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THE STATE OF SOUTH CAROLINA
In the Supreme Court

APPEAL FROM THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

Public Service Commission Docket Nos. 2018-319-E & 2018-318-E

Duke Energy Carolinas, LLC ..... Appellant-Respondent,

v.

The South Carolina Office of Regulatory Staff, Hasala Dharmawardena, CMC Recycling, Cypress Creek Renewables, LLC, SC Department of Consumer Affairs, Sierra Club, South Carolina Coastal Conservation League, South Carolina Energy Users Committee, South Carolina Solar Business Alliance, Inc., the South Carolina State Conference of the National Association for the Advancement of Colored People, Upstate Forever, Vote Solar, and Walmart, Inc. ..... Respondents,

of whom,

South Carolina Energy Users Committee is ..... Respondent-Appellant.

Duke Energy Progress, LLC ..... Appellant,

v.

The South Carolina Office of Regulatory Staff, Nucor Steel-South Carolina, Cypress Creek Renewables, LLC, SC Department of Consumer Affairs, Sierra Club, South Carolina Coastal Conservation League, South Carolina Energy Users Committee, South Carolina Solar Business Alliance, Incorporated, The South Carolina State Conference of the National Association for the Advancement of Colored People, Upstate Forever, Vote Solar, and Walmart, Inc., .. Respondents.

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Attorneys for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC

Heather Shirley Smith Deputy General Counsel Duke Energy Carolinas, LLC Duke Energy Progress, LLC 40 West Broad St., Suite 690 Greenville, SC 29601 heather.smith@duke-energy.com Thomas S. Mullikin Mullikin Law Firm 1308 Broad Street Camden, SC 29020 tommullikiin@mullikinlaw.com	Sarah P. Spruill Haynsworth Sinkler Boyd, P.A. ONE North Main Street, 2nd Floor Greenville, SC 29601 sspruill@hsblawfirm.com Frank R. Ellerbe, III Robert E. Stepp Robinson Gray Stepp & Laffitte, LLC P.O. Box 11449 Columbia, SC 29211 fellerbe@robinsongray.com rstepp@robinsongray.com

Attorneys for Respondents and Respondent/Appellant

Jeffery M. Nelson Jenny R. Pittman C. Lessie Hammonds Andrew M. Bateman Alexander W. Knowles Christopher M. Huber Office of Regulatory Staff 1401 Main Street, Suite 900 Columbia, SC 29201 jnelson@ors.sc.gov jpittman@ors.sc.gov lhammonds@ors.sc.gov abateman@ors.sc.gov chuber@ors.sc.gov aknowles@ors.sc.gov Wallace K. Lightsey Wyche, P.A. 200 East Camperdown Way Greenville, SC 29601-2972 wlightsey@wyche.com Attorneys for The South Carolina Office of Regulatory Staff	Richard L. Whitt Whitt Law Firm, LLC 401 Western Lane, Suite E Irmo, SC 29063 richard@rlwhitt.law Attorneys for Cypress Creek Renewables, LLC and S.C. Solar Business Alliance, Inc. Scott Elliott Elliott & Elliott, P.A. 1508 Lady Street Columbia, SC 29201 selliott@elliottlaw.us Attorneys for S.C. Energy Users Committee Hasala Dharmawardena 145 Cochran Road, Unit 4 Clemson, SC 29631 hasala@ieee.org *Pro Se*

L. Rebecca Dover
Carolyn Grube-Lybarker
SC Department of Consumer Affairs
P.O. Box 5757
Columbia, SC 29250
bdover@scconsumer.gov
clybarker@scconsumer.gov
Attorneys for SC Department of Consumer Affairs

Carrie H. Grundmann
Stephanie U. Eaton
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, NC 27103
cgrundmann@spilmanlaw.com
seaton@spilmanlaw.com
Derick P. Williamson
Spilman Thomas & Battle, PLLC
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, PA 17050
dwilliamson@spilmanlaw.com
Attorneys for Walmart, Inc.

Robert R. Smith, II
Moore & Van Allen, PLLC
100 North Tryon Street, Suite 4700
Charlotte, NC 28202
robsmith@mvalaw.com
Garrett A. Stone
Michael K. Lavanga
Stone Mattheis Xenopoulos & Brew, PC
8th Floor, West Tower
1025 Thomas Jefferson Street, NW
Washington, DC 20007-5201
gas@smxblaw.com
mkl@smxblaw.com
Attorneys for Nucor Steel-South Carolina

Alexander G. Shissias
The Shissias Law Firm, LLC
1727 Hampton Street
Columbia, SC 29201
alex@shissiaslawfirm.com
Attorneys for CMC Recycling

James Blanding Holman IV
Southern Environmental Law Center
Suite 200
525 East Bay Street
Charleston, SC 29403
bholman@selcsc.org
David L. Neal
Gudrun Elise Thompson
Southern Environmental Law Center
601 West Rosemary Street, Unit 220
Chapel Hill, NC 27516-2356
gthompson@selcnc.org
dneal@selcnc.org
Attorneys for S.C. Coastal Conservation League, Upstate Forever, and the South Carolina State Conference of the National Association for the Advancement of Colored People

Robert Guild
314 Pall Mall St.
Columbia, SC 29201
bguild@mindspring.com
Bridget M. Lee
50 F Street, NW, Floor 8
Washington, DC 20001
bridget.lee@sierraclub.org
Attorneys for the Sierra Club

Bess J. DuRant
Sowell & DuRant, LLC
1325 Park Street, Suite 100
Columbia, SC 29201
bdurant@sowelldurant.com
Thadeus B. Culley
1911 Ephesus Church Road
Chapel Hill, NC 27517
thad@votesolar.org
Attorneys for fVote Solar

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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.

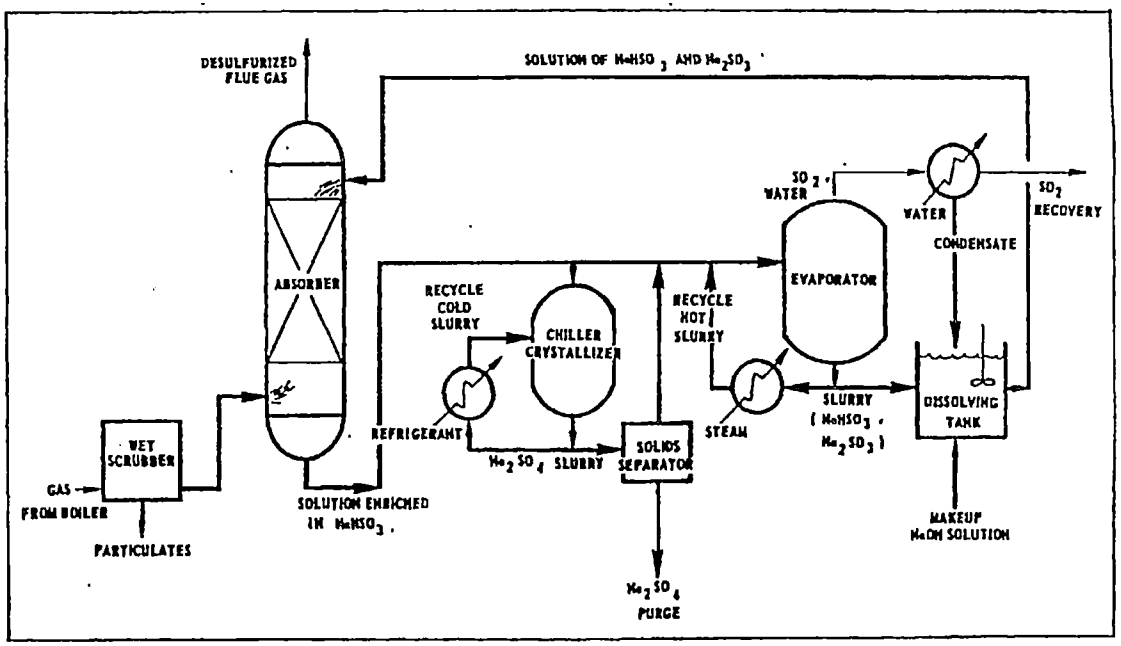
3.2.2.2 Quantities of FGD Sludge Generated

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



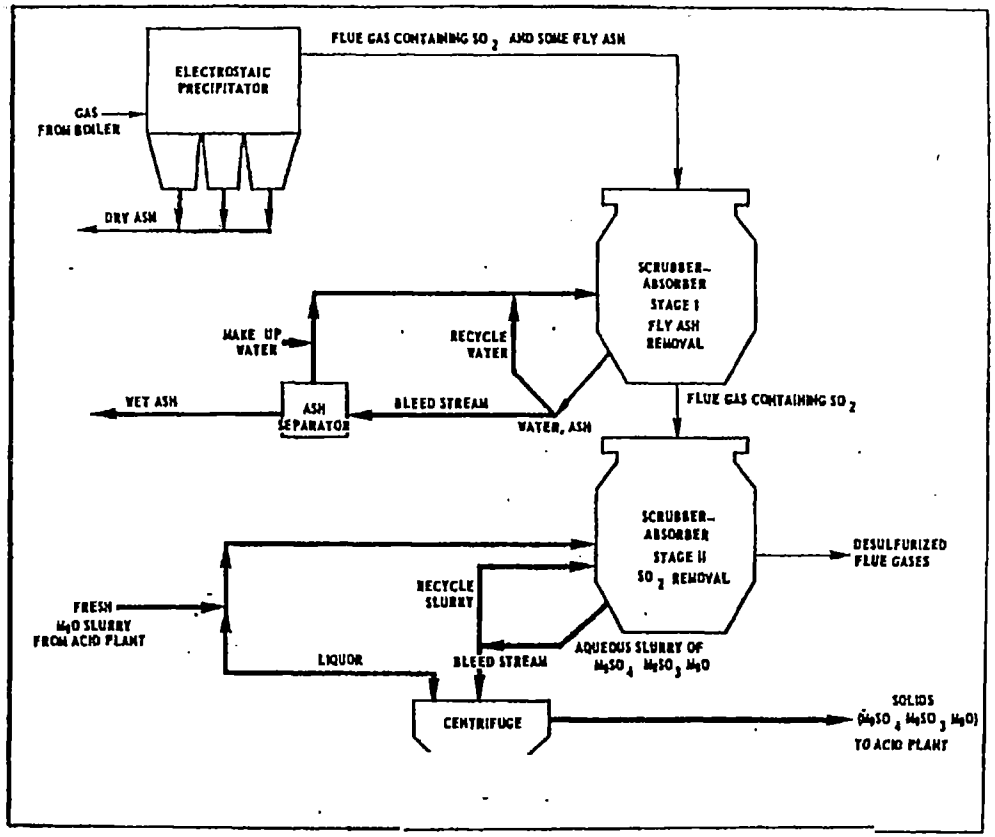
Source: Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, pp. VII-27, VII-30.

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FLOW DIAGRAMS OF RECOVERY FLUE GAS DESULFURIZATION SYSTEMS

MAGNESIUM OXIDE PROCESS



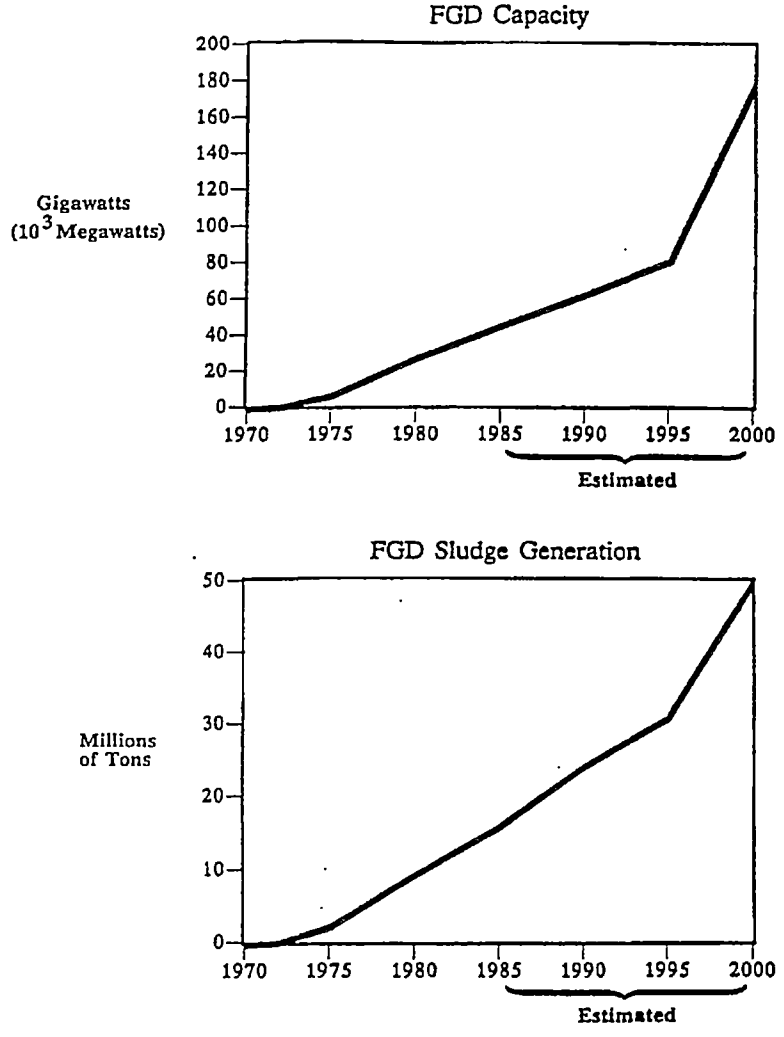
Source: Federal Power Commission, The Status of Flue Gas Desulfurization Applications in the United States: A Technological Assessment, July 1977, pp. VII-27, VII-30.

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EXHIBIT 3-14

FGD CAPACITY AND FGD SLUDGE GENERATION
1970-2000



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.

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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]

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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.

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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.

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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.

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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.

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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 ($CaSO_3$), calcium sulfate or gypsum ($CaSO_4$), or calcium sulfite-sulfate ($CaSO_3 \cdot CaSO_4$), 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 (Na_2SO_3) 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 (Na_2SO_4) and sodium sulfite (Na_2SO_3) or calcium sulfate ($CaSO_4$) and calcium sulfite ($CaSO_3$), 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

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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.

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EXHIBIT 3-17

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

Constituent b/	Direct Lime	Direct Limestone		Dual-Alkali
	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.

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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

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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

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.

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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

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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.

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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

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EXHIBIT 3-20

CHARACTERISTICS OF BOILER BLOWDOWN

Parameter	Range a/ Low	Range a/ 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

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.

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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

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EXHIBIT 3-21

CHARACTERISTICS OF COAL PILE RUNOFF

Parameter	Range a/ Low	Range a/ 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

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.

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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

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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

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EXHIBIT 3-22

CHARACTERISTICS OF COOLING TOWER BLOWDOWN

Parameter	Range a/ Low	Range a/ 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

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.

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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.

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EXHIBIT 3-23

CHARACTERISTICS OF
SPENT DEMINERALIZER REGENERANTS

Parameter	Range a/ Low	Range a/ 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

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.

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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

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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

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.

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EXHIBIT 3-25

CHARACTERISTICS OF SPENT WATER-SIDE
ALKALINE CLEANING WASTES

Parameter	Range a/ Low	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/

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.

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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.

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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

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.

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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

* 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.

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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.

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EXHIBIT 3-28

CHARACTERISTICS OF PYRITES AND
PYRITE TRANSPORT WATER

Parameter	Pyrite Slurry Water a/	Pyrites Solid Form b/
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

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.

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- 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.

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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

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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.

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[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.

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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

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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%	CE	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%	CE	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%	CE	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%	CE	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%	CE	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%	CE	ON & OFF SITE	YES	YES	YES	MAY	YES	NO
South Dakota	0.13%	SW	ON & OFF SITE	NO	NO	NO	NO	YES	NO

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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.

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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:

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- 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]

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- 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.

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- 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

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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.

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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.

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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

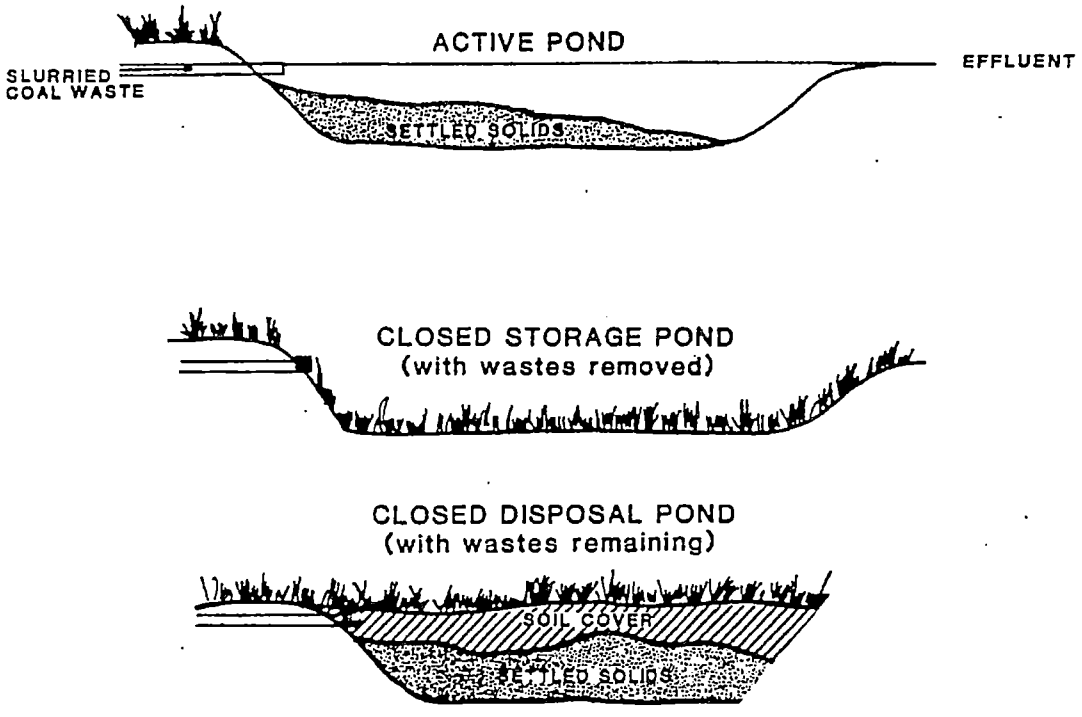
Surface impoundments are used to treat, store, and dispose of coal combustion wastes. Slurried coal ash and other wastes are introduced into the impoundment; the solids settle out and gradually accumulate at the bottom of the pond, leaving relatively clear water at the surface, which is often discharged 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

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EXHIBIT 4-2

TYPICAL SURFACE IMPOUNDMENT (POND) STAGES



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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

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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

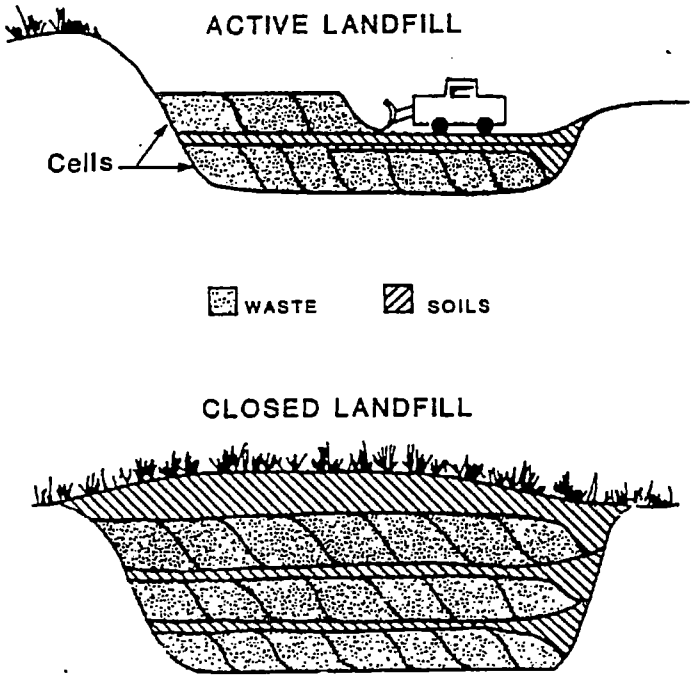
Landfills are used to dispose of coal combustion wastes such as fly ash, bottom ash, and FGD sludges when they are produced or after they are dredged from surface impoundments that are used as interim treatment facilities. The typical design of a landfill during its active stage and after closure is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

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EXHIBIT 4-3

DIAGRAMS OF ACTIVE AND CLOSED LANDFILLS



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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

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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.

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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.

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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.

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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

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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

* 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.

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- 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

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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

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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,

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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

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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.

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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.

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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

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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.

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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

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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

* 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.

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- 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

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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.

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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.

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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

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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

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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.

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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.

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-- 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

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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.

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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

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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

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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.

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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

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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

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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

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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

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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.

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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

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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]

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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.

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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.

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[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.

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[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.

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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

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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

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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

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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

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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.

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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.

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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

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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.

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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

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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.

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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.

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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

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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

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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

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

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.

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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

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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,

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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.

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EXHIBIT 5-5

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

Untreated Boiler Cleaning Waste Type

Metals	Maximum Allowable EP Toxicity Limits	Ammoniated EDTA with Inhibitor	Oxidizer	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/

Treated Boiler Cleaning Waste Type

Metals	Maximum Allowable EP Toxicity Limits	HCl+ Inhibitor, Chelant	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.

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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/l)

	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.

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EXHIBIT 5-7

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

ELEMENT	RCRA Limit	# of Tests	EP Test		TCLP Test	
			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.

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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

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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

*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.

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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

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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:

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EXHIBIT 5-9

PRIMARY DRINKING WATER STANDARDS

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

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

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- 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

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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

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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

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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.

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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		1/ Downgradient (11 wells)		1/ Upgradient (1 well)		1/ Downgradient (5 wells)		1/ Upgradient (1 well)		1/ Downgradient (3 wells)		1/ Upgradient (2 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.
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.

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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		1/ Downgradient (3 wells)		1/ Upgradient (2 wells)		1/ Downgradient (3 wells)		1/ Upgradient (1 well)		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.
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.

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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	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/
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		Sherburne County Site				Powerton Station Site				Lansing Smith Steam Plant			
SDWS		1/ Downgradient (3 wells)		1/ Upgradient (2 wells)		1/ Downgradient (3 wells)		1/ Upgradient (1 well)		1/ Downgradient (5 wells)		1/ Upgradient (3 wells)	
2/ Contam.	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.

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- 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	New Elrama Site				Powerton Station Site				Lansing Smith Steam Plant					
PDWS	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.
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.

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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	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/	Exceed./ Total 3/	Max. Exceed. 4/
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.

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- 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.

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- 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.

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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,

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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.

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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.

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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.

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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.

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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

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EXHIBIT 5-15

SUMMARY OF PDWS EXCEEDANCES IN ENVIROSPHERE'S GROUND-WATER DATA

Constituent	Total Observations	Downgradient Observations a/ Exceeding PDWS When: Upgradient Does Not Exceed — Number	%	Upgradient Exceeds — Number	%	Maximum Downgradient Observation (X PDWS) b/	
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/		

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.

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EXHIBIT 5-16

SUMMARY OF SDWS EXCEEDANCES IN ENVIROSPHERE'S GROUND-WATER DATA

Constituent	Total Observations	Downgradient Observations a/ Exceeding SDWS When: Upgradient Does Not Exceed Number	%	Upgradient Exceeds Number	%	Maximum Downgradient Observation (X SDWS)	b/
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/		

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.

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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.

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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

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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

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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.

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> 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

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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

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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 down-gradient 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.

- Pierce Site, Wallingford, Connecticut. 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

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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.

- Michigan City Site, Michigan City, Indiana. 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.

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- Bailly Site, Dune Acres, Indiana. 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.

- Zullinger Quarry Fly Ash Disposal Site, Franklin County, Pennsylvania. The Zullinger quarry was situated in a limestone formation in south-central Pennsylvania. The

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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

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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.

- Hunts Brook Watershed, Montville-Waterford, Connecticut
  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,

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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}

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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

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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

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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

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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.

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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

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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.

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- 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

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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.

