught in perimeter ditch is often diverted back to coal pile.	1. Co-disposal of sludge in landfill after treatment. 2. Co-disposal in ash pond.
Wastewater Treatment	Usually ponded with ash or as a separate waste. Sometimes solids co-disposed with bottom ash.	1. Ponding 2. Landfilling
Make-up Water Treatment	usually co-disposed in ash pond.	1. Co-disposal in pond.
Cooling Tower Basin Sludge	Very little survey or literature information; infrequent stream. Sludge comingled with wastewater treatment sludge.	1. Landfilling

EXHIBIT 4-7 (Continued)

SUMMARY OF CURRENT HANDLING, TREATMENT AND DISPOSAL OF LOW VOLUME WASTES

Low Volume Waste	Treatment	Predominant Disposal Method
Demineralizer Regenerants	Equalized in tanks, then comingled into ash ponds.	1. Ponding
Pyrite Wastes	Disposed in landfills with bottom ash or diverted to ash pond	1. Ponding 2. Landfilling

Source: EPRI, Characterization of Utility Low-Volume Wastes, prepared by Radian Corporation, Austin, Texas, May 1985.

-- Co-Disposal

Co-disposal of low-volume wastes with high-volume wastes into landfills and surface impoundments is commonly used in the utility industry. A January 1981 EPA letter (the Dietrich memorandum) currently allows co-disposal of low-volume wastes with high-volume wastes in landfills and surface impoundments.[21] In a 1985 EPRI study on low-volume waste management, about three-fourths of the power plants interviewed co-disposed some low-volume wastes in a surface impoundment or landfill.[22] The amount of treatment necessary before co-disposal varies with the waste stream. Solid wastes are typically disposed directly into the waste management facility. Liquid wastes are often routed to an interim treatment surface impoundment. Once in the surface impoundment, evaporation occurs and the remaining sludge is landfilled. If the liquid waste is chemically treated before ponding, heavy metals are often removed in a treatment facility; the treated liquid may then be reused or diverted to a surface impoundment while the residue from the treatment process is disposed in a landfill.

-- Contract Disposal

Many utilities hire outside contractors to treat and dispose of low-volume wastes. Contract disposal is most common for low-volume waste streams produced intermittently that are difficult to treat on-site. For example, hydrochloric acid boiler cleaning waste typically requires neutralization with high dosages of a caustic material. Construction of an on-site treatment system for this waste stream requires a large capital investment, although boiler cleaning wastes are produced only over a few hours once every two to five years. As a result, some utilities (7 of 22 power plants surveyed in EPRI's 1985 study) employ outside contractors when boiler cleaning is required.[23] The treated boiler cleaning waste is then co-disposed on-site or disposed of off-site.

Contract disposal is also a common waste management practice for spent ion exchange resin. In EPRI's 1985 study, of five power plants responding, four plants hauled these wastes off-site while one power plant co-disposed the waste on-site.[24]

-- Evaporation

Evaporation ponds are used to dispose of high concentration, low-volume liquid wastes. Prior to final disposal, liquid wastes are diverted to an evaporation pond, generally shallow ponds with a large surface area. The sludge remaining after most of the water evaporates is then dredged and disposed of in a landfill.

-- Incineration

Incineration of low-volume wastes includes injection into the boiler or mechanical evaporation. This method of disposal is most common with organic cleaning wastes (Ethylenediamide tetracedic acid (EDTA) or citrate waste). A 1987 EPRI study[25] examined the effect of incinerating EDTA and citrate wastes in a utility boiler. The findings showed that the additional metals contributed were minimal compared to the amount contributed by the coal.

Two of the twenty-two power plants interviewed in EPRI's 1985 study use this method of waste disposal.[26]

-- Neutralization

Acidic or alkaline wastes can be treated with either strong bases or acids, respectively, to produce a near neutral stream. For example, wastewaters, demineralizer regenerant, and coal pile runoff must typically be within a pH range of 6.0 to 9.0 to meet Clean Water Act (CWA) and National Pollutant Discharge Elimination System (NPDES) limits. Neutralization can be used to achieve these levels. Similarly, hydrochloric acid boiler cleaning waste, which may have a ph below 2.0, can undergo neutralization to raise the ph above RCRA corrosivity guidelines (ph values between 2.0 and 12.5 are not considered corrosive under RCRA).[27]

-- Other Physical/Chemical Treatment

Physical and/or chemical treatment systems can be used for reducing and removing dissolved and suspended contaminants from aqueous streams. The most prevalent treatments incorporate pH adjustment (i.e., addition of basic or acidic materials), precipitation (i.e., separating solids from solution or suspension), flocculation (i.e., aggregation of fine suspended particles), clarification (i.e., separating liquid and suspended solids) and filtration (i.e., trapping suspended solids). The continuous waste streams are treated to allowable levels. Boiler chemical cleaning and fireside cleaning wastes require higher reagent doses and occasionally additional processing to meet Clean Water Act (CWA) and National Pollutant Discharge Elimination System (NPDES) discharge limits for metals. Ten of the 15 power plants questioned in EPRI's 1985 study route boiler cleaning wastes through physical and/or chemical treatment systems prior to discharge.[28]

-- Reuse

Reuse is a common practice for many water-based low volume wastes, especially in water-limited regions of the country. For example, less contaminated streams (boiler blowdown, yard drains) can be used without treatment in cooling towers, ash handling systems, and flue gas desulfurization systems. Other wastes, such as boiler cleaning wastes and coal pile runoff, cannot easily be reused because they require extensive treatment prior to reuse. If a power plant does decide to treat these waste streams, the liquid portion of treated waste may be reused while the sludges produced during treatment are typically landfilled.

4.2.3 Ocean Disposal

Many different types of wastes, including industrial and municipal wastes, have been disposed at sea in the past, although the use of this method for disposing coal combustion wastes is only in the research and development phase. Typically, industrial and municipal wastes are shipped out to sea and disposed at any of several regulated dump sites, which are located anywhere from 20 miles to over 100 miles off the shore line. Another method of ocean disposal (seldom used, however) involves pumping or gravity feeding wastes through a pipeline that feeds directly from the land-based waste generating site or dump site into the ocean. When the wastes reach the final oceanic disposal site, they either dissolve and disperse or form a manmade reef.

The 1972 Marine Protection Research and Sanctuaries Act (MPRSA), EPA regulations regarding ocean disposal,[29] and the London Dumping Convention currently regulate ocean dumping with respect to the solids content, metals content, and toxicity of wastes considered for this method of disposal.

4.2.4 Waste Utilization and Recovery of Various Waste By-Products

Although the majority of the waste generated by coal-fired electric utilities is land disposed, a substantial percentage is recovered and reused. From 1970 to 1980, an average of 18 percent of all coal ash generated annually was utilized;[30] from 1980 to 1985, the average coal ash utilization rate exceeded 22 percent, with utilization in 1985 over 27 percent of all coal ash produced.[31] The amount of FGD sludge waste utilized is less than one percent of the total volume of FGD waste generated, although more efficient FGD sludge recovery and utilization processes currently being developed by the utility industry may increase this use. The combined utilization rate for all high-volume coal combustion wastes, i.e., fly ash, bottom ash, boiler slag, and FGD sludge, was about 21 percent in 1985.

The recovery processes are usually performed at the power plant. Use of the recycled waste may occur on-site or the recycled product may be sold for off-site use. Like any industrial product, the wastes to be recycled may be accumulated on-site prior to sale and delivery.

The recovery processes and the uses for waste by-products are numerous and quite varied:

- Bottom ash currently has the highest rate of utilization at 33 percent. It is used as blasting grit, road and construction fill material, for roofing granules, and has other miscellaneous uses.[32]
- Fly ash utilization is substantial. About 17 percent of fly ash production is used for concrete admixture, cement additives, grouting, road and construction fill material, and for miscellaneous other uses.[33]
- FGD wastes are not heavily utilized in the industry (less than 1 percent), but some utilities have the capacity to recover sulfur, sulfuric acid, or other sulfur products from the waste.[34]
- Some low-volume wastes (particularly solvents) that are segregated from the high-volume waste streams are potentially recoverable or available for other uses.
- Numerous other recovery processes and utilization techniques are currently in the research and development phase. At this time, however, the Agency is unaware of any advances in recovery processes that will significantly change the proportion of coal combustion wastes that are disposed.

Coal Ash

There are a variety of different options currently available for the utilization of fly ash, bottom ash, and boiler slag from coal-fired electric utilities. All types of coal ash are appropriate for use as construction materials, as cement additives, and for several other uses. Coal ash utilization is primarily centered in the southeast and north central United States.[35]

Most fly ash and some bottom ash exhibit pozzolanic (bonding) properties -- that is, the dried materials are cohesive and exhibit high shear strength and compressive load-bearing characteristics. These properties make ash an appropriate substitute for portland cement for many applications, including concrete production, standard cement production, and for special uses such as for the production of road base cement or even grouting.

Cement made with fly ash may be preferable to regular portland cement for some applications. One of the key benefits is the absence of heat release while the concrete or cement mixture cures; this absence of heat generation means that the design structural strength is more likely to be achieved. However, the use of fly ash and bottom ash as cement substitutes is limited because of the wide variability in ash composition, even in ash originating from the same coal supply or utility. The presence of metals in the ash can reduce the structural integrity of the final concrete by preventing the necessary chemical bonding. The presence of large quantities of sulfates or nitrates will also interfere with the pozzolanic properties. Because of this bonding interference, fly ash and bottom ash are thought to be able to replace no more than 20 percent of the cement used (or about 15 million tons of ash annually).[36] Improvements in utilization techniques may reduce the bonding interference and increase the reutilization potential of fly ash; however, the Agency is unaware of technical advances at this time that will allow substantially greater utilization in cement applications.

Fly ash and bottom ash are also commonly used as high-volume fill for various construction materials. The pozzolanic properties of these materials facilitate soil stabilization, making them desirable as fill additives. Coal ash has been used as fill in asphalt, road bases, parking lots, housing developments, embankments, and to line on-site disposal facilities at the utilities. In the future, numerous other construction applications may use coal ash as fill, particularly if the ash is available at lower cost than standard fill materials. However, the use of ash as fill is limited somewhat because of the variability of the ash composition.

Bottom ash and boiler slag have been used as substitutes for sand in sand-blasting operations and road de-icing. Ash and slag particles are similar in size and density to sand particles. In areas where sand is costly to transport, these wastes can be economical substitutes. Ash is less corrosive than salt and could therefore be a preferable de-icing material, although in some municipalities the use of ash for de-icing has been prohibited due to public concern over aesthetics (e.g., ash residue on cars).

A variety of minor uses for fly ash and bottom ash have been considered, some of which have already been implemented at a small number of utilities. For example, bottom ash has been used for granular roofing material. Fly ash has been used by some facilities as a stabilization reagent for acidic aqueous or semi-solid hazardous wastes: the high-pH fly ash reacts with other, low-pH waste to generate a neutral solution and to simultaneously precipitate dissolved metals as oxides and hydroxides. Because the fly ash exhibits pozzolanic properties, the ultimate waste product, when dried, often resembles concrete. The metals from the original waste stream are usually so strongly bound within the chemical structure of the final waste product that they will not leach out, even under acidic conditions.

Because fly ash has some of the same physical characteristics as a silty clay, fly ash may be used as an additive to clay liners for waste management facilities, particularly for impoundments. Fly ash is cohesive and fairly impermeable when properly compacted, and mixes well with some of the clays used in impoundment liners. However, because chemical composition of fly ash is variable, its utilization as liner material may be limited. If methods are improved to be sure that minimum permeability and shear strength requirements could be maintained over time, then the use of fly ash as an impoundment liner material may increase.

Fly ash has been used occasionally as a soil conditioner to increase the pH of acidic soils, thereby enhancing crop growth. Fly ash can also contribute minerals to the soil. However, soil conditioners in common use today, mostly agricultural limestones, are so inexpensive and easy to obtain that it would be difficult to penetrate this market with a fly ash product.

There are few processes currently available for recovery of materials from coal ash. One facility has had some commercial success at producing magnetite from fly ash.[37] Magnetite recovered from fly ash actually contains a higher percentage of magnetics than does natural magnetite, making it a more efficient coal cleaning agent. This particular technology shows some promise of expanding; other processes, mostly for metals recovery, are in the development stage. Recovery processes for alumina and titanium are at an advanced stage of development. However, while both these technologies have been proven feasible, neither is currently economically competitive with ore-processing technologies. Another potential metal recovery process, dubbed the DAL process and still in the research stage, involves a series of relatively simple operations that can be performed with commercially available process equipment to recover various metals from fly ash. Theoretically, this process could show a substantial return on investment soon after the recovery facility began operating.[38]

There is little information available to the Agency on the environmental effects of utilization of coal combustion wastes. For many applications, such as the use of coal ash in cement and concrete products, it would appear that any adverse environmental impacts would be minimal. To the extent that coal combustion wastes can be recycled in an environmentally acceptable manner, utilization would help to reduce the amount of waste disposed. The Agency is very interested in reducing the amount of waste that needs to be disposed by the utility industry; however, barring major breakthroughs in recycling techniques, it appears the potential for significantly increasing the amount of waste utilization may be limited.[39] Given current utilization techniques, the Agency expects that the major portion of coal combustion wastes will continue to be land disposed.

FGD Wastes

The prospects for utilization of FGD sludge are less promising than those for ash utilization. FGD sludge is not structurally stable or strong enough to serve as a construction material, nor does it show the pozzolanic properties required for a cement substitute. Current research in the field of FGD sludge utilization is focusing on a dry scrubber method in which reagents will be used to precipitate the FGD waste streams as dry gypsum powder. Gypsum is sold for use in wallboard; however, there is currently a glut on the market, and in any case, other sources of gypsum may be preferred because the gypsum produced from FGD is often of lesser quality. Some researchers are making an effort to find a reagent that will precipitate a dry powder which, when mixed with water, will exhibit pozzolanic properties and will harden to a concrete-like material. No testing has been done, however, as the research is still in the conceptual stage.

Although by-product utilization of FGD sludges comprises less than one percent of total sludge production, a much greater percentage of FGD by-products may be recoverable in the very near future since two full-scale recovery processes and one test-scale recovery process for FGD by-products are currently under development. Of the two full-scale processes, the Wellman-Lord process recovers both sulfuric acid and elemental sulfur from the waste stream, while the magnesium oxide scrubber process recovers only sulfuric acid.[40] The citrate scrubbing process, currently in the testing phase, recovers elemental sulfur. FGD recovery processes currently in the research stage will be used to recover elemental sulfur, sulfuric acid, and gypsum from the FGD process, and should be available for full-scale use within the next decade.[41] All recovery processes for FGD wastes generate both a by-product stream and a waste stream that must be disposed.

Low-Volume Utility Wastes

EPA currently assumes that most low-volume utility wastes are co-disposed with the high-volume wastes or, in some instances, burned in the boiler at the power plant, although little data exist that accurately describe industry-wide practices on low-volume waste disposal.[42] Since co-disposal is a common industry practice, low-volume wastes do not have specific processes associated with their recovery or utilization. Although this practice of co-disposal (or burning) may continue into the future, certain waste streams, such as spent cleaning solvents, might be recovered by distilling and collecting the solvents at high temperature, which would leave a low-volume residue to be disposed. The recovered solvent could then be reused on-site as a cleaning solvent or sold to another facility. If an organic solvent were contaminated in such a way that contaminant removal were difficult or impossible, the contaminated solvent could be burned. For low-volume waste streams burned in the boiler, these wastes could be transported to an off-site facility that would burn them as fuel. If low-volume wastes were considered hazardous, regulations might restrict the burning of these wastes, potentially making this option infeasible.[43]

Other recovery schemes for individual low-volume waste streams may be developed if these streams are segregated from the high-volume wastes. At this time, however, few recovery processes and utilization techniques have been considered separately for low-volume utility wastes.

Recycled Effluent

Approximately 25 percent of the utilities that utilize surface impoundments recycle some of their pond effluent back to the plant.[44] If the recycled effluent is used as sluice water, the system pH may increase to values well above 10. The recycled effluent may also be used as cooling water prior to ultimate discharge. Although effluent recycling is not a waste recovery or utilization technique, it can affect the chemical characteristics of the solid wastes that may come into contact with the recycled water.

4.3 SUMMARY

Coal combustion waste management practices by electric utilities vary widely across the industry. State regulation, regional factors such as land availability and water availability, and age of the power plant all have an effect on the type of waste management practices that are employed. Alternative practices, such as ground-water monitoring and leachate collection, are used by some utilities, and in some states are mandated by regulation. A significant portion of coal combustion by-products are recovered and utilized for various purposes.

- All but one state regulates the disposal of coal combustion wastes under their hazardous or solid waste disposal regulations. One state exempts these wastes from regulation.
- State solid waste regulations applicable to coal combustion wastes vary widely across the country. Generally, solid waste regulations require that disposal facilities have permits; location restrictions and standards related to liners, leachate control, and ground-water monitoring are applied on a case-by-case basis.
- Currently, about 80 percent of all coal-fired power plant wastes are land managed; the remaining 20 percent are recycled or recovered. The most common types of disposal facilities used by utilities generating coal-fired wastes are surface impoundments, landfills, and abandoned mines.
- Currently, about 25 percent of utility treatment, storage, and disposal facilities that receive combustion waste are lined. About 15 percent of all facilities have leachate collection systems, and 35 percent have ground-water monitoring.
- Newer facilities are more likely to be lined, have leachate collection systems, and ground-water monitoring systems. More than 40 percent of all generating units constructed since 1975 use lined disposal facilities.
- About 20 percent of all high-volume combustion wastes, particularly fly ash and bottom ash, are recycled, primarily as cement additives, high-volume road construction material, or blasting grit.
- About 99 percent of FGD wastes are currently disposed; however, recovery of sulfur and sulfur products from FGD wastes is a developing and promising technology.

CHAPTER 4

NOTES

[1] Wald, Harkrader & Ross, Survey of State Laws and Regulations Governing Disposal of Utility Coal-Combustion Byproducts, for the Utility Solid Waste Activities Group (USWAG), 1983.

[2] States have probably followed U.S. EPA's lead in exempting coal combusting wastes. Many states' regulations explicitly refer to 40 CFR 261.4, or use the clause's exact wording.

[3] The following State officials were interviewed: Brett Bettes, Solid Waste Division, Washington Department of Ecology, January 6, 1987; Ken Raymond, Industrial and Solid Waste Division, Oklahoma Department of Health, December 31, 1986; Dwight Hinch, Division of Waste Management, Tennessee Department of Health, December 31, 1986; Shelby Jett, Division of Waste Management, Kentucky Department of Environmental Protection, January 6, 1987; Vincent Nikle, Assistant Liaison's Office, New Jersey Department of Environmental Protection, December 17, 1986.

[4] According to Maine's Solid Waste Management Regulations: "More Stringent Criteria for Large-Scale Disposal of Oil, Coal and Incinerator Ash: Because of the concentration of heavy metals in residues from the combustion of municipal solid waste or the combustion of oil or coal, including bottom ash and fly ash, disposal of such ashes when they occur in amounts that exceed a total accumulation of 20 cubic yards of coal ash ... per week over any one-month period shall be confined to a secure landfill. For the purposes of these rules, a secure landfill shall mean a landfill with a liner and a leachate management system." (Maine's Solid Waste Management Regulations, Chapter 401.2.3.).

[5] The exhibit assumes that both on-site and off-site permits are required unless the regulations explicitly state otherwise.

[6] See Chapter One for discussion of the regulation of low-volume utility waste streams.

[7] Waste piling, a method occasionally employed by utilities, is not discussed in this report. Waste piles are mounds of ash placed on the ground and covered with soil.

[8] U.S. Department of Energy, Impacts of Proposed RCRA Regulations and Other Related Federal Environmental Regulations on Utility Fossil Fuel-Fired Facilities, Volume II. 1983.

[9] See Chapter 6 for a discussion of disposal costs.

[10] Haller, W.A., J.E. Harwood, S.T. Mayne, and A. Gnilka, "Ash Basin Equivalency Demonstration (for treatment of boiler cleaning wastes containing heavy metals)," Duke Power Company, 1976.

[11] Envirosphere Company, Environmental Settings and Solid Residues Disposal in the Electric Utility Industry, EPRI Report EA-3681, 1982.

[12] Ibid.

[13] Ibid.

[14] A low-permeable clay is one that has been determined in laboratory testing to have a permeability coefficient, K, of 10^{-7} cm/sec or less.

[15] There are one thousand mils per inch.

[16] See 40 CFR 264.

[17] Engineering-Science, Background Data on Utility Fossil Fuel-fired Facilities, prepared for USDOE, Office of Fossil Energy, 1983.

[18] Ibid.

[19] Ibid.

[20] EPRI Journal, 1985, op. cit.

[21] EPRI, Manual for Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared by Radian Corporation, Austin, Texas, July 1987.

[22] EPRI, Characterization of Utility Low-Volume Wastes, prepared by Radian Corporation, Austin, Texas, May 1985.

[23] Ibid.

[24] Ibid.

[25] EPRI, 1987.

[26] EPRI, 1985.

[27] EPRI, 1987.

[28] EPRI, 1985.

[29] 40 CFR 228, Criteria for the Management of Ocean Disposal Sites for Ocean Dumping.

[30] Envirosphere Company, "Economic Analysis of Impact of RCRA on Coal Combustion By-Products Utilization" in Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, Appendix G, prepared for Utility Solid Waste Activities Group (USWAG), October 1982.

[31] Information compiled by the American Coal Ash Association on 1985 ash utilization, August 1, 1986.

[32] EPRI Journal. 1985. op. cit.

[33] Ibid.

[34] Ibid.

[35] USWAG, 1982.

[36] EPRI Journal. 1985. op. cit.

[37] USWAG. 1982. op. cit.

[38] Ibid.

[39] For example, see comments by Garry Jablonski, section manager of ash utilization for the American Electric Power Company, "Coal Ash Market Report," Vol. 1, No. 9, July 15, 1987.

[40] EPRI, State-of-the-Art of FGD Sludge Fixation, 1978.

[41] Ibid.

[42] Envirosphere Company, Information Responding to EPA's Request Regarding Burning and Co-Treatment/Co-Disposal of Low Volume Wastes Generated At Fossil Fuel Electric Generating Stations, prepared for USWAG and Edison Electric Institute, August 1981.

[43] The economics of burning these wastes would depend on the applicable regulations. Regulations concerning the burning of hazardous wastes are currently being developed and are scheduled for final promulgation in mid-1987.

[44] U.S. Department of Energy. 1983. Op. cit.

GLOSSARY

acidity - the amount of free carbon dioxide, mineral acids and salts (especially sulfates or iron and aluminum) which hydrolyze to give hydrogen ions in water and is reported as milli-equivalents per liter of acid, or ppm acidity as calcium carbonate, or pH the measure of hydrogen ions concentration. Indicated by a pH of less than 7.

administrator - the Administrator of the United States Environmental Protection Agency, or his/her designee.

alkaline cleaning solution wastes - water-side cleaning waste resulting from the removal of high copper content scale from the utility boiler.

alkaline passivating waste - water-side cleaning waste resulting from the removal of iron and copper compounds and silica to neutralize acidity after acid cleaning.

alkalinity - the amount of carbonates, bicarbonates, hydroxides and silicates or phosphates in the water and is reported as grains per gallon, pH, or ppm of carbonate. Indicated by a pH of greater than 7.

alkaline fly ash scrubber - a flue gas desulfurization system in which flue gas reacts with alkaline fly ash that is augmented with a lime/limestone slurry.

anthracite - a high ASTM ranked coal with dry fixed carbon 92% or more and less than 98%; and dry volatile matter 8% or less and more than 2% on a mineral-matter-free basis.

aquifer - a water-bearing bed or structure of permeable rock, sand, or gravel capable of yielding quantities of water to wells or springs.

ash - the incombustible solid matter in fuel.

ash fusion - the temperatures at which a cone of coal or coke ash exhibits certain melting characteristics.

attenuation - a process that slows the migration of constituents through the ground.

baghouse - an air pollution abatement device used to trap particulates by filtering gas streams through large fabric bags usually made of glass fibers.

base load - base load is the term applied to that portion of a station or boiler load that is practically constant for long periods.

batch test - a laboratory leachate test in which the waste sample is placed in, rather than washed with, leachate solution.

bituminous coal - ASTM coal classification by rank on a mineral/matter-free basis and with bed moisture only.

<u>low</u> <u>volatile</u>: dry fixed carbon 78% or more and less than 86%; and dry volatile matter 22% or more and less than 14%.
<u>medium</u> <u>volatile</u>: dry fixed carbon 69% or more and less than 78%; and dry volatile matter 22% or more and less than 31%.
<u>high</u> <u>volatile</u> <u>(A)</u>: dry fixed carbon less than 69% and dry volatile matter more than 31% - Btu value equal to or greater than 14,000 moist, mineral-matter-free basis.
<u>high</u> <u>volatile</u> <u>(B)</u>: Btu value 13,000 or more and less than 14,000 moist, mineral-matter-free basis.
<u>high</u> <u>volatile</u> <u>(C)</u>: Btu value 11,000 or more and less than 13,000 moist, mineral-matter-free basis commonly agglomerating, or 8,300

to 11,500 Btu agglomerating.

blower - the fan used to force air through a pulverizer or to force primary air through an oil or gas burner register.

boiler - a closed vessel in which water is heated, steam is generated, steam is superheated, or any combination thereof, under pressure or vacuum by the application of heat.

boiler blowdown - removal of a portion of boiler water for the purpose of reducing solid concentration or discharging sludge.

boiler cleaning waste - waste resulting from the cleaning of coal combustion utility boilers. Boiler cleaning wastes are either water/side or gas-side cleaning wastes.

boiler slag - melted and fused particles of ash that collect on the bottom of the boiler.

boiler water - a term used to define a representative sample of the boiler circulating water. The sample is obtained after the generated steam has been separated and before the incoming feedwater or added chemical becomes mixed with it so that its composition is affected.

bottom ash - large ash particles that settle on the bottom of the boiler.

British Thermal Unit (Btu) - the mean British Thermal Unit is 1/180 of the heat required to raise the temperature of 1 pound of water from $32^{o}F$ to $212^{o}F$ at a constant atmospheric pressure. It is about equal to the quantity of heat required to raise 1 pound of water 1 degree F.

capacity factor - the total output over a period of time divided by the product of the boiler capacity and the time period.

CERCLA - The Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as Superfund.

cell - a section of a landfill, or the size of that section. Usually only a few cells of a landfill are open to accept waste at a time.

chain grate stoker - a stoker which has a moving endless chain as a grate surface, onto which coal is fed directly from a hopper.

coal pile runoff - surface runoff from a plant's coal pile.

cogeneration - the production of steam (or hot water) and electricity for use by multiple users generated from a single source.

column test - a leachate extraction procedure that involves passing a solution through the waste material to remove soluble constituents.

contingency plan - a document setting out an organized, planned, and coordinated course of action to be followed in case of a fire or explosion or a release of hazardous waste constituents into the environment.

cooling tower blowdown - water withdrawn from the cooling system in order to control the concentration of impurities in the cooling water.

cyclone furnace - specialty furnace for high intensity heat release. So named because of its swirling gas and fuel flows.

demineralizer regeneration and rinses waste - a low volume wastewater generated from the treatment of water to be used at the plant.

direct lime flue gas desulfurization - see lime/limestone FGD process.

direct limestone flue gas desulfurization - see lime/limestone FGD process.

disposal - the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste or hazardous waste into or on any land or water such that any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including ground waters.

dry-bottom furnace - a pulverized-fuel furnace in which ash particles are deposited on the furnace bottom in a dry, non-adherent condition.

dry scrubber - an FGD system for which sulfur dioxide is collected by a solid medium; the final product is totally dry, typically a fine powder.

dry sorbent injection - an FGD system in the research and development stage for which a powdered sorbent is injected into the flue gas before it enters the baghouse. Sulfur dioxide reacts with the reagent in the flue gas and on the surface of the filter in the baghouse.

dual alkali fly ash scrubber - a flue gas desulfurization system similar to the lime/limestone process, except that the primary reagent is a solution of sodium salts and lime.

effluent - a waste liquid in its natural state or partially or completely treated that discharges in to the environment from a manufacturing or treatment process.

electrostatic precipitator - an air pollution control device that imparts an electrical charge to particles in a gas stream causing them to collect on an electrode.

evapotranspiration - the combined process of evaporation and transpiration.

fabric filter - a cloth device that catches dust and particles from industrial or utility emissions.

flash point - the lowest temperature at which vapors above a volatile combustible substance ignite in air when exposed to flame.

flue gas - the gaseous products of combustion in the flue to the stack.

flue gas desulfurization (FGD) sludge - waste that is generated by the removal of some of the sulfur compounds from the flue gas after combustion.

fly ash - suspended ash particles carried in the flue gas.

furnace - the combustion chamber of a boiler.

gas-side cleaning waste - waste produced during the removal of residues (usually fly ash and soot) from the gas-side of the boiler (air preheater, economizer, superheater, stack, and ancillary equipment).

ground water - water found underground in porous rock strata and soils.

ground water monitoring well - a well used to obtain ground-water samples for water-quality analysis.

hazardous waste - a solid waste, or combination of solid wastes, which, because of its quantity, concentration, or physical, chemical, or infectious characteristics, may (1) cause, or significantly contribute to, an increase in serious irreversible, or incapacitating reversible illness; or (2) pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, disposed of, or otherwise managed.

hard water - Water that contains sufficient dissolved calcium and magnesium to cause a carbonate scale to form when the water is boiled or to prevent the sudsing of soap in the water.

high volume waste - fly ash, bottom ash, boiler slag, and flue gas desulfurization sludge.

hydraulic conductivity - the quantity of water that will flow through a unit cross-sectional area of a porous material per unit of time.

hydrochloric acid cleaning waste - wastes from the cleaning of scale caused by water hardness, iron oxides, and copper.

land disposal - the placement of wastes in a landfill, surface impoundment, waste pile, injection well, land treatment facility, salt dome formation, salt bed formation, or underground mine or cave.

landfill - a disposal facility or part of a facility where hazardous waste is placed in or on land and which is not a land treatment facility, a surface impoundment or injection well.

leachate - the liquid resulting from water percolating through, and dissolving materials in, waste.

leachate extraction test - a laboratory procedure used to predict the type and concentration of constituents that will leach out of waste material.

leachate collection, removal, and treatment systems - mitigative measures used to prevent the leachate from building up above the liner.

lift - the depth of a cell in a landfill.

lignite - a coal of lowest ASTM ranking with calorific value limits on a moist, mineral-matter-free basis less than 8,300 Btu.

lime - calcium oxide ($CaCO_3$), a chemical used in some FGD systems.

limestone - calcium carbonate ($CaOH_2$), a chemical used in some FGD systems.

lime/limestone FGD process - form of wet non-recovery flue gas desulfurization system in which flue gases pass through a fly ash collection device and into a contact chamber where they react with a solution of lime or crushed limestone to form a slurry which is dewatered and disposed.

liner - a mitigative measure used to prevent ground-water contamination in which synthetic, natural clay, or bentonite materials that are compatible with the wastes are used to seal the bottom or surface impoundments and landfills.

low volume waste - wastes generated during equipment maintenance and water purification processes. Low volume wastes include boiler cleaning solutions, boiler blowdown, demineralizer regenerant, pyrites, cooling tower blowdown.

mechanical stoker - a device consisting of mechanically operated fuel feeding mechanism and a grate, and is used for the propose of feeding solid fuel into a furnace, and to distribute it over a grate, admitting air to the fuel for the purpose of combustion, and providing a means for removal or discharge of refuse.

net recharge - the amount of precipitation absorbed annually into the soil.

off-site - geographically noncontiguous property, or contiguous property that is not owned by the same person. The opposite of on-site.

on-site - the same or geographically contiguous property which may be divided by public or private right(s)-of-ways, provided the entrance and exit between the properties is at across-roads, intersection, and access is by crossing as opposed to going along the right(s)-of-way. Noncontiguous properties owned by the same person but connected by a right-of-way which the person controls and to which the public does not have access, is also considered on-site property.

Part A - the first part of the two part application that must be submitted by a TSD facility to receive a permit. It contains general facility information.

Part B - the second part of the two part application that includes detailed and highly technical information concerning the TSD in question. There is no standard form for the Part B, instead the facility must submit information based on the regulatory requirements.

particulates - fine liquid or solid particles such as dust, smoke, mist, fumes, or smog, found in the air or emissions.

permeability (1) - the ability of a geologic formation to transmit ground water or other fluids through pores and cracks.

permeability (2) - the rate at which water will seep through waste material.

petroleum coke - solid carbaceous residue remaining in oil refining stills after distillation process.

pH - a measure of the acidity or alkalinity of a material, liquid or solid. pH is represented on a scales of 0 to 14 with 7 being neutral state, 0 most acidic and 14 most alkaline.

plume - a body of ground water originating from a specific source and influenced by such factors as the local ground-water flow pattern and character of the aquifer.

pond liquors - waste fluid extracted from a surface impoundment or landfill.

pozzolanic - forming strong, slow-hardening cement-like substance when mixed with lime or other hardening material.

PDWS - Primary Drinking Water Standards established by the Safe Drinking Water Act.

pulverizer - a machine which reduces a solid fuel to a fineness suitable for burning in suspension.

pyrites - solid mineral deposits of raw coal that are separated from the coal before burning.

reagent - a substance that takes part in one or more chemical reactions or biological processes and is used to detect other substances.

recharge - the replenishment of ground water by infiltration of precipitation through the soil.

RCRA - Resource Conservation and Recovery Act, as amended (Pub. L. 94-580). The legislation under which EPA regulates solid and hazardous waste.

RCRA Subtitle C Characteristics - criteria used to determine if an unlisted waste is a hazardous waste under Subtitle C of RCRA.

- corrosivity - a solid waste is considered corrosive if it is aqueous and has a pH less than or equal to 2 or greater than or equal to 12.5 or if it is a liquid and corrodes steel at a rate greater than 6.35 mm per year at a test temperature of 55°C.

- EP toxicity - a solid waste exhibits the characteristic of EP (extraction procedure) toxicity if, after extraction by a prescribed EPA method, it yields a metal concen- tration 100 times the acceptable concentration limits set forth in EPA's primary drinking water standards.

- ignitability - a solid waste exhibits the characteristic of ignitability if it is a liquid with a flashpoint below 60°C or a non-liquid capable or causing fires at standard temperature and pressure.

- reactivity - a waste is considered reactive if it reacts violently, forms potentially explosive mixtures, or generates toxic fumes when mixed with water, or if it is normally unstable and undergoes violent change without deteriorating.

SDWS - Secondary Drinking Water Standards established by the Safe Drinking Water Act.

settling lagoon - surface impoundment.

shear strength - the resistance offered by a material subjected to a compressive stress created when two contiguous parts of the material are forced in opposite parallel directions.

slag - molten or fused solid matter.

sludge - a soft water-formed sedimentary deposit that is mud-like in its consistency.

slurry - a mixture of insoluble mater in a fluid.

solid waste - As defined by RCRA, the term "solid waste" means any garbage, refuse, sludge from a waste treatment plant, water supply treatment plant, or air pollution control facility and other discarded material, including solid, liquid, semisolid, or contained gaseous material resulting from industrial, commercial, mining, and agricultural operations, and from community activities, but does not include solid or dissolved material in domestic sewage, or solid or dissolved materials in irrigation return flows or industrial discharges which are point sources subject to permits under the Clean Water Act, or special nuclear or byproduct material as defined by the Atomic Energy Act of 1954.

spray drying process - a flue gas desulfurization system in which a fine spray of alkaline solution is injected into the flue gas as it passes through a contact chamber, where the reaction with the sulfur oxides occurs. The heat of the flue gas evaporates the water in the solution, leaving a dry powder, which is collected by a particulate collector.

stabilization - making resistant to physical or chemical changes by treatment.

steady state - an adjective that implies that a system is in a stable dynamic state in which inputs balance outputs.

stoker - see mechanical stoker.

storage - the holding of waste for a temporary period, at the end of which the hazardous waste is treated, disposed of, or stored elsewhere.

subbituminous coal - An intermediate rank coal between lignite and bituminous with more carbon and less moisture than lignite.

sump effluent - waste from sumps that collect floor and equipment drains.

surface impoundment - a facility which is a natural topographic depression, artificial excavation, or diked area formed primarily of earthen materials (although it may be lined with artificial materials), which is designed to hold an accumulation of liquid wastes or wastes containing free liquids.

surface water - water that rests on the surface of the rocky crust of the earth.

traveling grate stoker - a stoker similar to a chain grate stoker except that the grate is separate from but is supported on and driven by chains.

trace element - An element that appears in a naturally-occurring concentration of less than 1 percent.

treatment - any method, technique, or process, including neutralization, designed to change the physical, chemical, or biological character or composition of a waste so as to neutralize it, recover it, make it safer to transport, store or dispose of, or amenable for recovery, storage, or volume reduction.

TSD facility - waste treatment, storage, or disposal facility.

utility boiler - a boiler which produces steam primarily for the production of electricity in the utility industry.

volatile - A volatile substance is one which tends to vaporize at a relatively low temperature.

water-side cleaning waste - waste produced during the removal of scale and corrosion products from the water side of the boiler (i.e., the piping systems containing the steam or hot water).

wet bottom furnace - a pulverized fuel fired furnace in which the ash particles are deposited and retained on the floor thereof and molten ash is removed by tapping either continuously or intermittently. (also called a slag tap furnace)

wet scrubber - a device utilizing a liquid, designed to separate particulate matter or gaseous contaminants from a gas stream by one or more mechanisms such as absorption, condensation, diffusion, inertial impaction.

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CHAPTER FIVE

POTENTIAL DANGERS TO HUMAN HEALTH AND THE ENVIRONMENT

Under Section 8002(n) of RCRA, EPA is to analyze the "potential danger, if any, to human health and the environment from the disposal and reuse" of coal combustion wastes and "documented cases in which danger to human health or the environment from surface runoff or leachate has been proved." This chapter examines potential and documented dangers to human health and the environment caused by wastes generated from the combustion of coal at electric utility power plants.

As described in Chapter One, special large volume wastes, including coal combustion wastes, are to be treated differently under RCRA than other industrial wastes. Due to the extremely large volume of coal combustion waste and the expectation of relatively low risk from its disposal, Congress directed EPA to evaluate all the factors in 8002(n) of RCRA in determining whether Subtitle C regulation is warranted. The danger from coal combustion waste management is only one of the factors EPA must consider. In order to provide a starting point for evaluating the potential danger from coal combustion waste management, this chapter begins by providing the reader with background information on the characteristics that an industrial solid waste must exhibit to be considered hazardous under RCRA, and then looks at which of these characteristics apply to coal combustion wastes. The next section analyzes several studies that monitored ground-water and surface-water concentrations in and around coal combustion waste disposal sites and documented the number of times that drinking water standards were exceeded. The third section of this chapter reviews studies that compiled and evaluated reported incidences of contamination to ground water and surface water due to the disposal of coal combustion wastes. Finally, the fourth section analyzes the factors affecting the exposure of humans, animals, and plants to contaminants from coal combustion waste by examining environmental setting and population data for a random sample of 100 coal-fired utility power plants.