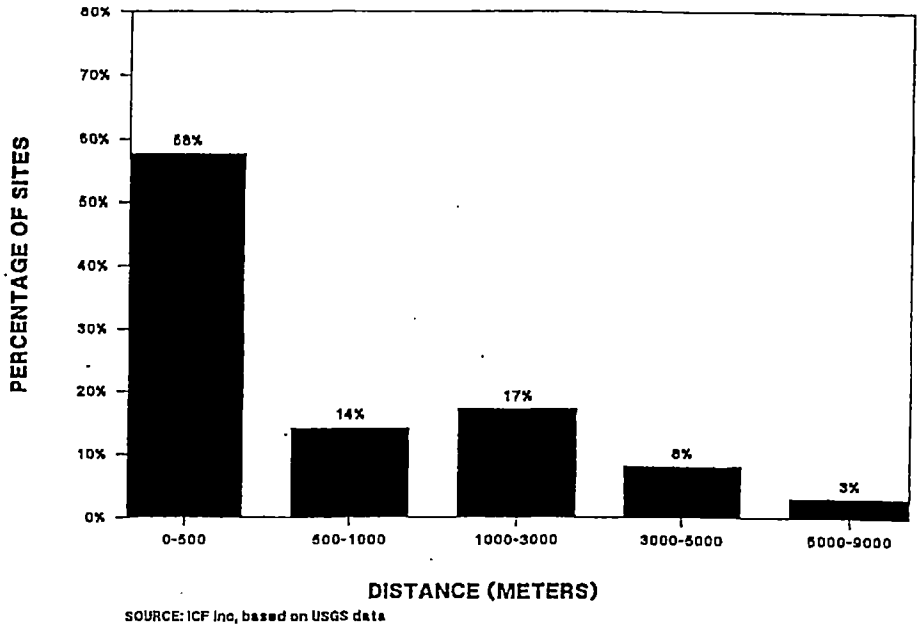
The average distance from the sample of coal-burning waste sites to surface-water body is 1279 meters. Distances range from 10 to 18,000 meters. Over 50 percent of the disposal sites are within 500 meters of surface water; more than 70 percent are within 1,000 meters of surface water. Exhibit 5-17 provides 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

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EXHIBIT 5-17

DISTANCE OF COAL COMBUSTION WASTE SITES TO SURFACE WATER



SOURCE: ICF Inc, based on USGS data

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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

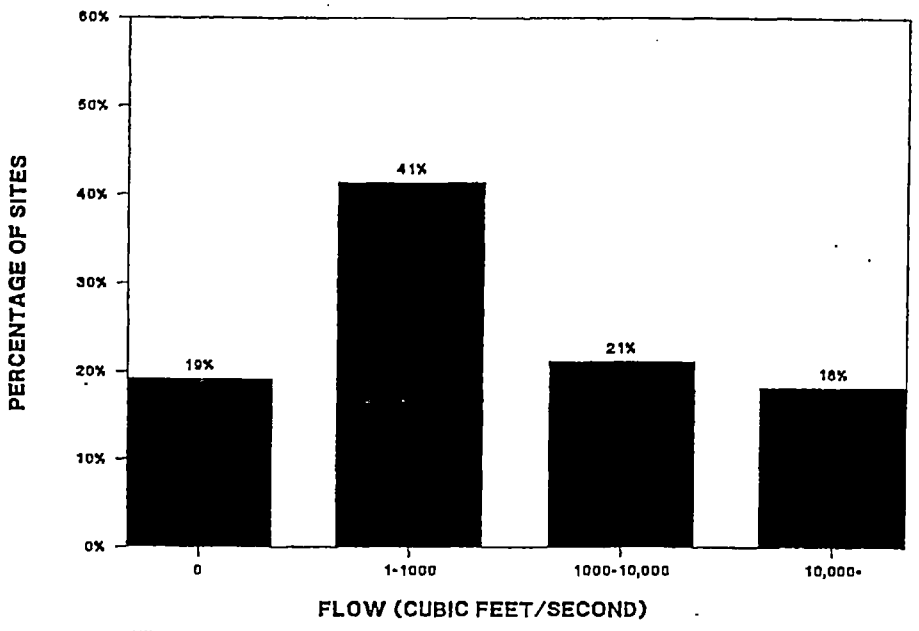
The hydrogeologic measurements of depth to ground water, hydraulic conductivity, and net recharge were determined through the use of information provided by the DRASTIC system. The DRASTIC system, developed by the National Well Water Association, categorizes aquifers on the basis of geographic region and subregion. Each site was located on a 7 1/2 or 15 minute U.S.G.S. map that

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EXHIBIT 5-18

FLOW OF NEAREST SURFACE-WATER BODY



SOURCE: ICF Inc, based on USGS data

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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 A Standardized System for Evaluating Ground-water Pollution Potential Using Hydrogeologic Settings, 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.

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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.

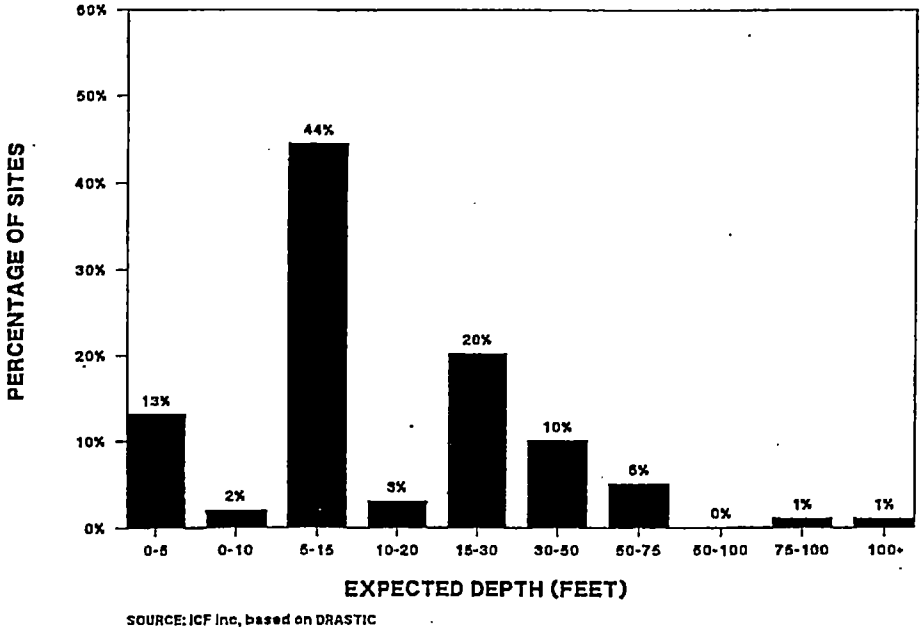
Hydraulic conductivity is one of the factors used to calculate ground-water velocity, or volumetric flow of the water table. Velocity has a direct bearing on the degree to which leachate constituents are diluted once they reach the ground water and travel to a point of exposure (i.e., human drinking 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.

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EXHIBIT 5-19

DEPTH TO GROUND WATER
AT COAL COMBUSTION WASTE SITES

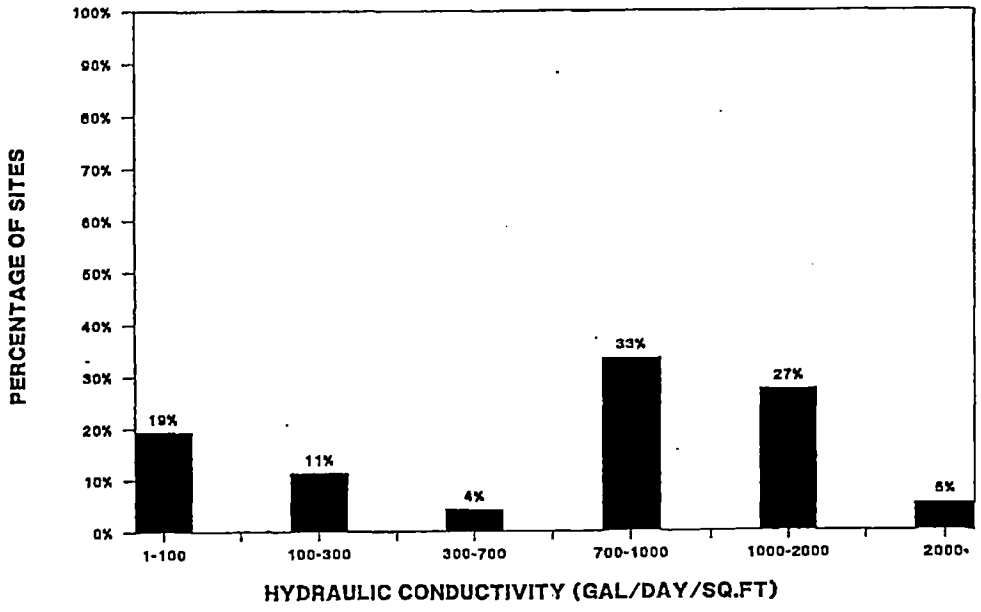


SOURCE: ICF Inc, based on DRASTIC

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EXHIBIT 5-20

HYDRAULIC CONDUCTIVITY
AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on DRASTIC data

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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.

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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

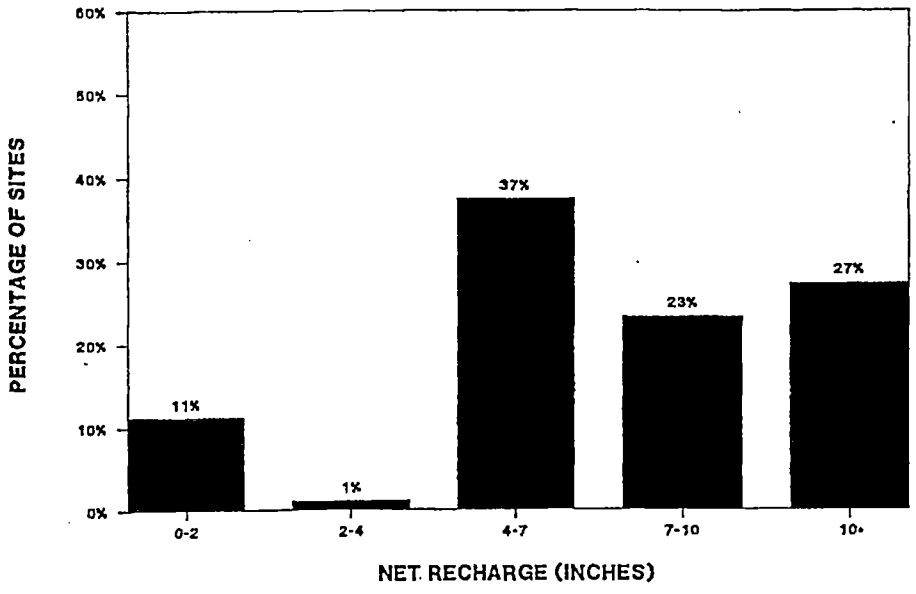
The hardness of the ground water near coal combustion waste sites will have an effect on potential exposure through drinking water since excessive hardness is typically treated in a public drinking water system. Treatment would lessen the exposure potential to humans from contaminants in the ground water from other sources (such as coal combustion wastes). Measurements for ground-water hardness were obtained by locating the sites on maps provided in Ground-water Contamination in the United States (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

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EXHIBIT 5-21

NET RECHARGE
AT COAL COMBUSTION WASTE SITES

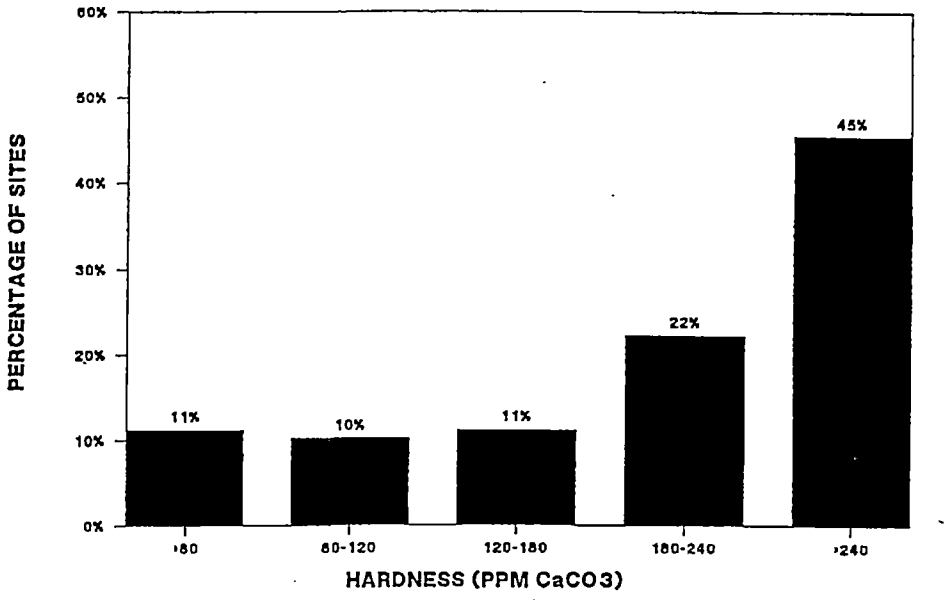


SOURCE: ICF Inc, based on DRASTIC

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EXHIBIT 5-22

GROUND-WATER HARDNESS
AT COAL COMBUSTION WASTE SITES



SOURCE: ICF Inc, based on Pye, et al, Groundwater Contamination in U.S.

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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.

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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.

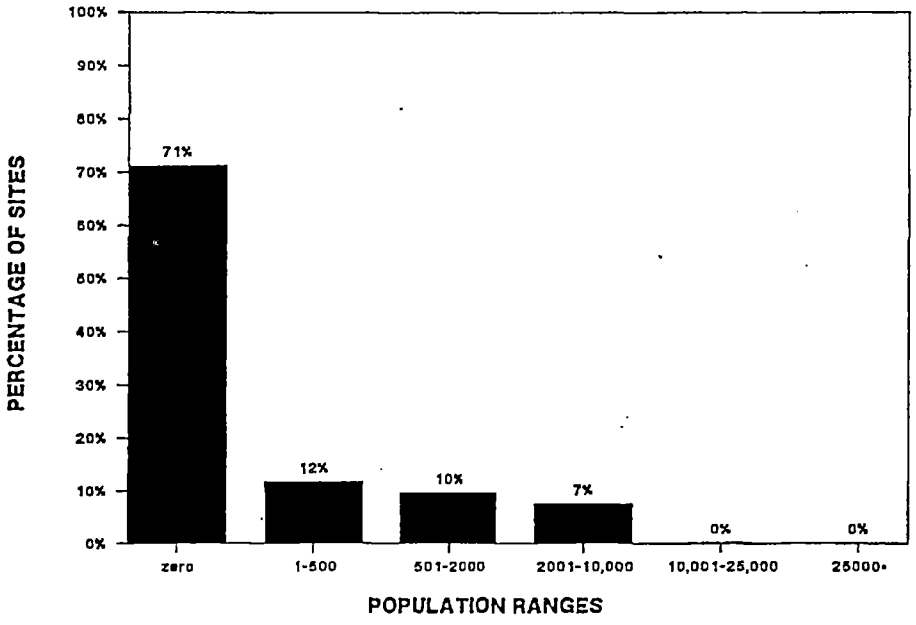
Exhibit 5-24 shows the population characteristics for the sample of coal combustion waste sites at a three-kilometer radius. When the search distance is increased to three kilometers, the percentage of sites that have no people within a three-kilometer radius decreases to 32 percent. Average population 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

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EXHIBIT 5-23

POPULATIONS WITHIN ONE KILOMETER OF WASTE SITES

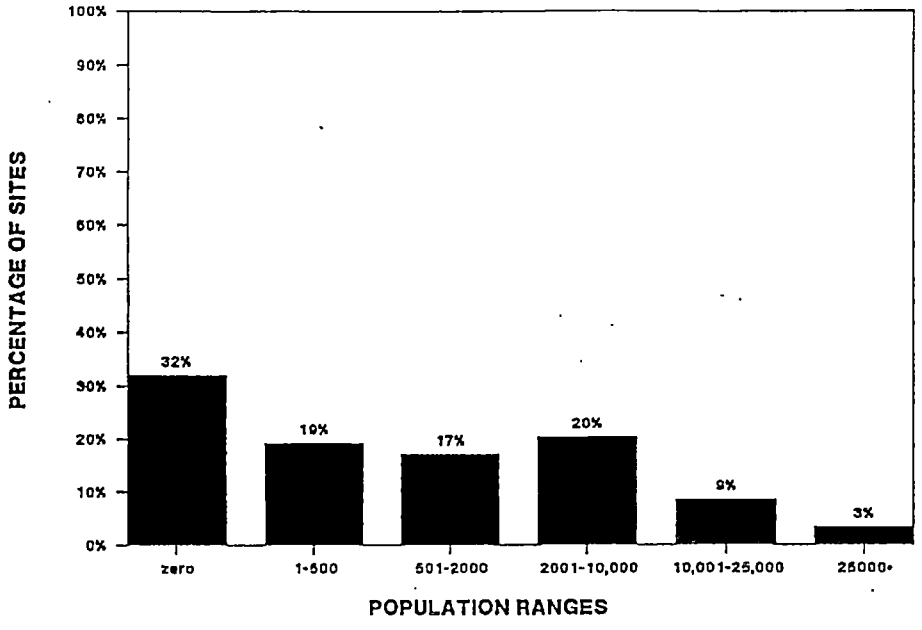


SOURCE: ICF Inc, based on CENBAT data

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EXHIBIT 5-24

POPULATIONS WITHIN THREE KILOMETERS OF WASTE SITES

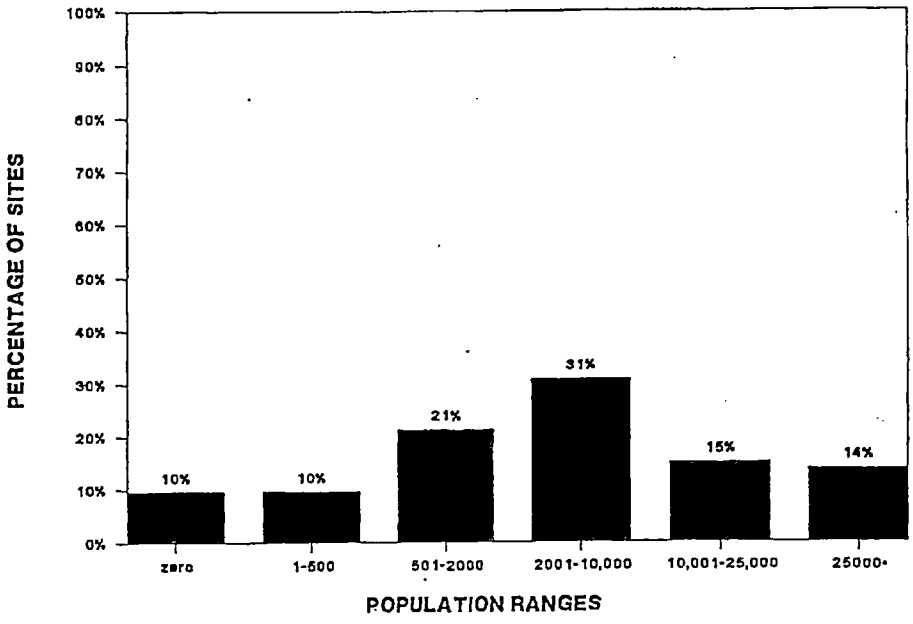


SOURCE: ICF Inc., based on CENBAT data

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EXHIBIT 5-25

POPULATIONS WITHIN FIVE KILOMETERS OF WASTE SITES



SOURCE: ICF Inc., based on CENBAT

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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.

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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

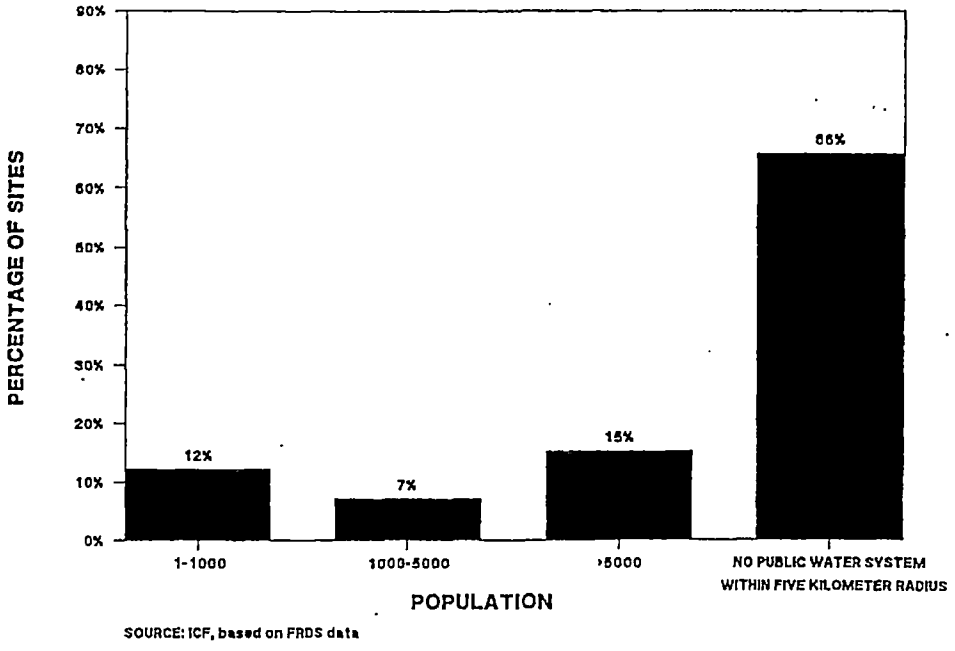
Ecological data on endangered, threatened, or unique plants and animals is available through state Heritage Programs. The Nature Conservancy established the Heritage Programs, which now usually function as offices of state governments. The Heritage Programs develop and maintain data bases that describe 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

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EXHIBIT 5-26

POPULATIONS SERVED BY PUBLIC WATER SYSTEMS NEAR WASTE SITES



SOURCE: ICF, based on FRDS data

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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.

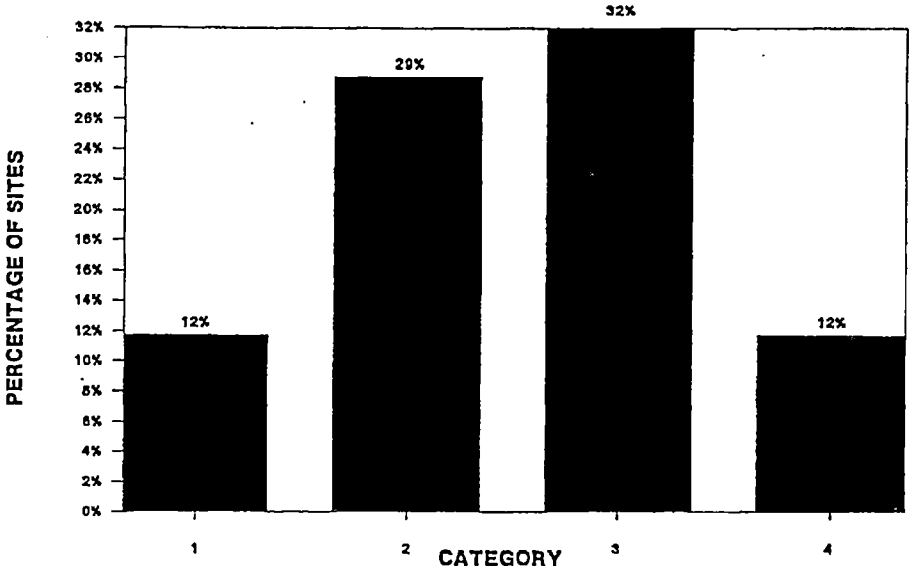
Information was available on 85 of the 100 coal combustion waste sites in the sample. Exhibit 5-27 presents the breakdown of sites according to the categories described above. Twelve percent of the sites fall into Category 1, 29 percent in Category 2; 32 percent in Category 3; and 12 percent in Category 4 (no information was available for 15 percent).

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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

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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

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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.

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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.

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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

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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 CaCO3) and hydrogeologic characteristics that indicate high potential for leachate migration.

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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.

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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.

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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.

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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.

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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.

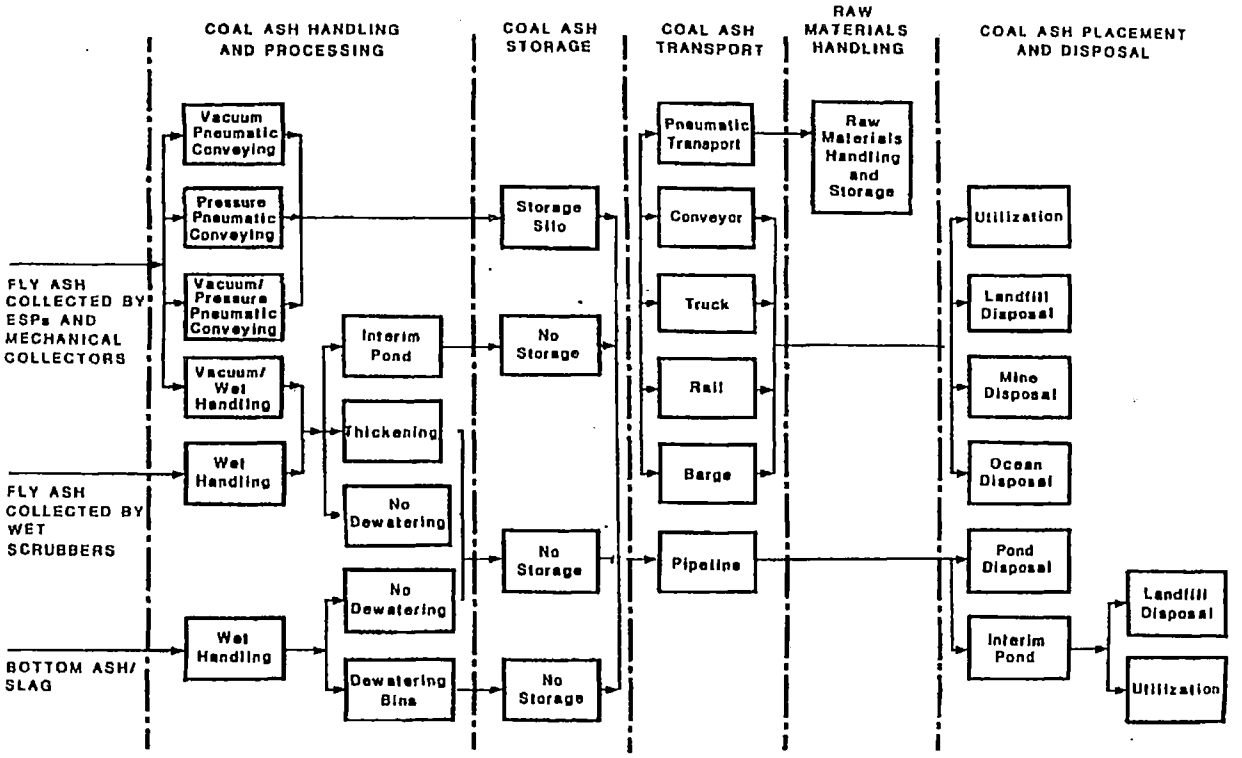
3. **Raw Materials Handling and Storage.** Some disposal processes involve stabilization or chemical fixation of the waste to prepare it for disposal. The raw materials used for this phase, including additives such as lime, Calcilox, and basic fly ash, often require special handling and storage facilities.

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

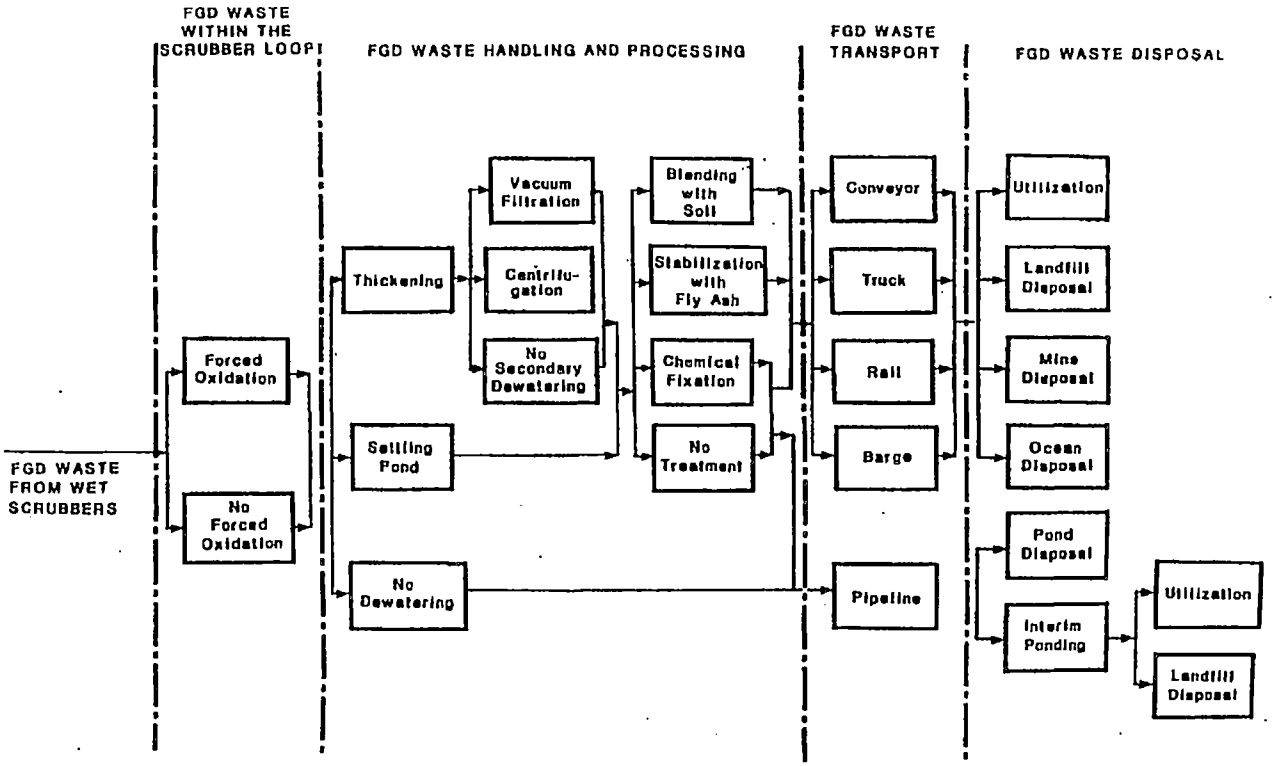
Exhibit 6-1
Overview of Waste Handling and Disposal Options for Coal Ash



Source: Arthur D. Little, Inc., *Full-Scale Field Evaluation of Waste Disposal From Coal-Fired Electric Generating Plants*, June 1985.

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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.

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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

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EXHIBIT 6-3

RANGES OF AVERAGE CAPITAL COSTS ASSOCIATED WITH
COAL-FIRED ELECTRIC UTILITY WASTE DISPOSAL
(4th quarter 1986 dollars per kilowatt)

Type of Waste	Size of Power Plant			
	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.

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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.

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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

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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

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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 unconsolidated waste (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.

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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

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$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

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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

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> 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)

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- **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.

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- 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,

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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

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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

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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

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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

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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

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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.

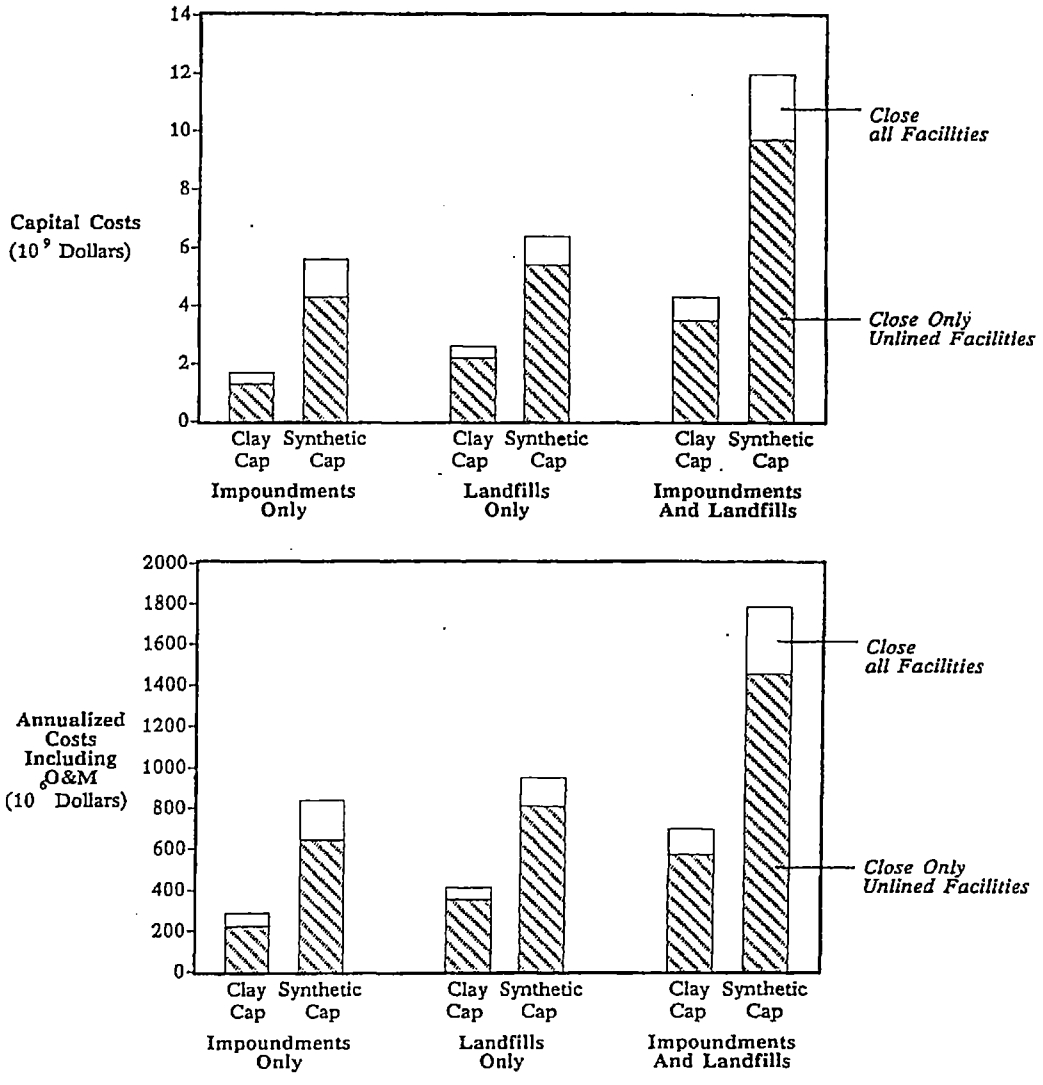
6.2.2.5 Financial Responsibility

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

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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.

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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

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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]

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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

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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.

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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

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.

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Preparation of Part B Permit		
Construction of New Disposal Facilities		
Landfills		
- Single clay liner		
- Single synthetic liner	2.6	
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

a/ Costs shown are for capital, operation, and maintenance costs for the entire industry since the amount of capital required was not readily available.

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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.

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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.

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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

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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

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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]

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- 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]

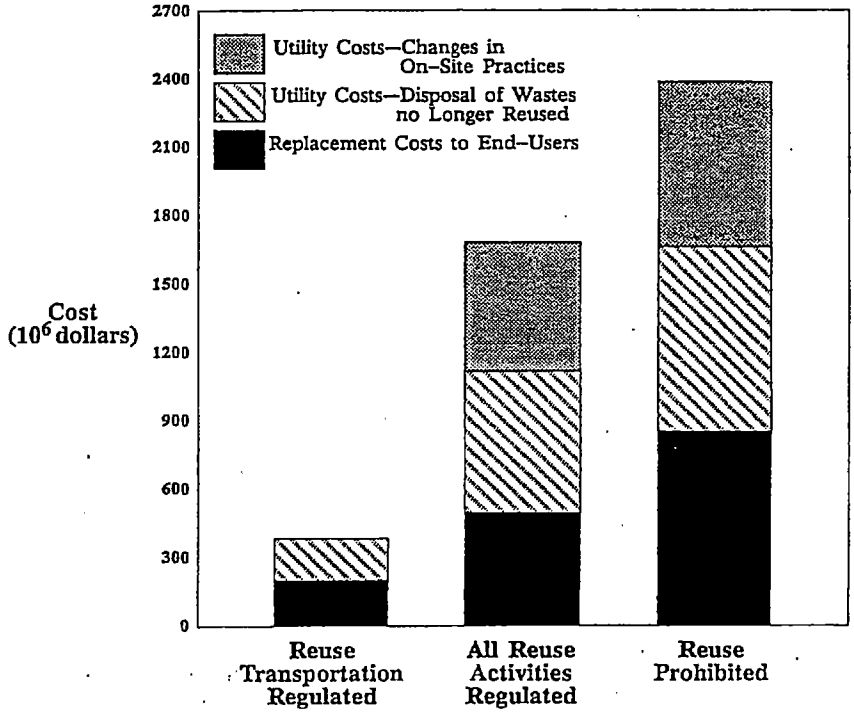
If the transportation of coal combustion by-products were subject to increased regulation under Subtitle C, the USWAG report estimated that the use of these by-products would decline by nearly 40 percent, increasing overall disposal volumes by about 8 percent.[45] The industries that would be affected 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

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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, Report and Technical Studies on the Disposal and Utilization of Fossil–Fuel Combustion By–Products, Appendix G, October 26, 1982

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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.

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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]

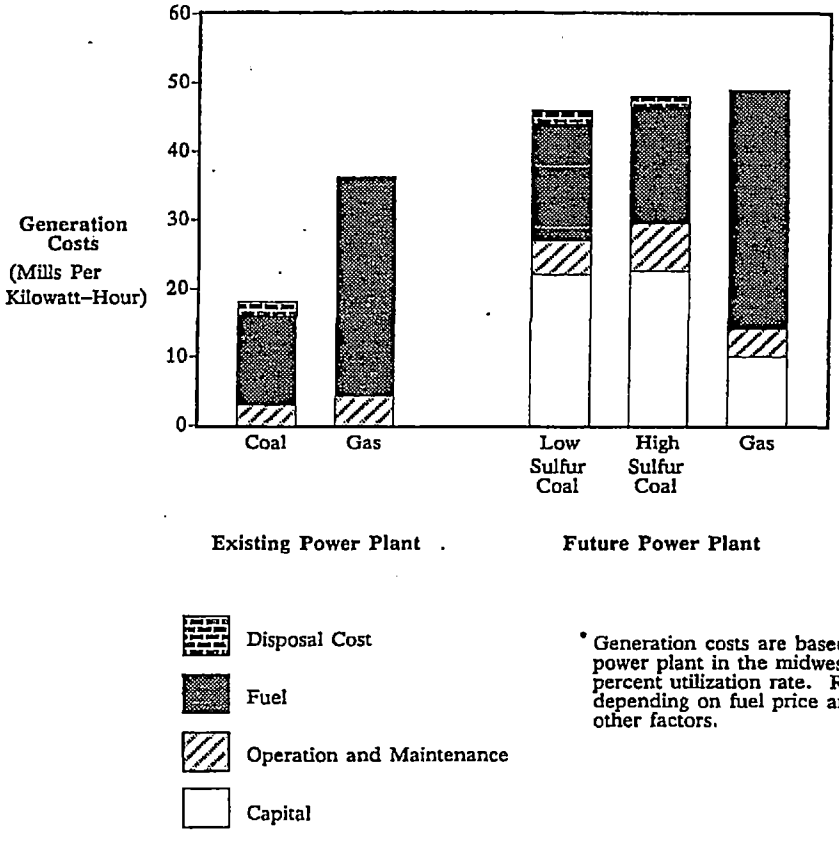
The economic impacts likely to result from the use of alternative coal-fired utility waste disposal practices will depend upon several factors, including which disposal options are required, how much the cost of coal-fired electricity generation changes, and whether these changes affect the relative 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

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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.

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EXHIBIT 6-10

IMPACT OF ALTERNATIVE DISPOSAL OPTIONS ON ELECTRICITY GENERATION COSTS

Option	Incremental Cost ($/ton of disposed waste)	Impact On Generation Costs: a/ mills/kilowatt-hour	Impact On Generation Costs: % of Total Generation Costs, Existing Plant	Impact On Generation Costs: % of Total Generation Costs, 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

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.

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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

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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

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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.

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- 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.

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[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.

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[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.

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[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

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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.

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[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.

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[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.

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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

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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.

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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.

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2. Quantities of waste produced will increase significantly as more electricity is generated by coal. 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. Coal combustion wastes are a common by-product from the generation of electricity. 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. High-volume coal combustion wastes do contain elements that in sufficient concentrations can pose a potential danger to human health and the environment. 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. Although most low-volume wastes do not appear to be hazardous, there are some waste streams from cleaning that could potentially be hazardous. 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.

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7.2.3 Waste Management Practices

1. Most coal combustion wastes are typically disposed in landfills or surface impoundments, with recent trends toward increased reliance on landfills. 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. 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. 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. The potential for increased waste utilization as a solution to waste management in the utility industry appears to be limited. 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. Coal combustion wastes are typically regulated under state solid waste laws, which treat these wastes as non-hazardous materials. The

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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.

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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

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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.

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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.

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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.

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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

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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.

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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.

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GLOSSARY

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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.

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

low volatile: dry fixed carbon 78% or more and less than 86%; and dry volatile matter 22% or more and less than 14%.
medium volatile: dry fixed carbon 69% or more and less than 78%; and dry volatile matter 22% or more and less than 31%.
high volatile (A): 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.
high volatile (B): Btu value 13,000 or more and less than 14,000 moist, mineral-matter-free basis.
high volatile (C): 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°F to 212°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.

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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.

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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.

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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 (CaCO3), a chemical used in some FGD systems.

limestone - calcium carbonate (CaOH2), 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.

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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.

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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,

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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.

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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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[Please note: The correction noted below reflects the testimony of the witness during the hearing in this matter.]

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Table 4.1: CCR VERSUS CAMA

FACTOR	N.C. CAMA Coal Ash Management Act of 2014. Law on 8/20/2014	EPA CCR RULE Final on 12/19/2014 and Effective on ~~10/14/2015~~ 10/19/2015	CAMA Amendments Law on 7/14/2016	Water Infrastructure Improvements for the Nation (WIIN) Act of 2016. Law on 12/16/2016.
1. APPLICABILITY	All ash basins , landfills, and beneficial reuses. Focus is on basin closure.	Surface impoundments, landfills, and inactive surface impoundments that impound water at stations with generation. Beneficial uses. Regulates CCR disposal.	Deletes references to Coal Ash Management Commission. Review of DEQ's quarterly reports left to Environmental Review Commission.	Establishes a state permit program for coal ash impoundments to be supervised by the U.S. Environmental Protection Agency. Amends the Resource Conservation and Recovery Act (RCRA), changing the EPA's self-implementing coal ash rule into an EPA-authorized state permit program. The EPA will only approve of the state programs if they incorporate already-established federal requirements.
2. BASIN CLOSURE	Required timing is based on risk rankings or "High Priority" designation.	Required if basins cannot meet various safety and environmental criteria. High priority is placed on stability evaluation.		
3. BASIN EVALUATION	All basins must close. Subjective risk ranking determines closure method. Ash basins to be risk-ranked by NCDEQ based on 9 factors in CAMA. CAMC reviews and approves risk rankings.	Basins can remain operating. Demonstrations that basins meet all Dam Safety, Liner, Groundwater, and Location restrictions must be made within 18 to 42 months of rule publication. Basins must be closed if demonstrations can't be made.	§ 130A-309.213. Prioritization of coal combustion residuals surface impoundments. Deletes specific criteria under (a) to be evaluated by DEQ in assessing surface impoundment risk. (d)(1) requires the DEQ to a low risk classification if it (a) Has established permanent water supplies as required for the impoundment pursuant to G.S. 130A-309.211(c1) and (b) Has rectified any deficiencies identified by, and otherwise complied with the requirements of, any dam safety order issued by the Environmental Management Commission for the impoundment pursuant to G.S. 143-215.32. (c) Other impoundments are classified as intermediate risk. § 130A-309.216. Ash beneficiation projects (new)	
4. CLOSURE METHOD	Cap in place allowed for "low risk" basins only. Clean closure via excavation required for "high priority", "high risk", and "intermediate risk" impoundments.	Cap in place and clean closure allowed. Requirements for each method is provided.		
5. CLOSURE TIMING	Closure timing is tied to risk ratings: 5, 10, or 15 years.	Forced closures within 5 years with possible extensions for certain factors (i.e., no alternate capacity available, size of impoundment). Up to 15.5 years in some cases.		
6. CONVERSION TO DRY ASH DISPOSAL	Requires dry fly ash disposal by Dec 2018 and dry bottom ash disposal by Dec 2019.	Does not expressly address conversion to dry ash disposal. However, in some cases, conversion is driven by basin closure requirements. EPA extended timelines to accommodate Steam Electric Effluent Limitations Guidelines that proposes to require conversion to dry ash disposal.		
7. ENFORCEMENT	State regulatory agency with Coal Ash Management Committee oversight. Enforcement through state agency action.	Self-implementing. Enforced through citizen suits in federal court.		TITLE II--WATER AND WASTE ACT OF 2016 Subtitle C--Control of Coal Combustion Residuals. [Sec. 2301] This bill amends the subtitle D (Resource Conservation and Recovery Act of 1976) of the Solid Waste Disposal Act to establish a permit program for coal combustion residuals (coal ash) that states, after approval by the EPA, may elect to administer in lieu of a federal regulatory program. The EPA must review the programs at least once every 12 years, or on the request of a state. The EPA may use specified authorities to enforce the prohibition against open dumping with respect to a coal combustion residual unit.

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8. GROUNDWATER MONITORING	Groundwater assessment required 180 days after DEQ's approval of the plan (pending??). Monitoring done at compliance boundary. Measuring for 15A NCAC 02L.0202 criteria (limit in parentheses). In Items IV.134-185 of the Plea Agreement, Duke acknowledged that water from seeps may transport pollutants such as aluminum (NL), arsenic (10 µg/L), barium (700 µg/L), boron (700 µg/L), cadmium (2 µg/L), chloride (250 mg/L), chromium (100 µg/L), copper (1 mg/L), fluoride (2 mg/L), iron (300 µg/L), lead (15 µg/L), manganese (50 µg/L), nickel (100 µg/L), selenium (20 µg/L), sulfate (250 mg/L), thallium (NL), zinc (1 mg/L), and TDS (NL).	Required within 30 months of rule publication (DATE). Monitoring done at waste boundary. Measuring for statistically significant increases over background (CONSTITUENTS AND LEVELS).	Review of DEQ's quarterly reports left to Environmental Review Commission. § 130A-309.211. Groundwater assessment and corrective action; drinking water supply well survey and provision of alternate water supply; reporting. New (c1) requires no later than October 15, 2018, the owner of a coal combustion residuals surface impoundment shall establish permanent replacement water supplies for (i) each household that has a drinking water supply well located within a one-half mile radius from the established compliance boundary of a coal combustion residuals impoundment, and is not separated from the impoundment by the mainstem of a river, as that term is defined under G.S. 143-215.22G, or other body of water that would prevent the migration of contaminants through groundwater from the impoundment to a well and (ii) each household that has a drinking water supply well that is located in an area in which contamination resulting from constituents associated with the presence of a coal combustion residuals impoundment is expected to migrate.	
9. STRUCTURAL FILLS	Governed as beneficial reuse solution with specific permitting and construction criteria (SPECIFY). CAMA regulated structural fills >8,000 tpy or 80,000 tons per project. Small structural fills <8,000 tons per acre or 80,000 tons per project are deemed permitted. Large SF >8,000 tons per acre or 80,000 tons per project require liners, caps, leachate control, groundwater monitoring, and financial assurance. NC CCP rule will add requirements to make as stringent as EPA CCR.	Must qualify as beneficial reuse under the rule or meet the requirements for a CCR landfill. EPA CCR requires reporting and environmental demonstrations for fills >12,400 tons.		
10. BENEFICIAL USE OF CCP	Draft of State CCP rule to be consistent with CAMA, coordinated with NCDOT and UNC Charlotte, and go to EMC in July 2016. NCDEQ will incorporate into current DWM and DWR beneficial use/reuse rules.			
11. COMPREHENSIVE SITE ASSESSMENTS (CSA) AND CORRECTIVE ACTION PLANS (CAP)	CSA and CAP containing over 1,000 pages each were submitted by Duke to NCDEQ. Largest investigation of its kind was completed over six months. Duke drilled over 870 wells and collected over 7,000 samples. However, this extensive work could not determine the horizontal and vertical extent of contamination or background levels of constituents critical to prioritization. DEQ is unable to determine with current (12/31/15) data is Duke coal ash ponds are impacting wells but there are known impacts at Sutton and Asheville. In 476 wells sampled, DHHS issued do not drink notices for 424 wells mainly for vanadium and hexavalent chromium BUT only 12 wells exceeded SDWA levels (7 for lead and 5 for arsenic) which could be attributed to poor well construction (lead) or naturally occurring (arsenic).			
12. DECANTING AND DEWATERING	On August 28, 2014, NCDEQ authorized decanting to begin under existing NPDES permits. Complete dewatering requires NPDES permit modification but is necessary for wet ash removal and must address engineered and non-engineered seeps. NPDES permits are on hold for 13 of 14 Duke facilities.	On September 10, 2014, EPA ordered NC decanting halted. On December 14, 2015, EPA authorized NC to resume decanting but is still unsure on permitting seeps that may be "waters of the US" -- a problem at 894 US impoundments. EPA appears to be backing away from written Hanlon Policy.		
13. GROUNDWATER AND DRINKING WATER STANDARDS	NC DHHS has the lowest groundwater standard (10 ppb) in the US but issues do not drink notices for 0.07 ppb for Cr(VI) and 0.03 ppb for Vanadium. More than 70% of the US public water supplies exceed DHHS screening levels for Cr(VI) or Vanadium.	Federal SWDA standard is 100 ppb Total Chromium and has no standard for Vanadium.		

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Table 4.2: CCR State Rules and Regs

FACTOR	Kentucky	West Virginia	Virginia	Tennessee	Georgia	South Carolina
1. APPLICABILITY	401 KAR 4:070. Applicability established by EPA CCR rule.	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopted federal regulations. Senate Bill 1533 from January 2019 requires CCR be removed for recycling or deposition in a lined landfill.	TN Rule 0400-11-01-.02	GA Rule 391-3-11. Adopts federal regulations.	SC Code Regs 61-79.261 establishes regulations for CCR impoundments as exempt from solid waste designation.
2. BASIN CLOSURE	401 KAR 4:070. Closure procedure established by EPA CCR rule	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopted federal regulations. In January 2019 Senate Bill 1533 requires that any CCR unit located in the Chesapeake Bay watershed be closed by recycling/beneficial use or deposition in a permitted and lined landfill.		GA Rule 391-3-11. Adopts federal regulations.	
3. BASIN EVALUATION		W.VA.REGS. 33-1-5. Adopts federal regulations.	Senate Bill 1398 required every owner/operator of CCR impoundments to conduct an assessment regarding closure of the unit, no later than December 1, 2017.	TDEC Order OGC15-0177 (to TVA). TVA shall conduct an investigation of CCR disposal areas listed in the order, to collect groundwater and other environmental data.		
4. CLOSURE METHOD	401 KAR 4:070. Closure procedure established by EPA CCR rule	W.VA.REGS. 33-1-5. Adopts federal regulations.	Senate Bill 1398 requires every owner/operator of CCR impoundments to conduct an assessment regarding closure of the unit, no later than December 1, 2017. January 2019's Senate Bill 1533 requires recycling or removal to a lined landfill.	Cap in place allowed. The TDEC order to the TVA requires a corrective action risk assessment plan that includes the methods TVA will employ to remove and/or close in place CCR material at the sites.		
5. CLOSURE TIMING	401 KAR 4:070. Closure procedure established by EPA CCR rule	W.VA.REGS. 33-1-5. Adopts federal regulations.	Senate Bill 1398 required every owner/operator of CCR impoundments to conduct an assessment regarding closure of the unit, no later than December 1, 2017. Senate Bill 1533 requires closure projects to be complete within 15 years of their initiation.			
6. CONVERSION TO DRY ASH DISPOSAL						
7. ENFORCEMENT	401 KAR 46:120. Permits given by state regulatory agency.	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopted federal regulations.			