5.1 RCRA SUBTITLE C HAZARDOUS WASTE CHARACTERISTICS AND LISTING CRITERIA

Under RCRA, solid wastes are classified as hazardous if they exhibit characteristics of ignitibility, corrosivity, reactivity, and/or EP toxicity as defined by RCRA or if they are listed as hazardous by the Administrator.

- Ignitibility refers to the tendency of a substance to catch fire. A liquid waste is ignitable if it has a flash point less than 60°C, as determined by EPA-specified test protocols. A non-liquid waste is ignitable if, under standard temperature and pressure, it is capable of causing a persistent, hazardous fire through friction, absorption of moisture, or spontaneous chemical change.[1]
- Corrosivity of waste is determined by measuring the waste's pH, the value used to express relative acidity or alkalinity. A pH value of 7.0 is neutral; substances with a pH less than 7.0 are acidic, while those with a pH greater than 7.0 are alkaline. A waste is corrosive, and therefore hazardous, if it is aqueous and has a pH less than or equal to 2.0 or greater than or equal to 12.5.[2] A waste is also corrosive if it is liquid and corrodes steel at a rate greater than 6.35 mm per year. The pH measurements and the corrosion rate must be determined using EPA-approved methods.[3]
- Reactivity refers to the stability of a substance. Wastes that are highly reactive and extremely unstable tend to react violently or explode. A waste is reactive if it undergoes violent physical change without detonating, if it reacts violently with water, if it forms a potentially explosive or toxic mixture with

water, or if it is capable of detonating or exploding at standard temperature and pressure.[4]

- Extraction Procedure (EP) Toxicity is determined from a laboratory procedure designed to simulate leaching from a disposal site under actual disposal conditions.[5] Concentrations in the effluent from this test are compared with the Primary Drinking Water Standards (PDWS) of eight constituent metals to determine whether a waste is hazardous. A waste is EP toxic if it produces a leachate using an EPA-approved procedure that has concentrations of contaminants that are 100 times the PDWS.[6]

Wastes are also regulated as hazardous wastes under Subtitle C if the Administrator lists them in 40 CFR 261.31-261.33. The Administrator may list wastes using several criteria:

- if they are ignitable, corrosive, reactive, or EP toxic as described above.
- if they have been found to be fatal to humans in low doses, or, in the absence of data on human toxicity, fatal to animals in laboratory tests (these wastes are designated Acute Hazardous Wastes).[7]
- if they contain any of the toxic constituents listed in Appendix VIII of 40 CFR 261, unless the Administrator, after considering the factors contained in 40 CFR 261.11(a)(3), concludes that "the waste is not capable of posing a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed." The factors that the Administrator may consider include the toxicity of the constituent, the concentration of the constituent in the waste, the potential for degradation, the degree of bioaccumulation to be expected from the constituent, and the quantities of the waste generated. These wastes are designated Toxic Wastes.[8]

Determining whether coal combustion wastes show any of the hazardous characteristics is important in analyzing potential danger to human health and the environment. In general, most coal combustion wastes, such as ash and FGD sludge, are not ignitable. Reactivity is also generally not a characteristic of concern for coal combustion wastes. The chemical and physical characteristics of most coal combustion wastes identified in Chapter Three indicate that these wastes are very stable and will likely not react with other substances in their disposal area. The remainder of this section will analyze data on coal combustion wastes to see if these wastes exhibit the characteristics of corrosivity and/or EP toxicity.

5.1.1 Corrosivity of Coal Combustion Wastes

Under current RCRA regulations, only liquid wastes can be considered corrosive. Coal combustion ash, therefore, could not by itself be considered corrosive, even if it generates a corrosive leachate.

For wastes that are aqueous, a waste is corrosive if its pH is less than or equal to 2.0 or greater than or equal to 12.5. Available data indicate that the pH values of most waste streams of coal-fired power plants do not fall within these ranges; in fact, the only wastes that may be classified as corrosive according to the above definition are water-side, hydrochloric acid-based cleaning wastes, which have had measured pH as low as 0.5 (see Exhibit 3-26). In an EPRI report on low volume wastes (see section 5.1.2) three samples of hydrochloric acid-based boiler cleaning waste all had pH levels less than 2. However, these wastes are often neutralized before disposal. Several other waste streams have pH levels which fall very near the corrosive ranges. Most of these are also low volume wastes. Boiler blowdown has measured pH as high as 12, with a range of 8.3-12 (see Exhibit 3-20), and coal pile runoff has measured pH as low as 2.1, with a range of 2.1-6.6 (see Exhibit 3-21). Sludge from dual-alkali FGD processes using eastern coal is a high volume waste with measured pH of approximately 12.1 (see Exhibit 3-17). Chapter Three contains a complete description of these wastes.

Several studies of coal combustion waste streams surveyed in this chapter indicate that the alkalinity or acidity of coal combustion wastes, while not necessarily falling in the RCRA corrosive ranges, may occasionally reach levels of potential concern. For example, pH readings of waste fluids taken during a study by Arthur D. Little were as high as 11.4 (see Section 5.2.1). Three case studies described in Appendix D (a study of 12 Tennessee Valley Authority power plants, an individual study at the Bull Run Power Plant, and a study of the Savannah River Project) showed pH readings of waste fluids at 2.0, 3.5, and 2.9, respectively. Section 5.3.1 describes a documented case in which highly alkaline coal combustion waste (pH 12.0) caused substantial harm to aquatic life after it accidentally spilled into Virginia's Clinch River in 1967.

5.1.2 Extraction Procedure (EP) Toxicity of Coal Combustion Wastes

Current RCRA regulations (40 CFR 261.24) specify that if a leachate extracted using an EPA-approved extraction procedure contains any of the metals shown in Exhibit 5-1 at concentrations equal to or greater than the given limit, the waste is classified as EP toxic and, unless otherwise exempted, will be subject to Subtitle C regulation.[9] The concentrations shown in Exhibit 5-1 are 100 times the current Primary Drinking Water Standards (PDWS) established by the Safe Drinking Water Act for those constituents.

Waste extraction tests are used to predict the type and concentration of constituents that may leach from a waste disposal site under field conditions.

EXHIBIT 5-1

MAXIMUM CONCENTRATION OF CONTAMINANTS FOR CHARACTERISTIC OF EP TOXICITY

Contaminant	Level
Arsenic	5.0 mg/l
Barium	100.0 mg/l
Cadmium	1.0 mg/l
Chromium	5.0 mg/l
Lead	5.0 mg/l
Mercury	0.2 mg/l
Selenium	1.0 mg/l
Silver	5.0 mg/l

Source: 40 CFR 261.24, January 16, 1987.

Most extraction tests are conducted by mixing or washing a waste sample with a water-based solution of a specified composition for a specified length of time. The resulting leachate solution is then separated from the solids and tested for constituent concentrations.

5.1.2.1 Types of Extraction Procedures

Several different types of waste extraction procedures are described in detail below. Although under current regulations only the Extraction Procedure (EP) toxicity test is used to determine whether a waste is EP toxic, EPA has recently proposed a new procedure, the Toxic Characteristic Leaching Procedure (TCLP), to replace the EP test (see Federal Register, Volume 51. No. 114, June 13, 1986, p. 21648). Furthermore, in the period since EPA has promulgated the Extraction Procedure (EP) toxicity test, many people have alleged that the EP provides an inappropriate measure of leaching under field conditions. For these reasons, EPA has reviewed the results of other extraction procedure tests as well as the EP. To the extent that the results of these other procedures on coal combustion wastes are generally consistent with the EP results, the debate over whether the EP test is appropriate or not is moot. Three of the extraction tests described below (EP, TCLP, and ASTM) are batch leaching tests. Batch tests are conducted by placing a waste sample in a water-based solution for a specified period of time. The fourth procedure, the column test, passes a solution through the waste.

- The procedure for the standard EPA extraction test, the Extraction Procedure (EP) toxicity test,[10] requires obtaining a waste sample of at least 100 grams and then separating the liquids from the solids. The solid portion is placed in a container along with 16 times its weight in deionized water, and continually agitated at 20-40°C. Throughout the test, the pH of the batch mixture is monitored. If the solution remains above pH 5.0, acetic acid is added to maintain a pH of 5.0. If the solution is less than pH 5.0, no acetic acid is added. If the pH of the batch solution is not below 5.2 after the initial 24-hour agitation period, the pH is adjusted to 5.0 ± 0.2 at the beginning of each hour during an additional 4 hour agitation period. After agitation, the leachate solution is then separated from the solid portion, and the liquid extracted from the original waste sample is added to the leachate solution. These combined liquids are then tested for constituent concentrations.

- Toxic Characteristic Leaching Procedure (TCLP), which EPA has proposed as a replacement for the EP,[11] uses a different leaching solution depending on the nature of the waste being tested. For wastes of low alkalinity, a pH 5.0 acetic acid/sodium acetate buffer is used for extraction. If the waste is more alkaline, a normal acetic acid solution is used. Unlike the EP toxicity test, the TCLP can be used for volatile waste constituents.

- The American Society for Testing and Materials (ASTM) developed the ASTM A procedure, which requires 48-hour agitation of a 1:4 mixture of waste to distilled deionized water. Another test, ASTM B, involves the extraction of waste constituents in a buffered acetic acid solution of pH 4.5.[12] ASTM D, similar to ASTM A, involves the 48-hour agitation of a 350-gram sample with 1400 milliliters of deionized distilled water, and the filtering of the aqueous phase, after agitation, with a 0.45 micron filter.

- Unlike the batch testing methods described above, the column test is conducted by passing a solution through the waste. This test process simulates the migration of leachate and ground water through waste, but still cannot duplicate field conditions perfectly. Because there is no standard column test procedure, column tests are described individually in the studies reviewed in the next section of this chapter.

The results of various studies (conducted with the above-mentioned extraction tests) on the leaching of constituents from coal combustion wastes are discussed below.

5.1.2.2 Results of Extraction Tests

Tetra Tech Study

In 1983 Tetra Tech conducted a literature review for the Electric Power Research Institute (EPRI) and reported results from a number of leachate extraction studies.[13] An examination of the results of various leaching tests (EP toxicity test, ASTM A, and ASTM B) on coal ash and flue gas desulfurization (FGD) sludge revealed that results differed by waste type and were ultimately dependent upon the source of the fuel (see Exhibit 5-2) and the mechanics of combustion. The study results were presented separately for ash and FGD sludge.

Results of the batch leaching tests (EP, ASTM A, and ASTM B) reported in the studies reviewed by Tetra Tech were presented as averages of the element concentrations found in numerous runs of one type of extraction test. Ranges of the concentrations were sometimes presented as well. Depending on the laboratory that ran the test, EP, ASTM A, and ASTM B batch leaching tests were run on as few as 3 and as many as 62 samples.

Tetra Tech reviewed 457 EP tests on various types of ash. Results from these EP tests show a geometric mean concentration for selenium equal to its PDWS. Geometric mean concentrations for the other 7 metals were below their respective PDWS. The maximum concentrations were 4 times the PDWS for silver, 29 times for arsenic, 8 times for barium, 140 times for cadmium, 14 times for chromium, 4 times for mercury, 5 times for lead, and 17 times for selenium.

Tetra Tech also reported results from 202 ASTM A tests on ash. Selenium was

EXHIBIT 5-2

EFFECT OF GEOGRAPHIC COAL SOURCE ON ELEMENT CONCENTRATION IN ASH

Element	Geographic Variation
Arsenic	low in western coal ash; difference in concentration between eastern coal and midwestern coal ashes indistinguishable
Barium	highest in western coal ash
Cadmium	most concentrated in midwestern coal ash
Chromium	low in western coal ash; difference in concentration between eastern and midwestern coal ashes indistinguishable
Mercury	highest in eastern coal ash; all distributions highly skewed toward high concentrations
Lead	highest in midwestern coal ash
Selenium	similar in eastern and midwestern coal ash; lower in western coal ash
Strontium	highest in western ash; lowest in midwestern ash
Vanadium	similar in eastern and midwestern coal ash; lower in western coal ash
Zinc	highest in midwestern ash; lowest in western ash

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EA-3236, September 1983.

the only constituent with a geometric mean concentration greater than the PDWS, at a level approximately 2 times the PDWS. The maximum concentrations were less than the PDWS for silver and mercury. For the other elements, the maximum concentrations from the ASTM-A procedure were 7 times PDWS for arsenic, 4 times for barium, 1.3 times for cadmium, 10 times for chromium, 5 times for lead, and 48 times for selenium.

Cadmium was the only constituent in fly ash leachate extracted using the EP for which there was a maximum concentration over 100 times the PDWS (and therefore above the EP toxicity level). The EP produced a leachate that had a maximum cadmium concentration 140 times the PDWS. However, the average cadmium concentration for the 62 EP samples was only half the PDWS. Tetra Tech did not report the percentage of samples whose cadmium concentration exceeded 100 times the PDWS. In general, the more acidic or alkaline the leaching solution, the higher the concentrations of leached constituents. Tetra Tech concluded that the geometric mean concentrations from the EP and ASTM-A tests were similar. The results of the EP and ASTM-A tests are presented in Exhibit 5-3.

Tetra Tech also reviewed data from a number of column tests on coal ash. The test results did not show any concentrations greater than 100 times the PDWS for any element tested. One test was conducted during a two-year period using a continuous-flow method to produce leachate from fly ash. In another test, fly ash and bottom ash were packed separately in glass columns, each of which was leached for 27 days with 200 milliliters per day of either distilled water, dilute base, or dilute acid. For a third test, fly ash and bottom ash were packed in water-saturated glass columns. At one-week intervals, the columns were flushed from below at a moderate rate for two hours. This test was

EXHIBIT 5-3

RESULTS OF TETRA TECH EXTRACTION TESTS ON COAL COMBUSTION ASH

		EP Test Results			ASTM A Test Results		
Constituent	Primary Drinking Water Standard (mg/l)	Range	Geometric Mean	Maximum Exceedance	Range	Geometric Mean	Maximum Exceedance
Arsenic	.05	<.004- 1.46 mg/l	.012 mg/l	29 X PDWS	<.0005-0.37 mg/l	.0072 mg/l	7 X PDWS
Barium	1.0	.003- 7.6 mg/l	0.222 mg/l	8 X PDWS	.0004-3.8 mg/l	0.208 mg/l	4 X PDWS
Cadmium	.01	.0001- 1.4 mg/l	.0047 mg/l	140 X PDWS	.0001-.013 mg/l	.00039 mg/l	1.3 X PDWS
Chromium	.05	.001- 0.68 mg/l	.036 mg/l	14 X PDWS	.0005-0.5 mg/l	.047 mg/l	10 X PDWS
Lead	.05	<.0001-0.25 mg/l	.005 mg/l	5 X PDWS	<.0001-0.25 mg/l	.0025 mg/l	5 X PDWS
Mercury	.002	<.0001- .007 mg/l	.00042 mg/l	4 X PDWS	<.0001-.0012 mg/l	.00027 mg/l	0.6 X PDWS
Selenium	.01	<.0001-0.17 mg/l	.01 mg/l	17 X PDWS	.0005-0.48 mg/l	.019 mg/l	48 X PDWS
Silver	.05	<.0001-0.20 mg/l	.00064 mg/l	4 X PDWS	<.0001-.03 mg/l	.0007 mg/l	0.6 X PDWS

Source: Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EA-3236, September 1983.

intended to simulate the intermittent wetting to which some ash disposal sites are subject.

Partly because flue gas desulfurization (FGD) technologies have only achieved widespread commercial usage in recent years, FGD sludge has not been as thoroughly characterized as coal ash. However, the Tetra Tech study reported the results of tests performed on sludges from a number of scrubber processes, including the lime/limestone/alkaline fly ash process, the dual alkali/sodium carbonate process (both these processes produce "lime sludge" and are the main technologies currently in use), and the spray drying process (this process produces calcium-based dry scrubber sludge and may be used more extensively in the future).

Results from EP tests on calcium-based dry scrubber sludge showed a maximum concentration of cadmium that was 150 times the PDWS, above the EP toxic level. Arsenic and selenium were also analyzed using the EP test; the maximum arsenic concentration was 32 times the PDWS and the maximum for selenium was 1.8 times the PDWS. No other constituents were tested for this waste stream. (Results from the EP studies on calcium-based dry scrubber sludge were not averaged but reported as ranges - the number of tests performed was not given).

Tetra Tech also presented results of EP tests on lime sludge. These tests measured concentrations of all EP toxicity constituents, and none were found to be at EP toxic levels.

Tetra Tech also reported on column tests performed on FGD sludge. In one column test, calcium-based dry scrubber sludge was leached with deionized water for 11 months. In another, various proportions of fly ash, wet calcium sulfate (i.e., gypsum), calcium sulfite precipitate, and calcium oxide (lime) were mixed, cured for 500 days, and leached with deionized water that was forced through the waste columns. The leaching test results (reported in a manner similar to that for reporting results of coal ash leaching studies) indicated, on the basis of an unreported number of tests, that PDWS constituents in lime sludge and calcium-based dry scrubber sludge leached at concentrations that exceeded their PDWS by multiples of less than 5 for silver, 32 for arsenic, 2 for barium, 30 for chromium, 10 for lead, and 15 for selenium; the concentration of mercury found in sludge leachate matched its PDWS. No constituents were at concentrations above 100 times the PDWS.

In summary, none of the coal ash or FGD sludge leaching studies reviewed by Tetra Tech showed constituent concentrations greater than 100 times the PDWS, with the exception of cadmium from calcium-based dry scrubber FGD sludge and from coal ash. Both results were from EP toxicity procedure tests. The behavior of these wastes primarily depended on the source of the fuel and the mechanics of combustion. Tetra Tech concluded that there were gaps in the characterization of these wastes that made definitive conclusions difficult to reach.

Department of Energy Study

The Department of Energy (DOE) conducted a compilation study of leaching test results, Analytical Aspects of the Fossil Energy Waste Sampling and Characterization Project,[14] for the purpose of generating a data base on the leaching characteristics of coals and their combustion wastes. The EP test was compared to a water leach test developed by ASTM (this test later became ASTM D) and evaluated to determine the precision of the EP toxicity method when applied to coal wastes. In their summary of the collected data, DOE reported that for six of the analyzed constituents there were no significant differences between the testing results derived from the two methods. The results of 2492 separate extraction tests for the eight PDWS constituent metals (arsenic, barium, cadmium, chromium, lead, mercury, selenium and silver) indicated that none of the metals leached at concentrations that exceeded the PDWS by 50 times, and most leached at concentrations less than 10 times the PDWS. This was true for both the EP test and the ASTM test.

Arthur D. Little Study

EPA sponsored a study by Arthur D. Little, Inc. (see Section 5.2.1) which included EP Toxicity tests on 20 fly ash samples from 16 power plants and 3 FGD waste samples from 3 power plants.[15] The names of the plants from which the samples were taken were not revealed because Arthur D. Little did not consider the single "grab" samples obtained for testing to be representative. The EP test results showed no EP toxic levels in the extracted leachates of any samples. Silver and mercury concentrations were below the reported detection limits of .001 mg/l and .002 mg/l, respectively, for all samples. Lead was detected in only three out of seventeen samples. Other PDWS constituents (arsenic, cadmium, chromium, selenium, and barium) were detected, but all were found at concentrations less than 100 times the PDWS. In contrast to the Tetra Tech study reported above, leachates extracted from FGD samples had concentrations of PDWS constituents that tended to be lower than the concentrations in leachates extracted from fly ash samples, whereas the Tetra Tech report indicated that, in general, higher concentrations of PDWS constituents were leached from FGD sludges than from coal ash. This discrepancy may be due to variations in the wastes themselves, which, in turn, are due to differences among coals derived from different sources. Results of the Arthur D. Little study are presented in Exhibit 5-4.

Battelle Pacific Northwest Study

In another study for the Electric Power Research Institute (EPRI), Battelle Pacific Northwest reviewed data developed during a round-robin study that compared results from three laboratories performing both the EP and TCLP tests.[16] Battelle Northwest compared the two extraction procedures by looking at the ratio of the mean TCLP concentrations to the mean EP concentrations for each element. These ratios fell within the range of 0.8 to 1.2 about 60 percent of the time. Only 15 percent of the ratios exceeded 2.0. In 83 percent of the comparisons, the TCLP test leachate contained greater concentrations of the PDWS constituents than the EP test leachate.[17]

Battelle compared the maximum mean concentration of each compound (taken from the pool of averaged results for each constituent from both EP and TCLP testing of all the waste samples) with the corresponding PDWS. This comparison indicated that for both the EP and the TCLP procedures, concentrations of silver, barium, and mercury were less than the established PDWS for those metals, whereas the concentration of arsenic was 21 times the PDWS; cadmium, 25 times; chromium, 13 times; lead, 4 times; and selenium, 14 times.

EXHIBIT 5-4

RESULTS OF ARTHUR D. LITTLE TESTING SHOWING THE RANGE OF CONCENTRATION OF METALS IN EP EXTRACTS a/

Metal	Average Values Fly Ash	Average Values FGD Waste	(A) Overall Range Observed (mg/l) Fly Ash	(A) Overall Range Observed (mg/l) FGD Waste	(B) Primary Drinking Water Standards	Ratio of Observed Range to PDWS (A/B) Fly Ash	Ratio of Observed Range to PDWS (A/B) FGD Waste
Arsenic	.08	0.20	0.002-.410	0.002-0.065	.05 mg/l	0.04-8.2	0.04-1.30
Barium	.34	.18	0.1-0.7	0.15-0.23	1.0 mg/l	0.1-0.7	0.15-0.23
Cadmium	.03	.01	0.002-0.193	0.002-0.020	0.01 mg/l	0.2-19.3	0.2-2
Chromium (CrVI) b/	.16	.02	0.008-0.930	.011-0.026	0.05 mg/l	0.16-18.6 c/	0.22-0.52
Lead	.01	.01	0.003-0.036	0.005	0.05 mg/l	0.06 to 0.72	0.1
Mercury	<.002	<.002	<0.002	<0.002	0.002 mg/l	<1	<1
Selenium	.05	.020	.002-0.340	0.008-0.049	0.01 mg/l	0.2 to 34	0.8-4.9
Silver	<.001	<.001	<0.001	<0.001	0.05 mg/l	<0.02	<0.02

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a/ Ranges are shown for fly ash and FGD samples; comparisons are made to the Primary Drinking Water Standards.

b/ The Arthur D. Little study tested the concentration of Cr(VI), an ion of chromium.

c/ Since total chromium values are measured by the graphite furnace atomic absorption analysis method, these are upper limits for the Cr(VI) values.

Source: Arthur D. Little, Inc., Full-Scale Evaluation of Waste Disposal from Coal-fired Electric Generation Plants, prepared for the Air and Energy Research Laboratory of the U.S. Environmental Protection Agency, for the Office of Solid Waste, EPA-600-7-85-028, June 1985.

University of Alberta Study

The University of Alberta conducted a study for EPRI that involved passing a water-based solution through a series of columns with increasing ash concentrations.[18] The study results indicate that while some constituent metals were initially released or mobilized from the wastes using this method, these same constituents were attenuated in columns further along in the series. Boron, selenium, and arsenic were initially mobilized, but only boron remained mobilized to a significant extent. Arsenic and selenium interacted in successive columns such that the movement of arsenic and selenium through the system was retarded.

In addition to studying the test leachates, the University of Alberta researchers studied the fly ash itself to determine the processes that affect the migration of metal constituents. The study results indicated that some constituents are not uniformly distributed within the fly ash particles. The fly ash particles typically consist of an interior "glass" matrix covered by a relatively reactive and soluble exterior coating. The study found that arsenic and selenium were concentrated almost exclusively in the coating of the fly ash particles and thus were readily leached; the barium concentration was split evenly between the interior and exterior of the particles; about 75 percent of the cadmium and chromium were concentrated in the interior glass matrix; and almost all the lead was concentrated in the interior glass matrix and was, therefore, not readily mobilized.

The study attributed the uneven concentration of constituents in the fly ash particles to the vaporization of relatively volatile constituents during combustion, followed by the condensation of these constituents on the exterior of fly ash particles entrained in the flue gas. However, this study reported that lead was contained within the interior glass matrix of the fly ash particles, while the Tetra Tech study discussed earlier reported that lead was volatile and thus likely to be found on the surface of fly ash particles. Both studies reported that arsenic and selenium were found on the surface of the fly ash particles. The University of Alberta concluded that the physical and chemical characteristics of the fly ash were determined by both the chemical composition of the coal from which it came and the mechanics of fly ash formation during combustion.

The difference between the University of Alberta study and the standard leaching test studies is that the mobility of constituents was observed under a variety of conditions. A number of waste concentrations could be tested in the columns to imitate specific field conditions. (Single column extractions also possess such flexibility, but to a lesser degree.) The University of Alberta study simulated landfill conditions by allowing the laboratory leachate solution to continually change as it migrated through multiple waste columns, whereas in batch extraction tests the laboratory leachate solution is allowed to come into contact with only one ash sample.

Battelle Chemical Characterization Study

Battelle Pacific Northwest Laboratories recently completed a study for EPRI on chemical characteristics of fly ash, bottom ash, and FGD sludge.[19] As part of this study, Battelle performed a comparison of the EP Toxicity Test and the TCLP test. While most of the results of the two procedures were consistent, differences were observed with acidic samples. One acidic fly ash EP sample had both arsenic and chromium above RCRA limits. Another acidic fly ash sample also exhibited elevated levels of arsenic and chromium, but not at levels exceeding RCRA limits. The study found, however, that the two samples showed considerably less leachability for arsenic and chromium with the TCLP, while other elements tested showed similar results from the two testing procedures. The study concluded that the difference between the two types of tests resulted from the acidic character of the samples.

Radian Corporation Study

The Radian Corporation conducted two studies for EPRI that involved testing various low-volume waste streams. In the first of these studies (published in May 1985),[20] Radian Corporation collected thirty-two samples on eight types of low volume wastes. These samples were tested using the EP toxicity test as well as some other testing procedures. The results of the EP toxicity test showed that the only waste stream Radian tested that exceeded the EP toxicity limits in the 1985 Radian study was untreated boiler chemical cleaning waste. Exhibit 5-5 presents the results for three samples of untreated boiler cleaning wastes. All three samples had elevated levels of chromium and cadmium, including exceedances of EP toxicity limits, and two samples of boiler cleaning wastes had elevated concentrations of lead, including an exceedance of EP limits. This study also performed EP tests on boiler cleaning wastes after neutralization in a plant treatment system. As shown in Exhibit 5-5, the two samples of treated boiler cleaning waste did not exceed EP toxicity limits for any metals.

EXHIBIT 5-5

EP TOXICITY ANALYSIS FOR UNTREATED AND TREATED BOILER CHEMICAL CLEANING WASTES a/ (concentrations in mg/l)

Metals	Maximum Allowable EP Toxicity Limits	Untreated Boiler Cleaning Waste Type: Ammoniated EDTA with Inhibitor	Untreated Boiler Cleaning Waste Type: Oxidizer	Untreated Boiler Cleaning Waste Type: Hydrochloric Acid
Silver	5.0	0.002 b/	0.002 b/	0.007
Barium	100.0	0.76	0.67	0.91
Cadmium	1.0	3.0	3.0	0.64
Chromium	5.0	4.7	4.7	20.0
Arsenic	5.0	0.006	0.002 b/	0.051
Mercury	0.2	0.0002 b/	0.0002 b/	0.0042
Lead	5.0	3.6	5.6	0.002 b/
Selenium	1.0	0.002 b/	0.002 b/	0.003 b/

Metals	Maximum Allowable EP Toxicity Limits	Treated Boiler Cleaning Waste Type: HCl+ Inhibitor, Chelant	Treated Boiler Cleaning Waste Type: Hydrochloric Acid
Silver	5.0	0.042	0.033
Barium	100.0	0.40	0.25
Cadmium	1.0	0.002 b/	0.012
Chromium	5.0	0.001 b/	0.099
Arsenic	5.0	0.002 b/	0.002 b/
Mercury	0.2	0.0002 b/	0.0002 b/
Lead	5.0	0.002 b/	0.002 b/
Selenium	1.0	0.002 b/	0.002 b/

a/ All underlined values exceed maximum allowable limits under current RCRA regulations for hazardous wastes.

b/ Values shown are detection limits. Actual values could be less than, but no greater than, the indicated value.

Source: Electric Power Research Institute, Characterization of Utility Low-Volume Wastes, Radian Corporation, May 1985.

In Radian Corporation's second study of low-volume wastes (published in July 1987),[21] they collected additional data on certain low-volume waste streams that the first study indicated might have high concentrations of metals. As shown in Exhibit 5-6, eight of twenty-one samples of low-volume liquid wastes from coal-fired plants were found to exceed EP toxicity limits. For boiler chemical cleaning wastes, 7 of 10 samples exceeded EP toxicity limits for at least one constituent. Six of the boiler chemical cleaning waste exceedances were for chromium and the remaining exceedance was for lead. One wastewater brine sample out of five tested samples exceeded the EP limits for selenium. There were no reported EP exceedances for waterside rinses or coal pile runoff.

Radian Corporation also conducted EP Toxicity tests on low-volume waste sludges. None of the three samples from coal-fired power plants were considered EP Toxic, including a boiler chemical cleaning waste sludge. For the two wastewater pond sludges, the study compared the EP and TCLP testing procedures. Results of the EP and TCLP tests are shown in Exhibit 5-7. The two extraction procedures produced nearly identical concentrations of metals in their extracts.

As in their first study, the Radian Corporation also sampled low-volume wastes that had been treated. This study found significant reductions in concentrations of chromium, copper, iron, nickel and zinc after hydrochloric acid boiler cleaning waste was neutralized.

The study also examined the treatment effectiveness of co-disposal of low-volume wastes with high-volume wastes. Results of EP toxicity tests on co-disposal mixtures found that co-disposal significantly reduced concentrations of contaminants in the co-disposed mixture. Results of the EP tests are

EXHIBIT 5-6

EP TOXICITY TEST RESULTS FOR LIQUID LOW-VOLUME WASTES
(mg/1)

	EP	Boiler Cleaning Waste			Waterside Rinses			Coal Pile Runoff			Wastewater Brines		
ELEMENT	Toxicity Limit	# of Tests	Range	Mean	# of Tests	Range	Mean	# of Tests	Range	Mean	# of Tests	Range	Mean
Arsenic	5.0	10	.002-0.36	0.112	3	0.01-0.018	0.014	3	0.002-0.006	0.003	5	0.019-0.52	0.194
Barium	100.0	10	0.022-2.6	0.629	3	0.005-0.097	0.064	3	0.04-0.078	0.054	5	0.1-0.18	0.134
Cadmium	1.0	10	0.002-0.21	0.181	3	0.002-0.04	0.015	3	0.001-0.004	0.002	5	0.002-0.04	0.019
Chromium	5.0	10	0.02-35	8.467 1/	3	0.028-0.77	0.303	3	0.005-0.005	0.005	5	0.005-0.31	0.148
Lead	5.0	10	0.008-23	2.603 2/	3	0.002-0.46	0.181	3	0.002-0.08	0.032	5	0.002-0.002	0.002
Mercury	0.2	10	.0002-0.0039	0.001	3	0.0002-0.0002	0.0002	3	0.0002-0.0003	0.0003	5	0.0002-0.025	0.005
Selenium	1.0	10	.002-.002	0.002	3	0.002-0.002	0.002	3	0.002-0.002	0.002	5	0.002-1.5	0.314 4/
Silver	5.0	10	.001-0.2	0.065	3	0.002-0.02	0.011	3	0.012-0.0023	0.002	5	0.002-0.03	0.013
ph (units)	2≤ph≤12.5	8	1.01-10.8	5.6 3/	2	9.3-9.4	9.35	3	3.1-9.3	6.9	4	4.6-4.9	4.75

1/ 6 of 10 tests exceeded RCRA limits; all underlined values indicate a measurement in excess of the allowable RCRA limits.

2/ 1 of 10 tests exceeded RCRA limits; all underlined values indicate a measurement in excess of the allowable RCRA limits.

3/ 3 of 8 tests were outside RCRA limits; all underlined values indicate a measurement in excess of the allowable RCRA limits.

4/ 1 of the 5 tests exceeded RCRA limits; all underlined values indicate a measurement in excess of the allowable RCRA limits.

NOTE: Boiler Cleaning Wastes include EDTA, Hydrochloric Acid, Bromate, Citric Acid, and Hydroxyacetic/formic acid..
Waterside Rinses are wastes resulting from washing the boiler and other plant equipment.
Wastewater Brines are produced during treatment of water-based low volume wastes.

Source: Manual for Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, Electric Power Research Institute, prepared by Radian Corporation, Austin, Texas, July 1987.

EXHIBIT 5-7

COMPARISON OF EP AND TCLP EXTRACTIONS FOR LOW-VOLUME SLUDGE DREDGED FROM WASTEWATER PONDS (mg/l)

			EP Test		TCLP Test	
ELEMENT	RCRA Limit	# of Tests	Range	Mean	Range	Mean
Arsenic	5.0	2	0.002-0.015	0.0085	0.004-0.016	0.010
Barium	100.0	2	0.045-0.12	0.0825	0.07-0.089	0.080
Cadmium	1.0	2	0.002-0.002	0.002	0.002-0.002	0.002
Chromium	5.0	2	0.01-0.011	0.0105	0.018-0.023	0.021
Lead	5.0	2	0.002-0.006	0.004	0.002-0.16	0.081
Mercury	0.2	2	.0002-0.0002	0.0002	0.0002-0.0002	0.0002
Selenium	1.0	2	.003-0.0003	0.003	0.003-0.03	0.017
Silver	5.0	2	0.002-0.004	0.003	0.009-0.012	0.011

Source: Manual for Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, Electric Power Research Institute, prepared by Radian Corporation, Austin, Texas, July 1987.

presented in Exhibit 5-8 for co-disposal with fly ash from three geographic areas.

5.1.2.3 Summary of Extraction Test Results

In conclusion, the results of these studies indicate that coal combustion utility wastes may leach several elements, including PDWS constituents. While a variety of extraction procedures were used in these studies, and questions have been raised about the applicability of certain testing methods to coal combustion wastes (which are generally disposed on-site in monofills), all of the extraction procedures used in the studies (EP, TCLP, ASTM, and column) produced average concentrations of constituents that were below the EP toxic level for all waste streams except untreated boiler cleaning waste. In the 1987 Radian Corporation study, untreated boiler cleaning wastes had a mean concentration 169 times the PDWS for chromium using the EP Toxicity test.

For the high-volume waste streams, cadmium, arsenic, and chromium were the only elements for which a maximum concentration was found that was over 100 times the PDWS. Arsenic and chromium were above EP toxicity limits based on EP tests for one acidic fly ash sample in the Battelle chemical characterization study. These were the only exceedances based on 23 samples. Cadmium was found at a concentration 150 times the PDWS in calcium-based dry scrubber sludge leachate and at a concentration 140 times the PDWS in some coal ash leachate as reported in the Tetra Tech study; these leachates were extracted using the EP test method. For both types of waste, however, the exceedances represented the maximum concentrations; all averages of cadmium concentration levels were below 100 times the PDWS. In fact, the geometric mean of cadmium in coal ash

EXHIBIT 5-8

EP TOXICITY TEST RESULTS OF LOW VOLUME WASTES BEFORE AND AFTER CO-DISPOSAL*

(mg/L)

Midwestern Bituminous Coal Fly Ash

ELEMENT	RCRA Limit	Fly Ash Waste	EDTA Waste	EDTA Waste Co-disposed With Ash	Citrate Waste	Citrate Waste Co-disposed With Ash	General Wastewater	Wastewater Co-disposed With Ash
Arsenic	5.0	0.006	0.006	0.026	0.21	0.037	0.003	0.031
Barium	100.0	0.006	0.76	0.23	1.6	0.006	1.2	0.17
Cadmium	1.0	0.02	3	0.02	0.64	0.02	0.008	0.02
Chromium	5.0	0.01	4.7	0.01	3.9	0.01	0.11	0.01
Lead	5.0	0.002	3.6	0.008	0.002	0.002	0.002	0.002
Mercury	0.2	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
Selenium	1.0	0.028	0.002	0.006	0.003	0.002	0.003	0.002
Silver	5.0	0.02	0.002	0.02	0.006	0.02	0.009	0.02

Southeastern Bituminous Coal Fly Ash

ELEMENT	RCRA Limit	Fly Ash Waste	EDTA Waste	EDTA Waste Co-disposed With Ash	Citrate Waste	Citrate Waste Co-disposed With Ash	General Wastewater	Wastewater Co-disposed With Ash
Arsenic	5.0	0.037	0.006	0.036	0.21	N/A	0.003	0.042
Barium	100.0	N/A	0.76	0.33	1.6	0.006	1.2	0.47
Cadmium	1.0	0.02	3	0.02	0.64	0.02	0.008	0.085
Chromium	5.0	0.036	4.7	0.01	3.9	0.15	0.11	0.01
Lead	5.0	0.002	3.6	0.002	0.002	0.004	0.002	0.023
Mercury	0.2	0.0002	0.0002	0.0003	0.0002	0.0002	0.0002	0.0002
Selenium	1.0	0.003	0.002	0.015	0.003	0.082	0.003	0.003
Silver	5.0	0.02	0.002	0.02	0.006	0.02	0.009	0.02

EXHIBIT 5-8 (Continued)

EP TOXICITY TEST RESULTS OF LOW VOLUME WASTES BEFORE AND AFTER CODISPOSAL

(mg/L)

Western Subbituminous Coal Fly Ash

ELEMENT	RCRA Limit	Fly Ash Waste	EDTA Waste	EDTA Waste Co-disposed With Ash	Citrate Waste	Citrate Waste Co-disposed With Ash	General Wastewater	Wastewater Co-disposed With Ash
Arsenic	5.0	0.006	0.006	0.08	0.21	0.45	0.003	0.005
Barium	100.0	0.94	0.76	0.7	1.6	0.43	1.2	0.8
Cadmium	1.0	0.02	3	0.02	0.64	0.02	0.008	0.02
Chromium	5.0	0.01	4.7	0.01	3.9	0.01	0.11	0.01
Lead	5.0	0.002	3.6	0.041	0.002	0.002	0.002	0.002
Mercury	0.2	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002	0.0002
Selenium	1.0	0.034	0.002	0.026	0.003	0.031	0.003	0.003
Silver	5.0	0.02	0.002	0.02	0.006	0.02	0.009	0.02

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*All underlined values indicate an exceedance of the current RCRA limit for hazardous wastes.