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8. GROUNDWATER MONITORING	401 KAR 46:110. Groundwater monitoring and corrective action are established in the EPA CCR rule.	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopts federal regulations. Senate Bill 1533 requires closure projects to be accompanied by water testing for every residence within one-half mile.	TDEC Order OGC15-0177 calls for plans to address groundwater monitoring for the future of the CCR impoundment	GA Rule 391-3-11. Adopts federal regulations.	
9. STRUCTURAL FILLS				TN Rule 0400-11-01-.02. Disposal is limited to coal ash in engineered structures for highway overpasses, levees, runways, or foundation backfill.	Not specifically authorized under Georgia law or regulations	Not specifically authorized under SC law or regulations. Regulations were drafted in 1994 by SCDHEC but were withdrawn.
10. BENEFICIAL USE OF CCP		CCRs may be reused as material in manufacturing another product or as a substitute for a natural resource, for the extraction of recovery materials and compounds contained within the CCRs, as a stabilization/solidification agent for other wastes, under the authority of the WVDoE, as pipe bedding, as antiskid material, as a construction base for roads or parking lots. W.VA.REGS. 33-1-5.5.b.4.A-H	Senate Bill 1533 requires that any owner of a CCR unit explain why recycling is not economically feasible if they choose to landfill the CCR instead.			
11. COMPREHENSIVE SITE ASSESSMENTS (CSA) AND CORRECTIVE ACTION PLANS (CAP)						
12. DECANTING AND DEWATERING						
13. GROUNDWATER AND DRINKING WATER STANDARDS	401 KAR 46:110. Groundwater monitoring and corrective action are established in the EPA CCR rule.	W.VA.REGS. 33-1-5. Adopts federal regulations.	9 VAC 20-60-261. Adopted federal regulations. Senate Bill 1522 in January 2019 required closure projects to be accompanied by water testing or a connection to municipal water for every residence within one-half mile.		GA Rule 391-3-11. Adopts federal regulations.	

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AUTHOR(S): Eugene M. Wewerka, H-12

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THE DISPOSAL AND RECLAMATION OF SOUTHWESTERN COAL AND URANIUM WASTES

BY

Eugene M. Wewerka

University of California
Los Alamos Scientific Laboratory
Los Alamos, NM 87545

1.0 INTRODUCTION

One of the major environmental problems confronting the coal and uranium industries of the Southwest is the disposal and reclamation of the large volumes of wastes produced by mining, processing, and on-site utilization of these resources. Wastes and drainages are produced during coal mining and cleaning, and the burning of coal in modern boilers produces large quantities of ash and sluige. Likewise, uranium mining and milling generates large amounts of solid and liquid waste materials. The wastes from both of these industries must be carefully deposited in waste disposal sites, and reclamation measures taken to ensure their long term stability. In this paper, the types of wastes produced by the coal and uranium industries in the Southwest will be described, some of the potential environmental impacts from these materials will be considered, and the procedures in current use for the disposal and reclamation of these wastes will be discussed.

2.0 DISPOSAL AND RECLAMATION OF COAL WASTES

Coal is a type of combustible rock that is formed from plant remains and various inorganic components. Because of this, coal is a highly heterogeneous material that contains a wide variety of rock and mineral impurities in addition to the carbon-like matrix. Most of the environmental contamination and waste materials produced by coals are a direct consequences of these impurities.

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In each step of the coal processing cycle, from mine to eventual utilization, various wastes or effluents are produced that must be treated, stored, or disposed of (Fig. 1.). These for the most part are high volume wastes that have the potential for causing great environmental damage if not properly handled. The coal industry of the Southwest is still in its infancy, but dramatic increases in the use of coal from the region (with the accompanying necessity to devote greater attention and resources to waste disposal and reclamation) will be necessary if our nation is to decrease its dependence on foreign energy sources and meet future energy needs.

2.1 COAL MINING WASTES

Coal is removed from the earth by two principal kinds of mining: strip mining and underground mining. In the Southwest, strip mining is the dominant form of coal extraction because most of the coal now being mined in this region is deposited relatively close to the surface.[1] In the strip mining of coal, heavy equipment such as power shovels, bulldozers, trucks, and draglines are used to remove the overburden and expose the coal seam, and remove the coal from the mine pit. In the past, many strip mines were simply abandoned with little or no effort to reclaim them after the accessible coal had been removed, but with the passage of the federal Surface Mining Control and Reclamation Act (1977) such practices are no longer allowable. Strip mine reclamation has become an integral part of the mining operation.

The surface mining act specifies that all surface soil must be carefully removed during mine development and stored so that it can be used later during reclamation. The remaining overburden must also be stored for reuse. As the coal is removed from the ground, the overburden is

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progressively backfilled into the previously mined areas. When the mining operation is completed the remaining overburden is put into the mine, the top soil is replaced, and native ground cover is reestablished.

Although adherence to the federal strip mine act eliminates the necessity to separately dispose of solid mine wastes, the problem of ground water contamination or disruption during or subsequent to mining remains a bothersome problem without an easy solution. Much of the strip-able coal in the southwestern region lies above major aquifers, but for that which does not, diversion and pumping of water from mining sites must be done. After mining is completed, it is very difficult to restore the condition of the original aquifers. Western coals and coal spoils are far less likely to produce contaminated drainages when gro. water passes through them than are eastern coals;[2] however, it would be a recommended practice to monitor the groundwater downfield from recently reclaimed mining areas to assure that undesirable contaminants are not being released.

In the underground mining of coal, access shafts are sunk vertically into the coal seam or mine shafts are bored directly into coal outcroppings; from these access points mine tunnels are distributed into the coal seam. Conventional room and pillar mining is most often practiced in the under-ground mining of coal; however, some highly mechanized forms of mining, such as long-wall mining, are becoming more popular where conditions permit their use.[3]

The underground mining of coal produces a large amount of spoil or mineral wastes. These are the overburden and rock removed from the mine shafts while gaining access to the coal seams, and the rock intrusions in the seams themselves. It has not yet proven feasible to replace under-ground mine spoils back into the mine, so these wastes must be discarded at the surface. The usual practice for disposing and re 'aiming western

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mine spoils is to place them into a depression or gully, were they can be compacted and graded to prevent erosion and perhaps seeded with native vegetation.[4] Nearby strip mines also provide a convenient place for the disposal of underground mine spoils.

One of the most serious environmental problems associated with the underground mining of southwestern coals is the possible disruption and degradation of aquifers located in the coal seam or associated strata. There are no effective remedial measures for restoring the original aquifer drainage once mining has disrupted it. Therefore, the best means of avoiding aquifer damage during underground coal mining is to preplan the mining operation with as much knowledge as possible of the geohydrology of the area.

2.2 COAL CLEANING WASTES

Coal, as mined, contains a great deal of extraneous rock and mineral matter. These constituents usually comprise about 10% to 20% of raw coals, but they can run as high as 50% for some coals.[5] The rock and mineral matter is expensive to ship, and it dilutes the energy content of the coal, but, of most importance from an environmental viewpoint, these impurities produce undesirable gaseous and particulate pollutants when the coal is burned. Therefore, about one-half of the total coal mined in the United States is prepared or cleaned prior to utilization to remove some of the noncombustible materials. Currently little western coal is washed or cleaned before combustion, but the demand for higher quality coal will undoubtedly result in a higher proportion of these coals being cleaned in the future.

Coal cleaning is largely a mechanical process, involving a series of crushing, sizing, separating and drying steps. In most cases, the coal is separated from the mineral matter on the basis of density. Modern coal

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preparation plants can recover about 90% of the energy content of the coal, while reducing the mineral content of the coal considerably.[6]

The wastes produced by coal cleaning are similar in composition to the spoil materials produced by coal mining. However, because cleaning wastes are more finely divided than mine wastes, they present a greater problem with regard to disposal and reclamation. The drainages from cleaning waste disposal sites are often contaminated with dissolved and suspended solids.[7] Also, because they contain some residual coal, cleaning waste dumps frequently catch fire; and, because of the poor structural quality of coal cleaning wastes, disposal areas for these materials often exhibit structural instabilities.[7]

The disposal and reclamation of coal cleaning wastes is governed by the Federal Coal Mine Health and Safety Act of 1969. Site choice and preparation methods are clearly defined by the act. Basically, the act specifies that coal cleaning wastes are to be discarded on an impermeable layer of clay, crushed refuse, or some other suitable material, and that successive additions of waste be compacted as they are added to the dump. Erosion stability of a completed refuse disposal area is provided by grading, followed by the addition of clay, top soil, or some other sealant. Although precautions are to be taken to direct surface and ground waters away from the disposal site, any water that does pass through the site must be impounded and treated, if necessary.

2.3 COAL COMBUSTION WASTES

The burning of coal, and the use of pollution control devices such as scrubbers and precipitators, produces large volumes of solid waste materials that need to be disposed of in environmentally compatible ways. The bulk of the residue is bottom ash formed by the nonvolatile mineral matter in

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the coal, and fly ash, which is a fine particulate material removed from the boiler effluents by precipitators or scrubbers. More than 60 million tons of bottom ash, fly ash and scrubber sludge are produced annually in the United States from coal combustion.[8] There is growing awareness that the discarded wastes from coal combustion are a serious potential source of surface and ground water contamination.

There is not yet federal legislation specifically addressing the disposal and reclamation of the various forms of coal combustion wastes. However, both the Federal Water Pollution Control Act (FWPCA) and The Resource Conservation and Recovery Act (RCRA) apply to coal combustion wastes, and, in effect, dictate to some extent how these w[illegible]s can be disposed.

Land filling and ponding are the two most prevalent methods for disposing of coal combustion wastes.[9] Land disposal sites for ash include gullies, natural depressions, excavated areas, and depleted strip mines. One disadvantage of using land fill methods for disposing of coal ash in the southwestern region is that considerable maintenance is needed to reduce ash loses from the dump by the winds that frequent the area.

Much of the ash produced by coal combustion is discharged into ash ponds. With increasing frequency fly ash and scrubber sludge are being discharged into the same pond.[9] In these ponds the solids are allowed to settle, and the water is decanted off into holding ponds or recycled for process use.

About 4×10^3 acre-ft of land are required for the disposal of the 5×10^6 tons of ash that accumulate in the lifetime of a 1000 MWe coal-fired power plant.[9] If scrubber sludge is also ponded in the same area, land requirements increase disproportionately due to the relatively large volume occupied by the sludge/ash mixtures.[9]

The reclamation of ash and sludge ponds is tricky business due to high amounts of residual water that these wastes retain. Often it is necessary

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to add cement, thickeners or stabilizing agents to the dried solids before reclamation can proceed.[9,10] Frequently stabilizing agents are added directly to the sludges before ponding, thus alleviating the need to rework the material during reclamation. The final stages of ash and sludge pond reclamation include compacting the dried stabilized solids, adding top soil and establishing vegetation to reduce surface erodibility.

The control of contaminated leachates and seepages from disposal ponds for fly ash and scrubber sludge represents, perhaps, the most significant environmental problem facing the southwestern coal and utilities industries. Many trace contaminants that are present in the fly ash or sludge can be mobilized by the waters present in the ponds.[9,10] The transport of contaminants from the disposal ponds into shallow or deep aquifers could result in degradation of the quality of these waters. Frequently, ash and sludge disposal areas are lined with impermeable materials to reduce the loss of water from them.[9,10] Nonetheless, careful monitoring of the surface and subsurface effluents from disposal ponds is a necessity in any well planned disposal and reclamation scheme for coal combustion wastes.

3.0 DISPOSAL AND RECLAMATION OF URANIUM MINING AND MILLING WASTES

In addition to coal, the southwestern region of the United States is blessed with an abundance of uranium ore. In fact, about 50% of our current national production of uranium concentrate comes from the San Juan Basin.[11] The uranium contents of the ores of the region are quite low (usually about 0.2%)[12] hence, a relatively large volume of waste material is produced by the uranium mining and milling industries compared to most other primary minerals extraction processes.

Precluding the possible disposal of reactor wastes in southwestern sites, the major types of wastes and effluents produced by the uranium industry in the region are depicted in Fig. 2. There are many analogies between the disposal and reclamation of coal mine and combustion wastes and uranium mining and milling

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wastes; however, the mobile radioactive and nonradioactive components in many uranium wastes pose a far greater potential for environmental harm than do most coal wastes, dictating that much more care and judgement be exercised in disposing of uranium industry wastes.

3.1 URANIUM MINING WASTES

There are three forms of mining practiced by the uranium industry: open pit, underground, and in situ leach mining. Most of the uranium ore in the Southwest is extracted either by underground or open pit mining.[13] Nationally, about 2% of the total uranium concentrate produced results from in situ leach mining, although this form of mining is likely to become more prevalent as dwindling resources force the exploitation of lower grade ores.

Underground mining of uranium ore produces many of the same types of waste materials as does the mining of coal. These include both mine spoils and mine drainage. Mine wastes (rock and soil) are generated while gaining access to the ore bearing strata, and associated rock and lower grade ores are removed as waste during the development of the mine. Often groundwater intrudes into the mining area and mine dewatering is required. The volumes of water pumped from active underground uranium mines vary between 20 and 4000 gal/min.[14] The quality of these water discharges is variable, but sometimes treatment may be needed to reduce contaminant levels, or contaminated water is ponded and evaporated.

The solid wastes or spoils produced by underground mining of uranium ore is usually discarded in convenient nearby disposal sites. Uranium mine spoils and ores are generally not considered to be highly hazardous materials; however, there are documented instances where the contaminated drainages from surface accumulations of these materials have caused severe environmental damage to plants and animals.[15]

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Mine water from underground uranium mines is usually pumped into surface drainage channels or into evaporation ponds. Some mine water is also used as process water for mining and milling operations. Where the volumes of water involved are very large, care must be exercised in disposing of them. Seepage from mine water holding ponds can pass through tailings or mine spoil disposal sites, picking up contaminants from these sources, and transporting these contaminants into the environment.

In some parts of the Grants Mineral Belt, mine dewatering has been shown to result in degradation to the quality of aquifers in the area.[16] This was due to the acute drawdown of the aquifer volume and subsequent increases in the salt contents of the water. Such consequences of mine dewatering activities may dictate in the future that mine waters be reinjected back into the strata in which they originated.

Open pit mining of uranium ore is practiced where the ore deposits are located relatively near the surface, usually at depths of less than 500 ft.[17] In a fashion similar to coal mining, overburden is removed with front end loaders, and scrapers. Additional spoils are produced during the mining operation when low grade ores are discarded or stored, or additional overburden must be removed to expose ore pockets. Water encountered during the open pit mining of uranium is either diverted away from the mining site or is pumped to the surface and released or impounded. Here too, aquifer disruption and loss of ground water quality are difficult problems to circumvent.

There are no federal laws pertaining specifically to mine spoils or reclamation following either the strip or underground mining of uranium ore. The recently enacted Uranium Mill Tailings Radiation Control Act (UMTCA) does instruct EPA and NRC to report to Congress by 1980 concerning the locations and potential environmental hazards of uranium mine wastes, along with recommendations to eliminate these hazards. For the time

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being FWPCA and RCRA provide the major guidelines for the dipsosal and reclamation of these wastes. Reclamation practices for both underground and open pit mine wastes produced by uranium extraction are similar to these employed for coal mine wastes.

In many instances, it is not practical to mine certain uranium ores, due to the inaccessability of the deposits or to the low quality of the ore. Such deposits may instead be exploited by in situ leaching techniques.[18] In situ leach mining involves the pumping of chemical leach solutions into the ore deposit through an injection well, forcing the leachate through the ore to dissolve or mobilize the uranium compounds, and collecting the pregnant leach solutions at a series of recovery wells. The uranium-bearing solutions are then processed at the surface to recover the uranium.

In situ leach mining is advantageous in that it produces very small amounts of waste materials or aqueous effluents to be disposed and reclaimed. However, these apparent advantages may be more than offset by the environmental problems caused by the escape of the chemical leach solutions into subsurface water systems. Unfortunately, even the best efforts at geologic mapping cannot result in the total assurance that a leach mining site is hydrologically isolated from its surroundings.

3.2 URANIUM MILLING WASTES

Uranium milling is the process in which crushed and powdered uranium ores are subjected to a series of chemical leaching and extraction steps to remove the minute amount of uranium from the ore. These chemical processing steps partially break down the structure of the ore matrix, thereby releasing the uranium contained within. As mentioned earlier, more than 99% of the contents of the uranium ore are eventually discarded as mill wastes. One very important consequence of the milling operation is that it also

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mobilizes other potentially harmful components in the ore (such as toxic trace elements or other radioactive substances) that are released as wastes i tailings disposal sites. In addition mill tailings also contain small amounts of chemicals and solvents used in the milling processes.

Tailings are discharged from uranium mills in the form of aqueous slurries. Typical mill tailings slurries contain water, sand, silt and various slimes. The slurries are pumped into impoundments where the solids settle out and the remaining water is decanted into evaporating ponds, or is recycled back into the mill. However, seepage or overflow from tailings ponds or holding ponds often escapes into the environment. When this happens there is the strong likelihood that these waters will carry undesirable quantities of radioactive and nonradioactive contaminants with them.[19,20]

Until recently the legal basis for regulating the disposal and reclamation of uranium mill wastes was quite confusing. NRC (or individual states in agreement with NRC) held licensing authority over active tailings disposal operations, but this authority terminated when the license was withdrawn at the cessation of the mill operation. The responsibility for inactive tailing disposal areas was left piecemeal up to the individual states. In late 1978, Congress passed UMTCA, which directs that NRC provide licensing authority over both active and inactive mill tailings disposal sites. EPA is charged by the act with developing standards for tailings areas, and DOE is responsib for the development of control and reclamation methods for both active and inactive disposal areas.

Environmentally, mill tailings disposal sites are particularly troublesome because they can be the source of both atmospheric and water-borne contaminants.[19,20] Radon, a radioactive gas, is produced by radioactive

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decay within the tailings materials, and may be emitted to the atmosphere if precautions are not taken to seal the surface of the tailing pile.[19] In addition, as alluded to earlier, the large volumes of contaminated water in or near tailings dump sites can seep or discharge into surface or ground-water systems. Thus, the disposal and reclamations of uranium mill tailings must provide for the containment of radon gas, the containment of aqueous solutions, and long-term resistance to erosion.

Past practices, where mill tailings were discarded without much regard to environmental consequences, are no longer acceptable. Although the details of current mill tailings disposal and reclamation strategies will depend both on the nature of the disposal site and the volume of the materials involved, several key components will be present in each.[21] In the future, mill tailings will more than likely be deposited into impoundments or settling ponds that are lined with an impermeable layer of rock, clay or other stable material. Frequently, stabilizing and flocculing agents will be used to more efficiently promote dewatering, and to assure the stability of the dried tailing solids. All waste water will be recycled, evaporated or treated prior to release. Upon completion of a disposal site, the entire site will be capped with another impermeable layer of clay, asphalt or concrete to retain radon and promote stability. Finally, the capping agent may be covered with soil and plant growth reestablished.

4.0 SUMMARY

The types of solid wastes and effluents produced by the southwestern coal and uranium mining and milling industries were considered, and the current methods for the disposal and reclamation of these materials were discussed. The major means of disposing of the solid wastes from both industries is by land fill or in some

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instances ponding. Sludges or aqueous wastes are normally discharged into settling and evaporative ponds. Basic reclamation measures for nearly all coal and uranium waste disposal sites include solids stabilization, compacting, grading, soil preparation and revegetation. Impermeable liners and caps are beginning to be applied to disposal sites for some of the more harmful coal and uranium waste materials.

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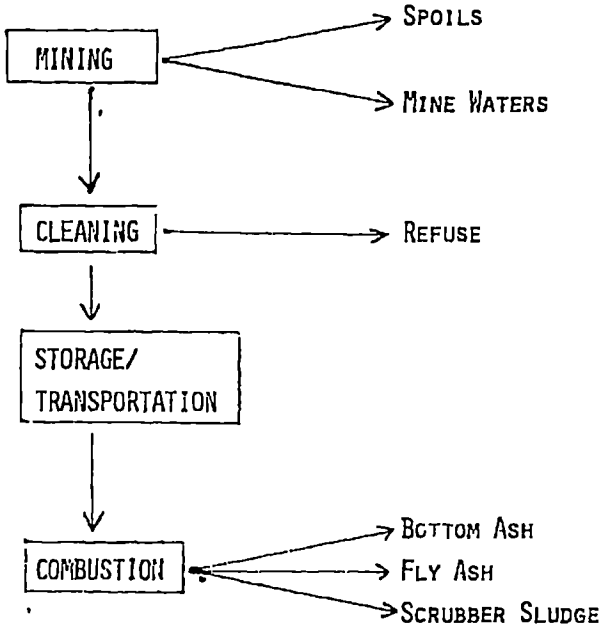


Fig. 1. Wastes produced by coal mining and combustion.

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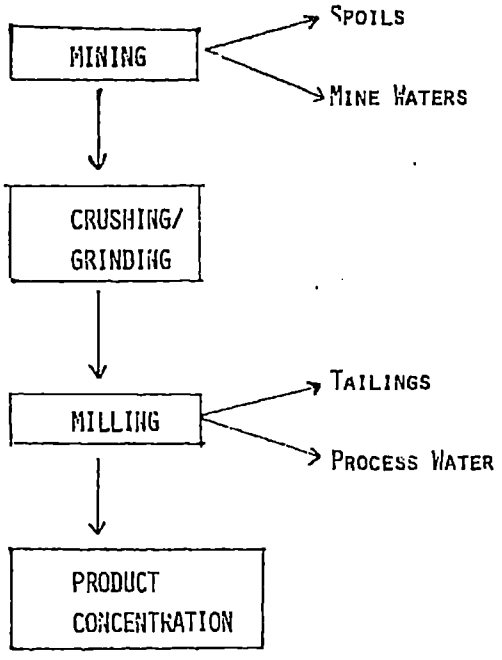


Fig. 2. Wastes produced by uranium mining and milling.

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GENERAL ASSEMBLY OF NORTH CAROLINA
SESSION 2015

HOUSE BILL 630
RATIFIED BILL

A BILL TO BE ENTITLED

AN ACT TO (1) REQUIRE A COAL COMBUSTION RESIDUALS IMPOUNDMENT OWNER TO PROVIDE PERMANENT ALTERNATIVE WATER SUPPLIES FOR RESIDENTS IN AREAS SURROUNDING COAL COMBUSTION RESIDUALS SURFACE IMPOUNDMENTS; (2) REPEAL STATUTORY PROVISIONS RELATED TO THE COAL ASH MANAGEMENT COMMISSION; (3) MODIFY THE CLOSURE REQUIREMENTS FOR COAL COMBUSTION RESIDUALS SURFACE IMPOUNDMENTS UNDER THE COAL ASH MANAGEMENT ACT OF 2014; AND (4) MODIFY APPOINTMENTS TO THE MINING COMMISSION AND THE OIL AND GAS COMMISSION.

The General Assembly of North Carolina enacts:

SECTION 1. Part 2I of Article 9 of Chapter 130A of the General Statutes reads as rewritten:

"Part 2I. Coal Ash Management.

"Subpart 1. Short Title, Definitions, and General Provisions.

"**§ 130A-309.200. Title.**

This Part may be cited as the "Coal Ash Management Act of 2014."

"**§ 130A-309.201. Definitions.**

Unless a different meaning is required by the context, the definitions of G.S. 130A-290 and the following definitions apply throughout this Part:

(1) "Beneficial and beneficial use" means projects promoting public health and environmental protection, offering equivalent success relative to other alternatives, and preserving natural resources.

(2) "Boiler slag" means the molten bottom ash collected at the base of slag tap and cyclone type furnaces that is quenched with water. It is made up of hard, black, angular particles that have a smooth, glassy appearance.

(3) "Bottom ash" means the agglomerated, angular ash particles formed in pulverized coal furnaces that are too large to be carried in the flue gases and collect on the furnace walls or fall through open grates to an ash hopper at the bottom of the furnace.

(4) "Coal combustion products" it means fly ash, bottom ash, boiler slag, or flue gas desulfurization materials that are beneficially used, including use for structural fill.

(5) "Coal combustion residuals" has the same meaning as defined in G.S. 130A-290.

(6) "Coal combustion residuals surface impoundment" means a topographic depression, excavation, or diked area that is (i) primarily formed from earthen materials; (ii) without a base liner approved for use by Article 9 of Chapter 130A of the General Statutes or rules adopted thereunder for a combustion products landfill or coal combustion residuals landfill, industrial landfill, or municipal solid waste landfill; and (iii) designed to hold accumulated coal combustion residuals in the form of liquid wastes, wastes containing free liquids, or sludges, and that is not backfilled or otherwise covered during periods of deposition. "Coal combustion residuals surface impoundment" shall only include impoundments owned by a public utility,

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as defined in G.S. 62-3. "Coal combustion residuals surface impoundment" includes all of the following:

a. An impoundment that is dry, due to the deposited liquid having evaporated, volatilized, or leached.
b. An impoundment that is wet with exposed liquid.
c. Lagoons, ponds, aeration pits, settling ponds, tailings ponds, and sludge pits, when these structures are designed to hold accumulated coal combustion residuals.
d. A coal combustion residuals surface impoundment that has been covered with soil or other material after the final deposition of coal combustion residuals at the impoundment.

~~(7) "Commission" means the Coal Ash Management Commission.~~

(8) "Flue gas desulfurization material" means the material produced through a process used to reduce sulfur dioxide emissions from the exhaust gas system of a coal-fired boiler. The physical nature of these materials varies from a wet sludge to a dry powdered material, depending on the process, and their composition comprises either sulfites, sulfates, or a mixture thereof.

(9) "Fly ash" means the very fine, powdery material, composed mostly of silica with nearly all particles spherical in shape, which is a product of burning finely ground coal in a boiler to produce electricity and is removed from the plant exhaust gases by air emission control devices.

(10) "Minerals" means soil, clay, coal, phosphate, metallic ore, and any other solid material or substance of commercial value found in natural deposits on or in the earth.

(11) "Open pit mine" means an excavation made at the surface of the ground for the purpose of extracting minerals, inorganic and organic, from their natural deposits, which excavation is open to the surface.

(12) "Owner" or "owner of a coal combustion residuals surface impoundment" means a public utility, as defined in G.S. 62-3, that owns a coal combustion residuals surface impoundment.

(13) "Receptor" means any human, plant, animal, or structure which is, or has the potential to be, affected by the release or migration of contaminants. Any well constructed for the purpose of monitoring groundwater and contaminant concentrations shall not be considered a receptor.