Source: Manual for Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, Electric Power Research Institute, prepared by Radian Corporation, Austin, Texas, July 1987.

leachates in the Tetra Tech study was just under 0.5 of the PDWS.

For the low-volume waste streams, the only exceedance of EP toxicity limits for wastes other than boiler cleaning waste was one wastewater brine sample that had selenium at 150 times the PDWS. The mean concentration of selenium in the wastewater brine samples was below EP toxicity limits. While untreated boiler cleaning wastes had exceedances of EP toxicity limits for chromium and lead, as noted above, EP toxicity tests on neutralized boiler cleaning wastes and on boiler cleaning wastes co-disposed with fly ash showed no exceedances of EP limits.

5.2 EFFECTIVENESS OF WASTE CONTAINMENT AT UTILITY DISPOSAL SITES

Coal combustion wastes contain trace elements that at certain levels could pose a potential danger to human health and the environment if they migrate from the disposal area. The extraction procedure tests described in Section 5.1.2 indicate that these trace elements may leach out of disposed wastes, although rarely at concentrations greater than 100 times the PDWS. This section of the report analyzes studies of ground-water and surface-water quality at and around utility disposal sites to ascertain whether potentially hazardous constituents that leach out of the waste migrate into surrounding ground water or surface water. The studies discussed in this section use as a measure of water quality the concentration of Primary Drinking Water Standards (PDWS) and Secondary Drinking Water Standards (SDWS) constituents in the water around utility waste disposal sites. Primary and Secondary Drinking Water Standards were established in the Safe Drinking Water Act. Primary Drinking Water Standards establish concentration limits for toxic constituents. Secondary Drinking Water Standards are based on aesthetic characteristics such as taste, color, and odor. Exhibit 5-9 shows the current PDWS and SDWS. If ground water and surface water downgradient from waste disposal sites have concentrations of constituents in excess of PDWS or SDWS, and upgradient concentrations are below the standards or are lower than the downgradient concentrations, the coal combustion waste could be one of the sources contributing to ground water or surface water contamination.

EPA has conducted a number of studies on the quality of ground water in the immediate vicinity of utility disposal sites. Arthur D. Little performed extensive ground-water monitoring at six utility disposal sites. In a second study, Franklin Associates compiled data from state records on ground-water quality in the vicinity of 66 utility disposal sites. This section also reviews and evaluates a study conducted by Envirosphere for USWAG on available data on ground-water quality at 23 electric utility sites to evaluate whether and to what extent occurrences of ground-water contamination have resulted from the disposal of coal combustion wastes.

5.2.1 ADL Study of Waste Disposal at Coal-Fired Power Plants

Arthur D. Little, Inc. (ADL), conducted a three-year study for EPA's Office of Research and Development to assess the environmental effects and engineering costs associated with coal ash and flue gas desulfurization waste disposal practices at six coal-fired power plants.[22] Appendix E contains a detailed discussion of the study, including how the six sampled sites were selected, the study approach, and results for each site. A summary of the six sites is presented below:

EXHIBIT 5-9

PRIMARY DRINKING WATER STANDARDS

Contaminant	Concentration (mg/1)
Arsenic	0.05
Barium	1.0
Cadmium	0.01
Chromium	0.05
Fluoride	4.0
Lead	0.05
Mercury	0.002
Nitrate (as N)	10.0
Selenium	0.01
Silver	0.05

SECONDARY DRINKING WATER STANDARDS

Contaminant	Level
Chloride	250 mg/1
Color	15 color units
Copper	1.0 mg/1
Corrosivity	Noncorrosive
Foaming Agents	0.5 mg/1
Iron	0.3 mg/1
Manganese	0.05 mg/1
Odor	3 Threshold odor number
pH	6.5 - 8.5
Sulfate	250 mg/1
Total Dissolved Solids	500 mg/1
Zinc	5.0 mg/1

Source: 40 CFR 141 and 143, September 1, 1986.

- The Allen Plant in North Carolina disposed of a mixture of fly ash and bottom ash in two unlined disposal ponds, one closed and one in active use. Intermittent waste streams, such as boiler wastes and coal pile runoff, were also disposed in the ponds. While concentrations of trace elements in downgradient ground water were higher than upgradient concentrations, exceedances of the Primary Drinking Water Standards were not found. Elevated concentrations of arsenic (up to 31 times the PDWS) were found in fluids within the active ash pond. Attenuation tests indicated that the arsenic concentrations would be chemically attenuated by iron and manganese in the soils beneath and surrounding the site. Ground-water contamination, particularly from arsenic, could have resulted if these attenuative soils had not been present. Secondary Drinking Water Standards were exceeded in both the upgradient and downgradient ground water for manganese and in the downgradient ground water for iron. This was attributed to high concentrations of these elements present in the soils of the site. Steady-state conditions have probably not been achieved at the Allen site; increases in downgradient ground-water concentrations of non-attenuated contaminants may be expected in the future.

- The Elrama Plant in western Pennsylvania disposed a fixated FGD sludge-fly ash mixture, along with small volumes of bottom ash and sludge from coal pile runoff treatment ponds, in an abandoned coal-mining area 12 miles from the plant. Part of the landfill is underlain by acid-producing spoils from the strip mining of coal. Cadmium was found in concentrations exceeding the Primary Drinking Water Standard by as much as 20 times in downgradient ground water; the highest concentration was found in the well closest to the landfill. There were no upgradient exceedances for cadmium. Steady-state conditions did not appear to have been achieved at the site, so that effects of leachate from the landfill may be expected to increase with time. Secondary Drinking Water Standards (for pH, manganese, sulfate, and iron) were exceeded at the site in both upgradient and downgradient ground water. These exceedances probably occurred because of characteristics of the disposal area and because ground water was already contaminated from acid mine drainage. Test results indicated that any constituent migration from the landfill did not measurably affect the water quality of the nearby Youghiogheny River.

  Arsenic was repeatedly detected at levels three to five times the Primary Drinking Water Standard in pond liquors, but appeared to be attenuated by soils at the site. This suggests the possibility that similar wastes at other sites could leach arsenic at higher levels if arsenic were not attenuated by surrounding soils or diluted before reaching drinking water.

The results discussed above indicate that the fixated FGD/fly ash wastes have been, and will continue to be, a source of contamination at the site. Because exceedances for many contaminants were probably due to concurrent contamination from acid mine drainage, leachate from coal combustion waste may have only a small incremental impact on water quality.

- The Dave Johnston plant in Wyoming is located in an arid region with little ground-water recharge. The plant is the oldest of the six sites, and burns low-sulfur western coal. There are a number of disposal areas at the site; the ADL study investigated two unlined fly ash landfills, one active and one closed. Exceedances of the Primary Drinking Water Standards for cadmium (up to 3 times the PDWS) were found in ground water upgradient and downgradient of the site. Cadmium was found at elevated concentrations in pond liquors and ground water beneath the wastes. Exceedances of Secondary Drinking Water Standards for manganese and sulfate were also observed in downgradient and upgradient ground water. These two contaminants and boron were found in elevated concentrations in ground water beneath the waste and in pond liquors. No samples were analyzed for the presence of arsenic in the pond liquors. Chemical attenuation by soils at the site was found to be low for trace metals such as arsenic.Interpretations of the sampling results were difficult to make because other potential contamination sources exist, such as other waste disposal areas at the site (the location and ages of which are uncertain) and contaminants naturally occurring in the soil, which is highly mineralized around the Johnston site; and uncertainties with regard to what degree leachate from the two landfills had reached the downgradient wells. Contamination from the site could possibly increase until steady-state concentrations are reached.

- The Sherburne County Plant in central Minnesota disposed of fly ash and FGD waste in one clay-lined pond and bottom ash in an adjacent clay-lined pond. Exceedances of the Primary Drinking Water Standards were observed in both upgradient and downgradient ground water for cadmium (up to 2 times the PDWS for both) and for nitrate, and in downgradient ground water for chromium (up to 1.2 times the PDWS). Pond liquors were found to exhibit high concentrations of several constituents, including cadmium (up to 30 times the PDWS), chromium (up to 16 times the PDWS), fluoride, nitrate, lead (up to 28 times the PDWS), and selenium (up to 25 times the PDWS). While the pond liquors exhibited high concentrations of contaminants, leachate from these wastes did not appear to have migrated into and mixed with ground water to a great extent. Ground-water samples collected at the site seemed to indicate that a few constituents (sulfate and boron) had migrated from the wastes, but not at levels exceeding SDWS. The clay liner appeared to have significantly reduced the rate of release of leachate from the disposal ponds, precluding the development of elevated trace metal concentrations at downgradient wells. Over time, downgradient wells will likely show increased levels of contamination, since steady-state conditions had not been achieved between leachate from the landfill and the ground water. Without the clay liner, the leachate seepage rate would probably have been much greater. Since the surrounding soils may not chemically attenuate selenium, this contaminant might cause PDWS exceedances once steady-state concentrations in ground water are reached.

- The Powerton Plant disposed fly ash, bottom ash, and slag in an older landfill approximately one mile south of the site. In a newer portion of the landfill, disposal operations consisted of disposing intermixed fly ash and slag. The newer landfill and part of the older one are underlain by a liner consisting of ash and lime. The downgradient ground-water wells exhibited levels of cadmium up to three times the Primary Drinking Water Standard and, in one sample, lead at four times the PDWS. An upgradient well, located on the border of the landfill wastes, exhibited a concentration of cadmium at the level of the Primary Drinking Water Standard. Secondary Drinking Water Standards for iron, manganese, and sulfate were exceeded in downgradient wells, and for manganese in an upgradient well (but at a level of exceedance lower than the downgradient measurements). These results indicate that leaching and migration of ash wastes had occurred at the site, but it was difficult to determine the effect the leachate had, or will have, on ground-water quality. Dilution and chemical attenuation may have prevented the buildup at downgradient locations of significant concentrations of trace metals such as arsenic and selenium. The degree to which Lost Creek, a nearby downgradient stream, was diluting waste constituents that reach it may be significant.

- The Lansing Smith plant in southern Florida disposed a mixture of fly ash and bottom ash in an unlined disposal pond located in a coastal area. Concentrations greater than the Primary Drinking Water Standards were observed for cadmium (up to five times the PDWS), chromium (up to four times the PDWS), and fluoride in the downgradient ground water at the site and, with the possible exception of fluoride, appeared to be due largely to the leaching of the ponded ash wastes. Exceedances of Secondary Drinking Water Standards for sulfate, chloride, manganese, and iron were also observed in downgradient ground water. However, most of these contaminants are seawater-related and their reported concentrations appeared to be influenced by the use of seawater in plant operations and infiltration of estuarine (saline) water at the site. The leachate generated migrates to a shallow, unused, tidal aquifer. These results indicate that ash disposal at this site appears to have had a measurable impact on ground-water quality. Health risks at this particular site, however, were probably minimal since the ground water and surface water were not used as a source of drinking water.

5.2.1.1 Ground-water Sampling

Exhibits 5-10 and 5-11 summarize the results of the ADL ground-water quality data at the six disposal sites for constituents with established Primary and Secondary Drinking Water Standards, respectively. As can be seen from Exhibit 5-10:

- One site had no exceedances of PDWS constituents, either upgradient or downgradient.
- One site had PDWS exceedances for cadmium only, with the same maximum PDWS exceedance upgradient and downgradient.
- One site had downgradient PDWS exceedances for cadmium, chromium, and nitrate, but for cadmium and nitrate the upgradient exceedances were at least as large as the downgradient exceedances. There were no upgradient exceedances of chromium; the one downgradient exceedance was 1.2 times PDWS.
- The three remaining sites had downgradient PDWS exceedances for cadmium that were more frequent and larger than upgradient exceedances. The largest downgradient exceedance for cadmium at any of the six sites was 20 times the PDWS.
- There were no upgradient chromium exceedances and only three exceedances out of 94 downgradient observations. Two of the downgradient exceedances were 1.2 times the PDWS and one was 4 times the PDWS. These three exceedances were at three different sites.

EXHIBIT 5-10

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY DATA ON PRIMARY DRINKING WATER EXCEEDANCES

Units = ppm		Allen Site				New Elrama Site				Dave Johnston Site			
PDWS		Downgradient (11 wells) 1/		Upgradient (1 well) 1/		Downgradient (5 wells) 1/		Upgradient (1 well) 1/		Downgradient (3 wells) 1/		Upgradient (2 wells) 1/	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Arsenic (liq.)	0.05	0/12		0/2		0/1		0/2		0/2		0/3	
Barium	1	0/31		0/3		0/19		0/4		0/9		0/6	
Cadmium	0.01	0/31		0/3		3/19	20	0/4		6/9	3	3/6	3
Chromium (Cr VI)	0.05	0/31		0/3		1/19	1.2	0/4		0/9		0/6	
Fluoride	4.0	0/34		0/4		0/21		0/4		0/12		0/8	
Lead	0.05	0/31		0/3		0/19		0/4		0/9		0/6	
Mercury	0.002	0/0		0/0		0/0		0/0		0/0		0/0	
Nitrate 5/	45	0/34		0/4		0/20		0/4		0/12		0/8	
Selenium (liq.)	0.1	0/5		0/2		0/1		0/2		0/2		0/3	
Silver	0.05	0/31		0/3		0/19		0/4		0/9		0/9	

1/ For specific site descriptions, including lists and maps of wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant.

5/ The PDWS for nitrate measured as N is 10 ppm.

EXHIBIT 5-10 (Continued)

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY DATA ON PRIMARY DRINKING WATER EXCEEDANCES

Units = ppm		Sherburne County Site				Powerton Station Site				Lansing Smith Steam Plant			
PDWS		Downgradient (3 wells) 1/		Upgradient (2 wells) 1/		Downgradient (3 wells) 1/		Upgradient (1 well) 1/		Downgradient (5 wells) 1/		Upgradient (3 wells) 1/	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Arsenic (liq.)	0.05	0/3		0/3		0/8		0/2		0/5		0/4	
Barium	1	0/12		0/8		0/9		0/4		0/14		0/6	
Cadmium	0.01	2/12	2	2/8	2	8/9	3	2/4	1	10/14	5	2/6	2
Chromium (Cr VI)	0.05	1/12	1.2	0/8		0/9		0/4		1/14	4	0/6	
Fluoride	4.0	0/12		0/8		0/9		0/4		5/14	13.5	0/6	
Lead	0.05	0/12		0/8		1/9	4	0/4		0/14		0/6	
Mercury	0.002	0/0		0/0		0/0		0/0		0/0		0/0	
Nitrate 5/	45	2/12	1.1	2/8	27	0/9		2/4	1.1	0/0		0/0	
Selenium (liq.)	0.1	0/3		0/3		0/8		0/2		0/5		0/4	
Silver	0.05	0/12		0/8		0/9		0/4		0/14		0/6	

1/ For specific site descriptions, including lists and maps of wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant.

5/ The PDWS for nitrate measured as N is 10 ppm.

EXHIBIT 5-11

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY DATA ON SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm		Allen Site				New Elrama Site				Dave Johnston Site			
SDWS		Downgradient (11 wells) 1/		Upgradient (1 well) 1/		Downgradient (5 wells) 1/		Upgradient (1 well) 1/		Downgradient (3 wells) 1/		Upgradient (2 wells) 1/	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Chloride	250	0/34		0/4		0/21		0/4		0/12		0/8	
Copper	1	0/31		0/3		0/19		0/4		0/9		0/6	
Iron	0.3	7/31	82	0/3		0/19		1/4	1.8	0/9		0/6	
Manganese	0.05	19/31	102	1/3	1.4	19/19	456	4/4	197	1/9	3.2	1/6	4.6
Sulfate	250	0/34		0/3		9/19	4.7	3/4	1.5	12/12	5.8	4/8	5.1
Zinc	5	0/31		0/3		0/19		0/4		0/9		0/6	
pH Lab 5/	<=6.5	10/10	4.7	1/1	5.9	0/0		0/0		0/0		0/0	
	>=8.5	0/10		0/1		0/0		0/0		0/0		0/0	
pH Field 5/	<=6.5	21/28	4.4	2/3	6.2	9/14	5.2	2/2	4.5	0/9		0/6	
	>=8.5	0/28		0/3		0/14		0/2		0/9		0/6	

1/ For specific site descriptions, including lists and maps of the wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.

5/ As indicated in footnote 15, the Max. Exceed column for the reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

EXHIBIT 5-11 (Continued)

SUMMARY OF ARTHUR D. LITTLE'S GROUND-WATER QUALITY DATA ON SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm SDWS		Sherburne County Site 1/ Downgradient (3 wells)		1/ Upgradient (2 wells)		Powerton Station Site 1/ Downgradient (3 wells)		1/ Upgradient (1 well)		Lansing Smith Steam Plant 1/ Downgradient (5 wells)		1/ Upgradient (3 wells)	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Chloride	250	0/12		0/8		0/9		0/4		14/14	22.4	0/6	
Copper	1	0/12		0/8		0/9		0/4		0/14		0/6	
Iron	0.3	0/12		1/8	1.9	4/9	42	0/4		14/14	118	6/6	37
Manganese	0.05	2/12	22	1/8	1.4	9/9	194	2/4	11	13/14	17.2	2/6	1.4
Sulfate	250	0/12		0/8		6/9	2.7	0/4		8/14	8.4	0/6	
Zinc	5	0/12		0/8		0/9		0/4		0/14		0/6	
pH Lab 5/	<=6.5	0/0		0/0		0/0		0/0		4/6	4.4	1/2	6.5
	>=8.5	0/0		0/0		0/0		0/0		0/6		0/2	
pH Field 5/	<=6.5	0/8		0/6		1/9	6	0/3		10/13	2.9	4/6	6
	>=8.5	0/8		0/6		0/9		0/3		0/13		0/6	

1/ For specific site descriptions, including lists and maps of the wells used for data, see Appendix E.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.

5/ As indicated in footnote 15, the Max. Exceed column for the reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

- One site had downgradient PDWS exceedances for fluoride in 5 of 14 samples. The maximum exceedance was 13.5 times the PDWS. There were no upgradient PDWS exceedances for fluoride at any of the six sites.
- There were no lead exceedances upgradient and only one PDWS exceedance out of 94 downgradient observations at 4 times the PDWS.
- The contaminants of most concern at the six sites appear to be cadmium and, to a lesser extent, chromium. For both of these contaminants, three sites had exceedances of the PDWS in downgradient ground water at levels higher than were found in upgradient ground water.

For constituents for which there are Secondary Drinking Water Standards, exceedances in downgradient ground water generally were higher than levels observed in upgradient wells. Results are shown in Exhibit 5-11.

5.2.1.2 Surface Water Sampling

Exhibit 5-12 summarizes the results of surface-water quality data obtained by ADL at background, peripheral, and downstream locations at three of the study sites -- Elrama, Powerton, and Lansing Smith -- for constituents with established Primary and Secondary Drinking Water Standards. Examination of these results for PDWS constituents indicates that:

- At the Lansing Smith site, downgradient and peripheral surface water samples showed cadmium concentrations up to 5 times the PDWS, chromium concentrations up to 1.2 times the PDWS, and fluoride concentrations up to 20 times the PDWS. No upgradient samples were collected at the Lansing Smith site.
- Exceedances were found for cadmium (up to 2 times the PDWS) and nitrate (up to 1.2 times the PDWS) in both upgradient and downgradient surface water at the Powerton site. The exceedances were similar in upgradient and downgradient samples both in terms of the proportion of samples in which exceedances were found and the magnitude of the exceedances.

EXHIBIT 5-12

SUMMARY OF ARTHUR D. LITTLE'S SURFACE-WATER QUALITY DATA ON PRIMARY AND SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm	PDWS	New Elrama Site				Powerton Station Site				Lansing Smith Steam Plant					
		Downgradient 1/ (4 stations)		Upgradient 1/ (1 station)		Downgradient 1/ (1 station)		Upgradient 1/ (3 stations)		Downgradient 1/ (6 stations)		Peripheral 1/ (3 stations)		Downgradient Saline 1/ (2 stations)	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Arsenic (liq.)	0.05	0/1		0/1		0/1		0/2		0/2		0/1		0/3	
Barium	1	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
Cadmium	0.01	0/7		0/3		2/3	2	5/8	2	10/13	5	4/8	4	5/5	4
Chromium (Cr VI)	0.05	0/7		0/3		0/3		0/8		0/13		0/8		1/5	1.2
Fluoride	4.0	0/7		0/3		0/3		0/8		5/13	6.5	2/8	2	2/5	20
Lead	0.05	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
Mercury	0.002	0/0		0/0		0/0		0/0		0/0		0/0		0/0	
Nitrate 5/	45	0/7		0/3		1/3	1.1	3/7	1.2	0/0		0/0		0/0	
Selenium (liq.)	0.1	0/1		0/1		0/1		0/2		0/2		0/1		0/3	
Silver	0.05	0/7		0/3		0/3		0/8		0/13		0/8		0/5	

1/ For specific site descriptions, including lists and maps of the stations used for data, see Appendix E. Peripheral stations are neither upgradient nor downgradient of the site. These stations are located across the gradient from the site, and may become contaminated by lateral dispersion of waste constituents.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant.

5/ The PDWS for nitrate measured as N is 10 ppm.

EXHIBIT 5-12 (Continued)

SUMMARY OF ARTHUR D. LITTLE'S SURFACE-WATER QUALITY DATA ON PRIMARY AND SECONDARY DRINKING WATER EXCEEDANCES

Units = ppm		New Elrama Site				Powerton Station Site				Lansing Smith Steam Plant					
SDWS		Downgradient (4 stations) 1/		Upgradient (1 station) 1/		Downgradient (1 station) 1/		Upgradient (3 stations) 1/		Downgradient (6 stations) 1/		Peripheral (3 stations) 1/		Downgradient Saline (2 stations) 1/	
Contam.	2/ Drinking Water Standard	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.	3/ Exceed./ Total	4/ Max. Exceed.
Chloride	250	0/7		0/3		0/3		0/8		13/13	11.9	5/8	10	5/5	58
Copper	1	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
Iron	0.3	0/7		0/3		0/3		0/8		11/13	370	6/8	34	0/5	
Manganese	0.05	7/7	7.4	3/3	4.2	2/3	2.2	2/8	1	11/13	64	6/8	4.8	0/5	
Sulfate	250	0/7		0/3		0/3		0/8		12/13	7.5	4/8	3.4	5/5	9.9
Zinc	5	0/7		0/3		0/3		0/8		0/13		0/8		0/5	
pH Lab 5/	<=6.5	0/0		0/0		0/0		0/0		5/6	3.3	2/3	3.8	0/1	
	>=8.5	0/0		0/0		0/0		0/0		0/6		0/3		0/1	
pH Field 5/	<=6.5	4/7	6.1	2/3	6	0/3		0/8		5/10	4.1	4/7	3.4	0/5	
	>=8.5	0/7		0/3		1/3	8.5	2/8	8.5	0/10		0/7		0/5	

1/ For specific site descriptions, including lists and maps of the stations used for data, see Appendix E. Peripheral stations are neither upgradient nor downgradient of the site. These stations are located across the gradient from the site, and may becom contaminated by lateral dispersion of waste constituents.

2/ Where the reported detection limit for a contaminant was greater than the drinking water standard and the sample contained less contaminant than the reported detection limit, the sample is tabulated as being below the drinking water standard. For a more detailed explanation, see Appendix E.

3/ The number of samples with reported concentrations above the drinking water standard (slash) the total number of samples.

4/ Max. Exceed. is the concentration of the greatest reported exceedance divided by the drinking water standard for that particular contaminant. The only exception is for pH, where Max. Exceed. is the actual measurement.

5/ As indicated in footnote 10, the Max. Exceed. column for reported pH measurements is a tabulation of the actual measurements, not the maximum exceedance divided by the drinking water standard.

- No exceedances of PDWS were found upgradient or downgradient at the Elrama site, although there had been downgradient exceedances at Elrama in ground water for cadmium and chromium.

5.2.1.3 Waste Fluid Sampling

In addition to ground-water monitoring, waste fluid samples were collected from the waste ponds at the Allen, Sherburne County, and Lansing Smith sites, and from dry fly ash landfills at the Dave Johnston site. Water from within and beneath FGD sludge and fly ash waste mixtures were collected from the Elrama landfill. No waste fluid samples were obtained at the Powerton site. Key observations are presented below.

- Arsenic was present in the waste fluids at elevated concentrations (up to 31 times the Primary Drinking Water Standard) at two of the five sites sampled. At these sites (Allen and Elrama), arsenic may be attenuated by soils at the site; attenuation tests indicate the soils had a moderate to high attenuation capacity, and no exceedances for arsenic were observed in ground water at the sites. The Dave Johnston site was the only disposal area where soils were found to have low attenuation capacities for arsenic; however, there are no data pertaining to waste fluids at this site, and exceedances for arsenic in the ground water were not observed. These results indicate that, depending on the coal source, arsenic may occur at elevated concentrations in waste fluids, but can be attenuated by soils within and surrounding a coal combustion waste disposal site. If the soils at a disposal site have low attenuation capacities for arsenic, this element may be of concern with regard to ground water and surface water contamination.

- Cadmium is present at elevated concentrations (up to 30 times the Primary Drinking Water Standard) in the waste fluids at all five sites. At Powerton, although no waste fluid samples were taken, ground-water samples obtained from directly beneath the wastes also exhibited elevated concentrations of cadmium. These results support the conclusion that elevated concentrations of cadmium observed in downgradient ground water may be attributable to coal combustion wastes.

- Chromium is present at elevated concentrations (up to 21 times the Primary Drinking Water Standard) in the waste fluids at two of the five sites. At these sites, higher chromium concentrations were found in downgradient ground water than were found in upgradient ground water. These observations suggest that ground-water contamination by chromium at these two study sites may be attributable to the coal combustion wastes. At a third site at which downgradient exceedances of chromium in ground water were observed, waste fluid samples were mixed with ground water occurring beneath the wastes during collection, which may account for lower waste fluid concentrations at this site.

- Other constituents that were found at elevated concentrations within the waste fluids include fluoride at all five sites (up to 10 times the PDWS); lead at one of five sites (up to 28 times the PDWS); nitrate at one of five sites (up to 7 times the PDWS); and selenium at one of four sites (up to 25 times the PDWS).

- Constituents for which Secondary Drinking Water Standards are established were found at the following elevated concentrations: chloride at three of five sites (up to 61 times the SDWS); iron at two of five sites (up to 221 times the SDWS); manganese at four of five sites (up to 466 times the SDWS); and sulfate at four of five sites (up to 42 times the SDWS). Exceedances of pH standards were found in the waste fluids at two of three sites tested. At these two sites, both acidic (as low as pH 5.9) and alkaline (as high as pH 11) conditions were found to exist. Average pH values measured in these waste fluids indicated that they were generally alkaline.

- Results of waste fluid sampling at the Sherburne County site showed exceedances of Primary Drinking Water Standards for cadmium (up to 30 times PDWS); chromium (up to 16 times the PDWS); fluoride (up to 13 times the PDWS); lead (up to 28 times the PDWS); nitrates (up to 6.9 times the PDWS); and selenium (up to 25 times the PDWS). Measurements also showed maximum exceedances of Secondary Drinking Water Standards for chloride (up to 1.9 times the SDWS); iron (up to 6.1 times the SDWS); manganese (up to 316 times the SDWS); and sulfate (up to 42 times the SDWS). This was the only site where disposal areas or ponds were completely lined. The clay liner appeared to have reduced the release of leachate, thereby concentrating waste constituents.

Results from waste fluid studies conducted by other organizations are described in Appendix D.

5.2.1.4 Summary

Results from the Arthur D. Little study suggest that under the waste management procedures used by the facilities studied, some coal combustion waste leachate was migrating into ground water beneath and downgradient from disposal sites. Five sites had concentrations of cadmium in downgradient ground water that exceeded the PDWS. Two of these five had maximum upgradient exceedances at the same level as the maximum downgradient exceedance, and two of the sites had upgradient concentrations that were equal to or above the PDWS, although the maximum concentration was less than the downgradient concentrations. One of the five sites had upgradient measurements of cadmium that were below the PDWS. Exceedances of chromium were detected in a few ground-water samples downgradient of three sites; there were no chromium concentrations above the PDWS in the upgradient ground water of any site. There were no detected exceedances of arsenic, barium, mercury, selenium, or silver in the ground water or surface water at any of the six sites. In total, approximately 5 percent of the downgradient observations exceeded the PDWS.

5.2.2 Franklin Associates Survey of State Ground-Water Data

EPA commissioned Franklin Associates to gather data from state regulatory agencies on the quality of ground water at or near coal-fired electric utility fly ash disposal sites.[23] The objective of this survey was to determine the level of ground-water contamination in the vicinity of disposal sites. However, according to the Franklin Associates report: "No attempt was made to determine what monitoring wells might be up gradient, or what wells might be down gradient, or even as to whether specific ash disposal sites were in fact contributing specific pollutants."

Franklin Associates contacted 44 states in which coal-fired facilities were located; of these 44 states, 13 provided data. The data base that was developed included data from more than 4700 well samples taken from 66 sites.

Analysis of these samples revealed 1129 exceedances of the PDWS out of more than 15,000 observations, as shown in Exhibit 5-13. Ninety-two percent of the exceedances were less than ten times the PDWS; eight of the exceedances were 100 times greater than the PDWS.

There were 5952 exceedances of the SDWS out of nearly 20,000 observations as shown in Exhibit 5-14. These secondary standards were exceeded more frequently than the primary standards, and exceedances were usually greater. For example, about 77 percent of the SDWS exceedances were less than 10 times the standard (compared with 92 percent for PDWS exceedances), whereas 4 percent of the exceedances were greater than 100 times the SDWS (compared with less than one percent for PDWS exceedances).

Since this study did not compare upgradient and downgradient concentrations, it is not possible to determine whether occurrences of contamination at particular sites are the result of utility waste disposal practices or background levels of contaminants.

EXHIBIT 5-13

SUMMARY OF PDWS EXCEEDANCES IN THE FRANKLIN ASSOCIATES SURVEY

Constituent	Total Observations	Number of Observations Exceeding PDWS By 1 X	10 X	100 X	Highest Exceedance (X PDWS)
Arsenic	1995	94	0	0	9.8
Barium	1353	108	9	0	44.0
Cadmium	1733	126	16	1	531.0
Chromium	1863	92	5	0	50.2
Fluoride	995	28	3	0	19.3
Lead	1722	243	20	1	182.0
Mercury	1282	30	8	5	500.0
Nitrate	1432	204	0	0	7.3
Selenium	2453	196	30	1	100.0
Silver	530	8	0	0	8.0
TOTAL	15,358	1129	81	8	

Source: Franklin Associates, Ltd., Summary of Ground-water Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for the U.S. Environmental Protection Agency, March 1984.

EXHIBIT 5-14

SUMMARY OF SDWS EXCEEDANCES IN THE FRANKLIN ASSOCIATES SURVEY

Constituent	Total Observations	Number of Observations Exceeding SDWS By 1 X	10 X	100 X	Highest Exceedance (X SDWS)
Chloride	2921	109	14	0	42.0
Copper	650	1	0	0	1.2
Iron	3140	1942	862	149	4,000.0
Manganese	1673	1050	467	80	2,400.0
pH	4107	843	-	-	-
Sulfate	4378	1059	13	0	23.2
TDS	1925	920	24	0	28.7
Zinc	1175	28	4	0	46.0
TOTAL	19,969	5952	1384	229	

Source: Franklin Associates, Ltd., Summary of Ground-water Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for the U.S. Environmental Protection Agency, March 1984.

5.2.3 Envirosphere Ground-Water Survey

In response to the temporary exemption of utility wastes from regulation under Subtitle C of RCRA, the Utility Solid Waste Activities Group (USWAG) commissioned Envirosphere, Inc., to review information available from electric utilities on the quality of ground water at utility waste disposal sites.[24] Envirosphere solicited information from 98 utilities on the number and type of constituents they monitored, the frequency with which measurements were taken, and the period of time for which they had collected ground-water monitoring data. Ninety-six of the contacted utilities responded to the request for information. From these 96 utilities, Envirosphere selected for further study those that appeared to have adequate data on ground-water quality. These utilities were contacted and asked to provide their available data for use in Envirosphere's study. The participating utilities (the exact number of utilities was not provided) forwarded the requested information to Envirosphere on the 28 disposal facilities they operated. The utilities chose to withdraw three of the 28 disposal sites from the study subsequent to the analysis of the data, leaving 25 disposal sites in the data pool.

In order to analyze the data, Envirosphere paired the measurements taken at upgradient and downgradient wells at approximately the same time and in the same aquifer.[25] These data were then compared to the applicable drinking water standards to determine whether the standards had been exceeded. Two disposal sites were then eliminated from further consideration because no upgradient wells could be identified. The remaining 23 disposal sites produced a total of 9,528 paired measurements of upgradient and downgradient ground-water concentrations.

Exhibit 5-15 summarizes the information from the Envirosphere data base for those cases where the Primary Drinking Water Standards (PDWS) were exceeded by the downgradient measurement. The most obvious indication that a waste facility is contributing to a PDWS exceedance is a measurement indicating downgradient values higher than the PDWS and upgradient values lower than the PDWS. According to Envirosphere's report, about 1.7 percent of the data fell into this category.[26] For those cases in which both the upgradient and downgradient values were exceeded, Envirosphere argued that it was difficult to attribute the exceedances to the disposal facility without further site-specific analysis. About 5 percent of the measurements fell into this category, with 60 percent of these indicating upgradient values equal to or greater than the downgradient values.

Maximum concentrations of several substances significantly exceeded the PDWS in downgradient wells: arsenic, 560 times the PDWS; lead, 480 times the PDWS; mercury, 235 times the PDWS, and selenium, 100 times the PDWS. These values must be compared to the maximum upgradient reading since some of the contamination may be unrelated to the disposal facility. As shown in Exhibit 5-15, the downgradient concentration was sometimes higher than the upgradient value even when the upgradient value exceeded the PDWS. However, exceedances of the magnitudes shown in Exhibit 5-15 comprised a small fraction of the total measurements in the Envirosphere data base.

The Envirosphere data also included information regarding exceedances of the Secondary Drinking Water Standards (SDWS). A summary of these data is shown in Exhibit 5-16. The data indicate that in 8.2 percent of the cases the

EXHIBIT 5-15

SUMMARY OF PDWS EXCEEDANCES IN ENVIROSPHERE'S GROUND-WATER DATA

		Downgradient Observations a/ Exceeding PDWS When:				Maximum Downgradient Observation (X PDWS) b/	
Constituent	Total Observations	Upgradient Does Not Exceed Number	%	Upgradient Exceeds Number	%		
Arsenic	588	7	1	0	0	560	(192)
Barium	298	0	0	0	0	1	(3)
Cadmium	571	59	10	9	2	6	(1)
Chromium	658	20	3	10	2	20	(76)
Lead	639	29	5	67	10	480	(220)
Mercury	575	8	1	2	c/	235	(9)
Selenium	489	5	1	34	7	100	(100)
Silver	261	0	0	0	0	1	(0.2)
TOTAL	4079	128	3 d/	122	3 d/		

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a/ Envirosphere classified measurements by comparing downgradient values with upgradient values. When the downgradient value exceeded the PDWS, classification depended on whether the upgradient value also exceeded the PDWS. Both categories of measurements are shown here, although Envirosphere focused primarily on pairs of measurements in which the downgradient value exceeded the PDWS but the upgradient value did not.

b/ Maximum downgradient value observed in the Envirosphere data base. The corresponding paired upgradient concentrations are not available. The maximum upgradient value of all measurements at the same facility is shown in parentheses.

c/ Less than 0.5 percent.

d/ These percentages apply to the total number of observations. Envirosphere "normalized" the data to correct for sites that had a high proportion of data points so that one site would not be overly represented; these normalized values are noted in the text of the report.

Source: Envirosphere Company, "Report on the Ground-water Data Base Assembled by the Utility Solid Waste Activities Group," in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix C.

EXHIBIT 5-16

SUMMARY OF SDWS EXCEEDANCES IN ENVIROSPHERE'S GROUND-WATER DATA

		Downgradient Observations a/ Exceeding SDWS When:				Maximum Downgradient Observation (X SDWS) b/	
		Upgradient Does Not Exceed		Upgradient Exceeds			
Constituent	Total Observations	Number	%	Number	%		
Chloride	502	4	1	7	1	22	(5)
Copper	452	9	2	0	0	2	(0.02)
Iron	964	60	6	376	39	3458	(2)
Manganese	487	157	32	143	29	474	(5)
Sulfate	1028	289	28	57	6	32	(8)
Total Dissolved Solids	908	159	18	292	32	31	(2)
Zinc	387	3	1	3	1	1	(0.1)
TOTAL	4728	681	14 c/	875	19 c/		

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a/ Envirosphere classified measurements by comparing downgradient values with upgradient values. When the downgradient value exceeded the SDWS, classification depended on whether the upgradient value also exceeded the SDWS. Both categories of measurements are shown here, although Envirosphere focused primarily on pairs of measurements in which the downgradient value exceeded the SDWS but the upgradient value did not.

b/ Maximum downgradient value observed in the Envirosphere data base. The corresponding (paired) upgradient concentrations are not available. The maximum upgradient value of all measurements at the same facility is shown in parentheses.

c/ These percentages apply to the total number of observations. Envirosphere "normalized" the data to correct for sites that had a high proportion of data points so that one site would not be overly represented; these normalized values are noted in the text of the report.

Source: Envirosphere Company, "Report on the Ground-water Data Base Assembled by the Utility Solid Waste Activities Group," in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix C.

downgradient value exceeded the SDWS while the upgradient value did not. In some cases the exceedances were substantially greater than the SDWS; e.g., the maximum observation for iron was 3458 times greater than the SDWS and manganese was 474 times greater.

In summary, the Envirosphere ground-water data show that Primary and Secondary Drinking Water Standards were exceeded in ground water downgradient from utility waste disposal facilities. However, the percentage of cases in which constituent concentrations in downgradient wells exceeded the standards when those in upgradient wells did not was small. There are limitations in the data, due in part to the way in which they were collected (e.g., only data from those utilities that voluntarily submitted data are included in the report). There is also a limited amount of information regarding the extent to which site-specific factors, such as environmental setting characteristics or other possible sources of contamination, could have had an effect on ground-water contamination.

5.2.4 Summary

The studies described in this section demonstrate that downgradient ground-water and surface-water concentrations exceeded the PDWS and SDWS for a few constituents. In some of these downgradient exceedances, corresponding upgradient exceedances also occurred, suggesting that the contamination was not necessarily caused by the waste disposal sites. For cases in which the downgradient ground water had constituent concentrations higher than the corresponding upgradient concentrations, the PDWS exceeded most often were those for cadmium, chromium, lead, and to a lesser extent, arsenic.

Some PDWS exceedances were quite high, e.g., up to 560 times for arsenic and 480 times for lead (see Exhibit 5-15). However, the frequency of PDWS exceedances for downgradient ground water and surface water is rather low. For example, 3.7 percent of the Envirosphere data had downgradient ground-water concentrations of PDWS higher than those measured in upgradient wells. Three of the six Arthur D. Little sites had downgradient ground water with concentrations of constituents that were both above the PDWS and above corresponding upgradient concentrations. Although the Arthur D. Little pond liquor data show high concentrations of PDWS and SDWS constituents, in most cases the constituents appeared to be contained within the disposal area or attenuated in the surrounding soils. This is particularly true for the case of arsenic, which was detected in the waste fluids at a level 31 times the PDWS, but was not found at elevated levels in ground water or surface water. There were no exceedances of arsenic, barium, mercury, selenium, or silver in downgradient ground water at any of the six Arthur D. Little sites. The Envirosphere study detected no exceedances of barium or silver.

5.3 EVIDENCE OF DAMAGE

This section examines documented cases in which danger to human health or the environment from surface runoff or leachate from the disposal of coal combustion wastes has been proved. The first part of this section reviews two major studies conducted for the Utility Solid Waste Activities Group (USWAG): a 1979 Envirosphere, Inc., study and a 1982 Dames and Moore study. To supplement these two major studies, in 1987 EPA conducted a literature review of all readily-available sources, which revealed only two additional case studies on proven damages occurring in 1980 and 1981. The Agency has not identified any proven damage cases in the last seven years; however, no attempt was made to compile a complete census of current damage cases by conducting extensive field studies.

As with all damage cases, it is not always clear whether damages could occur under current management practices or whether they are attributable to practices no longer used. As described in Chapter Four, there has been an increased tendency in recent years for utilities to utilize mitigative technologies, including a shift to greater use of landfills rather than surface impoundments and an increased use of liners.

5.3.1 Envirosphere Case Study Analysis

The Utility Solid Waste Activities Group (USWAG) and the Edison Electric Institute (EEI) commissioned the Envirosphere Company in 1979 to investigate and document available information on the nature and extent of the impact of utility solid waste disposal on public health, welfare, and the environment.[27] To conduct this analysis, Envirosphere reviewed various reports, including EPA's damage incident files, environmental monitoring studies at utility disposal sites, and other research and studies as available; they contacted state regulatory agencies to determine what information was available in state files.

From its review of the available data, Envirosphere found few documented cases where utility solid waste disposal had potentially adverse environmental effects. They identified nine cases from EPA's damage incident files that appeared to show damage to the environment. Envirosphere reviewed data from environmental monitoring studies at the utility disposal sites and other available research, and noted that the information available on the potential impacts of utility waste disposal was inconclusive. Some data indicated "... that elevated levels of some chemical parameters have occurred at locations downgradient of some utility solid waste disposal sites." Envirosphere concluded, however, that it was not clear to what extent these impacts could be attributed to utility solid waste disposal practices.

Some of the specific cases from Envirosphere's sources are summarized below:

- Texas, 1977. A clay liner was improperly installed in a 14.3 acre disposal pond for metal cleaning solutions. The liner dried and cracked before wastes were introduced into the facility. After the pond was put in service, ground-water monitoring wells detected contaminant migration. Levels of selenium and chromium occasionally exceeded the PDWS for these elements, and several SDWS were exceeded. The pond was taken out of service, the liner was saturated with water, and the pond was put back into operation.
- Indiana, 1977. Envirosphere found that leaching from two large, unlined ash disposal ponds was contributing to ground-water contamination. Arsenic and lead were found in downgradient ground water at concentrations about two times the PDWS, while concentrations of selenium were about four times the PDWS.
- Pennsylvania, 1975. A private waste handler illegally disposed fly ash in a marsh located in a tidal wetland area. Visual inspections by the state indicated marsh contamination due to fly ash leachate. When ordered to stop the dumping and clean up the site, the handler declared bankruptcy, and the ash remained in the marsh. Detailed analysis of any potential impacts has not been conducted.
- Connecticut, 1971. A municipal landfill, which was located in a marsh, accepted many substances, including large quantities of fly ash. Surveys revealed numerous SDWS contaminants, some of which appeared to be related to the ash. The site, considered unsuitable for disposal of solid waste, was closed and turned into a state park.
- Virginia, 1967. A dike surrounding a fly ash settling lagoon collapsed, and 130 million gallons of caustic solution (pH 12.0) were released into the Clinch River.

> Large numbers of fish were killed over a distance extending 90 miles from the spill site. Surveys conducted 10 days after the spill showed dramatic reductions in bottom dwelling fish food organisms for 77 miles below the release site. Virtually all such organisms were eliminated for a distance of 3 to 4 miles. The waste was eventually diluted, dispersed, and neutralized by natural physical/chemical processes. Two years after the spill, however, the river had not fully recovered.

5.3.2 Dames & Moore Study of Environmental Impacts

Dames & Moore, in a study for USWAG, conducted a survey of existing data and literature to document instances in which danger to human health and the environment was found to have occurred because of the disposal of coal combustion wastes.[28] Dames & Moore established criteria by which to evaluate whether a given record of a contamination incident could be considered "documented" evidence proving danger to health or the environment: 1) the report must exist in the public record; 2) the case must involve high-volume (utility) wastes; 3) information must exist to permit determination of possible health or environmental risks; and 4) the possible risks may have been caused by leachate migration or runoff from utility disposal sites.

The danger to health and the environment was examined by accounting for the types, concentrations, and locations of constituents shown to be present that could have harmful effects. In addition, Dames & Moore considered both the potential for public access to utility waste constituents and any observed effects on the population or environment. The three major data sources providing information reviewed in this study were computer data bases used to search for publicly available references; Federal Government agencies such as

EPA, U.S. Geological Survey, and the Tennessee Valley Authority; and 12 state environmental, natural resource, health or geological agencies.

Using information from these sources, Dames & Moore identified seven cases that presented a potential danger to human health and the environment. Six of the seven cases involved potential impacts from ground water and one case involved surface water. Dames & Moore concluded that none of these cases represented a "documented" case of such danger. However, Dames & Moore eliminated several sites from the documented category because they believed sufficient data from the sites were unavailable or did not meet the selection criteria described above. Dames & Moore evaluated in detail the seven sites at which there existed a potential for adverse environmental and health effects. Their findings are summarized below.

- Chisman Creek Disposal Site, York County, Virginia. The Chisman Creek disposal area was an inactive site with four separate fly ash disposal pits on both sides of Chisman Creek. An electric utility hired a private contractor to transport and dispose of fly ash and bottom ash from petroleum coke (a residual product of the oil distillation process) and coal combustion. The site was active from the late 1950's to 1974. In 1980, nearby residential drinking water wells became green from contamination of vanadium and selenium and could no longer be used. The site is currently on the CERCLA (Superfund) National Priorities List. A minimum of 38 domestic wells and 7 monitoring wells near the four disposal sites were sampled over time. Two off-site domestic wells located 200 feet from the disposal area had elevated concentrations of vanadium, selenium, and sulfate. One of these two wells was sampled four times. Three of the four measurements exceeded the PDWS for selenium up to 2 times. Another domestic well contained 0.11 mg/l of vanadium. (EPA has not established concentration limits for vanadium.) At both wells, sulfate concentrations exceeded the SDWS. In addition, samples from six of the seven monitoring wells exhibited increased concentrations of sulfates. The highest concentrations of selenium and vanadium that were observed in monitoring well samples were 0.03 (3 times the PDWS) and 30 mg/l, respectively. The high concentrations of selenium and vanadium were noticed in monitoring wells that were drilled directly through the disposal pits.

The Virginia State Water Control Board (SWCB) conducted the initial study at this site. The SWCB concluded that the quality of ground water immediately beneath and downgradient from the site had been affected. Moreover, the SWCB stated that the water in the two domestic wells had elevated concentrations of selenium and vanadium because of the disposal of the fly ash. Dames & Moore was critical of the conclusions reached by the SWCB because of what they termed "significant data gaps." Dames & Moore cited a lack of background water quality information and a general lack of information on the well installation, sample collection procedures, and other possible sources of contamination, such as the York County landfill which is adjacent to one of the ash disposal areas. The two contaminated off-site domestic wells identified by the SWCB, however, were over 2,000 feet from the county landfill but within a couple of hundred feet from the ash disposal areas. Additionally, monitoring wells located between the landfill and the affected domestic wells did not register the same elevated concentrations of selenium. Residents in the area no longer rely on ground water for their drinking water.

- <u>Pierce Site, Wallingford, Connecticut</u>. Coal fly ash had been deposited at the Pierce Site since 1953. In 1978, the United States Geological Survey (U.S.G.S.) collected ground-water quality data from three on-site wells - one upgradient and two downgradient. The U.S.G.S. took samples from the wells on three days over a period of two months. One sample from one downgradient well showed a concentration of chromium that exceeded the PDWS by a multiple of 1.6. Concentrations of cadmium, manganese, zinc, and sulfate were higher in the downgradient wells than in the upgradient well.

  According to Dames & Moore, there were not enough data at this site to state conclusively whether or not the ground water had been adversely affected by the fly ash pit. To determine potential damage to ground water quality, Dames & Moore stated that EPA recommends a minimum of three downgradient wells and one upgradient well. In this case, there were only two downgradient wells. Three samples over a period of two months were not considered sufficient because naturally occurring temporal changes in the area were believed to render comparisons invalid.

  The Pierce disposal site is situated on a deposit of thick, stratified sediments composed of particles that range in size from clay to coarse sand. The disposal site is located within a few hundred feet of the Quinnipiac River, and the ground water flows from the site to the river, which diluted contaminants in the ground water. Although there are residences within a few blocks of the power plant, they do not use local ground water for drinking supplies.

- <u>Michigan City Site, Michigan City, Indiana</u>. The Michigan City site, situated on the shore of Lake Michigan, contained two fly ash disposal ponds. Ground-water flow at the site was towards Lake Michigan, facilitated by the porous sand that underlies the site. Twenty-one monitoring wells were installed at this site. Two of these were placed upgradient from the site outside the site boundaries; the remaining 19 wells were established within the boundaries of the facility and downgradient from the disposal areas.

  Monitoring of the wells (which took place periodically over a one-year period) indicated that trace metals migrated from the disposal sites and that certain constituents had elevated ground-water concentrations. Arsenic and lead were observed in concentrations that exceeded their PDWS. Seven samples collected from three downgradient monitoring wells had arsenic concentrations that exceeded the standard -- up to 100 times the PDWS. All of the samples taken from the upgradient off-site monitoring wells contained arsenic at concentrations below the PDWS. Five of the downgradient monitoring wells contained lead concentrations which exceeded the PDWS, with the highest exceedance 7 times the PDWS. Three samples from the two upgradient monitoring wells also had lead concentrations in excess of the standard, with the highest exceedance 3 times the PDWS.

  Dames & Moore concluded that effects on ground water appeared to be limited to areas within the facility boundaries because of attenuation mechanisms operative at the site -- absorption, dilution, precipitation, and a steel slurry wall installed between the disposal site and Lake Michigan. However, no downgradient monitoring wells were situated off-site. Based on the locations of the waste disposal sites and the monitoring wells, it appears that the ash ponds are responsible for arsenic concentration above the PDWS in the ground water within the site boundaries. Because high lead concentrations were observed in some of the upgradient background wells, it is impossible to state with certainty that the high lead concentrations in the ground water are attributable to the disposal sites. Dames and Moore noted that nearby residents do not use the ground water for their water supply.

- <u>Bailly Site, Dune Acres, Indiana</u>. The Bailly site is located near the Indiana National Lakeshore on Lake Michigan in a highly industrialized area. Fly ash at this site has been slurried to interim settling ponds, which are periodically drained. The drained ash is then disposed in an on-site pit. Two aquifer units, designated Unit 1 and Unit 3, underlie the site. Unit 1 contains fine-to-medium sand and some gravel, while Unit 3 is composed of sand with overlying layers of varying amounts of sand, clay and gravel.

  Ground-water samples from Unit 1 were collected from an upgradient well and from several wells downgradient from the ash settling ponds. Samples from Unit 3 were collected upgradient and from one well downgradient from the ash ponds. These wells were sampled at five-week intervals between September 1976 and May 1978.

  In samples from Unit 1, arsenic, cadmium, fluoride, and lead occasionally exceeded the PDWS. Upgradient concentrations of arsenic never exceeded the PDWS, whereas the maximum downgradient concentration for arsenic was 4.6 times the PDWS. Downgradient on-site concentrations of cadmium exceeded the PDWS at one well by 25 times, while the maximum upgradient concentration of cadmium exceeded the PDWS by 22 times. One downgradient well measurement indicated lead concentrations that exceeded PDWS by 1.26 times.

  All of the above-mentioned exceedances were observed in Unit 1. None of the samples from Unit 3 contained constituents at concentrations that exceeded the PDWS.

  Aluminum, boron, iron, manganese, molybdenum, nickel, strontium, and zinc all increased in concentration downgradient from the disposal areas, though not in levels exceeding the SDWS.

  Leachate from the ash disposal ponds is the most probable contributor to the increased concentrations of arsenic and lead observed in the aquifer samples taken from the on-site wells. Cadmium was the only constituent whose downgradient off-site concentration was observed to exceed the PDWS. However, because elevated cadmium concentrations were also found in samples taken from the background well, the elevated concentrations of cadmium may not have been caused by the leachate from the coal ash. Dames and Moore noted that ground water at this site flows away from the nearest residential area.

- <u>Zullinger Quarry Fly Ash Disposal Site, Franklin County, Pennsylvania</u>. The Zullinger quarry was situated in a limestone formation in south-central Pennsylvania. The quarry was excavated to 40 feet below the water table. Fly ash was deposited in the quarry from 1973 to 1980 with no attempt to dewater the quarry prior to placement of the fly ash.

The site operator, consultants, and the Pennsylvania Department of Environmental Resources (DER) have been independently involved in water quality investigations at the site. Initially, six monitoring wells were established onsite. Later, several existing off-site domestic wells were added to the sampling program. Two of the monitoring wells were installed upgradient to provide background constituent concentrations. The other monitoring wells, and the domestic wells in the sampling program, were downgradient from the fly ash deposited in the quarry.

Lead was found to exceed its PDWS by up to eight times in eight out of over 100 samples. Six of these eight exceedances occurred in two on-site monitoring wells, while the seventh (2.6 times PDWS) was found in an off-site domestic well. Another exceedance (1.5 times PDWS) was found in the background well.

Several constituents for which there are secondary drinking water standards were found in elevated concentrations downgradient from the ash disposal site. Sulfate concentrations increased dramatically during the first few years of quarry filling, then began to sharply decline in 1976 when the fly ash had filled the quarry. From 1976 until deactivation of the disposal site in 1980, the fly ash was deposited above the water table. Zinc and iron were also found in elevated concentrations. Elevated levels of sulfate, zinc, and iron are probably attributable to leachate from the fly ash, as are the lead levels in excess of the PDWS. Most of the trace metals appear to be attenuated onsite by the limestone formation.

- Conesville Site, Conesville, Ohio. Various types of coal combustion waste had been deposited at the Conesville site in central Ohio. The monitoring program at the Conesville site was established to determine the ability of an FGD sludge fixation process (Poz-O-Tec, a solid material produced by mixing FGD sludge with fly ash and lime) to stabilize and thus immobilize potential contaminants. The stabilized FGD sludge has been deposited next to a fly ash pond. Permeable sand and gravel underlie the Muskingum River flood plain on which the Conesville site is located.

  A total of 34 monitoring wells were installed at the Conesville site. Two of the wells were situated upgradient from the disposal area to provide the necessary background water quality data. Two sets of water quality data were taken, the first between February 27 and April 12, 1979, and the second between December 4, 1979, and July 10, 1980.

Some samples from the first set of data contained constituents at concentrations that exceeded the PDWS. Lead concentrations exceeded the PDWS in two on-site wells by up to 3 times and three off-site wells by up to 2 times. The concentration of mercury found in one sample from an on-site well exceeded the PDWS by 1.4 times; however, this exceedance could not be attributed to the fly ash. One of the fourteen background measurements had the highest observed concentration of selenium, 6 times the PDWS. Thus, selenium appears to be leaching from indigenous sediments rather than from the FGD waste and fly ash deposited at the site. The first set of data also showed the SDWS constituents of calcium, magnesium, total dissolved solids, sulfate, and iron, had increased in those wells located on the site property and just across the property boundaries.

Measurements taken between December 1979 and July 1980 showed increases in calcium, magnesium, total dissolved solids, and sulfate relative to those measurements taken in the first data collection period. Concentrations in excess of the PDWS were found for selenium (several wells), arsenic (one sample), cadmium (four samples), and chromium (five samples). Two of the chromium exceedances were found in on-site wells, while three occurred in off-site wells, with concentrations ranging up to 16 times the PDWS on-site and 2 times the PDWS off-site. Background wells also had elevated levels of selenium. The single arsenic exceedance (2.4 times the PDWS) and all of the cadmium exceedances (up to 12 times the PDWS) were detected in on-site wells. In contrast to the first round of sampling, lead was not detected in concentrations greater than the PDWS. The only constituents that appear to be migrating offsite are lead and chromium. Based on the data collected, it appears there may be a temporal variation in the water quality at this site. Dames and Moore noted that the town of Conesville is downgradient from the site but on the other side of the river, which would tend to mitigate potential adverse impacts.

- <u>Hunts Brook Watershed, Montville-Waterford, Connecticut</u> The electric utility hired a private contractor to transport and dispose of fly ash in three separate sites (Chesterfield-Oakdale, Moxley Hill, and Linda Sites) along three different tributaries to Hunts Brook. Disposal of fly ash in this area began in the mid 1960's and ended in 1969. The surface-water quality studies that took place in this area focused on pH, iron,

> sulfate, and total dissolved solids (TDS). No analyses were performed for any of the PDWS constituents. Upstream surface water samples were compared to downstream samples to determine if the surface water quality had been degraded at any of the sites.
>
> At the Chesterfield-Oakdale site, concentrations of iron in the surface water increased from less than the SDWS to more than 100 times the SDWS between the upstream and downstream sampling points. Sulfate concentrations increased by over an order of magnitude, from 20 to 299 mg/l, (at 299 mg/l, still only 1.2 times the SDWS) between the upstream and downstream sampling positions, while TDS increased from less than the SDWS to 44 times the SDWS. At another sampling point approximately 1.2 miles downstream from the site, the measured parameters had all returned to levels close to the upstream values.
>
> At the Moxley Hill Site, the pH and iron concentrations remained relatively constant between the upstream and downstream sampling points; median sulfate values increased, although not to levels exceeding the SDWS. The elevated concentrations of sulfate and TDS had been significantly attenuated at another point three-quarters of a mile downstream.
>
> At the Linda Site, no upstream data were collected. It is therefore impossible to quantify the potential effects of fly ash deposition on the water quality.

5.3.3 Other Case Studies of the Environmental Impact of Coal Combustion By-Product Waste Disposal

This section presents a review of two independent case studies of ground-water contamination at utility disposal sites.

Cedarsauk Site, Southeastern Wisconsin

The Cedarsauk site is a fly ash landfill in southeastern Wisconsin. At the time of this study,[29] fly ash had been deposited at the site into an abandoned sand and gravel pit over a period of eight years. Part of the pit is in direct contact with an aquifer composed mainly of sand and gravel with some clay. This upper aquifer is approximately 15 to 20 meters thick with a permeability of 10^{-3}

to 10^{-2} cm/sec. Soluble carbon aqueous material comprises about 35 percent of the aquifer. The upper sandy aquifer overlies another aquifer consisting of fractured dolomite-bedrock.

A water quality study of the area was undertaken in 1975. This study eventually included 35 monitoring wells and seven surface-water sampling sites. Twenty of the wells were placed upgradient of the site to provide background water quality information, while the remaining wells were positioned downgradient. Sampling was performed on a monthly basis. Most of the ground-water flow beneath the site surfaced in a marsh directly east of the ash disposal area.

The monitoring results showed that downgradient ground water had SDWS exceedances. Background levels of total dissolved solids (TDS) were below 500 mg/l, while the levels in the ground water downgradient from the disposal site exceeded 800 mg/l, or 1.6 times the SDWS. After eight years of disposal, the contaminant plume appeared to stabilize approximately 200 meters downgradient from the ash disposal site. The stabilization of the constituent plume appeared to be due to dilution and the ability of the materials in the aquifer to attenuate contaminants. Only iron, manganese, and zinc were found in detectable quantities in the downgradient off-site wells.

The maximum detected iron concentration was more than 33 times the SDWS, while the maximum manganese concentration reached 30 times the SDWS. Neither iron nor zinc could be detected 200 meters downgradient from the disposal site. Another contributor to ground-water contamination at this site was sulfate. Background concentrations of sulfate varied between 20 and 30 mg/l (well below the SDWS), while the concentrations of sulfate in the contaminant plume achieved levels approximately 3.4 times the SDWS. Other trace metals for which analyses were performed, such as copper, molybdenum, nickel, lead, and titanium, were not detected.

As the leachate contacted the sediments in the aquifer, it was neutralized from an initial pH value of 4.5 to around neutral pH levels (i.e., about 7.0). This change in pH probably caused the precipitation of many of the trace metals and other constituents in the leachate. In addition, adsorption reactions between the clay in the sediments and the constituents probably attenuated the leachate concentrations of many of the potential contaminants observed in the leachate.

Center Mine, Center, North Dakota

Fly ash at this site had been deposited in a mine pit and between mine ash piles. A study was conducted to determine the potential effects of FGD and fly ash disposal on ground water quality at the surface mining site.[30] This investigation used field monitoring and laboratory column leaching experiments in conjunction with geochemical computations. By collecting both field and laboratory data, the investigators hoped to test the applicability of laboratory column experiments to field situations. Roughly 150 wells were placed both in the vicinity of the waste disposal sites and in unaffected areas.

Ground-water concentrations were generally within drinking water standards in the background wells. However, selected constituents were higher than the drinking water standards. For instance, sulfate concentrations tended to exceed the SDWS by a factor of 2 to 4. The maximum iron concentration was 4.3 times the SDWS. Manganese concentrations were all above the SDWS, varying from 0.06 to 2.75 mg/l, or 1.2 to 55 times the SDWS.

Samples collected from wells located adjacent to the FGD waste site indicated that none of the PDWS constituents exceeded the standards. For the SDWS constituents, molybdenum concentrations fluctuated between 0.070 and 4.850 mg/l, and sulfate concentrations reached a high of 9,521 mg/l, or 38 times the SDWS. (EPA has not established maximum concentration levels for molybdenum.)

Ground water in areas that appear to be affected by leachate from the fly ash disposal sites had sulfate concentrations ranging from 21.7 to 211 times the SDWS. Higher values were obtained immediately below recent deposits of fly ash, while lower values were observed at older sites or at greater distances from the disposal area. Arsenic and selenium concentrations in the ground water were as high as 0.613 mg/l (12 times the PDWS) and 0.8 mg/l (80 times the PDWS), respectively. The highest arsenic and selenium concentrations were associated with higher pH values. Ground-water pH values for samples in the area of the fly ash ranged from 6.95 to 12.1. (The Secondary Drinking Water Standard for pH is 6.5 to 8.5). Iron and manganese concentrations were also high in samples taken from around the fly ash disposal site. The maximum concentration of iron was 8.6 times the SDWS; the maximum concentration of manganese was 130 times the SDWS.

Leachates from the fly ash of western coals are often characterized by a high pH that tends to cause many potentially harmful constituents to be released. The pH-dependent solubility of many trace elements, as apparently observed at this site, demonstrates the importance of neutral pH values that are conducive to contaminant attenuation.

5.3.4 Summary

The studies reviewed in this section indicate that constituents from coal-combustion waste disposal sites have been detected in both on-site and off-site ground and surface water. However, those constituents that did exceed the drinking water standards seldom exceeded these standards by more than ten times. Moreover, the total number of exceedances is quite small compared to the total number of monitoring wells and samples gathered. The contaminant exceedances that do occur appear to be correlated to some extent with acidic or alkaline pH levels. At fly ash disposal sites, pH values between 2 and 12 have been measured. High and low pH values can contribute to metal solubility in ground water.

There are two documented cases of coal combustion waste disposal sites causing significant harm to the environment. Drinking water wells around the Chisman Creek fly ash disposal site in Virginia (which was closed in 1974) were contaminated with high concentrations of vanadium and selenium. Concentrations of these elements at this site were also due to petroleum coke waste (a product of oil combustion, not coal combustion). The site has been placed on the CERCLA National Priority List. In 1967, a dike failed at a utility waste disposal site on the banks of the Clinch River in Virginia, causing waste to spill into the river. This accident caused substantial damage to the biotic life in the river.

5.4. FACTORS AFFECTING EXPOSURE AND RISK AT COAL COMBUSTION WASTE SITES

The previous sections analyzed the constituents of coal combustion waste leachates and the quality of the ground water and surface water surrounding disposal sites. However, this is only part of determining the potential dangers that the wastes pose to human health and the environment. Exposure potential, the degree to which populations could be expected to be exposed to potentially harmful constituents, must also be analyzed. Exposure potential is determined by a variety of factors. Hydrogeologic characteristics of a site will affect the migration potential of waste constituents. Proximity of sites to drinking water sources and to surface-water bodies will determine potential for exposure to populations using the water sources.

In order to address this issue of exposure, EPA collected a wide variety of data on a random sample of 100 coal-fired utility plants around the country. The sample was taken from the Utility Data Institute Power Statistics Database, which contains information on every coal-fired electric utility plant in the country. Most plants dispose of their waste on-site, and in these cases information was collected on the plant location given by the data base. If the plant disposed off-site, data were collected on that off-site location. EPA assumed that off-site disposal took place at the nearest municipal landfill, unless additional information indicated otherwise. Characteristics such as depth to ground water, hydraulic conductivity, distance to surface water, location of private and public drinking water systems, type of surrounding natural ecosystems, and location of human population were obtained from a wide variety of sources. This simple aggregation of the individual factors affecting exposure at coal combustion waste sites provides a qualitative perspective on the potential risk that coal combustion waste sites pose, and is presented in Sections 5.4.1-5.4.3. Appendix F displays the data for each coal combustion waste site in the random sample.

5.4.1 Environmental Characteristics of Coal Combustion Waste Sites

Environmental characteristics of coal combustion utility waste sites will have a significant effect on the potential for the waste constituents to travel and reach receptor populations. Key environmental characteristics are:

- Distance to surface water - The distance between a coal combustion waste disposal site and the nearest surface water body. Proximity to surface water would decrease the possible health effects of ground-water contamination due to the fact that there would be fewer opportunities for drinking water intakes before the ground water reached the surface water body; once the plume reached the surface water, contamination would be diluted. However, proximity to surface water would possibly increase danger to aquatic life because less dilution of the contaminant plume would occur before the plume reached the surface water body.
- Flow of surface water - A high surface water flow will increase the dilution rate of coal combustion constituents that may enter the surface water, thereby reducing concentrations in the surface water.
- Depth to ground water - The distance from ground level to the water table. A larger depth to ground water will increase the time it takes for waste leachates to reach the aquifer; it also allows more dispersion of the leachate before it reaches the aquifer so that once the leachate reached the aquifer, concentrations of metals would be decreased.
- Hydraulic conductivity - This factor is an indication of the rate at which water travels through the aquifer. A high hydraulic conductivity indicates that constituents will travel quickly through the ground water and possibly more readily reach drinking water wells, although high conductivity also indicates a more rapid dilution of constituent concentration.

- Net recharge - This factor is a measure of net precipitation of a site after evapotranspiration and estimated runoff is subtracted. Recharge is calculated in order to determine the amount of rainfall annually absorbed by the soil. A high net recharge indicates a short period of time for contaminants to travel through the ground to the aquifer, but will also indicate a higher potential for dilution.
- Ground-water hardness - This factor is a measure of the parts per million (ppm) of calcium carbonate (CaCO3) in the aquifer. Ground water with over 240 ppm of CaCO3 is typically treated when used as a public drinking water supply. This treatment of the hard ground water has an indirect mitigative effect on exposure because treatment of the ground water will tend to remove contamination from other sources.

To conduct this exposure analysis, environmental data on the 100 randomly selected coal combustion waste sites were gathered using a number of sources. These data were then aggregated in order to present an overview of the environmental characteristics that contribute to exposure. The data collected on the sample of coal combustion waste sites were compared to information presented in a study by Envirosphere for the Electric Power Research Institute.[31] The Envirosphere report gave detailed information on the hydrogeologic settings of 450 operating utility plants. The information provided by the exposure analysis on the sample of 100 plants corresponded fairly closely with the settings described in the Envirosphere report.

The following sections summarize the data that were collected and the relationship of the various characteristics to potential exposure.

5.4.1.1 Distance to Surface Water and Surface-Water Flow

The proximity of a waste site to surface water affects exposure potential in several ways. If the site is very near a surface-water body, there is less opportunity for humans to use contaminated ground water as a source of drinking water. However, sites that are close to surface water can more easily contaminate the surface-water body, although waste constituents will be more quickly diluted if the flow of the surface water is high.

Distance to the nearest surface-water body, e.g., creek, river, lake, or swamp, was determined from measurements obtained using United States Geologic Survey (U.S.G.S.) maps. The sample of coal combustion waste sites was located on 7-1/2 or 15 minute maps, and the distance between the site and nearest surface water body was calculated.

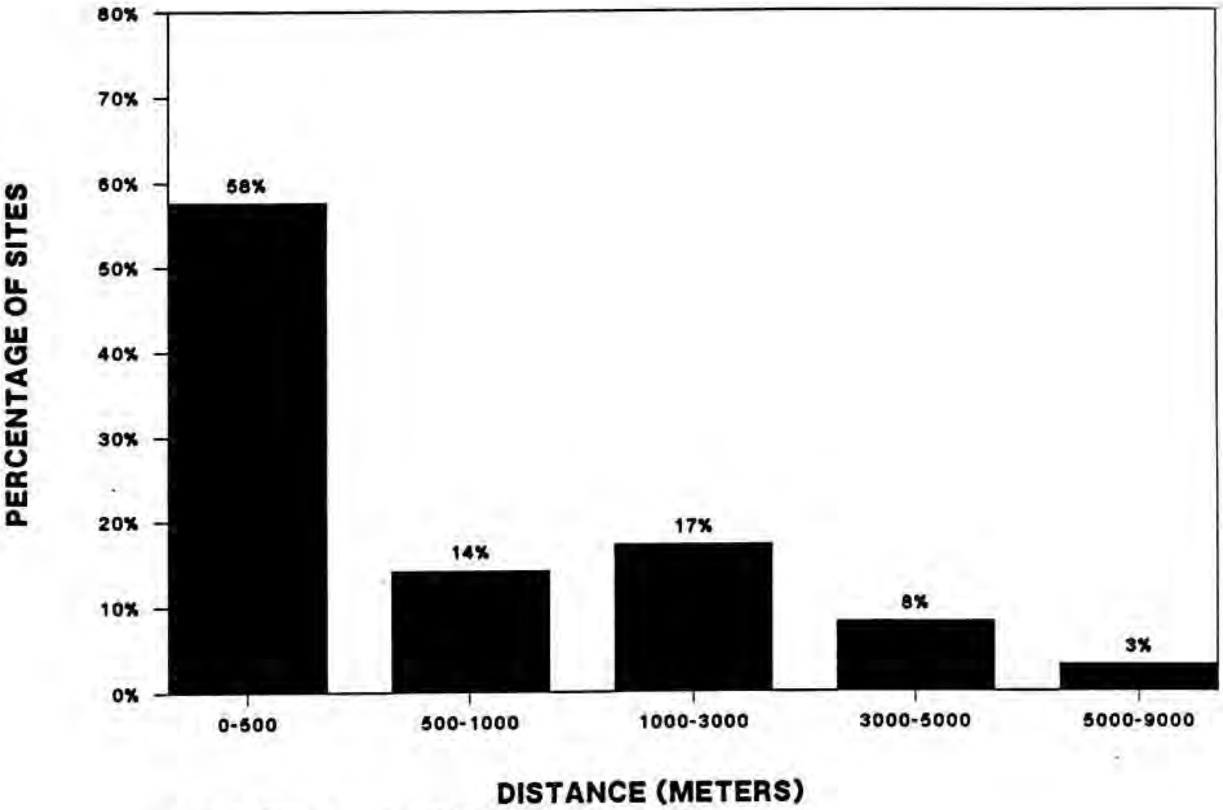
When the boundaries of the plant or waste site were marked on the maps, the reference point was the downgradient boundary of the site. If the boundaries were not marked, the latitude and longitude points for the sites provided by the Utility Data Institute Power Statistics Database were used.

The average distance from the sample of coal-burning waste sites to surface-water body is 1279 meters. Distances range from 10 to 18,000 meters. Over 50 percent of the disposal sites are within 500 meters of surface water; more than 70 percent are within 1,000 meters of surface water. Exhibit 5-17 provides the number and percentage of sites within specified distances of surface water.

Since most sites are located somewhat near surface-water bodies, the potential for human exposure to contaminated ground water seems to be low. The proximity of the sites to surface water could, however, pose a threat to aquatic life and to humans using the surface water if contaminants are entering

EXHIBIT 5-17

DISTANCE OF COAL COMBUSTION WASTE SITES TO SURFACE WATER



SOURCE: ICF Inc, based on USGS data

the surface water. The concentration in surface water will be less, however, if the surface-water body close to the site has a high flow.

Flow data on surface-water bodies near the sample of 100 sites were obtained from U.S.G.S. data. Flow is expressed in terms of cubic feet per second (cfs), and given for minimum and maximum average flow for one-month periods. In order to obtain a conservative estimate of exposure (i.e., one that does not understate exposure) this report used estimates for the month with the minimum monthly flow. The results are presented in Exhibit 5-18.

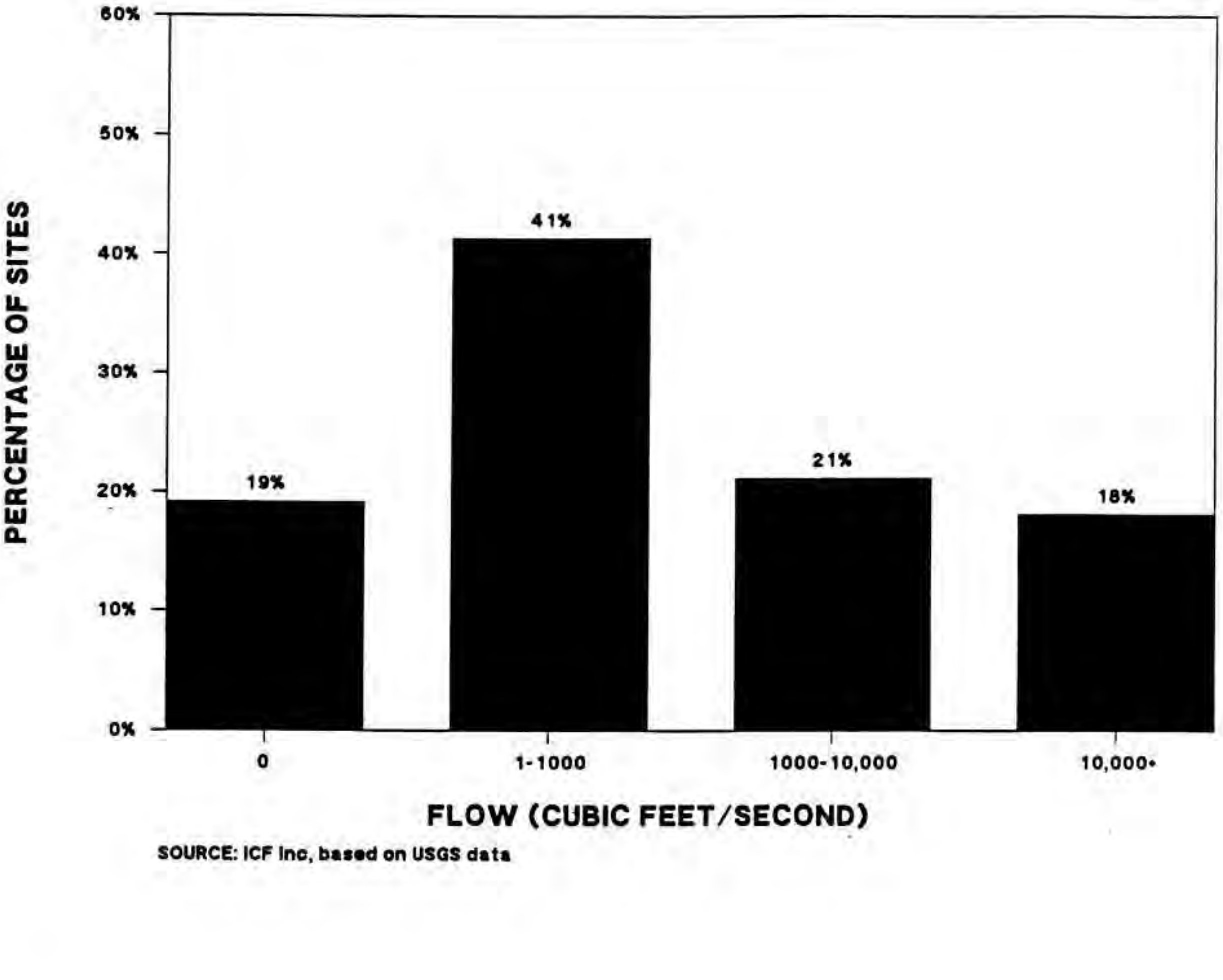
Exhibit 5-18 shows that 19 percent of the sites have a flow of zero. A zero flow generally indicates that the body of water is a lake, swamp, or marsh that does not have any continual flow of water, although this category could include a seasonal stream. For surface-water bodies with zero flow, dilution of potential contamination would occur because of the volume of water in the surface-water body, but there would not be any additional dilution as water flowed away from the source of contamination. Forty-one percent of the surface-water bodies have a flow of 1-1000 cubic feet per second, 21 percent have a flow of 1,000-10,000 cfs, and 18 percent have a flow of over 10,000 cfs.