(14) "Structural fill" means an engineered fill with a projected beneficial end use constructed using coal combustion products that are properly placed and compacted. For purposes of this Part, the term includes fill used to reclaim open pit mines and for embankments, greenscapes, foundations, construction foundations, and for bases or sub-bases under a structure or a footprint of a paved road, parking lot, sidewalk, walkway, or similar structure.

(15) "Use or reuse of coal combustion products" means the procedure whereby coal combustion products are directly used as either of the following:

a. As an ingredient in an industrial process to make a product, unless distinct components of the coal combustion products are recovered as separate end products.
b. In a function or application as an effective substitute for a commercial product or natural resource.

~~"§ 130A-309.202. (Repealed effective June 30, 2030) Coal Ash Management Commission.~~

~~(a) Creation. In recognition of the complexity and magnitude of the issues associated with the management of coal combustion residuals and the proper closure and remediation of coal combustion residuals surface impoundments, the Coal Ash Management Commission is hereby established.~~

~~(b) Membership. The Commission shall consist of nine members as follows:~~

~~(1) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in accordance with G.S. 120-121 who shall at the time of appointment be a resident of the State.~~

~~(2) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in accordance with G.S. 120-121 who shall at the time of appointment have special training or scientific expertise~~

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in waste management, including solid waste disposal, hauling, or beneficial use.

(3) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in accordance with G.S. 120-121 who shall at the time of appointment be a licensed physician or a person with experience in public health.

(4) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in accordance with G.S. 120-121 who shall at the time of appointment be a member of a nongovernmental conservation interest.

(5) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in accordance with G.S. 120-121 who shall at the time of appointment have special training or scientific expertise in waste management, including solid waste disposal, hauling, or beneficial use, or is a representative of or on the faculty of a State college or university that conducts coal ash research.

(6) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in accordance with G.S. 120-121 who shall at the time of appointment be a representative of an electric membership corporation organized under Article 2 of Chapter 117 of the General Statutes and have a background in power supply resource planning and engineering.

(7) One appointed by the Governor who shall at the time of appointment have experience in economic development.

(8) One appointed by the Governor who shall at the time of appointment have expertise in determining and evaluating the costs associated with electricity generation and establishing the rates associated with electricity consumption.

(9) One appointed by the Governor who shall at the time of appointment be a person with experience in science or engineering in the manufacturing sector.

(c) Chair. The Governor shall appoint the Chair of the Commission from among the Commission's members, and that person shall serve at the pleasure of the Governor. The Chair shall serve two-year terms. The Governor shall make:

(1) The initial appointment of the Chair no later than October 1, 2014. If the initial appointment is not made by that date, the Chair shall be elected by a vote of the membership; and

(2) Appointments of a subsequent Chair, including appointments to fill a vacancy of the Chair created by resignation, dismissal, death, or disability of the Chair, no later than 30 days after the last day of the previous Chair's term. If an appointment of a subsequent Chair is not made by that date, the Chair shall be elected by a vote of the membership.

(d) Vacancies. Any appointment to fill a vacancy on the Commission created by the resignation, dismissal, death, or disability of a member shall be for the balance of the unexpired term. The Governor may reappoint a gubernatorial appointee of the Commission to an additional term if, at the time of the reappointment, the member qualifies for membership on the Commission under subdivisions (7) through (9) of subsection (b) of this section. Appointments by the General Assembly shall be made in accordance with G.S. 120-121, and vacancies in those appointments shall be filled in accordance with G.S. 120-122.

(e) Removal. The Governor shall have the power to remove any member of the Commission from office for misfeasance, malfeasance, or nonfeasance in accordance with the provisions of G.S. 143B-13 of the Executive Organization Act of 1973.

(f) Powers and Duties. The Commission shall have all of the following powers and duties:

(1) To review and approve the classification of coal combustion residuals surface impoundments required by G.S. 130A-309.213.

(2) To review and approve Coal Combustion Residuals Surface Impoundment Closure Plans as provided in G.S. 130A-309.214.

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~~(3) To review and make recommendations on the provisions of this Part and other statutes and rules related to the management of coal combustion residuals.~~

~~(4) To undertake any additional studies as requested by the General Assembly.~~

~~(g) Reimbursement. The members of the Commission shall receive per diem and necessary travel and subsistence expenses in accordance with the provisions of G.S. 138-5.~~

~~(h) Quorum. Five members of the Commission shall constitute a quorum for the transaction of business.~~

~~(i) Staff. The Commission is authorized and empowered to employ staff as the Commission may determine to be necessary for the proper discharge of the Commission's duties and responsibilities. The Chair of the Commission shall organize and direct the work of the Commission staff. The salaries and compensation of all such personnel shall be fixed in the manner provided by law for fixing and regulating salaries and compensation by other State agencies. The Chair, within allowed budgetary limits and as allowed by law, shall authorize and approve travel, subsistence, and related expenses of such personnel incurred while traveling on official business. All State agencies, including the constituent institutions of The University of North Carolina, shall provide information and support to the Commission upon request.~~

~~(j) Repealed by Session Laws 2015-9, s. 1.1, effective April 27, 2015.~~

~~(k) Covered Persons; Conflicts of Interest; Disclosure. All members of the Commission are covered persons for the purposes of Chapter 138A of the General Statutes, the State Government Ethics Act. As covered persons, members of the Commission shall comply with the applicable requirements of the State Government Ethics Act, including mandatory training, the public disclosure of economic interests, and ethical standards for covered persons. Members of the Commission shall comply with the provisions of the State Government Ethics Act to avoid conflicts of interest. The Governor may require additional disclosure of potential conflicts of interest by members. The Governor may promulgate criteria regarding conflicts of interest and disclosure thereof for determining the eligibility of persons under this subsection, giving due regard to the requirements of federal legislation, and, for this purpose, may promulgate rules, regulations, or guidelines in conformance with those established by any federal agency interpreting and applying provisions of federal law.~~

~~(l) Meetings. The Commission shall meet at least once every two months and may hold special meetings at any time and place within the State at the call of the Chair or upon the written request of at least five members.~~

~~(m) Reports. The Commission shall submit quarterly written reports as to its operation, activities, programs, and progress to the Environmental Review Commission. The Commission shall supplement the written reports required by this subsection with additional written and oral reports as may be requested by the Environmental Review Commission. The Commission shall submit the written reports required by this subsection whether or not the General Assembly is in session at the time the report is due.~~

~~(n) Administrative Location; Independence. The Commission shall be administratively located in the Division of Emergency Management of the Department of Public Safety. The Commission shall exercise all of its powers and duties independently and shall not be subject to the supervision, direction, or control of the Division or Department.~~

~~(o) Terms of Members. Members of the Commission shall serve terms of six years, beginning effective July 1 of the year of appointment.~~

"§ 130A-309.203. Expedited permit review.

(a) The Department shall act as expeditiously as practicable, but no later than the deadlines established under subsection (b) of this section, except in compliance with subsection (c) of this section, to issue all permits necessary to conduct activities required by this Part.

(b) Notwithstanding G.S. 130A-295.8(e), the Department shall determine whether an application for any permit necessary to conduct activities required by this Part is complete within 30 days after the Department receives the application for the permit. A determination of completeness means that the application includes all required components but does not mean that the required components provide all of the information that is required for the Department to make a decision on the application. If the Department determines that an application is not complete, the Department shall notify the applicant of the components needed to complete the application. An applicant may submit additional information to the Department to cure the deficiencies in the application. The Department shall make a final determination as to whether

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the application is complete within the later of (i) 30 days after the Department receives the application for the permit less the number of days that the applicant uses to provide the additional information or (ii) 10 days after the Department receives the additional information from the applicant. The Department shall issue a draft permit decision on an application for a permit within 90 days after the Department determines that the application is complete. The Department shall hold a public hearing and accept written comment on the draft permit decision for a period of not less than 30 or more than 60 days after the Department issues a draft permit decision. The Department shall issue a final permit decision on an application for a permit within 60 days after the comment period on the draft permit decision closes. If the Department fails to act within any time period set out in this subsection, the applicant may treat the failure to act as a denial of the permit and may challenge the denial as provided in Chapter 150B of the General Statutes.

(c) If the Department finds that compliance with the deadlines established under subsection (b) of this section would result in insufficient review of a permit application that would pose a risk to public health, safety, and welfare; the environment; or natural resources, the applicable deadline shall be waived for the application as necessary to allow for adequate review. If a deadline is waived pursuant to this subsection, the Secretary shall issue a written declaration, including findings of fact, documenting the need for the waiver.

(d) Notwithstanding any other provision of this section or any other provision of law, the Department shall either issue or deny a permit required for dewatering of a retired impoundment within 90 days of receipt of a completed application, in such a form and including such information as the Department may prescribe, for the dewatering activities. The Department shall accept written comment on a draft permit decision for a period of not less than 30 days or more than 60 days prior to issuance or denial of such a permit. If the Department fails to act within any time period set out in this subsection, the applicant may treat the failure to act as a denial of the permit and may challenge the denial as provided in Chapter 150B of the General Statutes.

"**§ 130A-309.204. Reports.**

(a) The Department shall submit quarterly written reports to the Environmental Review Commission ~~and the Coal Ash Management Commission~~ on its operations, activities, programs, and progress with respect to its obligations under this Part concerning all coal combustion residuals surface impoundments. At a minimum, the report shall include information concerning the status of assessment, corrective action, prioritization, and closure for each coal combustion residuals surface impoundment and information on costs connected therewith. The report shall include an executive summary of each annual Groundwater Protection and Restoration Report submitted to the Department by the operator of any coal combustion residuals surface impoundments pursuant to G.S. 130A-309.211(d) and a summary of all groundwater sampling, protection, and restoration activities related to the impoundment for the preceding year. The report shall also include an executive summary of each annual Surface Water Protection and Restoration Report submitted to the Department by the operator of any coal combustion residuals surface impoundments pursuant to G.S. 130A-309.212(e) and a summary of all surface water sampling, protection, and restoration activities related to the impoundment for the preceding year, including the status of the identification, assessment, and correction of unpermitted discharges from coal combustion residuals surface impoundments to the surface waters of the State. The Department shall supplement the written reports required by this subsection with additional written and oral reports as may be requested by the Environmental Review Commission. The Department shall submit the written reports required by this subsection whether or not the General Assembly is in session at the time the report is due.

(b) On or before October 1 of each year, the Department shall report to each member of the General Assembly who has a coal combustion residuals surface impoundment in the member's district. This report shall include the location of each impoundment in the member's district, the amount of coal combustion residuals known or believed to be located in the impoundment, the last action taken at the impoundment, and the date of that last action.

(c) On or before October 1 of each year, a public utility generating coal combustion residuals and coal combustion products shall submit an annual summary to the Department. The annual summary shall be for the period of July 1 through June 30 and shall include all of the following:

(1) The volume of coal combustion residuals and products produced.

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(2) The volume of coal combustion residuals disposed.
(3) The volume of coal combustion products used in structural fill projects.
(4) The volume of coal combustion products beneficially used, other than for structural fill.

"**§ 130A-309.205. Local ordinances regulating management of coal combustion residuals and coal combustion products invalid; petition to preempt local ordinance.**

(a) It is the intent of the General Assembly to maintain a uniform system for the management of coal combustion residuals and coal combustion products, including matters of disposal and beneficial use, and to place limitations upon the exercise by all units of local government in North Carolina of the power to regulate the management of coal combustion residuals and coal combustion products by means of ordinances, property restrictions, zoning regulations, or otherwise. Notwithstanding any authority granted to counties, municipalities, or other local authorities to adopt local ordinances, including those imposing taxes, fees, or charges or regulating health, environment, or land use, all provisions of local ordinances, including those regulating land use, adopted by counties, municipalities, or other local authorities that regulate or have the effect of regulating the management of coal combustion residuals and coal combustion products, including regulation of carbon burn-out plants, within the jurisdiction of a local government are invalidated and unenforceable, to the extent necessary to effectuate the purposes of this Part, that do the following:

(1) Place any restriction or condition not placed by this Part upon management of coal combustion residuals or coal combustion products within any county, city, or other political subdivision.
(2) Conflict or are in any manner inconsistent with the provisions of this Part.

(a1) As used in this section, "Commission" means the Environmental Management Commission.

(b) If a local zoning or land-use ordinance imposes requirements, restrictions, or conditions that are generally applicable to development, including, but not limited to, setback, buffer, and stormwater requirements, and coal combustion residuals and coal combustion products would be regulated under the ordinance of general applicability, the operator of the proposed activities may petition the Environmental Management Commission to review the matter. After receipt of a petition, the Commission shall hold a hearing in accordance with the procedures in subsection (c) of this section and shall determine whether or to what extent to preempt the local ordinance to allow for the management of coal combustion residuals and coal combustion products.

(c) When a petition described in subsection (b) of this section has been filed with the Environmental Management Commission, the Commission shall hold a public hearing to consider the petition. The public hearing shall be held in the affected locality within 60 days after receipt of the petition by the Commission. The Commission shall give notice of the public hearing by both of the following means:

(1) Publication in a newspaper or newspapers having general circulation in the county or counties where the activities are to be conducted, once a week for three consecutive weeks, the first notice appearing at least 30 days prior to the scheduled date of the hearing.
(2) First-class mail to persons who have requested notice. The Commission shall maintain a mailing list of persons who request notice in advance of the hearing pursuant to this section. Notice by mail shall be complete upon deposit of a copy of the notice in a postage-paid wrapper addressed to the person to be notified at the address that appears on the mailing list maintained by the Commission in a post office or official depository under the exclusive care and custody of the United States Postal Service.

(d) Any interested person may appear before the Environmental Management Commission at the hearing to offer testimony. In addition to testimony before the Commission, any interested person may submit written evidence to the Commission for the Commission's consideration. At least 20 days shall be allowed for receipt of written comment following the hearing.

(e) A local zoning or land-use ordinance is presumed to be valid and enforceable to the extent the zoning or land-use ordinance imposes requirements, restrictions, or conditions that are generally applicable to development, including, but not limited to, setback, buffer, and stormwater requirements, unless the Environmental Management Commission makes a finding

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of fact to the contrary. The Commission shall determine whether or to what extent to preempt local ordinances so as to allow the project involving management of coal combustion residuals and coal combustion products no later than 60 days after conclusion of the hearing. The Commission shall preempt a local ordinance only if the Commission makes all of the following findings:

(1) That there is a local ordinance that would regulate the management of coal combustion residuals and coal combustion products.

(2) That all legally required State and federal permits or approvals have been issued by the appropriate State and federal agencies or that all State and federal permit requirements have been satisfied and that the permits or approvals have been denied or withheld only because of the local ordinance.

(3) That local citizens and elected officials have had adequate opportunity to participate in the permitting process.

(4) That the project involving management of coal combustion residuals and coal combustion products will not pose an unreasonable health or environmental risk to the surrounding locality and that the operator has taken or consented to take reasonable measures to avoid or manage foreseeable risks and to comply to the maximum feasible extent with applicable local ordinances.

(f) If the Environmental Management Commission does not make all of the findings under subsection (e) of this section, the Commission shall not preempt the challenged local ordinance. The Commission's decision shall be in writing and shall identify the evidence submitted to the Commission plus any additional evidence used in arriving at the decision.

(g) The decision of the Environmental Management Commission shall be final, unless a party to the action files a written appeal under Article 3 of Chapter 150B of the General Statutes, as modified by this section, within 30 days of the date of the decision. The record on appeal shall consist of all materials and information submitted to or considered by the Commission, the Commission's written decision, a complete transcript of the hearing, the specific findings required by subsection (e) of this section, and any minority positions on the specific findings required by subsection (e) of this section. The scope of judicial review shall be as set forth in G.S. 150B-51, except as this subsection provides regarding the record on appeal.

(h) If the court reverses or modifies the decision of the Environmental Management Commission, the judge shall set out in writing, which writing shall become part of the record, the reasons for the reversal or modification.

(i) In computing any period of time prescribed or allowed by the procedure in this section, the provisions of Rule 6(a) of the Rules of Civil Procedure, G.S. 1A-1, shall apply.

"§ 130A-309.206. Federal preemption; severability.

The provisions of this Part shall be severable, and if any phrase, clause, sentence, or provision is declared to be unconstitutional or otherwise invalid or is preempted by federal law or regulation, the validity of the remainder of this Part shall not be affected thereby.

"§ 130A-309.207. General rule making for Part.

The Environmental Management Commission shall adopt rules as necessary to implement the provisions of the Part. Such rules shall be exempt from the requirements of G.S. 150B-19.3.

"§ 130A-309.208: Reserved for future codification purposes.

"§ 130A-309.209: Reserved for future codification purposes.

"Subpart 2. Management of Coal Ash Residuals; Closure of Coal Ash Impoundments.

"§ 130A-309.210. Generation, disposal, and use of coal combustion residuals.

(a) On or after October 1, 2014, the construction of new and expansion of existing coal combustion residuals surface impoundments is prohibited.

(b) On or after October 1, 2014, the disposal of coal combustion residuals into a coal combustion residuals surface impoundment at an electric generating facility where the coal-fired generating units are no longer producing coal combustion residuals is prohibited.

(c) On or after December 31, 2018, the discharge of stormwater into a coal combustion surface impoundment at an electric generating facility where the coal-fired generating units are no longer producing coal combustion residuals is prohibited.

(d) On or after December 31, 2019, the discharge of stormwater into a coal combustion surface impoundment at an electric generating facility where the coal-fired generating units are actively producing coal combustion residuals is prohibited.

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(e) On or before December 31, 2018, all electric generating facilities owned by a public utility shall convert to the disposal of "dry" fly ash or the facility shall be retired. For purposes of this subsection, the term "dry" means coal combustion residuals that are not in the form of liquid wastes, wastes containing free liquids, or sludges.

(f) On or before December 31, 2019, all electric generating facilities owned by a public utility shall convert to the disposal of "dry" bottom ash or the facility shall be retired. For purposes of this subsection, the term "dry" means coal combustion residuals that are not in the form of liquid wastes, wastes containing free liquids, or sludges.

"**§ 130A-309.211. Groundwater assessment and corrective action; drinking water supply well survey and provision of alternate water supply; reporting.**

(a) Groundwater Assessment of Coal Combustion Residuals Surface Impoundments. – The owner of a coal combustion residuals surface impoundment shall conduct groundwater monitoring and assessment as provided in this subsection. The requirements for groundwater monitoring and assessment set out in this subsection are in addition to any other groundwater monitoring and assessment requirements applicable to the owners of coal combustion residuals surface impoundments:

(1) No later than December 31, 2014, the owner of a coal combustion residuals surface impoundment shall submit a proposed Groundwater Assessment Plan for the impoundment to the Department for its review and approval. The Groundwater Assessment Plan shall, at a minimum, provide for all of the following:

a. A description of all receptors and significant exposure pathways.
b. An assessment of the horizontal and vertical extent of soil and groundwater contamination for all contaminants confirmed to be present in groundwater in exceedance of groundwater quality standards.
c. A description of all significant factors affecting movement and transport of contaminants.
d. A description of the geological and hydrogeological features influencing the chemical and physical character of the contaminants.
e. A schedule for continued groundwater monitoring.
f. Any other information related to groundwater assessment required by the Department.

(2) The Department shall approve the Groundwater Assessment Plan if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

(3) No later than 10 days from approval of the Groundwater Assessment Plan, the owner shall begin implementation of the Plan.

(4) No later than 180 days from approval of the Groundwater Assessment Plan, the owner shall submit a Groundwater Assessment Report to the Department. The Report shall describe all exceedances of groundwater quality standards associated with the impoundment.

(b) Corrective Action for the Restoration of Groundwater Quality. – The owner of a coal combustion residuals surface impoundment shall implement corrective action for the restoration of groundwater quality as provided in this subsection. The requirements for corrective action for the restoration of groundwater quality set out in this subsection are in addition to any other corrective action for the restoration of groundwater quality requirements applicable to the owners of coal combustion residuals surface impoundments:

(1) No later than 90 days from submission of the Groundwater Assessment Report required by subsection (a) of this section, or a time frame otherwise approved by the Department not to exceed 180 days from submission of the Groundwater Assessment Report, the owner of the coal combustion residuals surface impoundment shall submit a proposed Groundwater Corrective Action Plan to the Department for its review and approval. The Groundwater Corrective Action Plan shall provide for the restoration of groundwater in conformance with the requirements of Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code. The Groundwater Corrective Action Plan shall include, at a minimum, all of the following:

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a. A description of all exceedances of the groundwater quality standards, including any exceedances that the owner asserts are the result of natural background conditions.
b. A description of the methods for restoring groundwater in conformance with the requirements of Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code and a detailed explanation of the reasons for selecting these methods.
c. Specific plans, including engineering details, for restoring groundwater quality.
d. A schedule for implementation of the Plan.
e. A monitoring plan for evaluating the effectiveness of the proposed corrective action and detecting movement of any contaminant plumes.
f. Any other information related to groundwater assessment required by the Department.

(2) The Department shall approve the Groundwater Corrective Action Plan if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

(3) No later than 30 days from the approval of the Groundwater Corrective Action Plan, the owner shall begin implementation of the Plan in accordance with the Plan's schedule.

(c) Drinking Water Supply Well Survey and Provision of Alternate Water Supply. – No later than October 1, 2014, the owner of a coal combustion residuals surface impoundment shall conduct a Drinking Water Supply Well Survey that identifies all drinking water supply wells within one-half mile down-gradient from the established compliance boundary of the impoundment and submit the Survey to the Department. The Survey shall include well locations, the nature of water uses, available well construction details, and information regarding ownership of the wells. No later than December 1, 2014, the Department shall determine, based on the Survey, which drinking water supply wells the owner is required to sample and how frequently and for what period sampling is required. The Department shall require sampling for drinking water supply wells where data regarding groundwater quality and flow and depth in the area of any surveyed well provide a reasonable basis to predict that the quality of water from the surveyed well may be adversely impacted by constituents associated with the presence of the impoundment. No later than January 1, 2015, the owner shall initiate sampling and water quality analysis of the drinking water supply wells. A property owner may elect to have an independent third party selected from a laboratory certified by the Department's Wastewater/Groundwater Laboratory Certification program sample wells located on their property in lieu of sampling conducted by the owner of the coal combustion residuals surface impoundment. The owner of the coal combustion residuals surface impoundment shall pay for the reasonable costs of such sampling. Nothing in this subsection shall be construed to preclude or impair the right of any property owner to refuse such sampling of wells on their property. If the sampling and water quality analysis indicates that water from a drinking water supply well exceeds groundwater quality standards for constituents associated with the presence of the impoundment, the owner shall replace the contaminated drinking water supply well with an alternate supply of potable drinking water and an alternate supply of water that is safe for other household uses. The alternate supply of potable drinking water shall be supplied within 24 hours of the Department's determination that there is an exceedance of groundwater quality standards attributable to constituents associated with the presence of the impoundment. The alternate supply of water that is safe for other household uses shall be supplied within 30 days of the Department's determination that there is an exceedance of groundwater quality standards attributable to constituents associated with the presence of the impoundment. The requirement to replace a contaminated drinking water supply well with an alternate supply of potable drinking water and an alternate supply of water that is safe for other household uses set out in this subsection is in addition to any other requirements to replace a contaminated drinking water supply well with an alternate supply of potable drinking water or an alternate supply of water that is safe for other household uses applicable to the owners of coal combustion residuals surface impoundments.

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(c1) Provision of Permanent Water Supply. – As soon as practicable, but no later than October 15, 2018, the owner of a coal combustion residuals surface impoundment shall establish permanent replacement water supplies for (i) each household that has a drinking water supply well located within a one-half mile radius from the established compliance boundary of a coal combustion residuals impoundment, and is not separated from the impoundment by the mainstem of a river, as that term is defined under G.S. 143-215.22G, or other body of water that would prevent the migration of contaminants through groundwater from the impoundment to a well and (ii) each household that has a drinking water supply well that is located in an area in which contamination resulting from constituents associated with the presence of a coal combustion residuals impoundment is expected to migrate, as demonstrated by groundwater modeling and hydrogeologic, geologic, and geotechnical investigations of the site, conducted in accordance with the requirements of G.S. 130A-309.214(a)(4), and the results of other modeling or investigations that may have been submitted pursuant to G.S. 130A-309.213(b)(4). Preference shall be given to permanent replacement water supplies by connection to public water supplies; provided that (i) a household may elect to receive a filtration system in lieu of a connection to public water supplies and (ii) if the Department determines that connection to a public water supply to a particular household would be cost-prohibitive, the Department shall authorize provision of a permanent replacement water supply to that household through installation of a filtration system. For households for which filtration systems are installed, the impoundment owner shall be responsible for periodic required maintenance of the filtration system. No later than December 15, 2016, an impoundment owner shall submit information on permanent replacement water supplies proposed to be provided to each household to the Department, including, at a minimum, the type of permanent water supply proposed; the location of the household and its proximity to the nearest connection point to a public water supply; projected cost of the permanent water supply option proposed for the household; and any proposal to connect to a public water supply. The Department shall evaluate information submitted by the impoundment owner and render a final decision to approve or disapprove the plan, including written findings of fact, no later than January 15, 2017. If disapproved, an impoundment owner shall resubmit a plan for the Department's approval within 30 days. No later than April 15, 2017, an impoundment owner shall notify all residents identified in the approved plan of their eligibility for establishment of a permanent water supply. Until such time as an impoundment owner has established a permanent water supply for each household required by this subsection, the impoundment owner shall supply the household with an alternate supply of potable drinking water and an alternate supply of water that is safe for other household uses. Nothing in this section shall be construed to (i) require an eligible household to connect to a public water supply or receive a filtration system or (ii) obviate the need for other federal, State, and local permits and approvals. All State entities and local governments shall expedite any permits and approvals required for such projects. The Department may grant an impoundment owner an extension of time, not to exceed one year, to establish permanent water supplies as required by this section, if the Department determines that it is infeasible for the impoundment owner to establish a permanent water supply for a household by October 15, 2018, based on limitations arising from local government resources, including limitations on water supply capacity and staffing limitations for permitting and construction activities.