5.4.1.2 Hydrogeologic Measurements

The hydrogeologic measurements of depth to ground water, hydraulic conductivity, and net recharge were determined through the use of information provided by the DRASTIC system. The DRASTIC system, developed by the National Well Water Association, categorizes aquifers on the basis of geographic region and subregion. Each site was located on a 7 1/2 or 15 minute U.S.G.S. map that

EXHIBIT 5-18

FLOW OF NEAREST SURFACE-WATER BODY



SOURCE: ICF Inc, based on USGS data

was then compared with a map on which the 11 major DRASTIC regions had been outlined. The topography and geology of the sites, which were determined from looking at the U.S.G.S. maps, were assessed in order to further classify thesites into DRASTIC subregions. Subregions are defined by hydrogeologic characteristics and vary in size from a few acres to hundreds of square miles. Measurements for depth to ground water, hydraulic conductivity, and net recharge of the sites were taken largely from <u>A Standardized System for Evaluating Ground-water Pollution Potential Using Hydrogeologic Settings</u>, by the National Well Water Association, which presents a range of values for each of these hydrogeologic properties for each subregion.[32] The ranges were compared with characteristics that could be observed by studying U.S.G.S. maps, and, when necessary, they were modified accordingly.

Depth to Ground Water

A small depth to ground water indicates a higher potential for waste constituents to reach the ground water at harmful concentrations than if the distance to ground water were greater, thereby increasing the chance of ground-water contamination. Depth to ground water was generally based on DRASTIC region and subregion, but was modified when the topography or site characteristics indicated a depth different from that provided by the DRASTIC system. For example, if the DRASTIC subregion indicated that there was a high depth to ground water range, but a particular site was located very near a surface-water body, the Agency used a smaller depth to ground water than the DRASTIC range indicated.

Exhibit 5-19 provides the number and percentage of sites within each range of depth to ground water. Depth to ground water is calculated in feet and based on 10 ranges. In over 80 percent of the sites depth to ground water is less than 30 feet, indicating a reasonably high potential that leachate from the disposal site would reach the ground water.

Hydraulic Conductivity

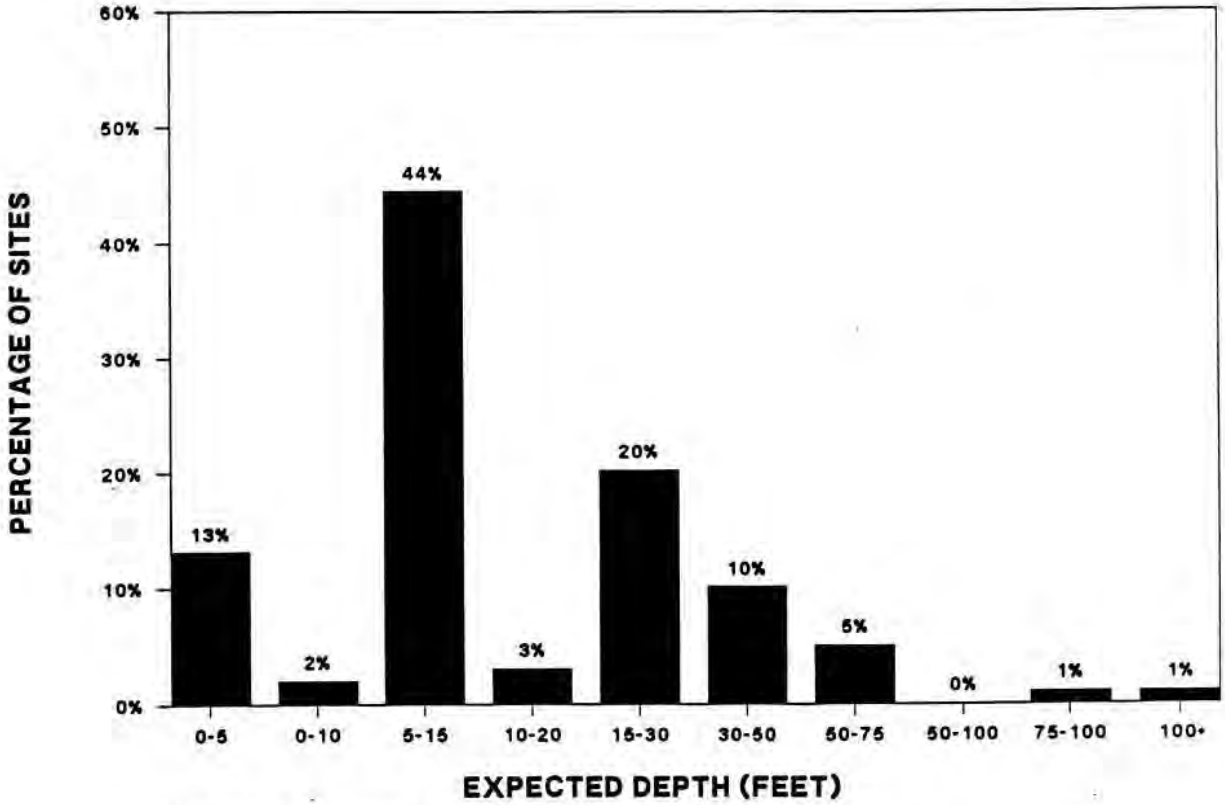
Hydraulic conductivity is an indication of the ease with which a constituent may be transported through the ground water. Conductivity is also based on the site's DRASTIC region and subregion, and is measured in gallons per day per square foot and grouped into six ranges.

Hydraulic conductivity is one of the factors used to calculate ground-water velocity, or volumetric flow of the water table. Velocity has a direct bearing on the degree to which leachate constituents are diluted once they reach the ground water and travel to a point of exposure (i.e., human drinking water source). High ground-water conductivity signifies high velocity and therefore a high dilution potential.

Exhibit 5-20 provides the number and percentage of sites falling into each hydraulic conductivity range. Thirty-three percent of the sites show a hydraulic conductivity of 700-1,000 gallons per day per square foot; 27 percent have a conductivity of 1,000-2,000 gallons per day per square foot. There is a wide spread of conductivity values -- indicating hydrogeologic diversity among sites.

EXHIBIT 5-19

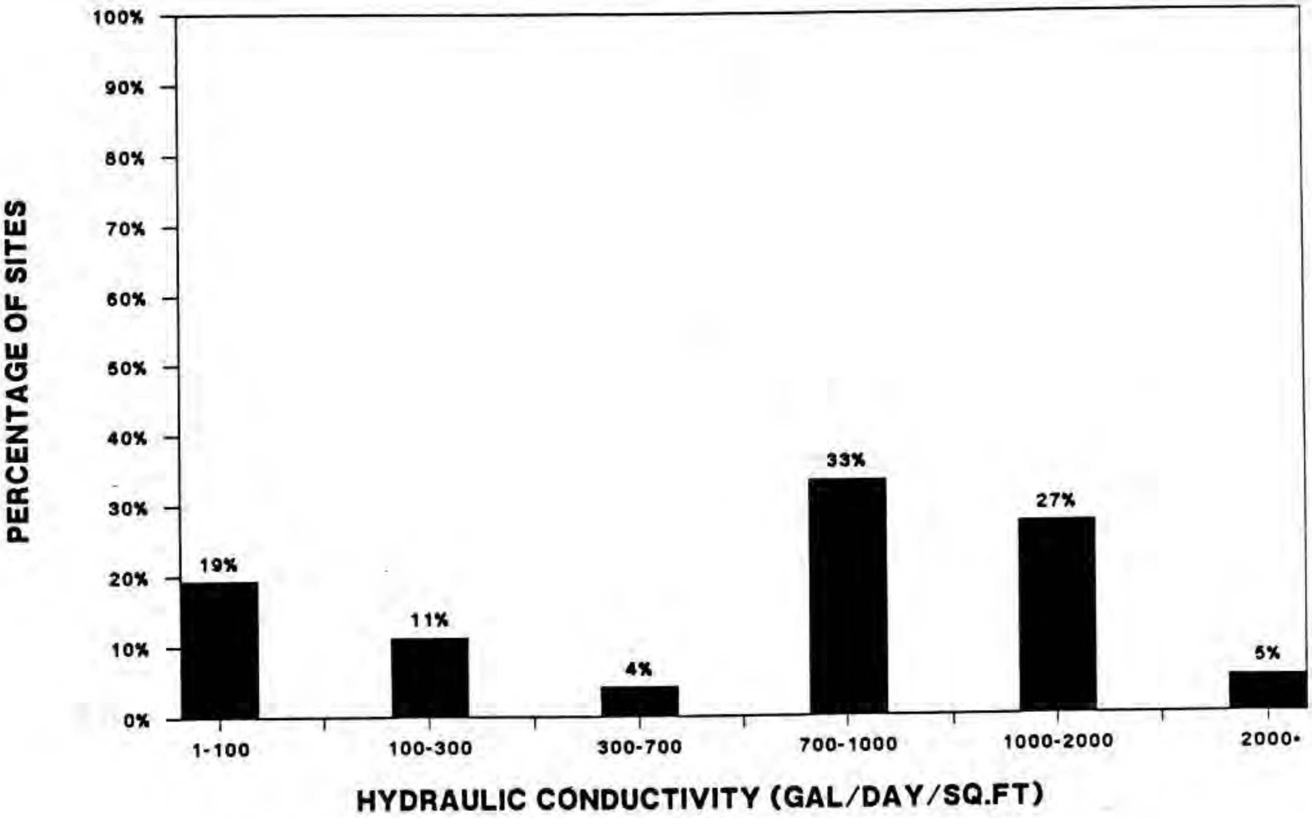
DEPTH TO GROUND WATER AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on DRASTIC

EXHIBIT 5-20

HYDRAULIC CONDUCTIVITY AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on DRASTIC data

While ground-water velocity gives an indication of how fast contamination may travel in the ground water, contaminants do not move at the same velocity as the ground water. This is because of basic interactions between contaminants and soil that retard the movement of the contaminants. There are three different mechanisms that affect the retardation of contaminant movement -- exchange on soil particle sites (ion exchange), adsorption onto soil particle surfaces, and precipitation. The exchange and adsorption mechanisms will retard the movement of contaminants but will not eliminate the movement of all contaminants due to limited soil attenuation capacity.

As with the diversity among sites in terms of hydraulic conductivity and ground-water velocity, the various attenuation mechanisms differ among sites. To determine the attenuation potential at a site requires detailed data inputs on water chemistry on a site-specific basis.

Net Recharge

Net recharge indicates how much water is annually absorbed into the ground. It is measured by subtracting evapotranspiration (the amount of rainfall that evaporates and transpires from plant surfaces) and estimated runoff from total precipitation at a site. It affects exposure potential in a number of ways. Low recharge will result in smaller volumes of more concentrated leachate, but if the aquifer is deep and/or has a high velocity, it will quickly dilute the leachate. High recharge produces more leachate, but may also indicate that the area has higher ground-water flow.

Exhibit 5-21 shows the number and percentage of sites that fall into each range. Recharge is measured in inches and is grouped into five ranges. Although a wide variety of net recharge ranges is represented by the sample, the recharge of sites generally falls into the higher ranges of 4-7 inches, 7-10 inches, and over 10 inches. For example, more than 80 percent of the sites have a net recharge of over 4 inches and over 50 percent have a recharge of over 7 inches. This implies that leachate constituents will be more quickly carried to the water table but the higher recharge rate will also result in greater dilution of the leachate.

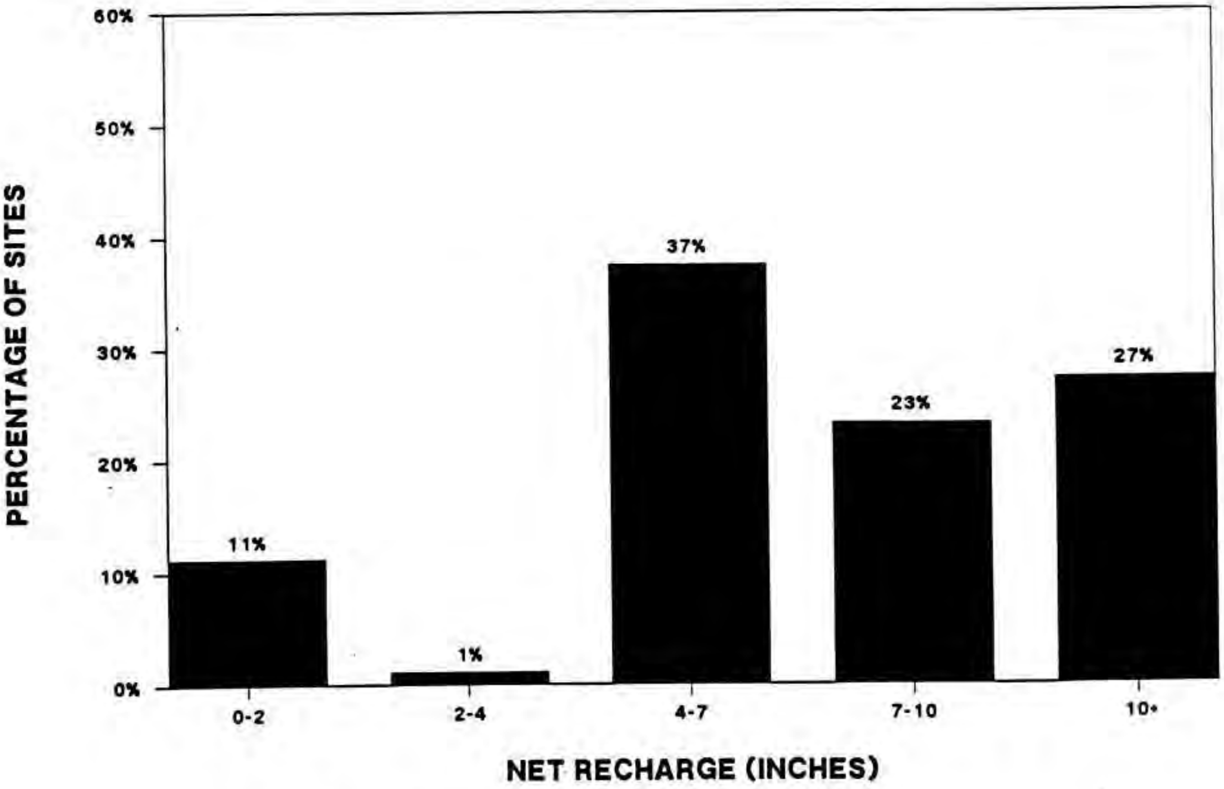
Ground-water Hardness

The hardness of the ground water near coal combustion waste sites will have an effect on potential exposure through drinking water since excessive hardness is typically treated in a public drinking water system. Treatment would lessen the exposure potential to humans from contaminants in the ground water from other sources (such as coal combustion wastes). Measurements for ground-water hardness were obtained by locating the sites on maps provided in <u>Ground-water Contamination in the United States</u> (Pye, Patrick, and Quarles).[33]

As shown in Exhibit 5-22, ground-water hardness is measured in parts per million (ppm) of calcium carbonate (CaCO3) and grouped into five ranges. Ground water with a hardness of over 240 ppm of calcium carbonate is typically treated if used in a public drinking water system. In this sample, 45 percent of the sites show ground-water hardness in this range. Ground water with a hardness of 180-240 ppm of calcium carbonate may also be treated, although

EXHIBIT 5-21

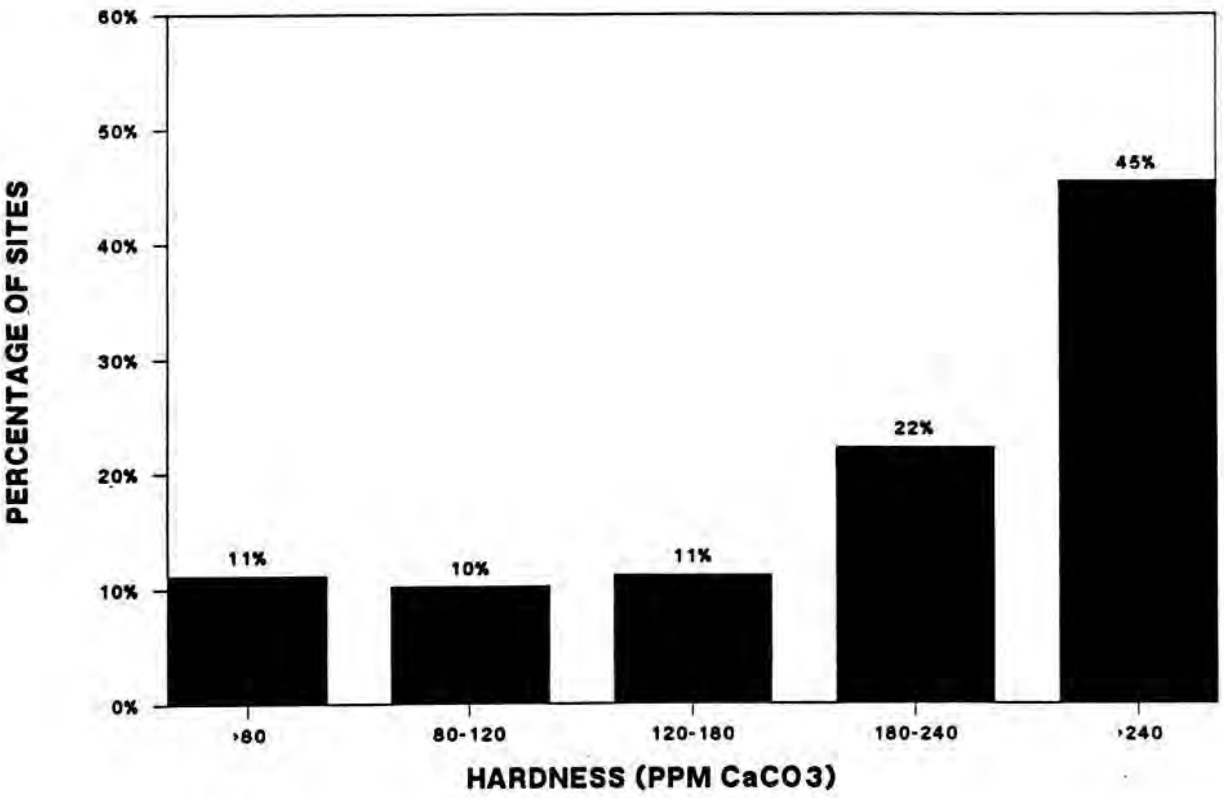
NET RECHARGE
AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on DRASTIC

EXHIBIT 5-22

GROUND-WATER HARDNESS AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on Pye, et al, Groundwater Contamination in U.S.

treatment is much less likely. An additional 22 percent fall in the 180-240 ppm range.

The high levels of calcium carbonate found in the ground water near coal combustion waste disposal sites suggest that if a drinking water supply is in the vicinity, the water would often require treatment before being used. Therefore, contamination that might exist in the drinking water from other sources would be mitigated due to the treatment process since trace constituents tend to be removed during the treatment process.

5.4.2 Population Characteristics of Coal Combustion Waste Sites

Environmental characteristics, such as distance and flow of surface water and hydrogeologic measurements, are only one part of the analysis of exposure potential. Opportunities for human exposure to coal combustion waste constituents depend in part on the proximity of coal combustion waste disposal sites to human populations and to human drinking water supplies. Census data (1980) provide information about the number of people living within specified distances from the coal combustion waste sites. This information is obtained through the CENBAT program, part of the Graphic Exposure Modeling System developed by EPA's Office of Solid Waste. The Federal Reporting Data System (FRDS) data base, developed by EPA's Office of Drinking Water, provides estimates of the number of public water supply systems and the size of the populations using them.

5.4.2.1 Proximity of Sites to Human Populations

CENBAT provides information on the number of people living within specified distances around designated locations. The sites were defined by latitude and longitude coordinates. Populations were analyzed for areas within 1-, 2-, 3-, 4-, and 5-kilometer radii of the waste disposal sites.

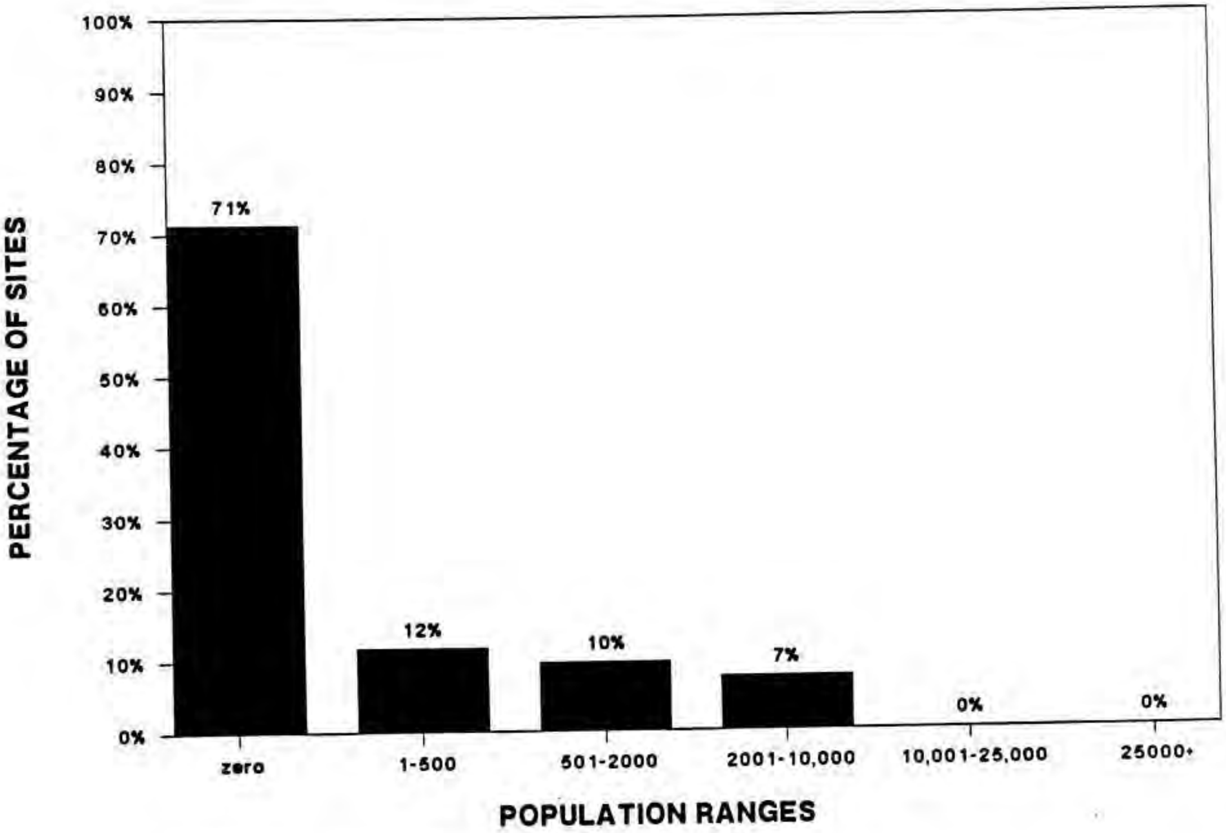
Exhibit 5-23 shows the distribution of population within one kilometer of the waste disposal sites. The CENBAT results show that most sites, 71 percent, do not have any population within a one-kilometer radius. Overall, the population range within a one-kilometer radius is 0 - 3708 people, with an average of 359 people.

Exhibit 5-24 shows the population characteristics for the sample of coal combustion waste sites at a three-kilometer radius. When the search distance is increased to three kilometers, the percentage of sites that have no people within a three-kilometer radius decreases to 32 percent. Average population within three kilometers is 3,737, and the range is 0 - 35,633 people. There is a large degree of diversity of populations at this distance. For example, while 32 percent of the sites have zero population, the same percentage has populations over 2,000.

Exhibit 5-25 shows the distribution of populations within a five-kilometer radius. Only 10 percent of the sites do not have any population living within this distance. The average population is 12,128 people, with a range from 0 to 123,160. The diversity among coal combustion waste disposal sites is even more apparent at this distance. While 20 percent of the sites have populations

EXHIBIT 5-23

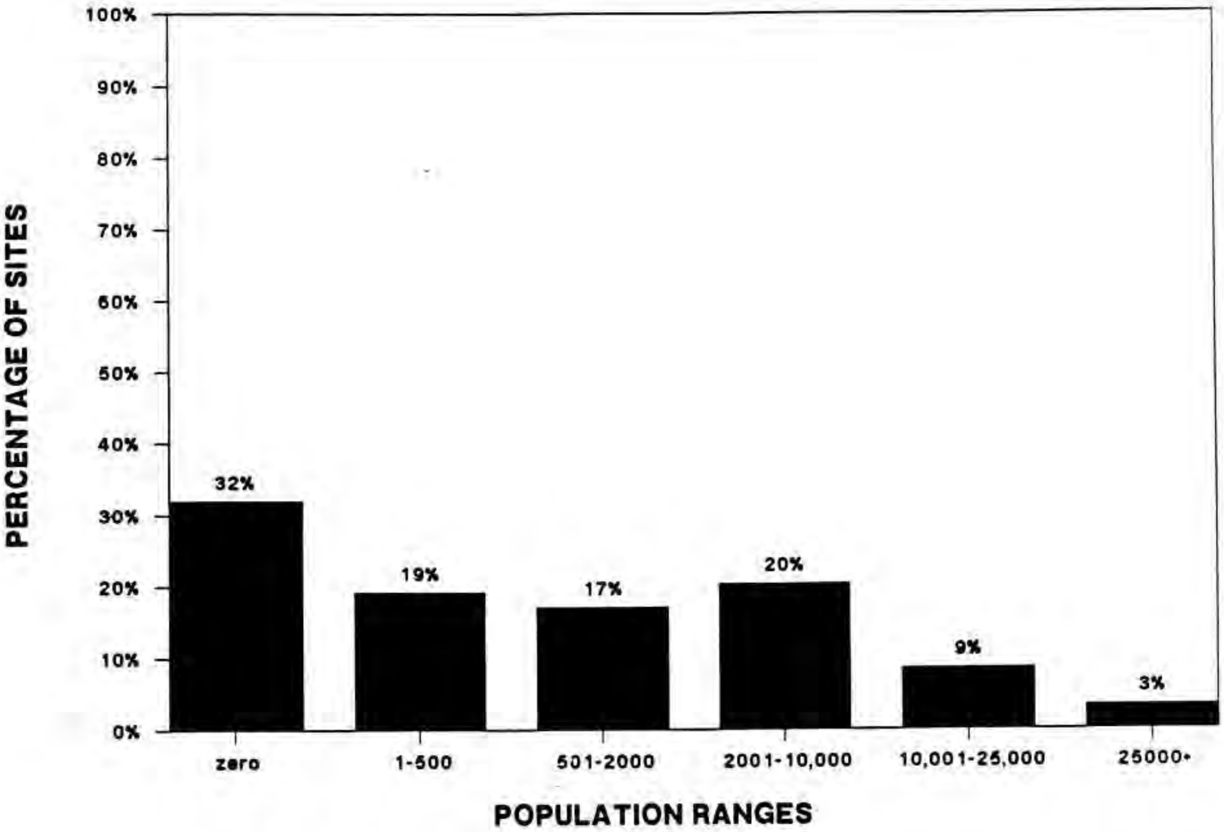
POPULATIONS WITHIN ONE KILOMETER OF WASTE SITES



SOURCE: ICF Inc, based on CENBAT data

EXHIBIT 5-24

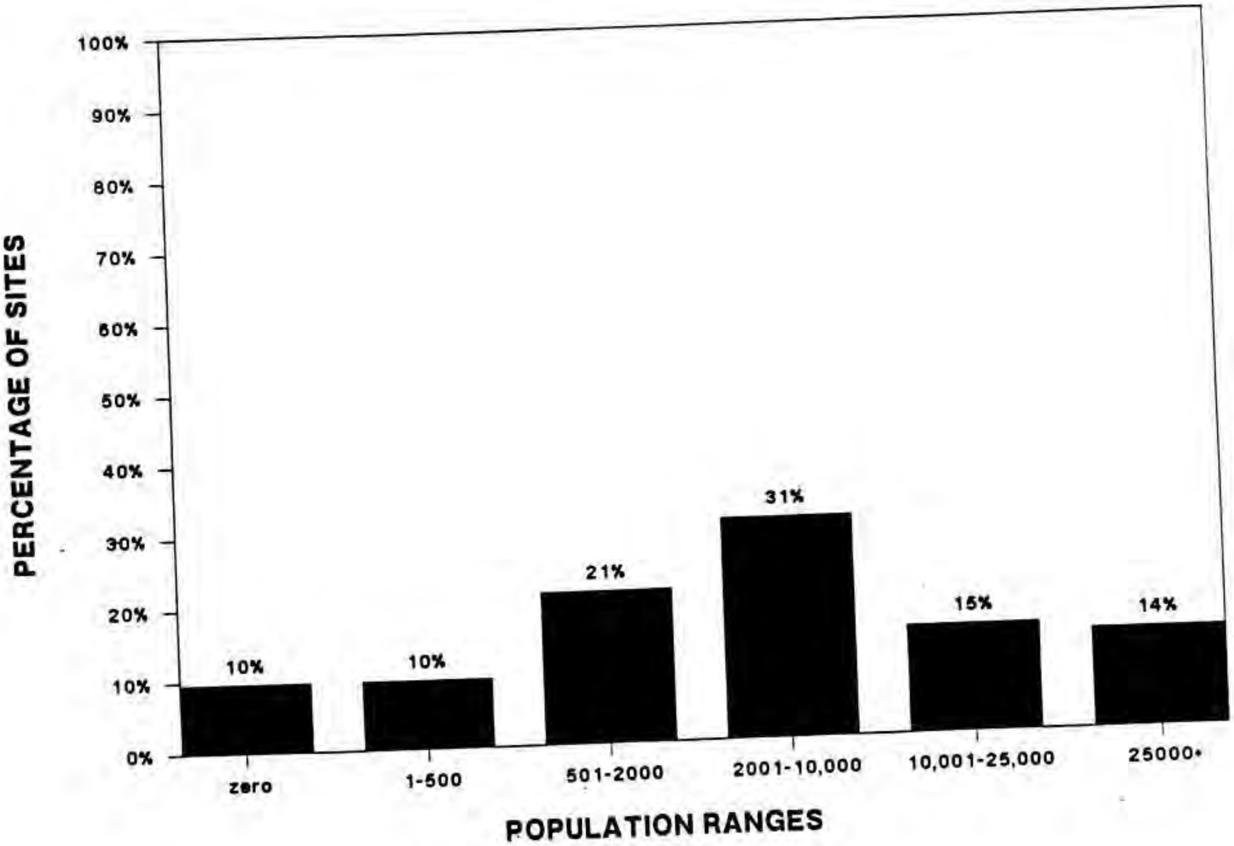
POPULATIONS WITHIN THREE KILOMETERS OF WASTE SITES



SOURCE: ICF Inc., based on CENBAT data

EXHIBIT 5-25

POPULATIONS WITHIN FIVE KILOMETERS OF WASTE SITES



SOURCE: ICF Inc., based on CENBAT

within a five-kilometer radius of fewer than 500 persons, 29 percent have populations over 10,000.

The CENBAT results indicate that density increases on average with distance from the disposal site. Many waste sites appear to be located on the outskirts of populated areas, with fairly low population immediately adjacent to the site, but with significant populations within a five-kilometer radius.

5.4.2.2 Proximity of Sites to Public Drinking Water Systems

If coal combustion waste sites are close to public drinking water systems, there may be potential for human exposure through drinking water supplies. The location of public water supplies was determined through the use of the Federal Reporting Data System (FRDS), developed by EPA's Office of Drinking Water.

The FRDS data base provides the number of public water supply systems located within specified distances from a site and the populations using the systems. It should be noted that the FRDS data base locates water systems based on the centroid of the zip code of the mailing address of each utility and that the actual location of the intake or well may be different. This can cause some inaccuracy in the calculation of the distance and location of public drinking water supplies in relation to the waste site. In order to remedy potential inaccuracies and omissions, the locations of public water systems that appeared on topographical maps but were not reported by FRDS are also recorded.

Exhibit 5-26 shows the population served by public water systems located in the downgradient plume from the sites and within a five-kilometer radius. The exhibit also shows how many sites have no public water systems within a five-kilometer radius. Sixty-six percent of the sites have no public water systems within a five-kilometer radius. Fifteen percent of coal combustion sites have public water systems located within a five-kilometer distance and had systems which served over 5,000 people, and 19 percent have public water systems that serve fewer than 5,000 people.

The population data indicate that while there are often quite large populations in the vicinity of coal combustion waste sites, only 34 percent of the sites have public drinking water systems downgradient from the site.

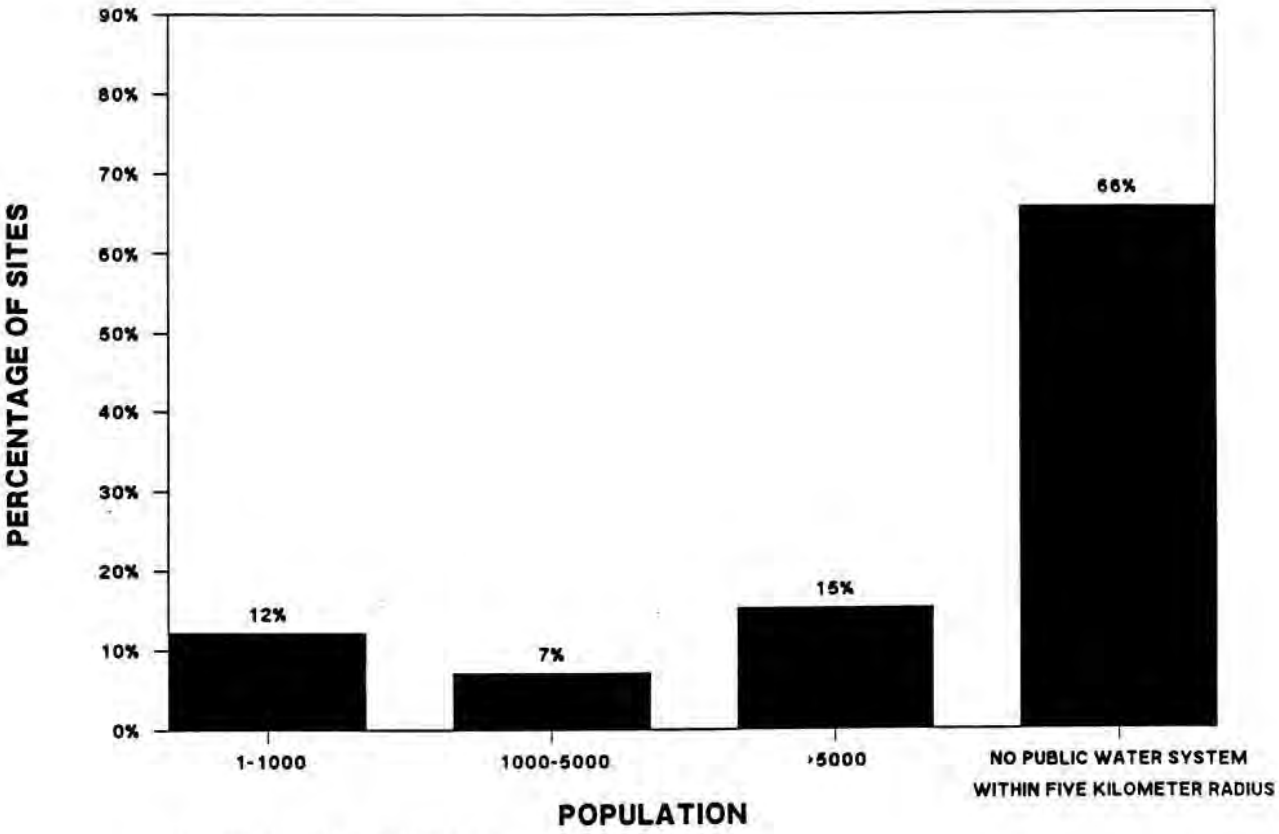
5.4.3 Ecologic Characteristics of Coal Combustion Waste Sites

Ecological data on endangered, threatened, or unique plants and animals is available through state Heritage Programs. The Nature Conservancy established the Heritage Programs, which now usually function as offices of state governments. The Heritage Programs develop and maintain data bases that describe jeopardized species and rare ecosystems within each state. It should be noted that there can be substantial variation in the completeness of data available from different states; some state Heritage Programs are fairly new, and basic data collection is still in its preliminary stages.

While it may not currently be possible to quantitatively model risk to ecosystems from coal combustion waste, the information provided by the Heritage Programs can indicate whether there are any jeopardized species near a specific

EXHIBIT 5-26

POPULATIONS SERVED BY PUBLIC WATER SYSTEMS NEAR WASTE SITES



SOURCE: ICF, based on FRDS data

waste site. If potentially hazardous constituents of coal combustion waste do migrate and produce environmental contamination, it could affect species and natural communities that are particularly vulnerable, thereby lessening ecosystem diversity.

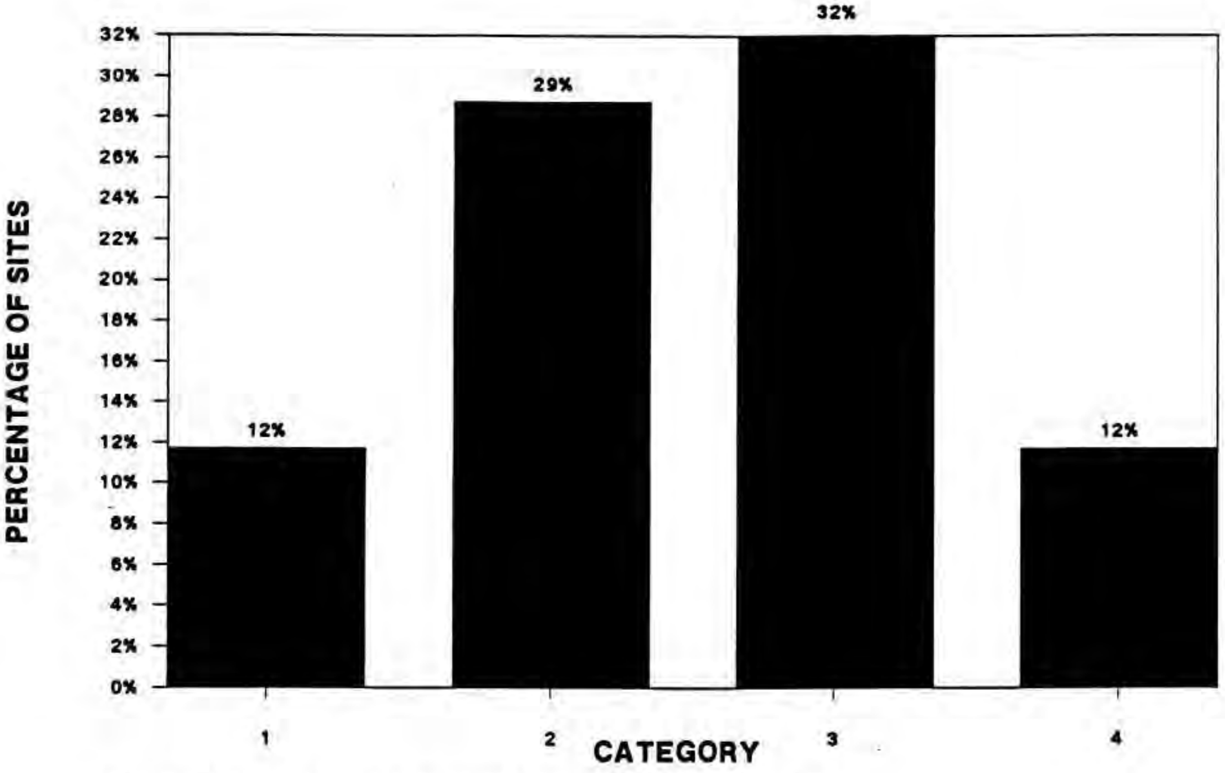
EPA provided Heritage Program staff with latitudes and longitudes for the sampled sites in states that had such programs. Using these coordinates, the Heritage Program staff performed a search of their data bases for rare or endangered species within a five-kilometer radius from the site.

The sample sites were grouped into four categories based on the results obtained from the Heritage Program. Category 1 includes sites having Federally designated threatened or endangered species within the five-kilometer radius. Category 2 includes sites that have no Federally designated threatened or endangered species within the five-kilometer distance, but which do contain species or natural communities designated by state Heritage Offices as critically endangered in that state. Category 3 contains sites for which there are species or natural communities of concern in the area. For sites in Category 4, there is no record of the existence of species of concern in the five-kilometer area.

Information was available on 85 of the 100 coal combustion waste sites in the sample. Exhibit 5-27 presents the breakdown of sites according to the categories described above. Twelve percent of the sites fall into Category 1, 29 percent in Category 2; 32 percent in Category 3; and 12 percent in Category 4 (no information was available for 15 percent).

EXHIBIT 5-27

ECOLOGICAL STATUS OF WASTE SITES



Category 1 : Federally designated plants or animals within a five km. radius
Category 2: Species of priority state concern within five km. radius
Category 3: species of concern to state environmental offices
Category 4: no data on ecosystem surrounding the site

SOURCE: ICF Inc., based on State Heritage Data

Given the high percentage of sites that have rare plant and animal communities within a five-kilometer radius supplies, and the proximity discussed earlier of waste disposal sites to surface-water bodies (which provide animals with drinking water), there could be a high potential for species exposure to coal combustion constituents.

5.4.4 Multivariate Analysis

The previous sections of this exposure analysis presented independent analyses of the population, environmental, and ecological characteristics of coal combustion waste sites. This section examines a number of these factors simultaneously in order to determine interactions that affect the overall potential for exposure from coal combustion waste sites.

As mentioned previously, only 34 percent of coal combustion waste sites (based on a random sample of 100 sites) have public drinking water systems in the downgradient plume within 5 kilometers of the waste site. Some of these public drinking water systems may use ground water that is currently treated before it is used as drinking water, indicating that human populations are unlikely to be directly exposed to any water that may be contaminated from coal combustion waste constituents. As discussed earlier, one reason for treating the water is ground-water hardness. Ground water that has a hardness greater than 240 ppm CaCO3 is likely to be treated if it is used as a drinking water source. Of the 34 percent of the sites in the sample that have public water systems in the downgradient plume within 5 kilometers of the waste site, just under one-half of these sites have ground water with a hardness over 240 ppm CaCO3. These results show that the potential for human exposure through drinking water is likely to be less than the proximity to public drinking water systems (FRDS data) indicates. Of all the sites sampled, only 18 percent have public drinking water systems within 5 kilometers and ground water under 240 ppm $CaCO_3$.[34]

The potential for human exposure through drinking water can be further evaluated by comparing the FRDS and ground-water quality characteristics with the hydrogeologic factors of net recharge and depth to ground water. Sites with a net recharge greater than 7 inches and a depth to ground water of fifteen feet or less are more likely to develop ground-water contamination due to waste leaching since water has a greater likelihood of contacting the coal combustion wastes. Of the 18 percent of the sites that have public water supplies and ground-water hardness below 240 ppm $CaCO_3$, two-thirds have a net recharge greater than 7 inches as well as a depth to ground water of 15 feet or less. Therefore, only 12 percent of the sites in the sample (18 percent x 2/3) have ground water that is likely to be used without treatment and hydrogeologic characteristics that indicate high potential for leachate migration.

This multivariate analysis of the factors affecting exposure at coal combustion waste sites illustrates the limited potential for human health risk through drinking water. Only 34 percent of the sites have public water systems within five kilometers and many of these public water systems are likely to treat the ground water due to hardness.

5.5 SUMMARY

This chapter has reviewed available information on the potential for coal-fired combustion wastes from electric utility power plants to affect human health and the environment. First, data on the potential corrosivity and EP toxicity of utility wastes was reviewed. After determining that coal combustion leachate sometimes contains hazardous constituents at levels above drinking water standards, the potential for this leachate to migrate from waste disposal sites was examined. Results of ground-water monitoring in several studies were interpreted and a number of compilations of "documented" damage cases were evaluated. After describing instances in which trace elements in coal combustion leachate have migrated from waste disposal sites, the potential effect of these migrations was examined. A sample of 100 utility waste disposal sites was selected, and these sites were evaluated in terms of population, environmental, and ecological characteristics to assess the potential for leachate migration and exposure of human and ecological populations.

Based on these data and analyses, several observations relating to potential dangers to human health and the environment can be made:

- If the current exemption from Subtitle C regulation were lifted for coal combustion wastes and these wastes were required to be tested for corrosivity or EP toxicity, most current waste volumes and waste streams would not be subject to hazardous waste regulation. The only waste stream which has had corrosive results is boiler cleaning waste. (Since coal ash is not aqueous, it cannot be corrosive.) For the other waste streams, available data indicate that while some of these waste streams could have high or low pH levels, they are not likely to fall under the RCRA definition of corrosive waste.

Similarly, while a few high-volume waste samples did exceed the EP toxicity limits for cadmium, chromium, and arsenic, this was limited to a few waste streams and represented only a small fraction of the samples for these waste streams (the chromium and arsenic exceedances were from only one fly ash sample). Available data on low-volume wastes showed that the only waste stream with significant RCRA exceedances was boiler cleaning waste, which had exceedances for chromium and lead. Wastewater brines were shown to exceed the RCRA standard for selenium in one sample. Results of EP tests on co-disposed wastes indicate that boiler cleaning wastes may not possess hazardous characteristics when co-disposed with ash. Results for all other waste streams and all other constituents were below EP toxicity limits.

- Results available from ground-water monitoring studies and documented cases of ground-water or surface-water contamination show some migration of PDWS constituents from utility waste disposal sites. In the most comprehensive and systematic of these studies, the Arthur D. Little survey of six utility sites, evidence of constituent migration downstream from the waste sites was conclusive only for cadmium. The Envirosphere ground-water study showed that only 3.7 percent of the samples showed downgradient concentrations of PDWS constituents that were higher than the concentrations of upgradient constituents (indicating that some contaminants are migrating from the site). This tends to support the results of the waste extraction tests. For the one utility disposal site on the National Priorities List, a site currently inactive since it was closed in 1974, the major ground-water contaminants were vanadium and selenium. However, this site differs from some other sites for which ground-water quality data are available in that wastes are from both coal and petroleum coke combustion.

- Although coal combustion waste leachate has the potential to migrate from the disposal area, the actual potential for exposure of human and ecological populations is likely to be limited. Because utility plants need a source of water to operate, most of the disposal sites are located quite close to surface water. Fifty eight percent of the 100 sample sites were within 500 meters of surface water. It is not common for drinking water wells to be located between the disposal site and the nearest downgradient surface water body. The effect of this proximity to surface water is that only 34 percent of the sampled sites had drinking water intakes within five kilometers. Furthermore, the flow of the surface water will tend to dilute the concentrations of trace metals to levels that satisfy drinking water standards.

- Simultaneously examining the environmental and population characteristics of coal combustion waste sites shows even less potential for exposure to human populations. 12 percent of the sites in the sample have public water systems within five kilometers of the site where the ground water may not be treated (i.e., ground-water hardness below 240 ppm $CaCO_3$) and hydrogeologic characteristics that indicate high potential for leachate migration.

CHAPTER 5

NOTES

[1] See 40 CFR 261.21.

[2] See 40 CFR 261.22. In using pH to determine corrosivity, EPA explained that "wastes exhibiting low or high pH can cause harm to human tissue, promote the migration of toxic contaminants from other wastes, and harm aquatic life."

[3] These methods are set forth in 40 CFR 260.21 and 260.22.

[4] See 40 CFR 261.23.

[5] See 40 CFR 261.24.

[6] See 40 CFR Part 261, Appendix II. These procedures for testing and the limits allowed for determining whether a waste is hazardous or not are currently under review.

[7] A waste would be considered hazardous if it has been shown to have an oral LD 50 toxicity to rats of less than 50 mg/kg, an inhalation LC toxicity to rats of less than 2 mg/l, or a dermal LD 50 toxicity to rabbits of less than 2000 mg/kg.

[8] See 40 CFR 261.11.

[9] See CFR 40 Section 261.24. RCRA also establishes EP toxicity limits for six pesticides.

[10] See CFR 40 Section 261, Appendix II.

[11] Federal Register, Volume 51, No. 114, Friday, June 13, 1986, p. 21648.

[12] Since the completion of the ASTM B tests discussed in this section, ASTM has dropped this extraction test (EPRI 1983).

[13] Tetra Tech, Inc., Physical-Chemical Characteristics of Utility Solid Wastes, prepared for Electric Power Research Institute, EA-3236, September 1983.

[14] Jackson, L. and Moore, F., Analytical Aspects of the Fossil Energy Waste Sampling and Characterization Project, prepared for the U.S. Department of Energy, Office of Fossil Energy, DOE/LC/00022-1599 (DE84009266), March 1984.

[15] Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-fired Electric Generation Plants, prepared for the Air and Energy Engineering Research Laboratory of the U.S. Environmental Protection Agency for the Office of Solid Waste, EPA-600-7-85-028, June 1985.

[16] Mason, B.J., and Carlile, D.W., draft report of Round Robin Evaluation for Selected Elements and Anionic Species from TCLP and EP Extractions, prepared by Battelle Pacific Northwest Laboratories, for the Electric Power Research Institute, EPRI EA-4740, April 25, 1986.

[17] Battelle's test varied from standard TCLP procedure by allowing 14 days, rather than the normal 7, for the completion of the test.

[18] Electric Power Research Institute, "Mobilization and Attenuation of Trace Elements in an Artificially Weathered Fly Ash," prepared by the University of Alberta, Edmonton, Canada, EPRI EA-4747, August 1986.

[19] Battelle Pacific Northwest Laboratories, Chemical Characterization of Fossil Fuel Combustion Wastes, prepared for the Electric Power Research Institute, September 1987.

[20] Radian Corporation, Characterization of Utility Low-Volume Wastes, prepared for the Electric Power Research Institute, May 1985.

[21] Radian Corporation, Manual For Management of Low-Volume Wastes From Fossil-Fuel-Fired Power Plants, prepared for the Electric Power Research Institute, July 1987.

[22] Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-fired Electric Generation Plants, prepared by the Air and Energy Engineering Research Laboratory of the U.S. Environmental Protection Agency, for the Office of Solid Waste, EPA-600-7-85-028, June 1985.

[23] Franklin Associates, Ltd., Survey of Ground-water Contamination Cases at Coal Combustion Waste Disposal Sites, prepared for U.S. Environmental Protection Agency, March 1984.

[24] Envirosphere Company, "Report on the Ground Water Data Base Assembled by the Utility Solid Waste Activities Group," in Utility Solid Waste Activities Group (USWAG), Report and Technical Studies on the Disposal and Utilization of Fossil·Fuel By-Products, October 26, 1982, Appendix C.

[25] It is not necessarily true that measurements taken from upgradient and downgradient wells at approximately the same time yield comparable measurements. In fact, due to migration time, there will be a lag between the time of comparable upgradient and downgradient measurements.

[26] Envirosphere Company, Op. cit., p. 38. These percentage numbers do not correspond precisely to the data in Exhibit 5-11 because Envirosphere normalized the data it received from the utilities so that each facility would be weighted evenly (i.e.,, a facility with many more measurements would not be weighted excessively). Envirosphere reports that 1.7 percent of the normalized data had upgradient measurements lower than the PDWS and the downgradient higher than the PDWS; 5 percent of the data indicated that both values exceeded the standard.

[27] Envirosphere Company, Environmental Effects of Utility Solid Waste Disposal, prepared for Utility Solid Waste Activities Group and Edison Electric Institute, July 1979.

[28] Dames & Moore, "Review of Existing Literature & Published Data to Determine if Proven Documented Cases of Danger to Human Health and the Environment Exist as a Result of Disposal of Fossil Fuel Combustion Wastes", in Utility Solid Waste Activities Group (USWAG), Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix B.

[29] Cherkauer, D. S. "The Effect of Fly Ash Disposal on a Shallow Ground-Water System." Ground Water, Vol. 18, No. 6, pp. 544-550, 1980.

[30] Groenewold, G. H., and B. W. Rehm. "Applicability of Column Leaching Data to the Design of Fly Ash and FGD Waste Disposal Sites in Surface- Mined Areas." In Proceedings of the Low-Rank Coal Technology Development Workshop, comp. Energy Resources Company, Inc., DOE/ET/17086-1932, CONF-8106235; Washington, D.C., U.S. Department of Energy, Technical Information Center, pp. 3-79 - 3-95, 1981.

[31] Envirosphere Company, Environmental Settings and Solid-Residues Disposal in the Electric Utility Industry; prepared for the Electric Power Research Institute, August 1984.

[32] Linda Aller, Truman Bennet, Jay H. Laher, Rebecca J. Betty, A Standardized System for Evaluating Ground Water Pollution Potential Using Hydrologic Settings, prepared by the National Well Water Association for U.S. EPA Office of Research and Development, Ada, OK, May 1985. EPA 600-285-018.

[33] Veronica T. Pye, Ruth Patrick, John Quarles, Ground Water Contamination in the United States, Philadelphia: University of Pennsylvania Press, 1983.

[34] Ground water over 180 ppm CaCO3 may also be treated. Of the 34 percent of the sites in the sample that have public water systems in the plume downgradient from the site within 5 kilometers, 73 percent have ground water with a hardness over 180 ppm CaCO3. Therefore, only 9 percent of the sites in the sample have both public water systems within 5 kilometers and ground water under 180 ppm CaCO3. Since many public water systems may not treat water in the range of 180-240 ppm CaCO3, the discussion in the report focuses only on ground water in excess of 240 ppm CaCO3. This is a conservative assumption since the water may be treated, either by the public authority or the private homeowner. In all cases, the extent of exposure through private wells would have to be evaluated on a site-by-site basis.

CHAPTER SIX

ECONOMIC COSTS AND IMPACTS

Section 8002(n) of RCRA requires that EPA's study of coal combustion wastes examine "alternatives to current disposal methods," "the costs of such alternatives," "the impact of those alternatives on the use of coal and other natural resources" and "the current and potential utilization of such materials." In response to these directives this chapter examines the potential costs to electric utilities if coal-fired combustion waste disposal practices are regulated differently than they are currently.

The first section of this chapter (Section 6.1) examines the costs incurred by electric utilities using current disposal methods for coal combustion wastes.[1] Section 6.2 follows with a discussion of the costs that could be incurred if coal combustion wastes were regulated differently than they are today. These costs include the costs of implementing alternative waste management practices and the costs of additional administrative responsibilities that would be incurred. Section 6.3 examines how new regulations might affect the cost of utilizing coal combustion wastes in various by-product applications. The last section of this chapter (Section 6.4) considers how energy use patterns in the electric utility industry might change if alternative waste management practices that significantly affect the cost of generating electricity with coal were imposed.

6.1 WASTE DISPOSAL COSTS ASSOCIATED WITH CURRENT DISPOSAL METHODS

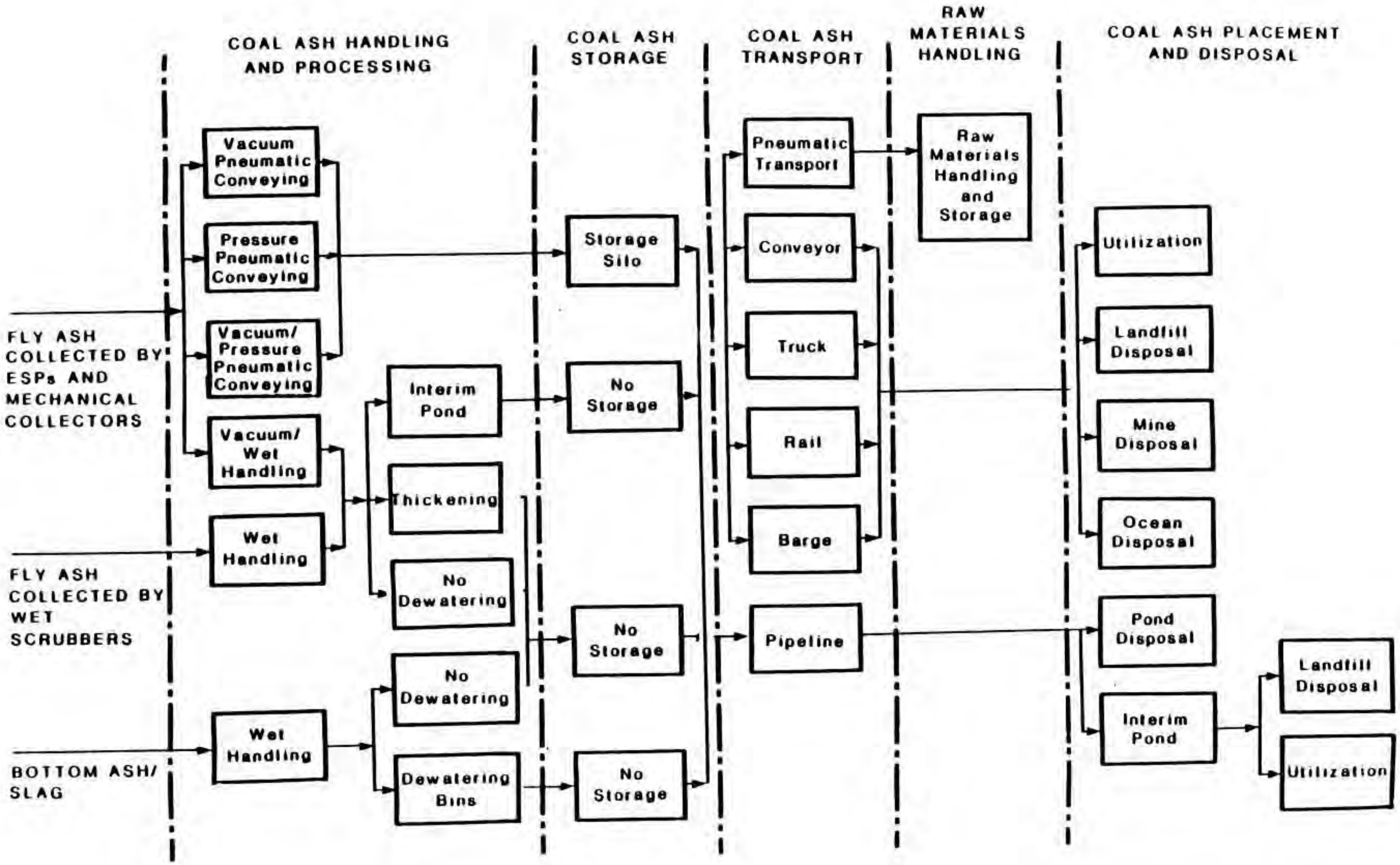
The management of utility wastes comprises a series of activities -- from initial waste collection to disposal. These current waste management activities can be classified into five basic components:[2]

1. **Waste Handling and Processing.** This is the initial phase of the disposal process, involving collection of the various waste products after they have been generated and initial treatment of the wastes to prepare them for final disposal.
2. **Interim Waste Storage at the Plant.** Some waste products that are dry when produced, such as fly ash or flue gas desulfurization (FGD) wastes from dry scrubbers, often require interim storage prior to final disposal.
3. **Raw Materials Handling and Storage.** Some disposal processes involve stabilization or chemical fixation of the waste to prepare it for disposal. The raw materials used for this phase, including additives such as lime, Calcilox, and basic fly ash, often require special handling and storage facilities.
4. **Waste Transport to a Disposal Facility.** Environmentally sound disposal requires careful transportation of the waste to the disposal site. Many modes of transportation can be used, including trucks, railroads, barges, pipelines, and conveyor systems.
5. **Waste Placement and Disposal.** This is the final stage of the waste disposal chain. It involves placing the waste in a suitable waste management facility (usually a surface impoundment or landfill) and all activities required after the facility is closed. Alternatively, the final disposition of a waste product may entail utilization of the waste in various applications (such as cement production or sandblasting operations).

Exhibit 6-1 presents a schematic illustration of the current waste management and disposal options for coal ash; Exhibit 6-2 illustrates the options available for FGD wastes. The waste management costs discussed in this

Exhibit 6–1

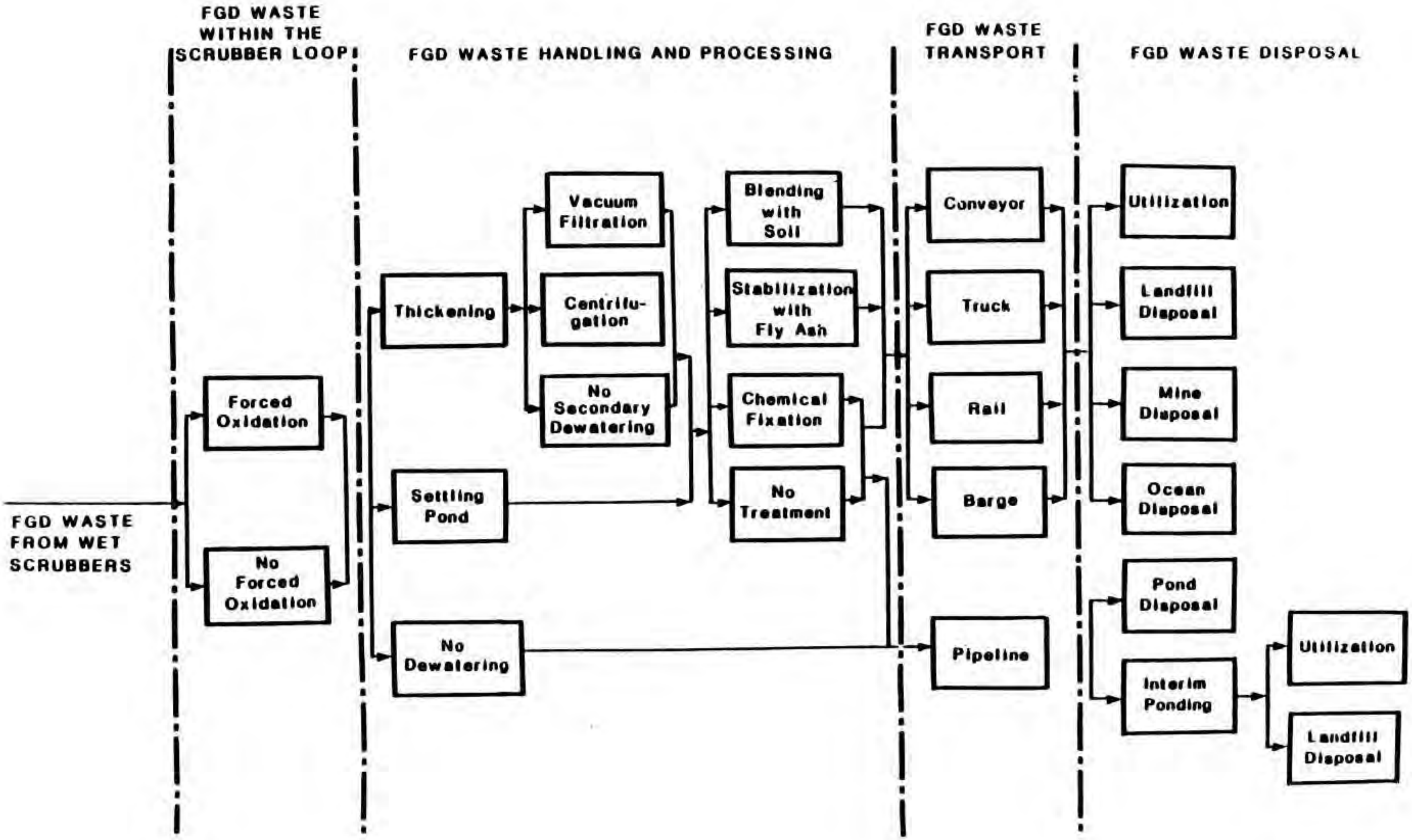
Overview of Waste Handling and Disposal Options for Coal Ash



Source: Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*, June 1985.

Exhibit 6-2

Overview of Waste Handling and Disposal Options for FGD Waste



Source: Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*, June 1985.

chapter are those associated with the last component of waste management (i.e., waste placement and disposal). These are the costs associated with actual construction of the waste management facility and placement of the wastes into the facility. If current practices for managing coal-fired wastes from electric utilities are altered, it is this final stage in waste management that would probably be most affected. However, as will be explored later in this chapter, some regulatory alternatives may affect other aspects of waste management.

6.1.1 Costs of Waste Placement and Disposal

The wastes from coal-fired combustion at electric utility power plants are often mixed together in the same waste management facility, typically a surface impoundment or landfill. Although surface impoundments were once the preferred method, and are still widely used, landfilling has become the more common practice because less land is required, and it is usually more environmentally sound (because of the lower water requirements, reduced leaching problems, etc.).

The costs of waste disposal can vary substantially. Exhibit 6-3 shows representative capital costs associated with constructing surface impoundments and landfills for coal-fired electric utility wastes. Exhibit 6-4 shows total costs (i.e., annualized capital costs plus operation and maintenance expenses).[3] Costs are shown for power plants that range in size from 100 to 3000 megawatts (Mw); power plants that fall outside of this range may incur

EXHIBIT 6-3

RANGES OF AVERAGE CAPITAL COSTS ASSOCIATED WITH COAL-FIRED ELECTRIC UTILITY WASTE DISPOSAL (4th quarter 1986 dollars per kilowatt)

	Size of Power Plant			
Type of Waste	100 MW	500 MW	1000 MW	3000 MW
Landfills				
Fly Ash	9-14	4-7	3-5	2-3
Bottom Ash	2- 5	2-3	1-2	1-1.3
FGD Waste	6-13	4-7	3-6	2-4
Surface Impoundments				
Fly Ash	27-50	15-27	13-23	10-18
Bottom Ash	10-20	6-11	5- 9	3- 6
FGD Waste	14-30	10-19	9-17	7-14

Source: Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants, EPA 600/7-85-028, June 1985.

EXHIBIT 6-4

RANGES OF AVERAGE TOTAL COSTS FOR COAL-FIRED ELECTRIC UTILITY WASTE DISPOSAL

(4th quarter 1986 dollars per ton)*

Type of Waste	Size of Power Plant 100 MW	 500 MW	 1000 MW	 3000 MW
Landfills				
Fly Ash	9-18	6-11	5-9	2-6
Bottom Ash	10-16	5-9	4-8	2-6
FGD Waste	4-10	4-7	3-6	2-4
Surface Impoundments				
Fly Ash	17-31	9-17	8-14	5-8
Bottom Ash	11-26	8-15	7-13	5-8
FGD Waste	8-17	7-13	6-10	5-7

* Dollar per ton estimates are based on the amount of waste produced each year. For purposes of this illustration, a power plant is assumed to generate annually 308 tons of fly ash per megawatt (MW), 77 tons of bottom ash per MW, and 264 tons of FGD waste per MW. Amounts will vary depending on coal quality, FGD technology, and boiler type, among other factors.

Source: Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants, EPA 600/7-85-028, June 1985.

different waste management costs. Both capital costs and total costs are shown for unlined facilities without ground-water monitoring or leachate control systems. The major factors affecting the cost of waste management are discussed below.

The amount of capital costs for a waste management facility can be attributed primarily to three factors: site preparation, excavation, and construction of containment structures.[4] Capital costs can be substantially reduced if the amount of earthwork can be minimized. Capital costs for surface impoundments, for example, increase significantly if dike construction or excavation is required. However, if existing site features can be used, such as valleys or abandoned pits, capital costs will be lower. Similarly, capital costs for landfills that require little excavation are lower than for those sites requiring extensive earthwork.

As Exhibit 6-3 illustrates, landfills are far less capital intensive than surface impoundments. For example, capital costs for fly ash placement in a surface impoundment at a 500 MW power plant would range from approximately $15 to $27 per kilowatt.[5] In contrast, capital costs for landfills range from about $4 to $7 per kilowatt. Landfills tend to cost less than impoundments primarily because the area required for a given amount of waste is less, and neither dikes nor piping and pumping systems are necessary.

Annual costs for landfills (see Exhibit 6-4) also tend to be less than those for surface impoundments primarily because landfills tend to be far less capital intensive. For example, costs for fly ash management at a 500 MW power plant range from about $9 to $17 per ton when the wastes are placed in surface impoundments, while the comparable range at a landfill is about $6 to $11 per ton. Similarly, the cost for bottom ash disposal at an impoundment for a 500 MW power plant ranges from $8 to $15 per ton, while the costs to dispose in a landfill range from about $5 to $9 per ton.

Other factors that affect the cost of utility waste disposal include

- **Size of the Power Plant.** Because larger power plants consume more coal than smaller facilities, they generate more waste material. However, more efficient operating procedures allow a larger disposal site to realize economies of scale not available at smaller sites; thus, the cost per ton of waste disposed is typically less.
- **Rate of Operation.** The number of hours that a coal-fired power plant operates varies from plant to plant, ranging from fewer than 3,500 hours per year to more than 6,500 hours. As operating levels increase, the amount of waste generated will increase as more coal is burned to meet the higher generation load.
- **Type of Coal.** The quantity of ash produced is proportional to the ash content of the coal, which ranges from 5 to 20 percent on average. Also, the grade of coal and boiler design will affect the relative proportions of fly ash and bottom ash (see Chapter Three for a discussion of the impact of boiler design on types and amount of wastes generated).
- **FGD Equipment.** Because of the additional materials used in flue gas desulfurization, a power plant that uses this process to remove sulfur dioxide generates substantially more waste than does a power plant with no sulfur dioxide controls. The amount of waste generated also varies from one FGD operation to the next, primarily because of differences in sulfur content among the various coals and, to a lesser extent, because of the type of FGD process employed.

For the few power plants currently disposing their waste in mines or quarries, this disposal method has been economic because of convenient access to the disposal site. Since much of the excavation normally required at a disposal site has already been performed as a result of the mining or quarrying operation, waste disposal costs can be quite competitive with costs associated with more traditional methods of disposal. The cost of disposing in mines or quarries for power plants that do not have easy access to the mine or quarry could quickly become prohibitive due to the costs of arranging for disposal at a remote site and of transporting the waste. Costs are also affected by whether or not the mine or quarry is still operating, whether the mining was surface or underground, and the amount of additional preparation required to dispose of the wastes, among other factors.

The costs of ocean disposal are not well known because there has been limited experience with this disposal method. Ocean disposal has been considered for <u>unconsolidated waste</u> (i.e., waste material that has not been physically or chemically altered prior to disposal)[6] and for more stabilized forms of waste, such as blocks for artificial reef construction;[7] however, this method has been attempted only for projects such as artificial reef construction, and then only on a trial basis. The most critical factors that would affect the magnitude of costs for ocean disposal are the availability of ash-handling facilities to load ocean-going vessels, the ability to gain easy access to the necessary waterways, and the physical characteristics of the wastes intended for disposal.

Because neither ocean disposal nor mine or quarry disposal is likely to be used on a widespread basis, they have been discussed here only briefly; see Chapter Four for a more detailed discussion of these two disposal options.

6.1.2 Costs Associated with Lined Disposal Facilities

The waste management costs presented above for surface impoundments and landfills do not include the cost of natural or synthetic liners to control the flow of leachate from the disposal area. Traditionally, most waste management sites, both surface impoundments and landfills, have not been lined to retard leaching, although this practice has become more widespread in recent years (see Chapter Four for a detailed discussion of liners). Currently, about 25 percent of all coal combustion waste management sites employ some type of liner system. Most liners are made of clay, synthetic materials, or stabilized utility waste.

Clay is used as a liner material because it is not very permeable, although its permeability will vary depending on the nature of the clay and the degree of compaction. Because clay is expensive to transport, the costs of the various clays used for liner material are directly related to the local availability of the clay. The installed cost of clay liners can range from $4.45 to $15.75 per cubic yard.[8] For a liner 36-inches thick, (liner thicknesses do vary), this results in a cost range of $21,000 to $75,000 per acre, or about $0.70 to $2.55 per ton of waste disposed in a landfill and $2.25 to $8.20 per ton for waste placed in an impoundment for a 500 MW power plant.[9]

Synthetic liner materials come in two basic varieties--exposable and unexposable. The membranes of exposable liners are resistant to degradation from exposure to the elements even if the liner is left uncovered. The membranes of unexposable liners will not function properly if the liner is exposed. Costs for installing exposable liners range from $43,000 to $113,000 per acre, or $1.45 to $3.85 per ton of waste disposed in landfills and from

$4.70 to $12.35 per ton of waste placed in surface impoundments.[10] Costs to install unexposable liners range from $59,000 to $123,000 per acre, or $2.00 to $4.15 per ton of waste disposed in landfills and $6.45 to $13.45 per ton placed in impoundments.[11] The ranges of costs are due primarily to differences in the cost of the material, differences in liner thickness, and allowances for various site-specific costs.

Stabilized utility waste, made from combinations of various ash wastes (such as fly ash or bottom ash), FGD waste, and lime, may be used as liner material when the required materials are available at the plant site. At an installed cost of about $13.70 per cubic yard, liners ranging from 3 feet to 5 feet in thickness can be constructed for $66,000 to $110,000 per acre,[12] which corresponds to total capital costs of $3.0-$5.0 million at a landfill, or about $2.25 to $3.75 per ton of disposed waste from a 500 Mw power plant. Total capital costs at impoundments would be $9.6-$16.0 million, or $7.20-$12.00 per ton of waste managed.[13]

6.2 COSTS OF ALTERNATIVE DISPOSAL OPTIONS

As described above, coal-fired utility wastes are currently exempt from RCRA Subtitle C waste management requirements. In the interim, coal combustion wastes are regulated under state statutes and regulations (see Chapter Four). If these wastes are subject to Subtitle C regulation, the incremental costs will depend on the regulatory option(s) ultimately selected. Section 6.2.1 outlines the major regulatory alternatives and discusses the flexibility allowed EPA under RCRA to promulgate regulations that account for the special nature of coal combustion wastes. Section 6.2.2 presents cost estimates for individual

Subtitle C disposal requirements, and Section 6.2.3 presents cost estimates for three regulatory scenarios if coal combustion wastes are regulated under Subtitle C.

6.2.1 Regulatory Alternatives under Subtitle C

As described in Chapter Five, there are two ways in which coal combustion wastes could be identified as hazardous and thus subject to requirements outlined in Part 264 of RCRA: the characteristic procedure and the listing procedure.

- **Regulation As Characteristic Waste.** Unless otherwise exempted, solid wastes are hazardous under RCRA if they display any of four characteristics: ignitibility, corrosivity, reactivity, or EP toxicity. Coal combustion wastes are unlikely to be ignitable or reactive, but could be corrosive (for aqueous wastes) or EP toxic. Subtitle C regulations would apply only to those waste streams that exhibited any of the hazardous characteristics. As discussed in Chapter Five, it is likely that only a small percentage of all waste generated would be hazardous. However, since some low volume wastes may be corrosive, this could have an impact on utilities that currently co-dispose high- and low-volume wastes. In these cases, the utility could either stop co-disposing or the landfill would have to conform to Subtitle C standards. In the case of surface impoundments, it might still be possible to co-dispose high- and low-volume wastes if the disposal impoundment met the requirements for a neutralization surface impoundment as set forth in 47 FR 1254, January 11, 1982.

- **Regulation as Listed Waste.** In addition to regulation under Subtitle C as characteristic waste, the Administrator may list a waste as hazardous under RCRA if it meets any of the three criteria contained in 40 CFR 261.11: (1) the waste exhibits any of the four characteristics described above; (2) it has been found to be fatal to humans in low doses or is otherwise measured as acutely hazardous; or (3) it contains any of the toxic constituents listed in Appendix VIII of Part 261. The Administrator does not have to list a

> waste that contains any of the toxic constituents listed in Appendix VIII if the Agency concludes that "the waste is not capable of posing a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported or disposed of, or otherwise managed". The Administrator could decide to list as hazardous all coal combustion waste streams or only selected ones.

If Subtitle C regulation is warranted for coal combustion wastes, all the requirements for hazardous waste treatment, storage, disposal, and recycling facilities in 40 CFR 264 could be applied to the wastes from coal-fired power plants. Since coal combustion waste is mainly managed in surface impoundments and landfills, the requirements of Subparts A-H, K, and N would apply. In general, the required activities include the following:

- **General Facility Standards.** Facilities must apply for an identification number, prepare required notices when necessary, perform general waste analysis, secure the disposal facility to prevent unauthorized entry, comply with general inspection requirements, provide personnel training, and observe location standards (these include a provision that facilities located in a 100-year flood plain must be designed, constructed, operated, and maintained to prevent washout of any hazardous waste by a 100-year flood). (40 CFR 264 Subpart B)
- **Preparedness and Prevention.** Hazardous waste facility operators must design and operate facilities to minimize the possibility of fire or explosion, equip the facility with emergency equipment, test and maintain the equipment, and provide EPA and other government officials access to communications or alarm systems. (40 CFR 264 Subpart C)
- **Contingency Plan and Emergency Procedures.** The facility operators must have a contingency plan to minimize hazards to human health or the environment in the event of fire or explosion. (40 CFR 264 Subpart D)

- **Manifest System, Recordkeeping, and Reporting.** Hazardous waste facility operators must maintain a manifest system, keep a written operating record, and prepare a biennial report. (40 CFR 264 Subpart E)
- **Ground-water Protection.** Unless a waste management facility meets certain standards,[14] a Subtitle C facility is required to comply with requirements to detect, characterize, and respond to releases from solid waste management units at the facility. These requirements include ground-water monitoring and corrective action as necessary to protect human health and the environment. (40 CFR 264 Subpart F)
- **Closure and Post-closure.** Subtitle C facilities must comply with closure and post-closure performance standards to minimize the risk of hazardous constituents escaping into the environment. (40 CFR 264 Subpart G)
- **Financial Requirements.** Subtitle C facilities must establish a financial assurance plan for closure of the facility and for post-closure care. Possible methods of financial assurance include a closure trust fund, surety bonds, closure letter of credit, closure insurance, or financial test and corporate guarantee.[15] (40 CFR 264 Subpart H)
- **Design and Operating Requirements.** Unless granted an exemption, new surface impoundments or landfills or new units at existing impoundments or landfills must install two or more liners and a leachate collection system between the liners. (40 CFR 264 Subparts K and H)

In recognition of the special nature of coal combustion wastes, Congress afforded EPA some flexibility in designing regulations for coal combustion wastes if they are subject to regulation under Subtitle C. This flexibility allows EPA to exempt electric utilities from some regulations imposed on owners and operators of hazardous waste treatment, storage, and disposal facilities by the Hazardous and Solid Waste Amendments of 1984. Specifically, section 3004(x) of RCRA allows the Administrator to modify the following requirements when promulgating regulations for utility waste.