(d) Reporting. – In addition to any other reporting required by the Department, the owner of a coal combustion residuals surface impoundment shall submit an annual Groundwater Protection and Restoration Report to the Department no later than January 31 of each year. The Report shall include a summary of all groundwater monitoring, protection, and restoration activities related to the impoundment for the preceding year, including the status of the Groundwater Assessment Plan, the Groundwater Assessment Report, the Groundwater Corrective Action Plan, the Drinking Water Supply Well Survey, and the replacement of any contaminated drinking water supply wells. ~~The owner of a coal combustion residuals surface impoundment shall also submit all information required to be submitted to the Department pursuant to this section to the Coal Ash Management Commission.~~

"**§ 130A-309.212. Identification and assessment of discharges; correction of unpermitted discharges.**

(a) Identification of Discharges from Coal Combustion Residuals Surface Impoundments. –

(1) The owner of a coal combustion residuals surface impoundment shall identify all discharges from the impoundment as provided in this subsection.

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The requirements for identifying all discharges from an impoundment set out in this subsection are in addition to any other requirements for identifying discharges applicable to the owners of coal combustion residuals surface impoundments.

(2) No later than December 31, 2014, the owner of a coal combustion residuals surface impoundment shall submit a topographic map that identifies the location of all (i) outfalls from engineered channels designed or improved for the purpose of collecting water from the toe of the impoundment and (ii) seeps and weeps discharging from the impoundment that are not captured by engineered channels designed or improved for the purpose of collecting water from the toe of the impoundment to the Department. The topographic map shall comply with all of the following:

a. Be at a scale as required by the Department.
b. Specify the latitude and longitude of each toe drain outfall, seep, and weep.
c. Specify whether the discharge from each toe drain outfall, seep, and weep is continuous or intermittent.
d. Provide an average flow measurement of the discharge from each toe drain outfall, seep, and weep including a description of the method used to measure average flow.
e. Specify whether the discharge from each toe drain outfall, seep, and weep identified reaches the surface waters of the State. If the discharge from a toe drain outfall, seep, or weep reaches the surface waters of the State, the map shall specify the latitude and longitude of where the discharge reaches the surface waters of the State.
f. Include any other information related to the topographic map required by the Department.

(b) Assessment of Discharges from Coal Combustion Residuals Surface Impoundments to the Surface Waters of the State. – The owner of a coal combustion residuals surface impoundment shall conduct an assessment of discharges from the coal combustion residuals surface impoundment to the surface waters of the State as provided in this subsection. The requirements for assessment of discharges from the coal combustion residuals surface impoundment to the surface waters of the State set out in this subsection are in addition to any other requirements for the assessment of discharges from coal combustion residuals surface impoundments to surface waters of the State applicable to the owners of coal combustion residuals surface impoundments:

(1) No later than December 31, 2014, the owner of a coal combustion residuals surface impoundment shall submit a proposed Discharge Assessment Plan to the Department. The Discharge Assessment Plan shall include information sufficient to allow the Department to determine whether any discharge, including a discharge from a toe drain outfall, seep, or weep, has reached the surface waters of the State and has caused a violation of surface water quality standards. The Discharge Assessment Plan shall include, at a minimum, all of the following:

a. Upstream and downstream sampling locations within all channels that could potentially carry a discharge.
b. A description of the surface water quality analyses that will be performed.
c. A sampling schedule, including the frequency and duration of sampling activities.
d. Reporting requirements.
e. Any other information related to the assessment of discharges required by the Department.

(2) The Department shall approve the Discharge Assessment Plan if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

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(3) No later than 30 days from the approval of the Discharge Assessment Plan, the owner shall begin implementation of the Plan in accordance with the Plan's schedule.

(c) Corrective Action to Prevent Unpermitted Discharges from Coal Combustion Residuals Surface Impoundments to the Surface Waters of the State. – The owner of a coal combustion residuals surface impoundment shall implement corrective action to prevent unpermitted discharges from the coal combustion residuals surface impoundment to the surface waters of the State as provided in this subsection. The requirements for corrective action to prevent unpermitted discharges from coal combustion residuals surface impoundments to the surface waters of the State set out in this subsection are in addition to any other requirements for corrective action to prevent unpermitted discharges from coal combustion residuals surface impoundments to the surface waters of the State applicable to the owners of coal combustion residuals surface impoundments:

(1) If the Department determines, based on information provided pursuant to subsection (a) or (b) of this section, that an unpermitted discharge from a coal combustion residuals surface impoundment, including an unpermitted discharge from a toe drain outfall, seep, or weep, has reached the surface waters of the State, the Department shall notify the owner of the impoundment of its determination.

(2) No later than 30 days from a notification pursuant to subdivision (1) of this subsection, the owner of the coal combustion residuals surface impoundment shall submit a proposed Unpermitted Discharge Corrective Action Plan to the Department for its review and approval. The proposed Unpermitted Discharge Corrective Action Plan shall include, at a minimum, all of the following:

a. One of the following methods of proposed corrective action:
   1. Elimination of the unpermitted discharge.
   2. Application for a National Pollutant Discharge Elimination System (NPDES) permit amendment pursuant to G.S. 143-215.1 and Subchapter H of Chapter 2 of Title 15A of the North Carolina Administrative Code to bring the unpermitted discharge under permit regulations.

b. A detailed explanation of the reasons for selecting the method of corrective action.

c. Specific plans, including engineering details, to prevent the unpermitted discharge.

d. A schedule for implementation of the Plan.

e. A monitoring plan for evaluating the effectiveness of the proposed corrective action.

f. Any other information related to the correction of unpermitted discharges required by the Department.

(3) The Department shall approve the Unpermitted Discharge Corrective Action Plan if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

(4) No later than 30 days from the approval of the Unpermitted Discharge Corrective Action Plan, the owner shall begin implementation of the Plan in accordance with the Plan's schedule.

(d) Identification of New Discharges. – No later than October 1, 2014, the owner of a coal combustion residuals surface impoundment shall submit a proposed Plan for the Identification of New Discharges to the Department for its review and approval as provided in this subsection:

(1) The proposed Plan for the Identification of New Discharges shall include, at a minimum, all of the following:

a. A procedure for routine inspection of the coal combustion residuals surface impoundment to identify indicators of potential new discharges, including toe drain outfalls, seeps, and weeps.

b. A procedure for determining whether a new discharge is actually present.

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c. A procedure for notifying the Department when a new discharge is confirmed.
d. Any other information related to the identification of new discharges required by the Department.

(2) The Department shall approve the Plan for the Identification of New Discharges if it determines that the Plan complies with the requirements of this subsection and will be sufficient to protect public health, safety, and welfare; the environment; and natural resources.

(3) No later than 30 days from the approval of the Plan for the Identification of New Discharges, the owner shall begin implementation of the Plan in accordance with the Plan.

(e) Reporting. – In addition to any other reporting required by the Department, the owner of a coal combustion residuals surface impoundment shall submit an annual Surface Water Protection and Restoration Report to the Department no later than January 31 of each year. The Report shall include a summary of all surface water sampling, protection, and restoration activities related to the impoundment for the preceding year, including the status of the identification, assessment, and correction of unpermitted discharges from coal combustion residuals surface impoundments to the surface waters of the State. ~~The owner of a coal combustion residuals surface impoundment shall also submit all information required to be submitted to the Department pursuant to this section to the Coal Ash Management Commission.~~

"**§ 130A-309.213. Prioritization of coal combustion residuals surface impoundments.**

(a) As soon as practicable, but no later than December 31, 2015, the Department shall develop proposed classifications for all coal combustion residuals surface impoundments, including active and retired sites, for the purpose of closure and remediation based on these sites' risks to public health, safety, and welfare; the environment; and natural resources and shall determine a schedule for closure and required remediation that is based on the degree of risk to public health, safety, and welfare; the environment; and natural resources posed by the impoundments and that gives priority to the closure and required remediation of impoundments that pose the greatest risk. In assessing the risk, the Department shall evaluate information received pursuant to G.S. 130A-309.211 and G.S. 130A-309.212 and any other information deemed ~~relevant and, at a minimum, consider all of the following:~~relevant.

~~(1) Any hazards to public health, safety, or welfare resulting from the impoundment.~~
~~(2) The structural condition and hazard potential of the impoundment.~~
~~(3) The proximity of surface waters to the impoundment and whether any surface waters are contaminated or threatened by contamination as a result of the impoundment.~~
~~(4) Information concerning the horizontal and vertical extent of soil and groundwater contamination for all contaminants confirmed to be present in groundwater in exceedance of groundwater quality standards and all significant factors affecting contaminant transport.~~
~~(5) The location and nature of all receptors and significant exposure pathways.~~
~~(6) The geological and hydrogeological features influencing the movement and chemical and physical character of the contaminants.~~
~~(7) The amount and characteristics of coal combustion residuals in the impoundment.~~
~~(8) Whether the impoundment is located within an area subject to a 100-year flood.~~
~~(9) Any other factor the Department deems relevant to establishment of risk.~~

(b) The Department shall issue a proposed classification for each coal combustion residuals surface impoundment based upon the assessment conducted pursuant to subsection (a) of this section as high-risk, intermediate-risk, or low-risk. Within 30 days after a proposed classification has been issued, the Department shall issue a written declaration, including findings of fact, documenting the proposed classification. The Department shall provide for public participation on the proposed risk classification as follows:

(1) The Department shall make copies of the written declaration issued pursuant to this subsection available for inspection as follows:

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a. A copy of the declaration shall be provided to the local health director.
b. A copy of the declaration shall be provided to the public library located in closest proximity to the site in the county or counties in which the site is located.
c. The Department shall post a copy of the declaration on the Department's Web site.
d. The Department shall place copies of the declaration in other locations so as to assure the reasonable availability thereof to the public.

(2) The Department shall give notice of the written declaration issued pursuant to this subsection as follows:
a. A notice and summary of the declaration shall be published weekly for a period of three consecutive weeks in a newspaper having general circulation in the county or counties where the site is located.
b. Notice of the written declaration shall be given by first-class mail to persons who have requested such notice. Such notice shall include a summary of the written declaration and state the locations where a copy of the written declaration is available for inspection. The Department shall maintain a mailing list of persons who request notice pursuant to this section.
c. Notice of the written declaration shall be given by electronic mail to persons who have requested such notice. Such notice shall include a summary of the written declaration and state the locations where a copy of the written declaration is available for inspection. The Department shall maintain a mailing list of persons who request notice pursuant to this section.

(3) No later than 60 days after issuance of the written declaration, the Department shall conduct a public meeting in the county or counties in which the site is located to explain the written declaration to the public. The Department shall give notice of the hearing at least 15 days prior to the date thereof by all of the following methods:
a. Publication as provided in subdivision (1) of this subsection, with first publication to occur not less than 30 days prior to the scheduled date of the hearing.
b. First-class mail to persons who have requested notice as provided in subdivision (2) of this subsection.
c. Electronic mail to persons who have requested notice as provided in subdivision (2) of this subsection.

(4) At least 30 days from the latest date on which notice is provided pursuant to subdivision (2) of this subsection shall be allowed for the receipt of written comment on the written declaration prior to issuance of a final risk classification. At least 20 days will be allowed for receipt of written comment following a hearing conducted pursuant to subdivision (3) of this subsection prior to issuance of a ~~final~~ preliminary risk classification.

~~(c) Within 30 days of the receipt of all written comment as required by subdivision (4) of subsection (b) of this section, the Department shall submit a proposed classification for a coal combustion residuals surface impoundment to the Coal Ash Management Commission established pursuant to G.S. 130A-309.202. The Commission shall evaluate all information submitted in accordance with this Part related to the proposed classification and any other information the Commission deems relevant. The Commission shall only approve the proposed classification if it determines that the classification was developed in accordance with this section and that the classification accurately reflects the level of risk posed by the coal combustion residuals surface impoundment. The Commission shall issue its determination in writing, including findings in support of its determination. If the Commission fails to act on a proposed classification within 60 days of receipt of the proposed classification, the proposed classification shall be deemed approved. Parties aggrieved by a final decision of the Commission pursuant to this subsection may appeal the decision as provided under Article 3 of Chapter 150B of the General Statutes.~~

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(d) No later than 30 days after expiration of the deadline set forth in G.S. 130A-309.211(c1), or any applicable extension granted by the Secretary pursuant G.S. 130A-309.211(c1), the Department shall issue a final classification for each impoundment as follows:

(1) The Department shall classify an impoundment as low-risk if the impoundment owner satisfies both of the following criteria:

a. Has established permanent water supplies as required for the impoundment pursuant to G.S. 130A-309.211(c1).

b. Has rectified any deficiencies identified by, and otherwise complied with the requirements of, any dam safety order issued by the Environmental Management Commission for the impoundment pursuant to G.S. 143-215.32. No later than July 1, 2018, the Department shall conduct the annual inspection of each dam associated with a coal combustion residuals surface impoundment required for that year, to detect any deficiencies and to ascertain, at a minimum, whether the dam is sufficiently strong, maintained in good repair and operating condition, does not pose a danger to life or property, and satisfies minimum streamflow requirements. The Department shall issue written findings of fact for each inspection and present such findings to the Environmental Management Commission. If the Department detects any deficiencies, the Commission shall issue an order directing the owner of the dam to take action as may be deemed necessary by the Commission within a time limited by the order, but not later than 90 days after issuance of the order.

(2) All other impoundments shall be classified as intermediate-risk.

(e) Parties aggrieved by a final decision of the Department issued pursuant to subsection (d) of this section may appeal the decision as provided under Article 3 of Chapter 150B of the General Statutes.

"**§ 130A-309.214. Closure of coal combustion residuals surface impoundments.**

(a) An owner of a coal combustion residuals surface impoundment shall submit a proposed Coal Combustion Residuals Surface Impoundment Closure Plan for the Department's approval. If corrective action to restore groundwater has not been completed pursuant to the requirements of G.S. 130A-309.211(b), the proposed closure plan shall include provisions for completion of activities to restore groundwater in conformance with the requirements of Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code. In addition, the following requirements, at a minimum, shall apply to such plans:

(1) High-risk impoundments shall be closed as soon as practicable, but no later than December 31, 2019. A proposed closure plan for such impoundments must be submitted as soon as practicable, but no later than December 31, 2016. At a minimum, (i) impoundments located in whole above the seasonal high groundwater table shall be dewatered; (ii) impoundments located in whole or in part beneath the seasonal high groundwater table shall be dewatered to the maximum extent practicable; and (iii) the owner of an impoundment shall either:

a. Convert the coal combustion residuals impoundment to an industrial landfill by removing all coal combustion residuals and contaminated soil from the impoundment temporarily, safely storing the residuals on-site, and complying with the requirements for such landfills established by this Article and rules adopted thereunder. At a minimum, the landfills shall have a design with a leachate collection system, a closure cap system, and a composite liner system consisting of two components: the upper component shall consist of a minimum 30-ml flexible membrane (FML), and the lower components shall consist of at least a two-foot layer of compacted soil with a hydraulic conductivity of no more than 1×10^{-7} centimeters per second. FML components consisting of high density polyethylene (HDPE) shall be at least 60 ml thick. The landfill shall otherwise comply with the construction requirements established by

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Section .1624 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, and the siting and design requirements for disposal sites established by Section .0503 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, except with respect to those requirements that pertain to buffers. In lieu of the buffer requirement established by Section .0503(f)(2)(iii) of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, the owner of the impoundment shall establish and maintain a 300-foot buffer between surface waters and disposal areas. After the temporarily displaced coal combustion residuals have been returned for disposal in the industrial landfill constructed pursuant to the requirements of this sub-subdivision, the owner of the landfill shall comply with the closure and post-closure requirements established by Section .1627 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code. A landfill constructed pursuant to this sub-subdivision shall otherwise be subject to all applicable requirements of this Chapter and rules adopted thereunder. Prior to closure, the Department may allow the disposal of coal combustion residuals, in addition to those originally contained in the impoundment, to the landfill constructed pursuant to this sub-subdivision, if the Department determines that the site is suitable for additional capacity and that disposal of additional coal combustion residuals will not pose an unacceptable risk to public health, safety, welfare; the environment; and natural resources.

b. Remove all coal combustion residuals from the impoundment, return the former impoundment to a nonerosive and stable condition and (i) transfer the coal combustion residuals for disposal in a coal combustion residuals landfill, industrial landfill, or municipal solid waste landfill or (ii) use the coal combustion products in a structural fill or other beneficial use as allowed by law. The use of coal combustion products (i) as structural fill shall be conducted in accordance with the requirements of Subpart 3 of this Part and (ii) for other beneficial uses shall be conducted in accordance with the requirements of Section .1700 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code (Requirements for Beneficial Use of Coal Combustion By-Products) and Section .1205 of Subchapter T of Chapter 2 of Title 15A of the North Carolina Administrative Code (Coal Combustion Products Management).

(2) Intermediate-risk impoundments shall be closed as soon as practicable, but no later than December 31, 2024. A proposed closure plan for such impoundments must be submitted as soon as practicable, but no later than December 31, ~~2017.~~2019. At a minimum, such impoundments shall be dewatered, and the owner of an impoundment shall close the impoundment in any manner allowed pursuant to subdivision (1) of this ~~subsection.~~subsection, or, if applicable, as provided in G.S. 130A-309.216.

(3) Low-risk impoundments shall be closed as soon as practicable, but no later than December 31, 2029. A proposed closure plan for such impoundments must be submitted as soon as practicable, but no later than December 31, ~~2018.~~2019. At a minimum, (i) impoundments located in whole above the seasonal high groundwater table shall be dewatered; (ii) impoundments located in whole or in part beneath the seasonal high groundwater table shall be dewatered to the maximum extent practicable; and (iii) at the election of the Department, the owner of an impoundment shall either:

a. Close in any manner allowed pursuant to subdivision (1) of this ~~subsection.~~subsection;

b. Comply with the closure and post-closure requirements established by Section .1627 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, except that such impoundments

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shall not be required to install and maintain a leachate collection system. Specifically, the owner of an impoundment shall install and maintain a cap system that is designed to minimize infiltration and erosion in conformance with the requirements of Section .1624 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code, and, at a minimum, shall be designed and constructed to (i) have a permeability no greater than 1×10^{-5} centimeters per second; (ii) minimize infiltration by the use of a low-permeability barrier that contains a minimum 18 inches of earthen material; and (iii) minimize erosion of the cap system and protect the low-permeability barrier from root penetration by use of an erosion layer that contains a minimum of six inches of earthen material that is capable of sustaining native plant growth. In addition, the owner of an impoundment shall (i) install and maintain a groundwater monitoring system; (ii) establish financial assurance that will ensure that sufficient funds are available for closure pursuant to this subdivision, post-closure maintenance and monitoring, any corrective action that the Department may require, and satisfy any potential liability for sudden and nonsudden accidental occurrences arising from the impoundment and subsequent costs incurred by the Department in response to an incident, even if the owner becomes insolvent or ceases to reside, be incorporated, do business, or maintain assets in the State; and (iii) conduct post-closure care for a period of 30 years, which period may be increased by the Department upon a determination that a longer period is necessary to protect public health, safety, welfare; the environment; and natural resources, or decreased upon a determination that a shorter period is sufficient to protect public health, safety, welfare; the environment; and natural resources. The Department may require implementation of any other measure it deems necessary to protect public health, safety, and welfare; the environment; and natural resources, including imposition of institutional controls that are sufficient to protect public health, safety, and welfare; the environment; and natural resources. The Department may not approve closure for an impoundment pursuant to sub-subdivision b. of subdivision (3) of this subsection unless the Department finds that the proposed closure plan includes design measures to prevent, upon the plan's full implementation, post-closure exceedances of groundwater quality standards beyond the compliance boundary that are attributable to constituents associated with the presence of the ~~impoundment.~~impoundment; or

c. Comply with the closure requirements established by the United States Environmental Protection Agency as provided in 40 CFR Parts 257 and 261, "Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities."

(4) Closure Plans for all impoundments shall include all of the following:

a. Facility and coal combustion residuals surface impoundment description. – A description of the operation of the site that shall include, at a minimum, all of the following:

1. Site history and history of site operations, including details on the manner in which coal combustion residuals have been stored and disposed of historically.
2. Estimated volume of material contained in the impoundment.
3. Analysis of the structural integrity of dikes or dams associated with impoundment.
4. All sources of discharge into the impoundment, including volume and characteristics of each discharge.
5. Whether the impoundment is lined, and, if so, the composition thereof.

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6. A summary of all information available concerning the impoundment as a result of inspections and monitoring conducted pursuant to this Part and otherwise available.

b. Site maps, which, at a minimum, illustrate all of the following:
   1. All structures associated with the operation of any coal combustion residuals surface impoundment located on the site. For purposes of this sub-subdivision, the term "site" means the land or waters within the property boundary of the applicable electric generating station.
   2. All current and former coal combustion residuals disposal and storage areas on the site, including details concerning coal combustion residuals produced historically by the electric generating station and disposed of through transfer to structural fills.
   3. The property boundary for the applicable site, including established compliance boundaries within the site.
   4. All potential receptors within 2,640 feet from established compliance boundaries.
   5. Topographic contour intervals of the site shall be selected to enable an accurate representation of site features and terrain and in most cases should be less than 20-foot intervals.
   6. Locations of all sanitary landfills permitted pursuant to this Article on the site that are actively receiving waste or are closed, as well as the established compliance boundaries and components of associated groundwater and surface water monitoring systems.
   7. All existing and proposed groundwater monitoring wells associated with any coal combustion residuals surface impoundment on the site.
   8. All existing and proposed surface water sample collection locations associated with any coal combustion residuals surface impoundment on the site.

c. The results of a hydrogeologic, geologic, and geotechnical investigation of the site, including, at a minimum, all of the following:
   1. A description of the hydrogeology and geology of the site.
   2. A description of the stratigraphy of the geologic units underlying each coal combustion residuals surface impoundment located on the site.
   3. The saturated hydraulic conductivity for (i) the coal combustion residuals within any coal combustion residuals surface impoundment located on the site and (ii) the saturated hydraulic conductivity of any existing liner installed at an impoundment, if any.
   4. The geotechnical properties for (i) the coal combustion residuals within any coal combustion residuals surface impoundment located on the site, (ii) the geotechnical properties of any existing liner installed at an impoundment, if any, and (iii) the uppermost identified stratigraphic unit underlying the impoundment, including the soil classification based upon the Unified Soil Classification System, in-place moisture content, particle size distribution, Atterberg limits, specific gravity, effective friction angle, maximum dry density, optimum moisture content, and permeability.
   5. A chemical analysis of the coal combustion residuals surface impoundment, including water, coal combustion residuals, and coal combustion residuals-affected soil.
   6. Identification of all substances with concentrations determined to be in excess of the groundwater quality

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standards for the substance established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code, including all laboratory results for these analyses.

7. Summary tables of historical records of groundwater sampling results.
8. A map that illustrates the potentiometric contours and flow directions for all identified aquifers underlying impoundments (shallow, intermediate, and deep) and the horizontal extent of areas where groundwater quality standards established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code for a substance are exceeded.
9. Cross-sections that illustrate the following: the vertical and horizontal extent of the coal combustion residuals within an impoundment; stratigraphy of the geologic units underlying an impoundment; and the vertical extent of areas where groundwater quality standards established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code for a substance are exceeded.

d. The results of groundwater modeling of the site that shall include, at a minimum, all of the following:
   1. An account of the design of the proposed Closure Plan that is based on the site hydrogeologic conceptual model developed and includes (i) predictions on post-closure groundwater elevations and groundwater flow directions and velocities, including the effects on and from the potential receptors and (ii) predictions at the compliance boundary for substances with concentrations determined to be in excess of the groundwater quality standards for the substance established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code.
   2. Predictions that include the effects on the groundwater chemistry and should describe migration, concentration, mobilization, and fate for substances with concentrations determined to be in excess of the groundwater quality standards for the substance established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code pre- and post-closure, including the effects on and from potential receptors.
   3. A description of the groundwater trend analysis methods used to demonstrate compliance with groundwater quality standards for the substance established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code and requirements for corrective action of groundwater contamination established by Subchapter L of Chapter 2 of Title 15A of the North Carolina Administrative Code.

e. A description of any plans for beneficial use of the coal combustion residuals in compliance with the requirements of Section .1700 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code (Requirements for Beneficial Use of Coal Combustion By-Products) and Section .1205 of Subchapter T of Chapter 2 of Title 15A of the North Carolina Administrative Code (Coal Combustion Products Management).

f. All engineering drawings, schematics, and specifications for the proposed Closure Plan. If required by Chapter 89C of the General Statutes, engineering design documents should be prepared, signed, and sealed by a professional engineer.

g. A description of the construction quality assurance and quality control program to be implemented in conjunction with the Closure

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Plan, including the responsibilities and authorities for monitoring and testing activities, sampling strategies, and reporting requirements.

h. A description of the provisions for disposal of wastewater and management of stormwater and the plan for obtaining all required permits.

i. A description of the provisions for the final disposition of the coal combustion residuals. If the coal combustion residuals are to be removed, the owner must identify (i) the location and permit number for the coal combustion residuals landfills, industrial landfills, or municipal solid waste landfills in which the coal combustion residuals will be disposed and (ii) in the case where the coal combustion residuals are planned for beneficial use, the location and manner in which the residuals will be temporarily stored. If the coal combustion residuals are to be left in the impoundment, the owner must (i) in the case of closure pursuant to sub-subdivision (a)(1)a. of this section, provide a description of how the ash will be stabilized prior to completion of closure in accordance with closure and post-closure requirements established by Section .1627 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code and (ii) in the case of closure pursuant to sub-subdivision (a)(1)b. of this section, provide a description of how the ash will be stabilized pre- and post-closure. If the coal combustion residuals are to be left in the impoundment, the owner must provide an estimate of the volume of coal combustion residuals remaining.

j. A list of all permits that will need to be acquired or modified to complete closure activities.

k. A description of the plan for post-closure monitoring and care for an impoundment for a minimum of 30 years. The length of the post-closure care period may be (i) proposed to be decreased or the frequency and parameter list modified if the owner demonstrates that the reduced period or modifications are sufficient to protect public health, safety, and welfare; the environment; and natural resources and (ii) increased by the Department at the end of the post-closure monitoring and care period if there are statistically significant increasing groundwater quality trends or if contaminant concentrations have not decreased to a level protective of public health, safety, and welfare; the environment; and natural resources. If the owner determines that the post-closure care monitoring and care period is no longer needed and the Department agrees, the owner shall provide a certification, signed and sealed by a professional engineer, verifying that post-closure monitoring and care has been completed in accordance with the post-closure plan. If required by Chapter 89C of the General Statutes, the proposed plan for post-closure monitoring and care should be signed and sealed by a professional engineer. The plan shall include, at a minimum, all of the following:

    1. A demonstration of the long-term control of all leachate, affected groundwater, and stormwater.
    2. A description of a groundwater monitoring program that includes (i) post-closure groundwater monitoring, including parameters to be sampled and sampling schedules; (ii) any additional monitoring well installations, including a map with the proposed locations and well construction details; and (iii) the actions proposed to mitigate statistically significant increasing groundwater quality trends.

l. An estimate of the milestone dates for all activities related to closure and post-closure.