- Section 3004 (c) prohibits the placement of uncontained liquids in landfills;
- Section 3004 (d) prohibits the land disposal of specified wastes;[16]
- Section 3004 (e) prohibits the land disposal of solvents and dioxins;
- Section 3004 (f) mandates a determination regarding disposal of specified wastes into deep injection wells;
- Section 3004 (g) mandates determinations on continued land disposal of all listed hazardous wastes;
- Section 3004 (o) lists minimum technical requirements for design and operation of landfills and surface impoundments, which specify the installation of two or more liners, a leachate collection system, and ground-water monitoring;
- Section 3004 (u) requires the Administrator to promulgate standards for facilities that burn hazardous waste as fuel; and
- Section 3005 (j) provides that interim-status surface impoundments must also meet minimum technical requirements specified in section 3004 (o).

In addition to the flexibility afforded by 3004 (x), it is possible for EPA to modify any of the standards applicable to waste treatment and disposal facilities if lesser standards are protective of human health and the environment. Section 3004 (a) states "... The Administrator shall promulgate regulations establishing such performance standards, applicable to owners and operators of facilities for the treatment, storage, or disposal of hazardous waste identified or listed under this subtitle, as may be necessary to protect human health and the environment."

There remains substantial uncertainty, however, about the extent to which, in practice, the statutory language of Subtitle C would provide sufficient flexibility to design a waste management program appropriate for high-volume, low-toxicity coal combustion wastes. EPA may also consider waste management requirements, as needed, under the current Subtitle D provisions for solid wastes, or may seek appropriate additional authorities.

6.2.2 Cost Estimates for Individual RCRA Subtitle C Disposal Standards

If EPA determines that Subtitle C regulation is warranted for coal combustion wastes, there is a wide range of regulatory options that could be undertaken. Required activities could consist of some, all, or variations of the requirements listed in 40 CFR Subparts B-H (and described briefly in Section 6.2.1). This section presents estimates for the costs that would be associated with compliance with individual Subtitle C requirements.

6.2.2.1 General Facility Standards; Preparedness and Prevention; Contingency Plan and Emergency Procedures; and Manifest System

Subparts B through E in Part 264 of the RCRA regulations list general requirements for such activities as preparing written notices and plans for submission to EPA; conducting waste analyses; providing security at the disposal site; and recordkeeping and reporting. Many of these activities would be undertaken during the permitting process, which is set forth in Part 270 of RCRA.

The Part B application must contain the technical information listed in Part 264 B through E. The cost to the electric utility industry to prepare a Part B permit application was estimated in a study done for the Utility Solid Waste Activities Group (USWAG), which calculated that the total cost of submitting

Part B permit analyses would be $721,000 per plant, or about $0.55 per ton of waste disposed.[17] The industry cost, if all power plants filed Part B applications, would be about $370 million, or about $54 million in annualized costs.

Location standards are also specified under Subpart B of Part 264 of RCRA. One such standard is for facilities located in a 100-year flood plain. Part 246.16(b) requires protective measures to prevent washout from flooding.

USWAG estimated the costs for protecting waste disposal facilities located within a 100-year flood plain to be about $740 per acre for surface impoundments and about $1,100 per acre for landfills on an annualized basis.[18] This corresponds to waste management costs of approximately $0.55 per ton of waste at surface impoundments and $0.25 per ton at landfills.[19] Industry-wide costs for flood protection at all impoundments are estimated to be about $92 million for capital expenditures (about $13 million in annualized costs); costs for flood protection at all landfills would be about $146 million for capital expenditures (about $20 million in annualized costs).[20]

6.2.2.2 Ground-water Protection

Subpart F of 40 CFR Part 264 lists requirements for ground-water monitoring systems. The costs of installing and maintaining an acceptable ground-water monitoring program are dependent on the number of monitoring wells required and the frequency of testing. The study conducted by Arthur D. Little for EPA estimated that capital costs for installing six monitoring wells at a facility would range from $18,000 to $25,000.[21] At a sampling frequency of four times per year, annual operating and maintenance costs would be $10,000 to $14,500. Total ground-water monitoring costs would range from $0.06 to $0.10 per ton of managed waste. In another study conducted for USWAG by Envirosphere, which used different well configurations and cost parameters, somewhat higher costs ($0.10-$0.12 per ton of waste managed) were estimated.[22]

It is not known how many coal-fired power plants currently have adequate ground-water monitoring systems in place. To estimate industry-wide costs, EPA has conservatively assumed that all power plants would be required to install new ground-water monitoring systems. Using the costs developed in the Arthur D. Little study, EPA calculated that total capital costs would be about $9.3 to $12.8 million. Total annualized costs would range from $6.5 to $9.3 million.

6.2.2.3 Corrective Action

Subpart F of 40 CFR Part 264 also lists requirements for corrective action. A variety of actions may be undertaken to correct ground-water contamination problems caused by a hazardous waste disposal facility. The facility owner or operator would need to conduct a site-specific investigation to ascertain the potential degree of contamination and the appropriate response that would be most effective in remedying the situation. Types of remedial responses that might be required would be placing a cap (made of either a clay or synthetic material) on the disposal unit, counter-pumping the ground water to retard contaminant migration, excavating the disposal area and removing the wastes to a Subtitle C landfill, or installing an impermeable curtain around the disposal area to prevent ground-water flow into or out of the disposal area. As one example of the potential magnitude of corrective action costs, this section evaluates the cost to excavate the existing disposal areas and transfer the wastes to RCRA Subtitle C-approved facilities.

EPA developed the following formula to calculate total excavation costs for Subtitle C units, (including closure of the existing site and removal of the wastes to a Subtitle C facility):

$$\text{Cost} = [(\text{Surface Area} \times \$45) + (\text{Volume} \times \$187)] \times 2.16$$

where the surface area is measured in square meters, and volume is measured in cubic meters.[23]

For a power plant of average size (500 MW), it has been assumed that a 45-acre landfill would be required, or about 182,000 square meters, with a capacity of approximately 5 million cubic meters. Based on the cost equation listed above, costs for excavation and waste transfer for a landfill site would be about $2.0 billion.[24] For surface impoundments, the appropriate parameters are 145 acres, or about 587,000 square meters, and a volume of about 5 million cubic meters, which works out to about $2.1 billion for the same type of corrective action. If this type of corrective action were required at all power plants, compliance costs for the industry would be enormous. At a cost of about $2 billion per plant, industry-wide costs would exceed one trillion dollars.

6.2.2.4 Closure and Post-closure

Subpart G of 40 CFR 264 specifies general closure and post-closure requirements for Subtitle C facilities and 40 CFR 264(K) and (N) list specific requirements for closure and post-closure care of surface impoundments and landfills, respectively. These requirements, as applied to coal combustion wastes, would require the dewatering of ash ponds, installation of a suitable cover liner made of synthetic materials, application of topsoil to support vegetation, seeding and fertilizing, installation of security fencing, and long-term ground-water monitoring. USWAG estimates that capital costs for closing a waste management facility range from \$39,000 to \$128,000 per acre for surface impoundments and from \$55,000 to \$137,000 per acre for landfills.[25] Once the facility is closed, additional costs would be incurred for post-closure care -- about \$1,050 per acre annually.[26] Total annual costs for closure of a surface impoundment would range from about \$1.0 to \$2.8 million for a typical 500 Mw power plant, or \$5.00 to \$14.75 per ton of waste managed. For a landfill, total annual costs would range from \$0.4 to \$0.9 million, or \$2.10 to \$4.90 per ton.[27].

An owner or operator that chooses to close a facility in the event that coal combustion wastes are brought under Subtitle C regulation would not necessarily have to follow the closure and post-closure requirements for hazardous waste facilities listed in 40 CFR Part 264. If regulations are proposed, there would be some period of time before final regulations take effect.[28] If the disposal facility is closed during this interim period, the closure standards that would apply would be those required under state regulations, not Subtitle C regulations.

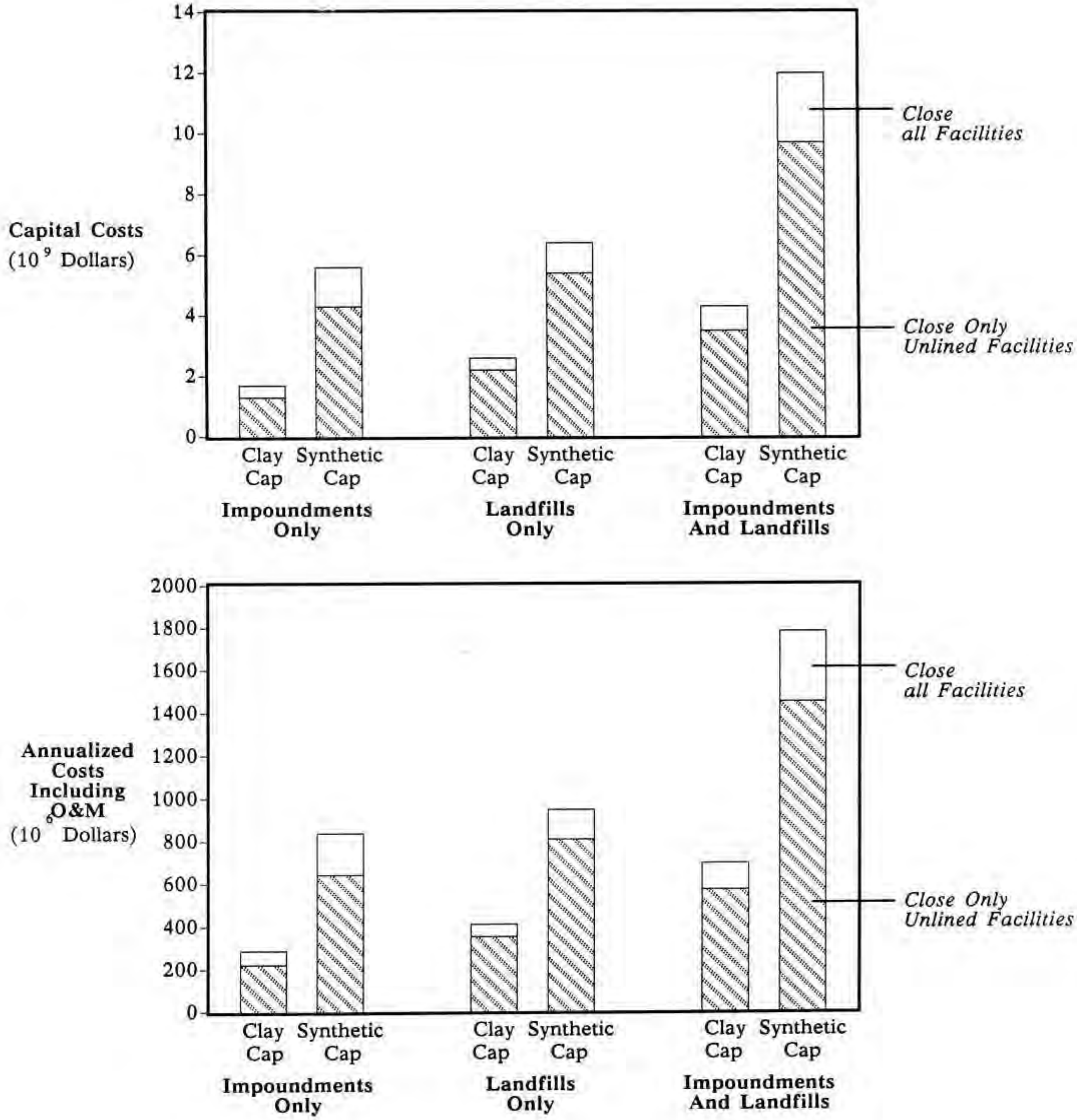
A facility that closes after the new regulations take effect, however, is subject to Subtitle C closure and post-closure requirements. The USWAG study provides an estimate of the total costs of closing all existing coal combustion waste disposal facilities and of the costs of closing only unlined facilities (See Exhibit 6-5). Total capital costs required to close all unlined landfills and impoundments would range from $3.5 billion for clay-capped facilities to $9.7 billion for synthetic-capped facilities. If all facilities closed under Subtitle C regulation, total capital costs would be about $4.3 billion for clay-capped closure and $12.0 billion for synthetic-capped closure.[29] Total annualized costs to close only unlined facilities would range from about $575 million for closure with clay caps to about $1.5 billion for synthetic caps. If all current waste management facilities were closed, annualized costs would be about $700 million for clay caps to $1.8 billion for synthetic caps.

6.2.2.5 Financial Responsibility

Subpart H of 40 CFR 264 sets forth requirements for financial responsibility for closure and post-closure care of hazardous waste facilities. A facility owner may use several different financial mechanisms to demonstrate financial responsibility, including purchasing a letter of credit, posting a surety bond, establishing a trust fund, purchasing an insurance policy, providing a corporate guarantee, or passing a financial test. Financial responsibility could be required for closure/post-closure costs or corrective action costs. The magnitude of the costs can vary considerably depending on the financial mechanism that is used and the type of activity for which financial assurance is required. For example, costs to provide a corporate guarantee or pass a financial test may be on the order of a few hundred dollars per facility; on the other hand, annual costs to obtain a letter of credit or to establish a trust fund are often based on some percentage (e.g., one to two percent) of the total

EXHIBIT 6-5

SUMMARY OF COSTS TO CLOSE EXISTING WASTE DISPOSAL FACILITIES



Source: Envirosphere Company, "Report on the Costs of Utility Ash and FGD Waste Disposal," in USWAG, *Report on the Costs of Utility Ash and FGD Waste Disposal,* Appendix F Part 2, October 19, 1982.

costs of the closure/post-closure or corrective action activity to be undertaken.[30]

6.2.2.6 Design and Operating Requirements for Landfills and Surface Impoundments

The level of effort required to come into compliance with Subtitle C design and operating requirements will depend on many site-specific considerations. In some cases, it may be possible to seal off the portion of the existing disposal site that has been in use and upgrade the remaining portion by installing a liner. In other situations the required changes may be sufficiently different from existing disposal practices that the most cost-effective action may be to open an entirely new disposal facility.

Given the variety of site-specific situations that may arise, and given the regulatory flexibility EPA has in designing coal combustion waste management standards, it is not feasible to estimate how many utility waste management facilities may be affected or what type of waste management measures may be required without conducting site-specific investigations. Nevertheless, to indicate the approximate magnitude of costs that may be involved for different waste management practices, the costs for three management options -- single-lined landfills, single-lined surface impoundments, and double-lined surface impoundments -- are presented below.

Landfills

As noted earlier, single clay liners can be installed in a landfill for about \$0.70 to \$2.55 per ton of disposed waste and single synthetic liners for about \$1.45 to \$4.15 per ton of disposed waste. The costs presented in Exhibit 6-4 indicate that waste disposal costs at a representative 500 Mw power plant with no flue gas desulfurization equipment would average about \$5 to \$11 per ton of disposed waste for a landfill operation. Adding a single clay liner to the landfill would increase total costs to \$5.70 to \$13.55 per ton of disposed waste; adding a single synthetic liner would increase costs to \$6.45 to \$15.15 per ton of disposed waste.

These estimates appear to be similar in magnitude, although somewhat lower than costs estimated in another study of utility waste disposal costs conducted for the Utility Solid Waste Activities Group (USWAG) by Econometric Research, Inc. That study estimated that total costs for complying with requirements related to the construction, operation, and maintenance of a single-lined landfill would range from about \$15 to \$24 per ton of waste, depending on the type of liner.[31]

The study for USWAG also analyzed the total costs to the electric utility industry if all power plants currently using landfills were required to construct new landfills with single liners. For this scenario, USWAG assumed that existing facilities, even if lined, would have to be replaced to comply with new requirements. Total capital costs for this alternative would range from \$2.6 billion for landfills with one synthetic liner to \$4.0 billion for landfills with a single clay liner.[32] Estimated annualized costs were about \$400 million for installing a single synthetic liner at all landfills and about \$600 million for installing a single clay liner.[33]

Surface Impoundments

The costs presented in Exhibit 6-4 for unlined surface impoundments indicated that waste managed at a representative 500 Mw power plant with no FGD waste production would cost about \$8 to \$17 per ton of waste. Using the cost estimates for liners noted earlier (see Section 6.1.2), adding a single clay liner would increase total management costs to about \$10.25-\$25.20 per ton of waste, and adding a synthetic liner would increase costs to \$12.70-\$30.45 per ton of waste.

These cost estimates for single-lined impoundments appear to be reasonably consistent with other estimates. Studies for USWAG indicated that management costs for impoundments with a single synthetic liner were about \$19 per ton of waste and \$30 per ton of waste for impoundments with a single clay liner.[34]

The USWAG report also estimated the total costs to the electric utility industry to construct new impoundments with single liners (i.e., all power plants currently using surface impoundments would be required to construct new facilities to meet disposal requirements even if the current impoundment is already lined). For this alternative total capital costs would range from \$5.8 billion for impoundments with single synthetic liners to \$9.5 billion for impoundments with single clay liners.[35] Annualized costs would range from \$850 million for single synthetic liners at all impoundments to \$1.4 billion for single clay liners.[36]

The study for USWAG also estimated management costs for surface impoundments with two different types of double liners -- a double synthetic liner (each with a 30 mil thickness) and a double liner system consisting of one synthetic liner (30 mil) and a clay liner (36 inches). Total management costs for double-lined surface impoundments would range from about $29 per ton of waste for a site with two synthetic liners to $36 per ton of waste for a site with one synthetic liner and one clay liner.[37]

Industry-wide costs were also estimated for the installation of new double-lined surface impoundments at all power plants currently using surface impoundments. Total capital costs for installing a double-lined impoundment ranged from $9.3 billion for a double synthetic liner to $11.6 billion for one clay and one synthetic liner.[38] Total annualized costs were estimated at $1.4 billion for all impoundments with a double synthetic liner and $1.7 billion for all impoundments with one clay liner and one synthetic liner. A summary of the costs for the various types of lined disposal facilities discussed herein is presented in Exhibit 6-6.

6.2.2.7 Summary of Costs for Various Waste Management Alternatives

Exhibit 6-7 summarizes the costs to the electric utility industry of each of the waste management options previously discussed. The exhibit presents cost estimates for the total amount of capital required for each waste management standard and for the total amount of annualized costs (i.e., annual capital, operation, and maintenance costs) that would be incurred in order to comply with each requirement if coal-fired combustion wastes were regulated as hazardous wastes.

EXHIBIT 6-6

SUMMARY OF COSTS FOR DIFFERENT TYPES OF LINED WASTE MANAGEMENT FACILITIES

	Cost per ton	Total Annual Costs for the industry a/ (millions of dollars)
Landfills		
Basic Practice--Unlined	\$ 5.00-\$11.00	N.A.
Single Clay Liner	\$ 5.70-\$13.55	600
Single Synthetic Liner	\$ 6.45-\$15.15	400
Surface Impoundments		
Basic Practice--Unlined	\$ 8.00-\$17.00	N.A.
Single Clay Liner	\$10.25-\$25.20	1,380
Single Synthetic Liner	\$12.70-\$30.45	865
Double Synthetic Liners	\$29.00	1,360
Double Liners: 1 Synthetic and 1 Clay	\$36.00	1,680

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a/ Total annual costs refer to annualized costs that capture capital, operation, and maintenance expenses. Since these costs were calculated by assuming that the utility industry would have to construct new facilities to comply with hypothetical alternative regulations, these costs are in addition to the current management costs incurred by the industry.

Source: Envirosphere Company, "Report on the Costs of Utility Ash and FGD Waste Disposal." In USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 19, 1982.

EXHIBIT 6-7

COSTS TO THE ELECTRIC UTILITY INDUSTRY FOR HYPOTHETICAL RCRA COMPLIANCE STRATEGIES

	Total Capital Costs (billions of dollars)	Total Annual Costs (millions of dollars)
Preparation of Part B Permit	0.37 a/	54
Construction of New Disposal Facilities		
Landfills		
- Single clay liner	4.0	600
- Single synthetic liner	2.6	400
Surface Impoundments		
- Single clay liner	9.5	1400
- Single synthetic liner	5.8	850
- Double liner		
- clay/synthetic	11.6	1700
- two synthetic	9.3	1400
Closure of Existing Disposal Facilities		
Only Unlined Facilities Close		
- Clay cap	3.5	575
- Synthetic cap	9.7	1500
All Facilities Close		
- Clay cap	4.3	700
- Synthetic cap	12.0	1800
Installation of Leachate Collection Systems	1.2	460
Provisions for Flood Protection		
Landfills	0.15	20
Impoundments	0.09	13
Ground-water Monitoring Systems	0.009-0.013	6-9
Excavate Existing Facilities, Removing Waste to Subtitle C Facilities	1028.0 a/	NA

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a/ Costs shown are for capital, operation, and maintenance costs for the entire industry since the amount of capital required was not readily available.

A combination of compliance alternatives could occur (e.g., closing existing disposal facilities and constructing new facilities with leachate collection and ground-water monitoring systems). The actual cost to the electric utility industry for complying with RCRA Subtitle C requirements would depend on the regulatory actions taken by the Agency if the temporary exemption under Section 3001 of RCRA is removed. Three possible regulatory scenarios are discussed in the following section.

6.2.3 Potential Costs to the Industry of RCRA Subtitle C Waste Management

Section 6.2.2 presented cost estimates for individual regulatory requirements that could be imposed on utilities if EPA determines that Subtitle C regulation is warranted for coal combustion wastes. In this section, three possible regulatory scenarios are examined to quantify the range of incremental costs that could result from various regulatory options. In the first scenario, the incremental costs of regulating a portion of low volume wastes under Subtitle C are presented. The second scenario assumes that all coal combustion waste would be subject to Subtitle C requirements. The third scenario assumes that high volume coal combustion wastes would be tested for RCRA hazardous characteristics and that a small portion of the waste would be classified as Subtitle C characteristic waste. For all three regulatory scenarios, costs are shown only for bringing all existing power plants into compliance with the assumed RCRA Subtitle C management regulations.

Low Volume Waste Scenario

This scenario evaluates the costs to the utility industry if some low volume waste streams are classified as hazardous wastes under Subtitle C. As discussed in Chapter Three, some of these wastes can exhibit hazardous characteristics such as corrosivity. The information available to EPA at this time does not permit the Agency to quantify the amount of low volume wastes that may exhibit hazardous characteristics. In this scenario, EPA has assumed that all water-side boiler cleaning wastes are regulated as hazardous wastes since these waste streams may exhibit corrosive characteristics. These waste streams are assumed to be hazardous to provide an approximate estimate of the costs to the industry if some low volume wastes display RCRA hazardous characteristics. That is, both high-volume and low-volume wastes could be tested for RCRA hazardous characteristics, but only a small portion of the low-volume wastes (as represented by all water-side boiler cleaning wastes) would need to be treated as hazardous.

As shown in Exhibit 3-19, a representative power plant generates about 180,000 gallons per year of water-side boiler cleaning wastes. The cost to dispose of these wastes as hazardous liquids can vary depending on waste stream variability, regional differences in disposal costs, and quantity to be disposed, among other factors.[39] For purposes of this analysis, an incremental cost of $2 per gallon (including transportation) has been assumed based on a 1985 survey of hazardous waste management prices.[40] With 180,000 gallons generated per year at a representative power plant, annual disposal costs would be about $360,000 per power plant. Since there are 514 power plants in the U.S., annual disposal costs to the utility industry would be about $185 million.

Full Subtitle C Regulation Scenario

If EPA lists high volume coal combustion waste streams in 40 CFR 261.31-261.33, all utilities will be affected. Utilities would be required to manage all coal combustion wastes in Subtitle C permitted facilities. To estimate the incremental costs to the industry of this regulatory scenario, the Agency assumed that all utilities would close existing facilities and open new waste management facilities that complied with Subtitle C standards. This scenario assumes that the costs of managing wastes off-site will equal the costs of managing wastes on-site and that existing facilities would be closed in the six months before Subtitle C regulation took effect, thereby avoiding Subtitle C closure and post-closure requirements.

Under existing state regulations, a clay cap is assumed to be adequate to close existing waste management facilities. The total annual costs of closing all existing facilities with a clay cap would be $700 million. For the new facilities, EPA assumed utilities would prepare a Part B permit application, construct new landfills and surface impoundments with clay/synthetic double liners, install leachate collection systems, make provisions for flood protection, and install ground-water monitoring systems. To determine incremental costs for the industry, EPA assumed that the current proportions of waste management facilities that were landfills and surface impoundments would remain unchanged under Subtitle C regulation. As summarized in Exhibit 6-7, total annual costs of the new Subtitle C facilities would be $54 million for Part B permit applications, $725 million for new double lined landfills,[41] $1700 million for new double lined surface impoundments, $460 million for leachate collection systems, \$33 million for flood protection, and \$9 million for ground-water monitoring. Total incremental costs for this regulatory scenario would be \$3.7 billion annually.[42]

High Volume Characteristic Waste Scenario

If coal combustion wastes were not exempt from RCRA Subtitle C regulation, utilities would have to test high-volume and low-volume coal combustion wastes for RCRA hazardous characteristics. Based on the RCRA characteristic results in Chapter Five, it appears that only a small portion of coal combustion wastes possess the hazardous characteristics of EP Toxicity or corrosivity. For purposes of this scenario, the Agency assumed that five percent of the wastes generated by utilities would need to be disposed in Subtitle C permitted facilities. The Agency does not have sufficient information to know exactly the amount of coal combustion waste that would exhibit RCRA hazardous characteristics. EPA believes that coal combustion wastes generally would not fail the RCRA hazardous characteristic tests. Based on limited information presented in Chapter Five that indicate about five percent of all ground-water observations at utility sites exceed the Primary Drinking Water Standards, the Agency assumed that five percent of all wastes would require Subtitle C treatment. The total annual cost to the industry if utilities close existing facilities and construct new double lined facilities for five percent of all coal combustion wastes would be \$185 million.

6.3 IMPACT OF REGULATORY ALTERNATIVES ON UTILIZATION OF COAL COMBUSTION WASTES

As discussed in Chapter Four, coal-fired utility wastes have been used in a variety of applications by electric utilities and other industries to replace other types of material. The use of utility wastes as a replacement for other materials has reduced the amount of wastes utilities have had to dispose, while correspondingly reducing the resource requirements of other industries that have managed to find a productive use for the waste material.

In the event that some or all of these wastes were declared hazardous, it is possible that the amount of by-product utilization of coal-fired utility wastes would decline as a result of increased costs for their use and the potential for outright prohibition of their use in some applications. On the other hand, it is possible that certain forms of utilization (e.g., the use of fly ash in cement) may be deemed environmentally acceptable practices if the wastes would be unlikely to pose an environmental threat when used for such purposes. Since costs for other forms of disposal may increase, utilization may also increase. However, for discussion purposes, this section assumes that designation as a hazardous waste would tend to discourage by-product utilization.

The costs that would be incurred as a result of environmental concerns over the utilization of coal-fired utility wastes would depend on the regulatory requirements that would have to be followed to use the wastes. The more stringent the additional regulatory burden imposed, the greater the impact on by-product utilization due to the higher costs of using the wastes.

In the USWAG study referenced above, the potential range of costs associated with reduced use of coal combustion by-products was also evaluated. Three different regulatory scenarios were analyzed.[43]

- The transportation of coal-fired utility wastes is regulated as hazardous waste transportation under Subtitle C of RCRA; use or disposal of the wastes would not be regulated.
- All activities associated with reuse of coal combustion by-products is regulated, and the regulations affect both the transporter and owner/operator of a Subtitle C hazardous waste management facility.
- Reuse of coal combustion by-products is prohibited.

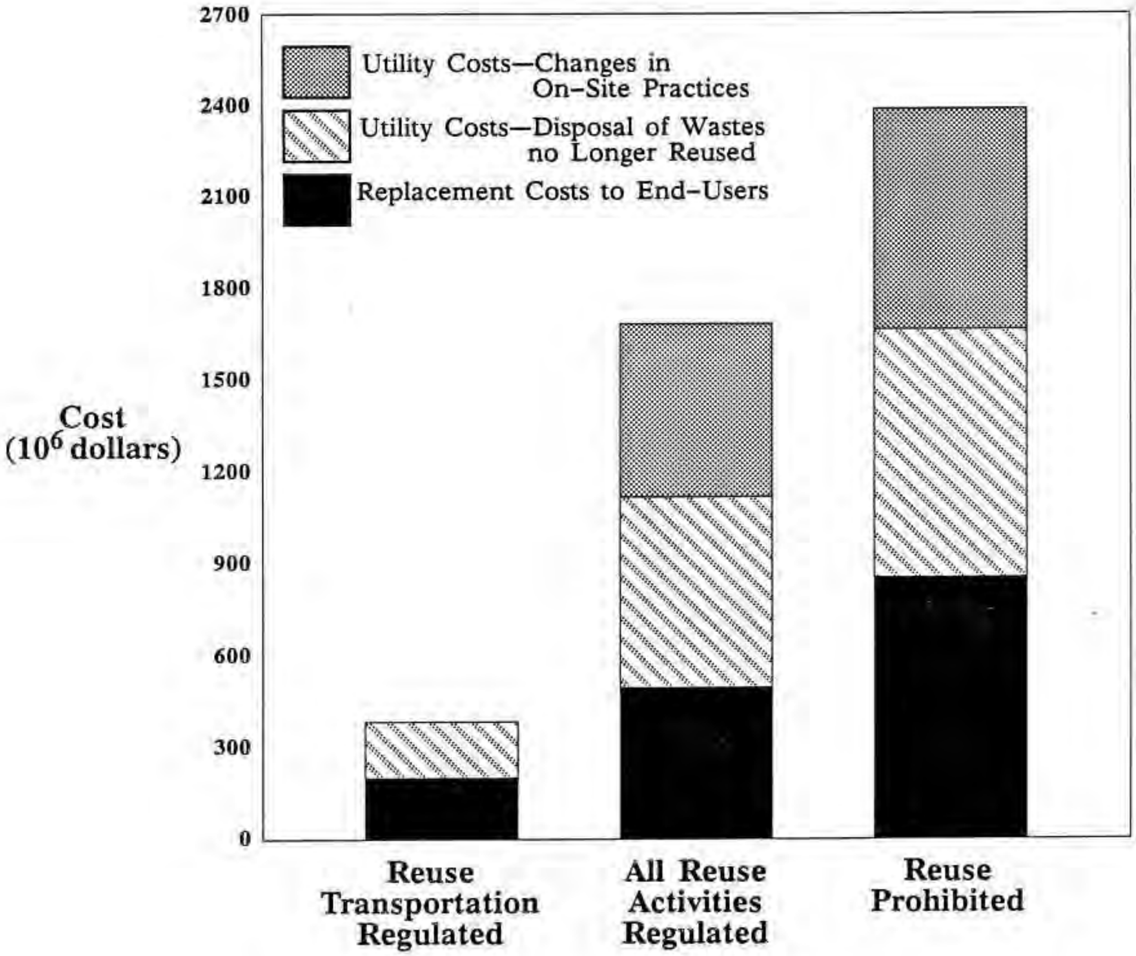
There would be three types of costs incurred under these regulatory scenarios: (1) replacement costs to the end-users who would no longer find it economic to utilize the coal combustion by-products, (2) costs to utilities to dispose of wastes no longer reused by other industries, and (3) additional costs to the utility industry for replacement and disposal of wastes that could no longer be used on-site. A summary of the costs associated with each scenario is provided in Exhibit 6-8.[44]

If the transportation of coal combustion by-products were subject to increased regulation under Subtitle C, the USWAG report estimated that the use of these by-products would decline by nearly 40 percent, increasing overall disposal volumes by about 8 percent.[45] The industries that would be affected the most would be the roofing granules industry (conventional roofing granules would replace bottom ash and boiler slag at a cost of about $115 million in annual costs) and the concrete industry (portland cement would replace fly ash at a cost of about $40 million in annual costs).[46]

If all activities pertaining to reuse of coal combustion wastes were subject to Subtitle C regulations, utilization of coal combustion

EXHIBIT 6-8

Summary of Economic Impacts on By-Product Utilization under Different RCRA Regulatory Scenarios*



*All costs are annualized based on impacts estimated from 1984-2000.

Source: *USWAG,* *<u>Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products</u>, Appendix G, October 26, 1982* by-products was estimated to decline by about 75 percent, increasing overall disposal volumes by about 14 percent.[47] The greatest impact would be on the concrete industry, which would spend about $270 million annually to replace fly ash with portland cement.[48]

If all reuse of coal combustion by-products were prohibited, industries using these by-products would have to find suitable replacements; total disposal volumes would increase by nearly 20 percent.[49] The largest impacts would be on the asphalt industry, which would be forced to replace ash with asphalt at a cost of approximately $250 million annually, and the concrete industry, which would replace fly ash with portland cement at a cost of about $270 million annually.[50]

6.4 ECONOMIC IMPACTS OF ALTERNATIVE WASTE DISPOSAL OPTIONS

Since many alternative disposal practices discussed in this chapter could impose additional costs on the electric utility industry, this section evaluates the effect that these increased costs might have on electricity generation costs and U.S. coal consumption. This study employs three measures to determine the potential economic impact of alternative disposal practices:

1. Average increase in electricity generation costs at existing coal-fired power plants,
2. Average increase in electricity generation costs at coal-fired power plants yet to be constructed, and
3. Impact on the electric utility industry's consumption of coal.

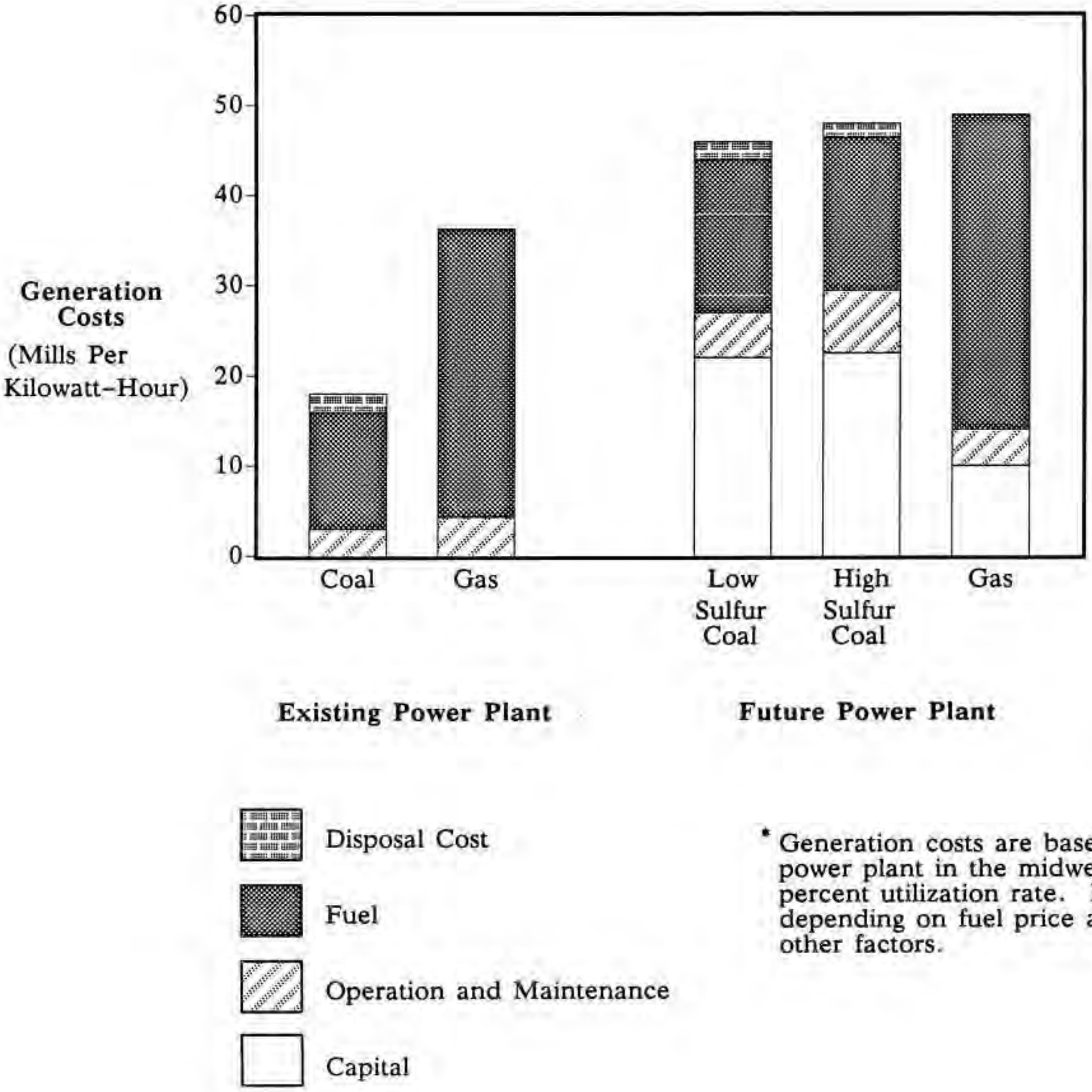
Exhibit 6-9 summarizes the cost of generating electricity at both existing and yet-to-be-constructed power plants (see Appendix G for a detailed discussion of the assumptions used to determine these generation costs).[51] Disposal costs average about 3-5 percent of total generation costs at existing coal-fired power plants, but only about 1-3 percent at future power plants. Although the actual costs of disposal at existing and future power plants are similar, the percentages are different because total generation costs at future power plants are higher than generation costs at existing power plants (resulting in a lower overall percentage for disposal costs at future power plants). Total generation costs are higher at future power plants because they include capital, operation and maintenance, and fuel costs, while the generation costs for existing power plants include operation and maintenance and fuel costs only.[52]
Based on the cost assumptions used to develop Exhibit 6-9, coal-fired electricity generation at both new and future baseload[53] power plants is less expensive than generation with natural gas.[54]

The economic impacts likely to result from the use of alternative coal-fired utility waste disposal practices will depend upon several factors, including which disposal options are required, how much the cost of coal-fired electricity generation changes, and whether these changes affect the relative competitiveness between coal and other fuels. To indicate the potential magnitude of these impacts, Exhibit 6-10 summarizes the potential cost impacts on electricity generation rates due to the alternative waste disposal options discussed earlier in this chapter.

As indicated in Exhibit 6-10, some alternative disposal options could

EXHIBIT 6-9

IMPACT OF CURRENT WASTE DISPOSAL COSTS ON TOTAL ELECTRICITY GENERATION COSTS*



* Generation costs are based on typical 500 Mw power plant in the midwest operating at 70 percent utilization rate. Regional costs will vary depending on fuel price and availability, among other factors.

Source: Generation cost estimates are from ICF Incorporated. Waste disposal costs are taken from Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*. June 1985.

EXHIBIT 6-10

IMPACT OF ALTERNATIVE DISPOSAL OPTIONS ON ELECTRICITY GENERATION COSTS

		Impact On Generation Costs		
	Incremental Cost		% of Total Generation Costs	
Option	($/ton of disposed waste)	mills/kilowatt-hour a/	Existing Plant	Future Plant
Part B Permit	$0.55	0.03	0.2	0.1
Existing Landfills b/				
Single Clay Liner	$0.70-$2.55	0.04-0.16	0.2-0.9	0.1-0.3
Single Synthetic Liner	$1.45-$4.15	0.09-0.26	0.5-1.4	0.2-0.6
Existing Surface Impoundments				
Single Clay Liner	$2.25-$8.20	0.14-0.51	0.8-2.8	0.3-1.1
Single Synthetic Liner	$4.70-$13.45	0.30-0.84	1.7-4.7	0.6-1.8
New Landfills				
Single Clay Liner	$ 5.70-$12.55	0.36-0.79	2.0-4.4	0.8-1.7
Single Synthetic Liner	$ 6.45-$15.15	0.40-0.95	2.2-5.3	0.9-2.0
New Surface Impoundments				
Single Clay Liner	$10.25-$25.20	0.64-1.58	3.6-8.8	1.4-3.4
Single Synthetic Liner	$12.70-$30.45	0.80-1.91	4.4-10.6	1.7-4.1
Double Synthetic Liner	$29.00	1.82	10.1	3.9
Double Synthetic/ Clay Liner	$36.00	2.26	12.6	4.8
Site Closure	$2.10-$14.75	0.13-0.93	0.7-5.2	0.3-2.0
Leachate Control	$4.70	0.30	1.7	0.6
Flood Protection	$0.25-$0.55	0.02-0.03	0.1-0.2	c/
Ground-water Monitoring	$0.06-$0.10	0.004-0.006	c/	c/
Utilization				
Transportation Regulated	$3.00	0.19	1.1	0.4
All Activities Regulated	$13.20	0.83	4.6	1.8
Reuse Prohibited	$18.75	1.18	6.6	2.5

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a/ Based on a representative 500 Mw plant operating at a 70 percent utilization rate. Costs are incremental costs only; that is, cost impact of new disposal facilities is only that portion of costs in excess of current disposal costs (see Exhibit 6-4 for these costs). A mill is one-tenth of a cent ($0.001).

b/ Costs for existing waste disposal facilities refer only to the cost of liner installation. Costs for new waste disposal facilities refer to all the costs for site construction and liner installation.

c/ Less than 0.1 percent.

increase electricity generation costs at existing power plants by several percent. In some cases the cost impact could be substantial if several options were combined as part of an integrated waste management strategy. For example, if new waste management regulations led to closure of the current disposal site and the construction of a new lined facility with a leachate control system, flood protection, and ground-water monitoring system, coal-fired generation costs at existing coal-fired power plants could increase by nearly 20 percent (roughly 3.5 mills/kilowatt-hour).

Generation cost increases of this magnitude have the potential to reduce coal consumption at existing coal-fired power plants if these cost increases make it more expensive to generate electricity with coal than with other fuels. A utility decides how much electricity to generate at any existing power plant primarily by comparing the operation and maintenance costs (including fuel) associated with generating electricity at all of its power plants. Power plants with the lowest generation costs will be operated first. Generally, it is less expensive to generate electricity with coal than with other fuels such as oil or gas, but oil-fired electricity generation can be competitive with coal when the price of oil is approximately \$10-\$15 per barrel.[55] However, whether and to what degree electric utilities would shift away from the use of coal would depend on several factors, including the relative price of coal compared with the price of other fuels, the magnitude of the increase in generation costs if disposal practices were altered, and the overall efficiency of competing power plants.

For power plants yet to be constructed, the impact of higher disposal costs on coal consumption could be more substantial, with possible generation cost increases approaching 8-10 percent if several options are combined. Generation cost increases of this magnitude could have a substantial effect on the amount of coal consumed at future power plants since many utilities may decide not to build coal-fired power plants. Although currently coal-fired electricity generation may be a more economic option than oil-fired or gas-fired generation at plants yet to be constructed, this situation could change if more expensive disposal practices were required for coal combustion wastes. This is because the higher capital costs of coal-fired electricity generation, compared with oil- or gas-fired generation, reduces the overall cost differential between the use of coal and the use of oil or gas at future power plants (compared to the cost differential between coal and oil or gas at existing power plants). As a result, coal is more likely to be replaced by alternative fuels at future power plants than it is at existing power plants.

In fact, since oil prices dropped below $20 per barrel in early 1986, many utilities have been seriously evaluating the feasibility of building oil- or gas-fired generating capacity in lieu of coal-fired units. As a result, in some instances even an increase of a few percent in coal-fired generation costs could be sufficient to tip the balance in favor of using natural gas or oil to fuel power plants that have not yet been constructed. If increased disposal costs do promote such competition, growth in future U.S. consumption of coal would probably decline. The exact magnitude of this decrease in future coal consumption would depend on many factors, including the type of new waste disposal practices adopted and the price of alternative fuels in different regions of the country. An in-depth analysis of the potential impact of alternative waste management scenarios on electric utility generation practices and investment decisions and, as a result, the level of coal consumption, is beyond the scope of this Report to Congress. However, EPA intends to seek more information and analysis on the issue of economic impacts through the public hearing process and through its own additional investigations. As required by law EPA will conduct the appropriate regulatory impact analyses, including the economic impact analysis, during the six month public review period following submission of this report to Congress if it is determined that current utility waste management practices for coal-fired combustion wastes are inadequate and additional regulations are warranted.

6.5 SUMMARY

The cost to manage coal combustion waste in basic waste management facilities currently ranges from as little as \$2 to as much as \$31 per ton. The wide range in management costs is primarily due to differences in (1) the type of facility, (2) the size of the facility and (3) the characteristics of the waste.

- Some facilities currently incur additional costs because they have undertaken additional safeguards against leaching, including liner installation, leachate collection and treatment, and ground-water monitoring.
- Management costs at surface impoundments tend to be greater than those at landfills because of the higher costs of site preparation at impoundments.
- The size of larger waste disposal facilities allows them to operate more efficiently, which tends to reduce the cost per ton of waste management.
- Fly ash is typically more expensive to manage than bottom ash or FGD waste because of additional requirements for collection, handling, and treatment prior to disposal.

- If additional regulations are promulgated requiring electric utilities to alter the current methods by which they manage coal-fired wastes, additional costs may be incurred by the industry as it complies with the new requirements.

- The most common practice for controlling leaching at a waste management site is installation of a liner prior to placement of the waste. Liners are usually made of low permeable clay or a synthetic material and can be installed in one or more layers. The cost of installing a liner ranges from $0.70 to $8.20 per ton of waste for clay liners and $1.45 to $13.45 per ton for synthetic liners. Total disposal costs for single-lined landfills range from about $6 to $15 per ton of waste, while costs for single-lined surface impoundments range from $10 to $30 per ton. Industry-wide costs to construct and install lined management facilities could range from $0.4 to $1.7 billion on an annualized basis, depending on type of facility, type of liner material, and number of liners installed.

- Installation of leachate collection systems to control potential environmental problems that might result from substances leaching from a waste management site could cost about $4 to $5 per ton of waste. Total costs to the utility industry to install leachate collection systems could be $1.2 billion in capital costs, or about $460 million in annualized costs.

- The cost of installing a ground-water monitoring system to detect the presence and concentration of various waste constituents in the ground water surrounding a waste management facility is generally less than $0.25 per ton of waste. Total capital requirements to the industry would likely range from $9 to $13 million, with annual costs of $6 to $9 million.

- If coal combustion wastes were regulated under Subtitle C of RCRA, costs to the utility industry could approach $3.7 billion annually if all wastes were listed as hazardous. Costs would be substantially lower than $3.7 billion annually if coal combustion wastes were tested for hazardous characteristics since only a small portion of coal combustion wastes would be likely to fail the RCRA hazardous characteristic tests. These costs to comply with Subtitle C do not include corrective action costs or the higher costs that may be associated with recycling coal combustion wastes; these costs to the utility industry could be very high.

- New waste management practices could increase the cost of generating electricity at existing coal-fired power plants by nearly 20 percent in some cases. Although coal is generally the preferred boiler fuel at existing power plants, an increase of this magnitude could cause a decline in the amount of coal consumed at these power plants if alternative fuel prices were reasonably competitive.

- If new management practices are required at future power plants, the increase in generation costs is unlikely to exceed 10 percent. Although on a percentage basis this increase would be less than the percentage increase possible at existing power plants, the choice of fuels at future power plants is much more competitive (due to the capital costs that must be included in the costs of a future power plant). In some instances this could lead to a decrease in coal consumption if the use of alternative fuels is found to be more cost effective since many utilities may decide not to build coal-fired power plants.

CHAPTER SIX

NOTES

[1] The disposal costs in this chapter are assumed to apply to high-volume and low-volume wastes since these wastes are often co-disposed in the same disposal facility.

[2] Arthur D. Little, Inc., Full-Scale Field Evaluation of Waste Disposal from Coal-Fired Electric Generating Plants, Final Report, EPA-600/7-85-0286, June 1985, p. 6-1.

[3] The methodology used to develop the cost estimates presented in this chapter is detailed in Appendix G. All costs in this report are presented in fourth quarter 1986 dollars. Costs were escalated to this level based on the GNP price deflator index reported by the U.S. Department of Commerce. The value of this index for fourth quarter 1986 was 115.2 (1982 = 100). Capital charges not already annualized in the various studies cited in this report were annualized by using a 14.5 percent capital recovery factor. This capital recovery factor was chosen to approximate the factors used in the two primary studies cited throughout this chapter -- the ADL study (which used a capital recovery factor of 14.7 percent) and the USWAG study (14.1 percent).

[4] Arthur D. Little, Inc., p. 6-112.

[5] Many of the cost estimates presented throughout this chapter are based on a 500 Mw power plant in order to approximate representative costs for a "typical" size power plant. Capital costs are often expressed on a "per kilowatt" basis to reflect the amount of capital required for each kilowatt of a power plant's capacity. Total disposal costs are often expressed on a "per ton" basis, which refers to each ton that must be disposed over the life of the facility. The amount of waste generated each year from a 500 Mw plant is assumed to be 154,000 tons of fly ash, (308 tons/Mw), 38,500 tons of bottom ash (77 tons/Mw), and 132,000 tons of FGD waste (264 tons/Mw). These estimates are based on average values reported in Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants, Arthur D. Little, Inc., June 1985. The actual amount of waste generated at a plant will vary depending on plant size, coal quality, FGD technology, and boiler type, among other factors.

[6] In one study for Consolidated Edison of New York, analyses were conducted on the feasibility of ocean disposal of coal-fired utility wastes from the Arthur Kill and Ravenswood oil-to-coal conversions. Capital costs for this 612,500 tons per year operation were estimated at $36 million. Annual operation and maintenance costs were approximately $2.7 million, for total costs of about $13 per ton of waste disposed. See Energy Resources, Inc., Demonstration of Compliance of Coal-Ash Disposal at the 106-Mile Ocean Waste Disposal Site with Subpart C of the Ocean Dumping Regulations, Attachment I, May 1981, p. I-26.) Capital costs would be about $5.2 million on an annualized basis, resulting in total annualized costs of about $7.9 million.

[7] In one study, the cost of building and operating an artificial reef construction system was estimated to be about $50 per ton, roughly double the amount estimated by the study authors for more conventional waste disposal. In those situations where space constraints or other factors would substantially increase the costs for conventional disposal, ocean disposal through reef construction was seen as an economically viable option. See J.H. Parker, P.M.J. Woodhead, and I.W. Dued all, "A Constructive Disposal Option for Coal Wastes -- Artificial Reefs," in Proceedings of the Second Conference on Management of Municipal, Hazardous, and Coal Wastes, S. Sengupta (Ed.), September 1984, p. 134.

[8] Arthur D. Little, p. 6-132. "Installed cost" of a liner (expressed in terms of cost per ton of disposed waste) refers to the increase in the cost of disposing of one ton of waste as a result of adding a liner to an unlined landfill or surface impoundment.

[9] Ibid. The costs in the Arthur D. Little report were presented for an 18-inch clay liner. Costs were doubled to approximate the costs for installing a 36-inch clay liner, which is currently a more common practice. The dollar per ton estimate was derived by multiplying total capital costs by a 14.5 percent capital recovery factor to determine annual capital charges. Assuming that a 500 Mw power plant has a 45 acre landfill disposal site, total capital charges would range from $945,000 to $3.4 million, or about $140,000 to $490,000 in annualized charges. Assuming that a 500 Mw power plant would need a 145-acre wet surface impoundment, total costs would range from $3.0 to $10.9 million, or $440,000 to $1.6 million in annualized costs. These annualized charges were then divided by the amount of waste produced annually by a 500 Mw power plant with no FGD process, (i.e., 192,500 tons) to determine the dollar per ton cost. This approach is used throughout the report to calculate dollar per ton estimates. See Appendix G for more detail on this methodology.

[10] Ibid. For landfills, total installed costs would range from $1.9 to $5.1 million per plant, assuming a 45-acre disposal site. Annual costs would range from about $280,000 to $740,000. Based on 192,500 tons of waste, the cost is $1.45-$3.85 per ton. For ponds (i.e., impoundments), total installed costs would be $6.2-$16.4 million, or $900,000-$2.4 million annualized. On a dollar per ton basis, this range is $4.70-$12.35.

[11] Ibid. For landfills total installed costs would range from $2.7-$5.5 million, or about $385,000-$800,000 in annual costs per ton. This corresponds to $2.00-$4.15 per ton. Total installed costs for ponding operations are $8.6-$17.8 million, or $1.2-$2.6 million annualized. This corresponds to $6.45-$13.45 per ton.

[12] Ibid.

[13] Total capital costs for landfills of $3.0 to $5.0 million correspond to annual charges of about $430,000 to $720,000. Assuming 192,500 tons of waste, the per ton cost is $2.25 to $3.75. Using the same approach to derive disposal costs at a 145-acre lined impoundment yields $7.20 to $12.00 per ton.

[14] A waste management unit is not subject to regulation under Section 264.1 if the Regional Administrator finds that the unit (1) is an engineered structure, (2) does not receive or contain liquid waste or waste containing free liquids, (3) was designed and is operated in such a way to exclude liquids, precipitation, and other run-on and run-off (4) has both inner and outer layers of containment enclosing the waste, (5) has a leak detection system built into each containment layer, (6) will have continuing operation and maintenance of these leak detection systems during its active life and throughout the closure and post-closure care periods, and (7) is constructed in such a way that, to a reasonable degree of certainty, hazardous constituents will not migrate beyond the outer containment layer prior to the end of the post-closure care period. (40 CFR 264.90(b)(vii).

[15] See 40 CFR 246.143.

[16] These specified wastes are liquid hazardous wastes that have a pH less than or equal to 2.0 and/or (1) free cyanides at concentrations greater than or equal to 1,000 mg/l, (2) arsenic and/or arsenical compounds at concentrations greater than or equal to 500 mg/l, (3) cadmium and/or cadmium compounds at concentrations greater than or equal to 100 mg/l, (4) chromium and/or chromium compounds at concentrations greater than or equal to 500 mg/l (5) lead and/or lead compounds at concentrations greater than or equal to 500 mg/l, (6) nickel and/or nickel compounds at concentrations greater than or equal to 134 mg/l, (7) mercury and/or mercury compounds at concentrations greater than or equal to 20 mg/l, (8) selenium and/or selenium compounds at concentrations greater than or equal to 100 mg/l, (9) thallium and/or thallium compounds at concentrations greater than or equal to 130 mg/l, (10) polychlorinated biphenyls at concentrations greater than or equal to 50 mg/l, (11) halogenated organic compounds at concentrations greater than or equal to 1,000 mg/kg.

[17] Envirosphere Company, "Report on the Costs of Utility Ash and FGD Waste Disposal", in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 19, 1982, p. 21, Appendix F, part 2. Dollar per ton estimates were determined by calculating annual costs ($721,000 x 14.5 percent capital recovery factor = $104,500). The capital recovery factor was applied to all costs since a breakdown of different types of costs required for a Part B permit was not available.

[18] Ibid, p. 18.

[19] Assuming a 145-acre impoundment site, costs would be about $107,000. On a per ton basis, this corresponds to about $0.55. For a 45-acre landfill with costs of $1100 per acre, total costs would be about $50,000, for a per ton cost of $0.25.

[20] Envirosphere, in USWAG, Appendix F, Part 2, p. 27, 32.

[21] Arthur D. Little, p. 6-133. On an annualized basis, capital costs would range from about $2,650 to $3,550.

[22] Envirosphere Company, in USWAG, Appendix F, Part 2, p. 37. Envirosphere estimated that about four wells, one upgradient from the site and three downgradient, would be required for each 100 acre disposal site (or about six wells for a site of 145 acres) at a capital cost of approximately $6,000 per well. Total capital costs for six wells would be $36,000, which is about $5,200 on an annualized basis. It was assumed that the wells would be sampled quarterly the first year, then semi-annually thereafter. The operation and maintenance costs would average about $2,500 to $3,000 per well, for facility costs (assuming six wells) of $15,000 to $18,000 per year. Total annualized costs, therefore, would range from $20,200 to $23,200, or $0.10 to $0.12 per ton of waste disposed.

[23] For a more complete discussion, see ICF Incorporated, Liner Location Risk and Cost Analysis Model, Draft Phase II Report, Appendix F-2, Office of Solid Waste, U.S. Environmental Protection Agency, March 1987.

[24] The cost equation on which this cost estimate is based was developed for typical RCRA Subtitle C landfills. Since these facilities tend to be much smaller than the size of utility disposal areas, extrapolating the cost equation for larger sizes may introduce some errors. Nevertheless, these cost estimates do indicate the approximate magnitude of corrective action costs that would likely be incurred.

[25] Econometric Research, "The Economic Costs of Potential RCRA Regulations Applied to Existing Coal-Fired Electric Utility Boilers," in USWAG, Report and Technical Studies on the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, p. 15, Appendix F, part 1.

[26] Ibid, p. 15.

[27] Ibid, p. 18. On a per acre basis, total annual costs range from $6,700 to $19,600 for surface impoundments and $9,000 to $21,000 for landfills. For a 145-acre impoundment, this corresponds to $1.0 to $2.8 million in total annual costs, or $5.00 to $14.75 per ton of waste. For landfills the per ton cost would be $2.10 to $4.90 based on total annual costs of $0.4 to $0.9 million.

[28] See Administrative Procedure Act, U.S. Code 5 Sec. part 551.

[29] Ibid, see pages 26 and 31 of the Econometric report for all closure costs.

[30] For further discussion of the potential magnitude of these costs, see ICF Incorporated, Flexible Regulatory and Enforcement Policies for Corrective Action, prepared for U.S. Environmental Protection Agency, September 12, 1985.

[31] Econometric Research, in USWAG, Appendix F, Part 1, p. 15. Econometric Research used capital costs for disposal of about $5.20 per ton of waste produced over a 20-year life of the facility for synthetic liners and about $8.10 per ton for clay liners, plus about $0.06 per ton per year for operation and maintenance costs. Total initial capital outlays would then be $104 per ton ($5.20 per ton times 20 years) for synthetic liners, or about $15.08 per ton on an annualized basis, and $162 per ton ($8.10 per ton times 20 years) for clay liners, or $23.49 per ton on an annualized basis. With the addition of

the $0.06 per ton for operation and maintenance costs, total costs would range from $15.14 per ton for synthetic liners and $23.55 per ton for clay liners for each ton of waste produced annually.

[32] Ibid., p. 27. Total capital costs for existing power plants were assumed to be $2.1 billion for single synthetic liners and $3.2 billion for single clay liners. Since these cost estimates were based on a universe of 412 power plants, costs were adjusted upward by 514/412 to approximate total industry costs for the number of power plants estimated at the time of this study -- 514 power plants. This adjustment was made for all industry-wide costs cited from the USWAG report.

[33] Ibid., p. 32.

[34] Ibid., p. 18. Econometric Research, Inc., calculated that disposal costs for an impoundment with a single synthetic liner were about $0.95 per ton of waste over the life of the facility and about $1.50 per ton of waste for clay-lined impoundments. For a plant generating 192,500 tons each year for 20 years (or 3.85 million tons), that corresponds to 3.85 million tons x $0.95 per ton = $3.7 million for an impoundment with a single synthetic liner (or about $19 per ton based on $3.7 million divided by 192,500 tons of waste annually) and 3.85 million tons x $1.50 per ton = $5.8 million for an impoundment with a single clay liner (or about $30 for each ton of waste disposed in a year).

[35] Ibid, p. 26. The costs in the USWAG report were adjusted by 514/412 to account for the 514 power plants estimated at the time of this study compared to the 412 power plants assumed in the USWAG report.

[36] Ibid. p. 31.

[37] Ibid, p. 18. The double synthetic liner disposal system averages about $1.45 per ton over the life of the facility and a system with one synthetic liner and one clay liner costs about $1.80 per ton. At 3.85 million tons of waste over a 20 year facility life, that is $5.6 million for a double synthetic liner (or about $29 for each ton disposed in a year). For a combination synthetic/clay liner system, 3.85 million tons x $1.80 per ton = $6.9 million (or about $36 per ton).

[38] Ibid, p. 26.

[39] ICF Incorporated, 1985 Survey of Selected Firms In The Commercial Hazardous Waste Management Industry, Prepared for U.S. Environmental Protection Agency, November 6, 1986.

[40] Ibid.

[41] To develop a cost estimate for landfills constructed with clay/synthetic double liners, the ratio of the cost of single clay and synthetic liners at landfills in Exhibit 6-7 to the cost of single clay and synthetic liners at surface impoundments was multiplied by the cost of clay/synthetic liners at surface impoundments.

[42] The costs to close and cap existing facilities have been included in this estimate, while corrective action costs have not been included. Although closure costs will be incurred eventually by the industry, in most cases they would not be incurred for many years to come. To be conservative, EPA has included closure costs as part of potential RCRA Subtitle C compliance costs.

[43] Envirosphere Company, "Economic Analysis of Impact of RCRA On Coal Combustion By-Products Utilization." In USWAG, Report and Technical Studies On the Disposal and Utilization of Fossil-Fuel Combustion By-Products, October 26, 1982, Appendix G.

[44] Envirosphere Company, in USWAG, Appendix G. The costs in Exhibit 6-8 are based on estimated impacts between 1984 and 2000 and adjusted by a capital recovery factor of 14.5 percent to annualize the costs (total capital requirements were not identified). It was estimated that about 203 million tons of coal combustion by-products would be used over this period, with a similar amount used on-site by the utilities. That is, the costs assume that the amount of by-products utilized would have increased over time.

[45] Ibid., p. 89. Total ash generation in 2000 was assumed to be 169.5 million tons, with about 27.3 million tons utilized and therefore, 142.2 million tons destined for disposal areas. Utilization was estimated to decline about 11.5 million tons, so the total amount of waste to be disposed would increase to 153.7 million tons.

[46] Ibid.

[47] Ibid., p. 91. Total utilization was assumed to decline by about 20.3 million tons in 2000. Therefore, the total amount of waste disposed would increase from 142.2 million tons to 162.5 million tons.

[48] Ibid.

[49] Total utilization was assumed to be 27.3 million tons in 2000, thereby increasing total disposal volume from 142.2 million tons to 169.5 million tons.

[50] Envirosphere Company, in USWAG, Appendix G, p. 93.

[51] To estimate the potential impact of alternative disposal practices on electricity generation costs, the first step was to calculate the approximate portion of generation costs due to current basic disposal practices. Current basic disposal practices for coal-fired utility wastes were assumed to be disposal in either an unlined pond or landfill, although other practices are sometimes followed. Generation costs for a typical coal- and gas-fired power plant are shown to indicate the relative competitiveness of these two fuels when current disposal practices for coal-fired utility wastes are followed. See Appendix G for a detailed discussion of the assumptions used to determine these generation costs.

[52] Capital costs are not included in the cost estimates for existing power plants because these are "sunk" costs, i.e., they have already been spent. As a result, the percentage impact on total generation costs at existing power plants is larger because the cost base is smaller compared to future power plants.

[53] Baseload refers to power plants that are operated as much as possible to maximize the amount of electricity these plants can generate. For this analysis a baseload power plant is assumed to operate 70 percent of the time.

[54] The generation costs in Exhibit 6-9 are intended to be representative of typical power plants. However, the actual cost of generation and the relative competitiveness between coal and gas depends on many factors, including plant size, utilization rate, and delivered fuel cost.

[55] This price range is only intended to illustrate the approximate range at which oil becomes competitive with coal at existing power plants. The actual level at which coal might begin to lose market share depends on many factors, including relative price differentials, fuel availability, gas prices vis-a-vis oil prices, types of power plants (i.e., overall plant efficiency), etc.

CHAPTER SEVEN

CONCLUSIONS AND RECOMMENDATIONS

This chapter concludes the Environmental Protection Agency's Report to Congress on fossil fuel combustion wastes. Pursuant to the requirements of Section 8002(n) of the Resource Conservation and Recovery Act (RCRA), the Report addresses the nature and volumes of coal combustion wastes, the environmental and human health effects of the disposal of coal combustion wastes, present disposal and utilization practices, and the costs and economic impacts of employing alternative disposal and utilization techniques. A statement of the scope of the report and a summary of the report's findings are presented below, followed by the Agency's recommendations.

7.1 SCOPE OF REPORT

As discussed in Chapter One, this Report to Congress covers the generation of coal-fired combustion wastes by the electric utility industry. Other fossil fuel combustion wastes not discussed in this report include coal, oil and gas combustion wastes from other industries and oil and gas combustion wastes from electric utilities. Overall, coal combustion by electric utilities accounts for approximately 90 percent of all fossil fuel combustion wastes that are produced. Moreover, this percentage is likely to increase in the future since coal consumption by the electric utility industry is expected to increase substantially while coal use by other sectors remains relatively constant. Electric utility coal consumption will grow as new coal-fired power plants are constructed to meet increasing electricity requirements in the United States.

7.2 SUMMARY OF REPORT

The Agency's conclusions from the information presented in this report are summarized under seven major groupings paralleling the organization of the report: 1) Location and Characteristics of Coal-Fired Power Plants, 2) Waste Quantities and Characteristics, 3) Waste Management Practices, 4) Potential Hazardous Characteristics, 5) Evidence of Environmental Transport of Potentially Hazardous Constituents, 6) Evidence of Damage, and 7) Potential Costs of Regulation.

7.2.1 Location and Characteristics of Coal-Fired Power Plants

1. There are about 500 power plant sites in the United States that consume coal to generate electricity. Each power plant may be the location for more than one generating unit; at these 500 power plants there are nearly 1400 generating units.

2. The size of coal-fired power plants can vary greatly. The size of a power plant is typically measured by the number of megawatts (Mw) of generating capacity. Coal-fired power plants can range in size from less than 50 Mw to larger than 3000 Mw.

3. Coal-fired power plants are located throughout the United States. Coal is used to generate electricity in every EPA region; almost every state has some coal-fired generating capacity.

4. More coal-fired power plants will be built as the demand for electricity increases. Coal is a fuel often used by the electric utility industry to generate power. This reliance on coal is unlikely to change for many years to come in the absence of greatly increased costs for coal-fired electricity.

5. Coal-fired power plants are located in areas of widely-varying population density. Some power plants are located in remote rural areas, whereas others are located in urban environments. They are usually, although not always, located at least a couple of kilometers from major population concentrations. In general they are located near a major body of surface water such as a lake, river, or stream.

7.2.2. Waste Quantities and Characteristics

1. The amount of wastes generated annually by coal-fired power plants is large by any standard. About 84 million tons of high-volume wastes -- fly ash, bottom ash, boiler slag, and FGD sludge -- are generated annually. The total amount of low-volume wastes generated from equipment maintenance and cleaning operations is not known precisely, but is also substantial.

2. <u>Quantities of waste produced will increase significantly as more electricity is generated by coal</u>. The amount of high-volume wastes produced annually could double by the year 2000. In particular, the amount of FGD sludge produced will triple (to about 50 million tons) as newly-constructed power plants install FGD equipment to remove sulfur dioxide from the flue gases.

3. <u>Coal combustion wastes are a common by-product from the generation of electricity</u>. The noncombustible materials are present in the coal as a result of geologic processes and mining techniques. Given current technologies for generating electricity, wastes from coal combustion will continue to be produced in significant quantities.

4. <u>High-volume coal combustion wastes do contain elements that in sufficient concentrations can pose a potential danger to human health and the environment</u>. Most elements in coal are not hazardous. However, trace elements typically found in coal become concentrated as a result of the combustion process. Certain elements known to pose health risks can be found in the wastes at hazardous levels.

5. <u>Although most low-volume wastes do not appear to be hazardous, there are some waste streams from cleaning that could potentially be hazardous</u>. The waste streams of most concern are water-side boiler cleaning solutions, which may be corrosive or toxic. Because the amount and type of low-volume wastes produced can vary substantially from one power plant to the next, not as much is known about low-volume wastes compared to high-volume wastes.

7.2.3 Waste Management Practices

1. <u>Most coal combustion wastes are typically disposed in landfills or surface impoundments, with recent trends toward increased reliance on landfills</u>. Although some disposal does occur off-site, most wastes are disposed on-site; it is likely that most power plants built in the future will dispose on-site in a landfill.

2. <u>Typical industry practice is to co-dispose low-volume wastes with high-volume wastes or, in some instances, to burn the low-volume wastes in the utility boiler</u>. There are many other types of waste management practices that are also used to alter the physical and chemical characteristics of low-volume wastes prior to disposal. These practices vary widely from plant to plant. There are no reliable data sources that accurately describe the types of low-volume disposal practices used at each power plant.

3. <u>The potential for increased waste utilization as a solution to waste management in the utility industry appears to be limited</u>. About 21 percent of all high-volume wastes are currently recycled; some opportunities appear to exist to increase utilization, but not in a major way.

4. <u>Coal combustion wastes are typically regulated under state solid waste laws, which treat these wastes as non-hazardous materials</u>. The

extent of state regulation can vary significantly from one state to another.

5. Many waste management practices applied to hazardous waste in other industries, such as liners, have only seen limited use for coal combustion waste management. In recent years, some of these practices, including liners and leachate collection systems, have become more common. There is an increasing tendency to manage coal combustion wastes by disposing on-site (at the power plant) in landfills.

6. There are few major innovations under development that would lead to major changes in waste management practices.

7.2.4 Potential Hazardous Characteristics

1. The RCRA hazardous characteristics of most concern are corrosivity and EP toxicity. Coal combustion wastes are generally not ignitable or reactive.

2. Most waste streams would not be considered corrosive under RCRA definitions. Only aqueous wastes, which most coal combustion wastes are not, are considered corrosive under RCRA. There are some aqueous coal combustion waste streams that are very near corrosive levels, particularly low volume wastes such as boiler blowdown or coal pile runoff. In some instances, boiler cleaning wastes may be corrosive, particularly those that are hydrochloric acid-based.

3. Coal combustion wastes generally are not EP toxic, although there are some exceptions. It is rare for coal combustion wastes to fail the EP test (or the TCLP test developed more recently). Extract concentrations in excess of 100 times the Primary Drinking Water Standards have been found only for the elements cadmium, chromium, and arsenic from some FGD sludges and coal ash samples, although these levels are quite rare -- average levels are substantially below 100 times the PDWS.

4. There are insufficient data to determine a priori which waste streams at a power plant will exhibit RCRA hazardous characteristics. Accurate determinations could only be made if site-specific analyses were conducted.

7.2.5 Evidence of Environmental Transport of Potentially Hazardous Constituents.

1. Migration of potentially hazardous constituents has occurred from coal combustion waste sites. From the limited data available, exceedances of the Primary Drinking Water Standards have been observed in the ground water for several elements, including cadmium, chromium, lead, selenium, and arsenic.

2. Ground-water contamination does not appear to be widespread. Only a few percent of all ground-water quality observations indicate that a PDWS exceedance has occurred, although many utility waste management

sites at which ground-water monitoring has been done have had at least one exceedance. However, the observed contamination may not necessarily be chronic since sites at which exceedances have been noted do not consistently register in excess of the PDWS.

3. When ground-water contamination does occur, the magnitude of the exceedance is generally not large. Most PDWS exceedances tend to be no more than 10 or 20 times the PDWS, although a few observations greater than 100 times the PDWS have been noted.

4. Human populations are generally not directly exposed to the groundwater in the vicinity of utility coal combustion waste management sites. Public drinking water intakes are usually at least a few kilometers away. Also, most power plants are located near surface water bodies that dilute the concentration of any elements found in the ground water.

5. Because high-volume and low-volume waste streams are often co-disposed, it cannot be determined if one specific waste stream was the source of contamination.

6. The ground-water quality information on which this evidence is based is limited. Data were only available from a small number of utility waste management sites; no comprehensive database on ground-water contamination potentially attributable to coal combustion wastes exists.

7.2.6 Evidence of Damage

1. There are few cases considered to be documented evidence of damage from coal combustion wastes. Among these cases there is some dispute whether any observed damage can be attributed to the utility waste management facility.

2. Damage cases are dominated by chronic incidents (seepage, periodic runoff) as opposed to catastrophic incidents (sudden releases, spills), although one documented damage case was due to structural failure of a surface impoundment.

3. Documented damage typically involves physical or chemical degradation of ground water or surface water, including fish kills or reduction in biota, but seldom involves direct effects on human health because the water is not consumed for drinking water purposes. Much of the damage has occurred in the immediate vicinity of the waste management site; drinking water intakes are generally far enough away such that any contaminated water is not being directly used for human consumption.

7.2.7 Potential Costs of Regulation

1. If additional regulations are promulgated for utility waste management, the total costs incurred by the industry could vary considerably depending on the extent of the additional regulations.

For example, total annual costs to install and operate ground-water monitoring systems would be unlikely to exceed $10 million. On the other hand, total annual costs for the industry could approach $5 billion if all existing facilities were capped and closed and new facilities were constructed with liners, leachate collection systems, flood protection, and ground-water monitoring. (Corrective action costs, such as excavating all existing facilities for removal of the wastes to RCRA Subtitle C facilities, are not included in this estimate; such costs would be extremely high.)

2. Regulation of utility coal combustion wastes under full RCRA Subtitle C requirements could halt all recycling of coal combustion wastes if recycling was also subject to Subtitle C requirements. Total costs to the industry could approach $2.4 billion annually. If recycled wastes were not subject to Subtitle C disposal requirements, it is possible the amount of recycling could increase as the utility industry increased waste utilization to avoid full Subtitle C disposal costs.

3. The costs to the utility industry for full RCRA Subtitle C compliance could decrease the amount of coal consumed in coal-fired power plants. The costs of generating electricity with coal could increase by several percent (depending on the extent of additional regulations), making it economic to generate electricity with other fuels. These impacts could be felt in two ways: 1) lower coal consumption at existing power plants and 2) construction of fewer coal-fired power plants in the future.

7.3 RECOMMENDATIONS

Based on the findings from this Report to Congress, this section presents the Agency's preliminary recommendations for those wastes included in the scope of this study. The recommendations are subject to change based on continuing consultations with other government agencies and new information submitted through the public hearings and comments on this report. Pursuant to the process outlined in RCRA 3001(b)(3)(C), EPA will announce its regulatory determination within six months after submitting this report to Congress.

First, EPA has concluded that coal combustion waste streams generally do not exhibit hazardous characteristics under current RCRA regulations. EPA does not intend to regulate under Subtitle C fly ash, bottom ash, boiler slag, and flue gas desulfurization wastes. EPA's tentative conclusion is that current waste management practices appear to be adequate for protecting human health and the environment. The Agency prefers that these wastes remain under Subtitle D authority. EPA will use section 7003 of RCRA and sections 104 and 106 of CERCLA to seek relief in any cases where wastes from coal combustion waste disposal sites pose substantial threats or imminent hazards to human health and the environment. Coal combustion waste problems can also be addressed under RCRA Section 7002, which authorizes citizen lawsuits for violations of Subtitle D requirements in 40 CFR Part 257.

Second, EPA is concerned that several other wastes from coal-fired utilities may exhibit the hazardous characteristics of corrosivity or EP toxicity and merit regulation under Subtitle C. EPA intends to consider whether these waste streams should be regulated under Subtitle C of RCRA based on further study and information obtained during the public comment period. The waste streams of most concern appear to be those produced during equipment maintenance and water purification, such as metal and boiler cleaning wastes. The information available to the Agency at this time does not allow EPA to determine the exact quantity of coal combustion wastes that may exhibit RCRA Subtitle C characteristics. However, sufficient information does exist to indicate that some equipment maintenance and water purification wastes do occasionally exhibit RCRA hazardous characteristics, and therefore, may pose a danger to human health and the environment. These wastes are similar to wastes produced by other industries that are subject to Subtitle C regulation, and waste management practices for coal combustion wastes are often similar to waste management practices employed by other industries. EPA is considering removing the exemption for all coal-fired utility wastes other than those identified in the first recommendation. The effect would be to apply Subtitle C regulation to any of those wastes that are hazardous by the RCRA characteristic tests. EPA believes there are various treatment options available for these wastes that would render them nonhazardous without major costs or disruptions to the utilities.

Third, EPA encourages the utilization of coal combustion wastes as one method for reducing the amount of these wastes that need to be disposed to the extent such utilization can be done in an environmentally safe manner. From the information available to the Agency at this time, current waste utilization practices appear to be done in an environmentally safe manner. The Agency supports voluntary efforts by industry to investigate additional possibilities for utilizing coal combustion wastes.

Through its own analysis, evaluation of public comments, and consultation with other agencies, the Agency will reach a regulatory determination within six months of submission of this Report to Congress. In so doing, it will consider and evaluate a broad range of management control options consistent with protecting human health and the environment. Moreover, if the Agency determines that Subtitle C regulation is warranted, in accordance with Section 3004(x) EPA will take into account the "special characteristics of such waste, the practical difficulties associated with implementation of such requirements, and site-specific characteristics . . . ," and will comply with the requirements of Executive Orders 12291 and 12498 and the Regulatory Flexibility Act.