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m. Projected costs of assessment, corrective action, closure, and post-closure care for each coal combustion residuals surface impoundment.

n. A description of the anticipated future use of the site and the necessity for the implementation of institutional controls following closure, including property use restrictions, and requirements for recordation of notices documenting the presence of contamination, if applicable, or historical site use.

(b) The Department shall review a proposed Coal Combustion Residuals Surface Impoundment Closure Plan for consistency with the minimum requirements set forth in subsection (a) of this section and whether the proposed Closure Plan is protective of public health, safety, and welfare; the environment; and natural resources and otherwise complies with the requirements of this Part. Prior to issuing a decision on a proposed Closure Plan, the Department shall provide for public participation on the proposed Closure Plan as follows:

(1) The Department shall make copies of the proposed Closure Plan available for inspection as follows:

a. A copy of the proposed Closure Plan shall be provided to the local health director.

b. A copy of the proposed Closure Plan shall be provided to the public library located in closest proximity to the site in the county or counties in which the site is located.

c. The Department shall post a copy of the proposed Closure Plan on the Department's Web site.

d. The Department shall place copies of the declaration in other locations so as to assure the reasonable availability thereof to the public.

(2) Before approving a proposed Closure Plan, the Department shall give notice as follows:

a. A notice and summary of the proposed Closure Plan shall be published weekly for a period of three consecutive weeks in a newspaper having general circulation in the county or counties where the site is located.

b. Notice that a proposed Closure Plan has been developed shall be given by first-class mail to persons who have requested such notice. Such notice shall include a summary of the proposed Closure Plan and state the locations where a copy of the proposed Closure Plan is available for inspection. The Department shall maintain a mailing list of persons who request notice pursuant to this section.

c. Notice that a proposed Closure Plan has been developed shall be given by electronic mail to persons who have requested such notice. Such notice shall include a summary of the proposed Closure Plan and state the locations where a copy of the proposed Closure Plan is available for inspection. The Department shall maintain a mailing list of persons who request notice pursuant to this section.

(3) No later than 60 days after receipt of a proposed Closure Plan, the Department shall conduct a public meeting in the county or counties in which the site is located to explain the proposed Closure Plan and alternatives to the public. The Department shall give notice of the hearing at least 30 days prior to the date thereof by all of the following methods:

a. Publication as provided in subdivision (1) of this subsection, with first publication to occur not less than 30 days prior to the scheduled date of the hearing.

b. First-class mail to persons who have requested notice as provided in subdivision (2) of this subsection.

c. Electronic mail to persons who have requested notice as provided in subdivision (2) of this subsection.

(4) At least 30 days from the latest date on which notice is provided pursuant to subdivision (2) of this subsection shall be allowed for the receipt of written comment on the proposed Closure Plan prior to its approval. At least 20 days

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will be allowed for receipt of written comment following a hearing conducted pursuant to subdivision (3) of this subsection prior to the approval of the proposed Closure Plan.

(c) The Department shall disapprove a proposed Coal Combustion Residuals Surface Impoundment Closure Plan unless the Department finds that the Closure Plan is protective of public health, safety, and welfare; the environment; and natural resources and otherwise complies with the requirements of this Part. The Department shall provide specific findings to support its decision to approve or disapprove a proposed Closure Plan. If the Department disapproves a proposed Closure Plan, the person who submitted the Closure Plan may seek review as provided in Article 3 of Chapter 150B of the General Statutes. If the Department fails to approve or disapprove a proposed Closure Plan within 120 days after a complete Closure Plan has been submitted, the person who submitted the proposed Closure Plan may treat the Closure Plan as having been disapproved at the end of that time period. The Department may require a person who proposes a Closure Plan to supply any additional information necessary for the Department to approve or disapprove the Closure Plan.

~~(d) Within 30 days of its approval of a Coal Combustion Residuals Surface Impoundment Closure Plan, the Department shall submit the Closure Plan to the Coal Ash Management Commission. The Commission shall evaluate all information submitted in accordance with this Part related to the Closure Plan and any other information the Commission deems relevant. The Commission shall approve the Closure Plan if it determines that the Closure Plan was developed in accordance with this section, that implementation of the Closure Plan according to the Closure Plan's schedule is technologically and economically feasible, and the Closure Plan is protective of the public health, safety, and welfare; the environment; and natural resources. In addition, the Commission may consider any impact on electricity costs and reliability, but this factor may not be dispositive of the Commission's determination. The Commission shall issue its determination in writing, including findings in support of its determination. If the Commission fails to act on a Closure Plan within 60 days of receipt of the Closure Plan, the Closure Plan shall be deemed approved. Parties aggrieved by a final decision of the Commission pursuant to this subsection may appeal the decision as provided under Article 3 of Chapter 150B of the General Statutes.~~

(e) As soon as practicable, but no later than 60 days after a Coal Combustion Residuals Surface Impoundment Closure Plan has been approved by the ~~Coal Ash Management Commission,~~Department, the owner of the coal combustion residuals impoundment shall begin implementation of the approved plan. Modifications to an approved Closure Plan may only be allowed in conformance with the requirements of this Part, upon written request of an owner of an impoundment, with the written approval of the Department, and after public notice of the change in accordance with the requirements of subdivision (2) of subsection (b) of this section. Provided, however, minor technical modifications may be made in accordance with standard Department procedures for such minor modifications and may be made without written approval of the Department or public notice of the change.

(f) Nothing in this section shall be construed to obviate the need for sampling, remediation, and monitoring activities at the site as required by G.S. 130A-309.211 and G.S. 130A-309.310 [G.S. 130A-309.212].

"**§ 130A-309.215. Variance authority.**

(a) In recognition of the complexity and magnitude of the issues surrounding the management of coal combustion residuals and coal combustion residuals surface impoundments, the General Assembly authorizes the ~~Commission~~ Secretary to grant a variance to extend any deadline ~~for closure of an impoundment established under G.S. 130A 309.214 in conformance with the requirements of this section. To request such a variance the owner of an impoundment~~ under this act, on the Secretary's own motion, or that of an impoundment owner, on the basis that compliance with the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and would produce serious hardship without equal or greater benefits to the public.

(a1) For variances requested by an impoundment owner, the owner shall, no earlier than ~~two years~~one year prior to the applicable deadline, submit an application in a form acceptable to the Department which shall include, at a minimum, all of the following information: identification of the site, applicable requirements, and applicable deadlines for which a variance is sought, and the site-specific circumstances that support the need for the variance. The owner of the impoundment shall also provide detailed information that demonstrates (i) the owner has

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substantially complied with all other requirements and deadlines established by this Part; (ii) the owner has made good faith efforts to comply with the applicable deadline for closure of the impoundment; and (iii) that compliance with the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and would produce serious hardship without equal or greater benefits to the public. As soon as practicable, but no later than 60 days from receipt of an application, the Secretary shall evaluate the information submitted in conjunction with the application, and any other information the Secretary deems relevant, to determine whether the information supports issuance of a variance. ~~After such evaluation, if the Secretary finds that the information supports issuance of a variance from the deadline, the Secretary shall issue a proposed variance. Within 10 days after a proposed variance has been issued, the Secretary shall issue a written declaration, including findings of fact, documenting the proposed variance.~~

(a2) The Department shall provide for public participation on ~~the~~a proposed variance in the manner provided by G.S. 130A-309.214(b) and shall take the public input received through the process into account in its decision concerning ~~the proposed~~issuance of a variance. ~~Within 30 days of the receipt of all public input received, the Department shall submit a proposed variance to the Coal Ash Management Commission. The Commission shall evaluate all information submitted in accordance with this section and any other information the Commission deems relevant.~~ The ~~Commission~~ Department shall only approve a variance if it determines that compliance with the deadline cannot be achieved by application of best available technology found to be economically reasonable at the time and would produce serious hardship without equal or greater benefits to the public. The ~~Commission~~ Department shall issue its determination in writing, including findings in support of its determination. If the ~~Commission~~ Department fails to act on a variance request within 60 days of receipt, the variance shall be deemed denied.

(a3) Parties aggrieved by a final decision of the Commission pursuant to this subsection may appeal the decision as provided under Article 3 of Chapter 150B of the General Statutes.

~~(b) A variance granted pursuant to this section shall not extend a deadline for closure of an impoundment more than three years beyond the date applicable to the impoundment as provided under G.S. 130A-309.214.~~

~~(c) No more than one variance may be granted pursuant to this section per impoundment.~~

"**§ 130A-309.216. Ash beneficiation projects.**

(a) On or before January 1, 2017, an impoundment owner shall (i) identify, at a minimum, impoundments at two sites located within the State with ash stored in the impoundments on that date that is suitable for processing for cementitious purposes and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project at each site capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundment(s) located at the sites. As soon as legally practicable thereafter, the impoundment owner shall apply for all permits necessary for the ash beneficiation projects from the Department. The Department shall expedite any State permits and approvals required for such projects. No later than 24 months after issuance of all necessary permits, operation of both ash beneficiation projects shall be commenced. An impoundment owner shall use commercially reasonable efforts to produce 300,000 tons of ash to specifications appropriate for cementitious products from each project.

(b) On or before July 1, 2017, an impoundment owner shall (i) identify an impoundment at an additional site located within the State with ash stored in the impoundment on that date that is suitable for processing for cementitious purposes and (ii) enter into a binding agreement for the installation and operation of an ash beneficiation project capable of annually processing 300,000 tons of ash to specifications appropriate for cementitious products, with all ash processed to be removed from the impoundment(s) located at the site. As soon as legally practicable thereafter, the impoundment owner shall apply for all permits necessary for the ash beneficiation project from the Department. The Department shall expedite any State permits and approvals required for such projects. No later than 24 months after issuance of all necessary permits, operation of the ash beneficiation project shall be commenced. An impoundment owner shall use commercially reasonable efforts to produce 300,000 tons of ash to specifications appropriate for cementitious products from the project.

(c) Notwithstanding any deadline for closure provided by G.S. 130A-309.214, any impoundment classified as intermediate- or low-risk that is located at a site at which an ash

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beneficiation project is installed, operating, and processing at least 300,000 tons of ash annually from the impoundment, shall be closed no later than December 31, 2029.

"**§ 130A-309.217: Reserved for future codification purposes.**"

SECTION 2. G.S. 62-302.1 reads as rewritten:

"**§ 62-302.1. Regulatory fee for combustion residuals surface impoundments.**

(a) Fee Imposed. – Each public utility with a coal combustion residuals surface impoundment shall pay a regulatory fee for the purpose of defraying the costs of oversight of coal combustion residuals. The fee is in addition to the fee imposed under G.S. 62-302. The fees collected under this section shall only be used to pay the expenses of the ~~Coal Ash Management Commission and the~~ Department of Environmental Quality in providing oversight of coal combustion residuals.

(b) Rate. – The combustion residuals surface impoundment fee shall be ~~three-hundredths of one percent (0.03%)~~ twenty-two thousandths of one percent (0.022%) of the North Carolina jurisdictional revenues of each public utility with a coal combustion residuals surface impoundment. For the purposes of this section, the term "North Carolina jurisdictional revenues" has the same meaning as in G.S. 62-302.

(c) When Due. – The fee shall be paid in quarterly installments. The fee is payable to the ~~Coal Ash Management Commission~~ Department of Environmental Quality on or before the 15th of the second month following the end of each quarter. Each public utility subject to this fee shall, on or before the date the fee is due for each quarter, prepare and render a report on a form prescribed by the ~~Coal Ash Management Commission.~~ Department of Environmental Quality. The report shall state the public utility's total North Carolina jurisdictional revenues for the preceding quarter and shall be accompanied by any supporting documentation that the ~~Coal Ash Management Commission~~Department of Environmental Quality may by rule require. Receipts shall be reported on an accrual basis.

(d) Use of Proceeds. – A special fund in the ~~Office of State Treasurer and the Coal Ash Management Commission~~ Department of Environmental Quality is created. The fees collected pursuant to this section ~~and all other funds received by the Coal Ash Management Commission~~ shall be deposited in the Coal Combustion Residuals Management Fund. The Fund shall be placed in an interest-bearing account, and any interest or other income derived from the Fund shall be credited to the Fund. Subject to appropriation by the General Assembly, ~~twenty-six and one-half percent (26.5%) of the moneys in the Fund shall be used by the Coal Ash Management Commission and the remainder~~ one hundred percent (100%) shall be used by the Department of Environmental Quality. ~~The Coal Ash Management Commission shall be subject to the provisions of the State Budget Act, except that no unexpended surplus of the Coal Combustion Residuals Management Fund shall revert to the General Fund.~~ All funds credited to the Fund shall be used only to pay the expenses of the ~~Coal Ash Management Commission and the~~ Department of Environmental Quality in providing oversight of coal combustion residuals.

(e) Recovery of Fee. – The North Carolina Utilities Commission shall not allow an electric public utility to recover this fee from the retail electric customers of the State."

SECTION 3.(a) Notwithstanding G.S. 130A-309.213 or G.S. 130A-309.214, as amended by Section 1 of this act, and except as otherwise preempted by the requirements of federal law, the following coal combustion residuals surface impoundments shall be deemed intermediate-risk and, as soon as practicable, but no later than August 1, 2028, shall be closed in conformance with Section 3(b) of this act:

(1) Coal combustion residuals surface impoundments located at the H.F. Lee Steam Station, owned and operated by Duke Energy Progress, and located in Wayne County.

(2) Coal combustion residuals surface impoundments located at the Cape Fear Steam Station, owned and operated by Duke Energy Progress, and located in Chatham County.

(3) Coal combustion residuals surface impoundments located at the Weatherspoon Steam Station, owned and operated by Duke Energy Progress, and located in New Hanover County.

SECTION 3.(b) The impoundments identified in subsection (a) of this section shall be closed as follows:

(1) Impoundments located in whole above the seasonal high groundwater table shall be dewatered. Impoundments located in whole or in part beneath the

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seasonal high groundwater table shall be dewatered to the maximum extent practicable.

(2) All coal combustion residuals shall be removed from the impoundments and transferred for (i) disposal in a coal combustion residuals landfill, industrial landfill, or municipal solid waste landfill or (ii) use in a structural fill or other beneficial use as allowed by law. The use of coal combustion products (i) as structural fill shall be conducted in accordance with the requirements of Subpart 3 of Part 2I of Article 9 of the General Statutes and (ii) for other beneficial uses shall be conducted in accordance with the requirements of Section .1700 of Subchapter B of Chapter 13 of Title 15A of the North Carolina Administrative Code (Requirements for Beneficial Use of Coal Combustion By-Products) and Section .1200 of Subchapter T of Chapter 2 of Title 15A of the North Carolina Administrative Code (Coal Combustion Products Management), as applicable.

(3) If restoration of groundwater quality is degraded as a result of the impoundment, corrective action to restore groundwater quality shall be implemented by the owner or operator as provided in G.S. 130A-309.211.

SECTION 4. There is appropriated a sum of up to four hundred fifty thousand dollars ($450,000) to the State Water Infrastructure Authority from the Coal Combustion Residuals Management Fund cash balance on June 30, 2016, to fund grants to local governments operating public water supplies in areas surrounding coal combustion residuals impoundments to provide moneys for additional staff for permitting and construction activities as may be needed to facilitate establishment of permanent water supplies to households eligible for connection to public water supplies pursuant to G.S. 130A-309.211(c1).

SECTION 5.(a) Section 3(e) of S.L. 2014-122 is repealed.

SECTION 5.(b) Section 4(e) of S.L. 2014-122 reads as rewritten:

"**SECTION 4.(e)** All electric generating facilities owned by a public utility that produce coal combustion residuals and coal combustion products shall issue a request for proposals on or before December 31, 2014, for (i) the conduct of a market analysis for the concrete industry and other industries that might beneficially use coal combustion residuals and coal combustion products; (ii) the study of the feasibility and advisability of installation of technology to convert existing and newly generated coal combustion residuals to commercial-grade coal combustion products suitable for use in the concrete industry and other industries that might beneficially use coal combustion residuals; and (iii) an examination of all innovative technologies that might be applied to diminish, recycle or reuse, or mitigate the impact of existing and newly generated coal combustion residuals. All electric generating facilities shall present the materials and information received in response to a request for proposals issued pursuant to this section and an assessment of the materials and information, including a forecast of specific actions to be taken in response to the materials and information received, to the Environmental Management Commission ~~and the Coal Ash Management Commission~~ on or before August 1, 2016."

SECTION 6.(a) G.S. 143B-291 reads as rewritten:

"**§ 143B-291. North Carolina Mining Commission – members; selection; removal; compensation; quorum; services.**

(a) Repealed by 2014-4, s. 5(a), effective July 31, 2015.

(a1) Members, Selection. – The North Carolina Mining Commission shall consist of eight members appointed as follows:

(1) One member who is the chair of the North Carolina State University Minerals Research Laboratory Advisory ~~Committee.~~Committee, ex officio and nonvoting.

(2) The State Geologist, ex officio and nonvoting.

(3) One member appointed by the Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who is a representative of the mining industry.

(4) One member appointed by the Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who is a representative of the mining industry.

(5) One member appointed by the ~~General Assembly upon recommendation of the Speaker of the House of Representatives~~ Governor subject to

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confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who is a representative of the mining industry.

(6) One member appointed by the ~~General Assembly upon recommendation of the President Pro Tempore of the Senate~~ Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who is a representative of the mining industry.

(7) One member appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in conformance with G.S. 120-121, who is a ~~member of~~ representative of a nongovernmental conservation ~~interests.~~interest.

(8) One member appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in conformance with G.S. 120-121, who is a ~~member of~~representative of a nongovernmental conservation ~~interests.~~interest.

(a2) Process for Appointments by the Governor. – The Governor shall transmit to the presiding officers of the Senate and the House of Representatives, within four weeks of the convening of the session of the General Assembly in the year for which the terms in question are to expire, the names of the persons to be appointed by the Governor and submitted to the General Assembly for confirmation by joint resolution. If an appointment is required pursuant to this subsection when the General Assembly is not in session, the member may be appointed and serve on an interim basis pending confirmation by the General Assembly. For the purpose of this subsection, the General Assembly is not in session only (i) prior to convening of the regular session, (ii) during any adjournment of the regular session for more than 10 days, or (iii) after sine die adjournment of the regular session.

(b) Terms. – The term of office of a member of the Commission is ~~six years.~~four years, beginning effective January 1 of the year of appointment and terminating on December 31 of the year of expiration. At the expiration of each member's term, the appointing authority shall replace the member with a new member of like qualifications for a term of ~~six~~ four years. ~~The term of the member appointed under subdivision (5) of subsection (a1) of this section shall expire on June 30 of years that precede by one year those years that are evenly divisible by six. The term of members appointed under subdivisions (3) and (6) of subsection (a1) of this section shall expire on June 30 of years that follow by one year those years that are evenly divisible by six. The term of members appointed under subdivisions (4) and (7) of subsection (a1) of this section shall expire on June 30 of years that follow by three years those years that are evenly divisible by six. Upon the expiration of a six year term, a member may continue to serve until a successor is appointed and duly qualified as provided by G.S. 128-7.~~In order to establish regularly overlapping terms, initial appointments shall be made effective June 1, 2016, or as soon as feasible thereafter, and expire as follows:

(1) The initial appointments made by the Governor:

a. Pursuant to subdivision (a1)(3) of this section shall expire December 31, 2020.

b. Pursuant to subdivision (a1)(4) of this section shall expire December 31, 2020.

c. Pursuant to subdivision (a1)(5) of this section shall expire December 31, 2019.

d. Pursuant to subdivision (a1)(6) of this section shall expire December 31, 2019.

(2) The initial appointment made by the General Assembly upon recommendation of the Speaker of the House of Representatives pursuant to subdivision (a1)(7) of this section shall expire December 31, 2018.

(3) The initial appointment made by the General Assembly upon recommendation of the President Pro Tempore of the Senate pursuant to subdivision (a1)(8) of this section shall expire December 31, 2018.

(c) Vacancies. – In case of death, incapacity, resignation, or vacancy for any other reason in the office of any member appointed by the Governor, prior to the expiration of the member's term of office, the name of the successor shall be submitted by the Governor within four weeks after the vacancy arises to the General Assembly for confirmation by the General Assembly. In case of death, incapacity, resignation, or vacancy for any other reason in the office of any member appointed by the General Assembly, vacancies in those appointments

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shall be filled in accordance with G.S. 120-122. If a vacancy arises or exists when the General Assembly is not in session, and the appointment is deemed urgent by the Governor, the member may be appointed by the Governor and serve on an interim basis pending confirmation or appointment by the General Assembly, as applicable. An appointment to fill a vacancy shall be for the unexpired balance of the term.

(d) Removal. – The Governor may remove any member of the Commission from office for misfeasance, malfeasance, or nonfeasance in accordance with the provisions of ~~G.S. 143B-13.~~ G.S. 143B-13, or for good cause.

(e) Compensation. – The members of the Commission shall receive per diem and necessary traveling and subsistence expenses in accordance with the provisions of G.S. 138-5.

(f) Quorum. – A majority of the Commission shall constitute a quorum for the transaction of business.

(g) Staff. – All clerical and other services required by the Commission shall be supplied by the Secretary of Environmental ~~Quality.~~Quality. The Commission staff shall be housed in the Department of Environmental Quality and supervised by the Secretary of Environmental Quality."

SECTION 6.(b) Notwithstanding the provisions of G.S. 143B-291(a2) and G.S. 143B-291(b), as enacted and amended by Section 6(a) of this act, initial appointments made by the Governor to the Commission shall not require confirmation by the General Assembly.

SECTION 7.(a) G.S. 143B-293.2 reads as rewritten:

"**§ 143B-293.2. North Carolina Oil and Gas Commission – members; selection; removal; compensation; quorum; services.**

(a) Repealed by Session Laws 2014-4, s. 4(a), effective July 31, 2015.

(a1) Members Selection. – The North Carolina Oil and Gas Commission shall consist of nine members appointed as follows:

(1) One appointed by the ~~General Assembly upon recommendation of the Speaker of the House of Representatives~~ Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who, at the time of initial appointment, is an elected official of a municipal government located in a region of North Carolina that has oil and gas potential. A person serving in this seat may complete a term on the Commission even if the person is no longer serving as an elected official of a municipal government but may not be reappointed to a subsequent term.

(2) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in conformance with G.S. 120-121, who shall be a geologist with experience in oil and gas exploration and development.

(3) One appointed by the General Assembly upon recommendation of the Speaker of the House of Representatives in conformance with G.S. 120-121, who is a ~~member~~ representative of a nongovernmental conservation interest.

(4) One appointed by the ~~General Assembly upon recommendation of the President Pro Tempore of the Senate~~ Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who, at the time of initial appointment, is a member of a county board of commissioners of a county located in a region of North Carolina that has oil and gas potential. A person serving in this seat may complete a term on the Commission even if the person is no longer serving as county commissioner but may not be reappointed to a subsequent term.

(5) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in conformance with G.S. 120-121, who is a ~~member~~representative of a nongovernmental conservation interest.

(6) One appointed by the General Assembly upon recommendation of the President Pro Tempore of the Senate in conformance with G.S. 120-121, who shall be an engineer with experience in oil and gas exploration and development.

(7) One appointed by the Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who shall be a representative of a publicly traded natural gas company.

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(8) One appointed by the Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, who shall be a licensed attorney with experience in legal matters associated with oil and gas exploration and development.

(9) One appointed by the Governor subject to confirmation in conformance with Section 5(8) of Article III of the North Carolina Constitution, with experience in matters related to public health.

(a2) Process for Appointments by the Governor. – The Governor shall transmit to the presiding officers of the Senate and the House of Representatives, within four weeks of the convening of the session of the General Assembly in the year for which the terms in question are to expire, the names of the persons to be appointed by the Governor and submitted to the General Assembly for confirmation by joint resolution. If an appointment is required pursuant to this subsection when the General Assembly is not in session, the member may be appointed and serve on an interim basis pending confirmation by the General Assembly. For the purpose of this subsection, the General Assembly is not in session only (i) prior to convening of the regular session, (ii) during any adjournment of the regular session for more than 10 days, or (iii) after sine die adjournment of the regular session.

(b) Terms. – The term of office of members of the Commission is ~~three years.~~four years, beginning effective January 1 of the year of appointment and terminating on December 31 of the year of expiration. A member may be reappointed to no more than two consecutive ~~three-year~~four-year terms. The term of a member who no longer meets the qualifications of their respective appointment, as set forth in subsection ~~(a)~~(a1) of this section, shall terminate but the member may continue to serve until a new member who meets the qualifications is appointed. ~~The terms of members appointed under subdivisions (1), (4), and (7) of subsection (a1) of this section shall expire on June 30 of years evenly divisible by three. The terms of members appointed under subdivisions (2), (5), and (8) of subsection (a1) of this section shall expire on June 30 of years that precede by one year those years that are evenly divisible by three. The terms of members appointed under subdivisions (3), (6), and (9) of subsection (a1) of this section shall expire on June 30 of years that follow by one year those years that are evenly divisible by three.~~ In order to establish regularly overlapping terms, initial appointments shall be made effective June 1, 2016, or as soon as feasible thereafter, and expire as follows:

(1) The initial appointments made by the Governor:
  a. Pursuant to subdivision (a1)(1) of this section shall expire December 31, 2020.
  b. Pursuant to subdivision (a1)(4) of this section shall expire December 31, 2020.
  c. Pursuant to subdivision (a1)(7) of this section shall expire December 31, 2020.
  d. Pursuant to subdivision (a1)(8) of this section shall expire December 31, 2019.
  e. Pursuant to subdivision (a1)(9) of this section shall expire December 31, 2019.

(2) The initial appointments made by the General Assembly upon recommendation of the Speaker of the House of Representatives:
  a. Pursuant to subdivision (a1)(2) of this section shall expire December 31, 2018.
  b. Pursuant to subdivision (a1)(3) of this section shall expire December 31, 2019.

(3) The initial appointments made by the General Assembly upon recommendation of the President Pro Tempore of the Senate:
  a. Pursuant to subdivision (a1)(5) of this section shall expire December 31, 2018.
  b. Pursuant to subdivision (a1)(6) of this section shall expire December 31, 2019.

(c) ~~Vacancies; Removal from Office.~~ Vacancies. – In case of death, incapacity, resignation, or vacancy for any other reason in the office of any member appointed by the Governor, prior to the expiration of the member's term of office, the name of the successor shall be submitted by the Governor within four weeks after the vacancy arises to the General Assembly for confirmation by the General Assembly. In case of death, incapacity, resignation,

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or vacancy for any other reason in the office of any member appointed by the General Assembly, vacancies in those appointments shall be filled in conformance with G.S. 120-122. If a vacancy arises or exists when the General Assembly is not in session and the appointment is deemed urgent by the Governor, the member may be appointed by the Governor and serve on an interim basis pending confirmation or appointment by the General Assembly, as applicable. An appointment to fill a vacancy shall be for the unexpired balance of the term.

(c1) Removal. –

~~(1) Any appointment by the Governor to fill a vacancy on the Commission created by the resignation, dismissal, death, or disability of a member shall be for the balance of the unexpired term.~~ The Governor shall have the power to remove any member of the Commission from office for misfeasance, malfeasance, or nonfeasance in accordance with the provisions of G.S. 143B-13 of the Executive Organization Act of ~~1973.~~1973, or for good cause.

~~(2) Members appointed by the President Pro Tempore of the Senate and the Speaker of the House of Representatives shall be made in accordance with G.S. 120-121, and vacancies in those appointments shall be filled in accordance with G.S. 120-122. In accordance with Section 10 of Article VI of the North Carolina Constitution, a member may continue to serve until a successor is duly appointed.~~

(d) Compensation. – The members of the Commission shall receive per diem and necessary traveling and subsistence expenses in accordance with the provisions of G.S. 138-5.

(e) Quorum. – A majority of the Commission shall constitute a quorum for the transaction of business.

(f) Staff. – All staff support required by the Commission shall be supplied by the Division of Energy, Mineral, and Land Resources and the North Carolina Geological ~~Survey.~~ Survey, and supervised by the Secretary of Environmental Quality.

(g) Committees. – In addition to the Committee on Civil Penalty Remissions required to be established under G.S. 143B-293.6, the chair may establish other committees from members of the Commission to address specific issues as appropriate. No member of a committee may hear or vote on any matter in which the member has an economic interest. A majority of a committee shall constitute a quorum for the transaction of business.

(h) Office May Be Held Concurrently With Others. – Membership on the Oil and Gas Commission is hereby declared to be an office that may be held concurrently with other elective or appointive offices in addition to the maximum number of offices permitted to be held by one person under G.S. 128-1.1."

SECTION 7.(b) Notwithstanding the provisions of G.S. 143B-293.2(a1) and G.S. 143B-293.2(b), as enacted and amended by Section 7(a) of this act, initial appointments made by the Governor to the Commission shall not require confirmation by the General Assembly.

SECTION 7.(c) For purposes of the rules set forth in 15A NCAC 05H (Oil and Gas Conservation Rules), modifications made to the Oil and Gas Commission under Section 7(a) of this act shall, pursuant to G.S. 150B-21.7, be construed to (1) have repealed authority to adopt such rules given to previously constituted commissions and (2) transferred the authority to adopt such rules to the Oil and Gas Commission as modified by Section 7(b) of this act. Therefore, pursuant to G.S. 150B-21.7, rules set forth in 15A NCAC 05H (Oil and Gas Conservation Rules) shall be effective until the Oil and Gas Commission, as modified Section 7(a) of this act, amends or repeals the rules.

SECTION 8. The provisions of this act shall be severable, and if any phrase, clause, sentence, or provision is declared to be unconstitutional or otherwise invalid, the validity of the remainder of this act shall not be affected thereby.

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SECTION 9. Except as otherwise provided, this act is effective when it becomes law. Requirements for establishment of a permanent alternative water supply under G.S. 130A-309.211(c1), as enacted by Section 1 of this act, shall apply only to households with drinking water supply wells in existence on the date this act becomes effective.

In the General Assembly read three times and ratified this the 1st day of July, 2016.

s/ Philip E. Berger
President Pro Tempore of the Senate

s/ Tim Moore
Speaker of the House of Representatives

_____
Pat McCrory
Governor

Approved _____.m. this _____ day of _____, 2016

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Date: May 14, 2015
Document: EXHIBIT 2 – AMENDED STIPULATIONS – PLEA AGREEMENT
Cases: US DISTRICT COURT FOR THE EASTERN DISTRICT OF NORTH CAROLINA WESTERN DIVISION NUMBERS 5:15-CR-67-H-2 AND 5:15-CR-68-H-2

Findings:

1. Dan River Steam Station (pages 43 - 48) – The Court found Defendants guilty and Defendants plead guilty to four counts (sets of violations) at Dan River.
    a. Count One is that the company violated the Clean Water Act for the unpermitted discharge through the 48-inch stormwater so and the Defendant aided and abetted another in doing so. Furthermore, the Court found that the Defendant acted negligently in doing so.
    b. Count Two is that Defendant violated the CWA by not maintaining the 48-inch storm water pipe which constituted a violation of its NPDES permit which requires that the permittee to properly maintain its equipment. Furthermore, the Court found that the Defendant acted negligently in doing so and that the Defendant aided and abetted another in doing so.
    c. Count Three is that Defendant violated the CWA for the unpermitted discharge through the 36-inch stormwater pipe at Dan River of coal ash and coal ash wastewater from a point source into a water of the US. . Furthermore, the Court found that the Defendant acted negligently in doing so and that the Defendant aided and abetted another in doing so.
    d. Count Four is that Defendant violated the CWA by not maintaining the 36-inch storm water pipe which constituted a violation of its NPDES permit which requires that the permittee to properly maintain its equipment. Furthermore, the Court found that the Defendant acted negligently in doing so and that the Defendant aided and abetted another in doing so.
2. Riverbend Steam Station (pages 48 - 49) – The Court found Defendants guilty and Defendants plead guilty to four counts (sets of violations) at Riverbend Steam Station.
    a. Count One is that Defendant violated the CWA by making an unpermitted discharge of coal ash and coal ash wastewater from a toe drain (point source) at the ash impoundment at Riverbend Steam Station into a water of the US. Furthermore, the Court found that the Defendant acted negligently in doing so and that the Defendant aided and abetted another in doing so.

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Document: Joint Factual Statement Exhibit A Duke-EPA Plea Agreement
Date: May 14, 2015
Defendants: Duke Energy Business Services, Duke Energy Progress, and Duke Energy Carolinas (together, Duke Energy)
Plaintiff: Eastern, Middle, and Western Districts of North Carolina and USDOJ

Document provides sufficient basis for DE's pleas of guilty for each of the three cases outstanding against DE's three business entities.

Section II of the Joint Factual Statement provides overview and background on: (1) Dan River Station, (2) Cape Fear Plant, and (3) Asheville, Riverbend, and Lee Stations.

Item 1 – "From at least January 1, 2012, DEC and DEB failed to properly maintain and inspect the two stormwater pipes underneath the primary coal ash basin at the Dan River Steam Station." On February 2, 2014, one of the pipes failed resulting in the discharge of about 27 million gallons of coal ash wastewater and between 30 and 39 thousand tons of coal ash into the Dan River. The material travelled more than 62 miles to the Kerr Lake Reservoir. Video inspections of the pipe after the spill showed both pipes had deteriorated also and DEC and DEB "had not taken appropriate action to prevent unauthorized discharges from the pipe."

Item 2 – DEP and DEB "failed to maintain the riser structures in two of the coal ash basins at the Cape Fear Steam Electric Plant, resulting in the unauthorized discharge of leaking coal ash wastewater into the Cape Fear River."

Item 3 – DEC and DEP allowed unauthorized discharges via "seeps" from ash basins into waters of the US at the Asheville, Riverbend, and H.F. Lee Stations. The seeps were "naturally occurring" and channeled to engineered drains, ditches, and waters of US.

Item 4 – Defendants' conduct violated the Federal Water Pollution Control Act (33 USC 1251 et seq.).

Item 12 – Lists the DEP and DEC plants (14) operating with coal ash basins (32) in the state of North Carolina.

Item 13 (page 7) – Describes the process of generating electricity by burning coal thus generating "waste byproducts" called "coal combustion residuals" which include fly ash and bottom ash (collectively "coal ash"). Describes the heavy metals and potentially hazardous constituents. Concedes that coal ash has not been defined as a "hazardous waste" under federal law, but constituents may be hazardous in sufficient quantities or concentrations.

Item 14 – Describes coal ash basins as "coal ash ponds," coal ash impoundments," and "ash dikes." These "may" be part of the waste treatment at the coal-fired power plants. Describes the process for handling coal ash using these historically unlined earthen impoundments.

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Item 15 (page 8) – "Coal ash basins generally continued to store settled ash and particulate material for years or decades. From time to time, the Defendants dredged settled coal ash from the basins, storing the ash in dry stacks on plant property."

Item 16 – Defendants store a total of 108 million tons in coal ash basins in North Carolina, 5.99 million tons in South Carolina, 1.5 million tons in Kentucky, 35.6 million tons in Indiana, and 5.9 million tons in Ohio.

Item 17 – All DEP and DEC plants with coal ash basins in North Carolina have permits to discharge.

Section III of the Joint Factual Statement discusses the legal requirements of the CWA.

Items 18 and 19 – Describe the purpose of the CWA and its prohibition against unpermitted discharges into waters of the US.

Item 20 – Describes "discharge of pollutants" and identifies coal ash and coal ash wastewater as pollutants.

Item 21 – Defines "point source" and identifies pipes and channelized ditches as point sources.

Item 22 (page 10) – Defines "navigable waters" and "waters of the US." Also identifies eleven rivers, branches, or tributaries as well as six lakes or reservoirs as waters of the US.

Item 23 – Except for dredge and fill permits, discharge of pollutants to waters of the US is permitted under NDPES. Draft permits or applications for permits are not considered permits.

Item 24 – 26 (page 11)-- States may apply for delegation to administer EPA programs. On October 19, 1975, EPA approved North Carolina to administer the NPDES program. Permits have effluent limitations, water quality standards, monitoring and reporting requirements, standard conditions, and special conditions.

Item 27 – DEP and DEC plants are required to comply with Standard Conditions (40 CFR 122.41): (a) take all reasonable steps to minimize or prevent any discharge or sludge use or disposal in violation of this permit with a reasonable likelihood of adversely affecting human health or the environment and (b) all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used to achieve compliance with permit conditions.

Section IV of the Joint Factual Statement describes the factual basis for the plea and relevant conduct.

Items 28 and 29 (page 12) – Dan River began operation in 1949 as a coal combustion plant and was retired in 2012. A natural gas fired combined cycle plant now operates on the site. In 1956, the Primary Ash Basin was built.

Items 30 - 36 – Describes the stormwater pipes (48 and 36 inch diameter) pipes running under the Primary Ash Basin. The larger pipe was installed in 1954 and is galvanized corrugated metal pipe. In a

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2009 EPA Dam Safety Assessment it was noted that "the Primary and Secondary coal ash basins were classified as a significant hazard potential structure due to the environmental damage that would be caused by the mis-operation or failure of the structure."

Items 37 - 39 (page 14) – On January 31, 2013, NCDENR's DWR issued a new permit NC0003468 to Dan River Plant. The permit required the facility meet the dam safety and dam design requirements in 15A NCAC 2K. As per 15A NCAC 2K.0301, dams such as the Primary Ash Basin at Dan River are subject to annual safety inspections by state authorities.

Items 40- 42 (page 15) – In 2006 DEC applied for NPDES stormwater permits for both the 48 and 36-inch pipes. Stormwater permits do not generally allow discharges of wastewater or particulates from coal ash basins or other industrial processes. Neither of these pipes was a permitted wastewater outfall.

Items 43 – 44 – In 1979, DEC inspected the 48-inch pipe using its internal engineering group. No major leaks were identified, but engineers noted water leaking into the pipe. Repairs were made to the pipe. Also in 1979, DEC's engineers inspected the 36-inch pipe. Twenty-two joints were noted for major leaks. While the leaks were repaired as recommended by DEC personnel, DEC personnel also recommended that the pipeline be rerouted as discharges could be violations of EPA regulations.

Item 45 (page 16) – As required by NC's dam safety laws, from 1981 through 2007, DEC used consultants to inspect coal ash basins at Dan River every five years. During the same time frame, DEC conducted annual coal ash basin inspections using its own personnel. DEC also performed less detailed monthly inspections.

Item 46 -48 (page 17) – In 1981. Engineering Firm #1 conducted the first of five independent inspections. They noted more water leaving the two pipes than entering them. The firm recommended flow rate checks over the next few months followed by semi-annual flow check afterwards. Should the flow rates increase, the firm recommended further inspections and repairs as were done in 1979.

Items 49 – 50 (page 17) – A 1984 Annual Inspection by DEC recommended continued monitoring of flow from the pipes every six months. A 1985 Annual Inspection by DEC identified the 48-inch pipe as corrugated metal pipe (CMP). At least one of the engineers on this 1985 inspection also conducted inspections of the Primary and Secondary Ash Basins in 2008.

Items 51 – 54 (page 18) – In 1986. Engineering Firm #1 conducted the second five-year inspection. This report shows the 48-inch pipe being part CMP and part RCP with the 36-inch pipe being RCP. The 1986 report repeated the 1981 recommendations and recommended quantitative measures of the inflow and outflow rather than qualitative assessments of in and out flows. The firm also noted that part of the 48-inch pipe is CMP which would be expected to have less longevity than RCP. In the 1986 annual report, DEC personnel asked plant personnel to install V-notch weirs at the inlets and conduct monitoring at six-month intervals bolstered by bucket and stop watch random tests. DEC Dan River plant personnel did not install the V-notch weirs. Plant personnel apparently did conduct the flow monitoring between 1991 and 1998 but did not report it on the requested forms.

Item 55 - 56 (page 19) – In 1991. Engineering Firm #2 conducted the third five-year inspection. In their report, the firm incorrectly identified the entire length of the 48-inch pipe as RCP and DEC

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engineers did not correct the error. This error was repeated in the 1998, 2001, and 2007 five-year inspection reports. In addition, DEC engineers did not correct the error. The 1991 repeated the prior monitoring recommendations and noted that turbidity should be monitored as an indicator of leaks.

Items 57 – 59 (page 20) – In 1998. Engineering Firm #1 conducted the fourth five-year inspection. The firm recommended that the outflow of the stormwater pipes "be monitored for turbidity of the discharge, which would be indicative of soil entrance into the pipes though leaks under the basin. The appearance of turbidity would make it advisable to perform a TV camera inspection of the pipe to determine if a leak or leaks are a threat." This language was repeated in the 2001 five-year report by Firm #1 and in 2007 five-year report by Firm #3. In the 2007 report, Firm #3 said DEC and not performed annual inspections since 2001 and performed no monthly inspections in 2003. Further, Firm #3 recommended that "Duke reinstitute more clearly defined engineering responsibility for the receiving and plotting of data from the dikes at the individual stations."

Item 60 (page 21) – After 2008, DEC installed a metal platform to allow personnel to access the river bank near the outfalls of the two pipes. However, DEC employees still could not view the outfall of the 36-inch pipe.

Item 61 - 62 (page 21) – A 2009 EPA Dam Safety Assessment restated the recommendations from the 2007 (Sixth) Five-Year Independent Inspection Report and that visual monitoring of the two stormwater pipes is performed on a monthly basis. In addition, the inspectors noted that in May 2009 the outflow was clear. The last monthly inspection of the stormwater pipes was on January 31, 2014. The DEC employee stated she did not observe turbidity in the outflow from the 48-inch pipe but could not see the outflow from the 36-inch pipe.

Items 63 – 65 (page 22) – Between 1999 and 2008 and from January 2013 through January 2014, DEC employees did not perform any visual inspections of the 36-inch pipe. Between 1999 and 2008 from May to September, DEC employees were generally unable to access the end of the 48-inch pipe from land because of snakes and vegetation. Each DEC employee responsible for monitoring from 1991 through 2012 was aware that the 48-inch pipe was CMP.

Items 66 – 68 (page 23) – On or about January 22, 2014, Engineering Firm #4 prepared "Design Report – DRAFT Ash Basin Closure – Conceptual Design for Dan River Steam Station." Appendix 4 of the report identifies the 48-inch pipe as CMP, but did not state this fact in the body of the report. Firm #4 relied in information provided by DEC and DEB including a 2008 schematic of the Primary Ash Basin which correctly identified the 48-inch pipe as CMP. When the Dan River spill occurred, DEC and DEB record-keeping and information-sharing practices did not ensure that information such as the composition of the 48-inch pipe was communicated from employees with knowledge to engineers and employees making budget decisions. Also, engineers in DEB responsible for Dan River did not sufficiently review available information and continued to believe the 48-inch pipe was entirely RCP.

Items 69 – 80 (pages 24 – 27) – From at least 2011 through February 2014, DEB has a group of engineers assigned to Program Engineering which supported fossil impoundments and dam inspections. In May 2011 two engineers recommended budgeting $20,000 to conduct camera inspections of four pipes including the 48-inch stormwater pipe. DEC did not fund this request. Learning that the request was not funded, the Dan River Station Manager called the V-P of Transitional Plants and Merger Integration who

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was in charge of approving the budget for the Dan River Plant. The station manager affirmed the need for the camera inspections, the condition of the pipes was unknown, and environmental harm would result from a pipe failure. The request was denied. This request was resubmitted in May 2012 with the same result. The Senior Program Engineer emailed his intention to eliminate the camera survey budget line because of the anticipated closure of the basins. In response to this email, the Equipment Owner at DEB responsible for monitoring the Primary Ash Basin wrote "I would think with the basin closing you would want to do the camera survey. I don't think the drains have ever been checked and since they go under the basin I would like to ensure that we are eliminating any risk before closing the basins." Another Duke employee also responded to the Senior Program Engineer that "I don't know if this changes your opinion, but [it] isn't likely that the ash basin will close in 2013. We have to submit a plan to the state at least one year prior to closure and we haven't begin to prepare that." Sometime between May 2012 and July 2012 a DEB Program Engineer asked the V-P of Transitional Plants and Merger Integration if the camera survey would be funded to which the answer was no. The June 2012 preliminary engineering plans for Dan River ash basins called for removing both big pipes but no date was set for removal and no formal closure plan was submitted to NCDENR between 2012 and 2014. In December 2012, the estimated closure of Dan River ash basins was expected by December 2016. The Statement of Facts concluded "If a camera inspection has been performed as requested, the interior corrosion of the elbow joint in the 48-inch pipe would likely have been visible." Also the Statement of Facts observed "From at least January 1, 2012 through February 2, 2014, DEC and DEB :failed to take reasonable steps to minimize or prevent discharge of coal ash to the Dan River that would adversely affect the environment and failed to properly operate and maintain the Dan River coal ash basins and the related stormwater pipes located beneath the Primary Coal Ash Basin, this, negligently violating the Dan River NPDES permit."

Items 81 – 89 (pages 27 – 29) – Describes the February 2014 discharges into the Dan River which began on February 2 when a five-foot long CMP elbow of the 48-inch pipe failed releasing coal ash and coal ash wastewater into the Dan River. Later inspection revealed extensive corrosion in the elbow. The Statement of Fact concluded "the age of the pipe was at or beyond the reasonably expected serviceable life for CMP under similar conditions." From the afternoon of February 2, 2014 through February 8, 2014, "the unpermitted discharge of approximately 27 million gallons of coal ash wastewater and between 30,000 and 39,000 tons of coal ash into the Dan River occurred through the 48-inch pipe from the Primary Coal Ash Basin." USFWS reported that the ash form the release travelled more than 62 miles down the Dan River into the John H. Kerr Reservoir on the border with Virginia. DEC personnel sealed the outfall of the 48-inch pipe stopping the flow.

Items 90 – 93 (pages 29 – 30) – Describes discharges from the 36-inch line. A February 6, 2014 video inspection showed: (1) wastewater infiltration through joints, (2) pressurized infiltration at three joints, (3) separation in one joint, (4) cracks running lengthwise in several pipe segments, and (5) ponding of water indication pipe misalignment. Water samples indicated elevated levels of arsenic 140 ug/L on February 14 and 180 ug/L on February 17 compared to the NC drinking water standard of 10 ug/L and aquatic life standard of 50 ug/L. Discharge from the 36-inch pipe continued from February 6 through February 21, 2014. The Statement of Fact concludes that the nature of the infiltration and DEC employees' visual and auditory confirmation of flow from the 36-inch pipe began a "significant period of time before February 6, 2014." The discharge began at least as early as January 1, 2012 and continued until the pipe was sealed on February 21, 2014. None of this discharge was authorized by the NPDES permit.

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Items 94 – 97 (pages 30 – 31) – Describes costs of responding to the Dan River Spill. To the date of the Statement of Fact, DEC had spent about $19 million in responding to the spill. In addition, the spill adversely impacted the drinking water intakes for four public water supplies. NCDHHS issued fish consumption and recreational contact advisories.

Items 98 – 103 (pages 31 - 33) – CAPE FEAR STEAM ELECTRIC PLANT – Cape Fear has five coal ash basins. Three were built in 1956, 1963, and 1970 and are inactive. Two basins built in 1978 and 1985 received ash and other wastewater through at least November 2011. 1978 basin is 43 acres with a capacity of 880 acre-feet and a maximum structural height (?) of 27 feet. It has a vertically stacked 18-inch diameter concrete riser for discharging decanted wastewater. !985 basin is 65 acres with a capacity of 1,764 acre-feet and a maximum structural height (?) of 28 feet. It has a vertically stacked 48-inch diameter concrete riser for discharging decanted wastewater. Both of these risers were identified as having a "significant hazard potential" in a 2009 EPA Dam Safety Assessment. Cape Fear ceased electric generation operations by December 2011, but the two basins continued to receive rainwater or stormwater.

Items 104 – 115 (pages 33 – 35) – In May 2008, DEP engaged outside engineering firm #3 to perform annual and five-year inspections of the Cape Fear ash basins. The report was submitted to DEP and reviewed by the plant manager and environmental coordinator. The report described the risers as "marginal" condition and "likely to develop problems in two to five years from the report." Firm #3 recommended that DEP inspect by boat the two risers to better assess their condition. This recommendation was repeated in annual reports by engineering firms to DEP and its predecessor in 2009, 2010, 2012, and 2013. At no time from May 1, 2008 until March 2014 did DEP or its predecessor conduct an inspection of the risers by boat. During the summer of 2011, DEP Environmental Coordinator and the NPDES Subject Matter Expert visited the site and became aware that the risers were leaking. During the fall of 2011, they informed DEP management that repairs were needed on the risers. No additional inspection or monitoring was undertaken prior to March 2014. A January 26, 2012 Five-Year Independent Consultant Report, Firm #4 noted that skimmer at the top of the 1978 ash basin riser was corroded and tilted. Annual inspection reports in 2012 and 2013 also reported the condition of the 1978 basin riser and recommended that DEP replace or repair the skimmer. At no time from January 26, 2012 through March 2014 did DEP repair or replace the skimmer. The annual inspection report produced in January 2013 by Firm #4 noted a "trickle of flow" at the outfalls leading from the risers and concluded this was evidence of possible leakage.

Items 116 – 132 (pages 36 – 41) – Describes the dewatering of the ash basins and the repair of the risers. During summer of 2013, DEB contacted a contractor (diving and underwater pipe repair and mentioned the possible need for riser repair at Cape Fear. Contactor was not engaged and no schedule for the work was discussed. During summer of 2013, DEB and DEP were planning for ash basin closure at Cape Fear. In July 2013, consulting engineers produced a "site investigation plan" that included locating, inspecting, and determining the composition of risers and discharge pipes for each ash basin. As part of their ash basin closure strategy, DEB and DEP sought to eliminate the need for NPDES permits at Cape Fear as a way to reduce O&M costs while the ash basin closure was pending. To do this, DEB and DEP would have to place the basins in a no flow state. This meant eliminating the riser leaks and lowering the level of the basin contents to prevent overtopping during a 25-year rain event. This approach was discussed during the summer of 2013 by DEB SME for NPDES and the DEB Director of Plant

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Demolition and Retirement. DEP and DEB recognized dewatering would lessen hydrostatic pressure in order to reduce or eliminate seepage. Seepage from the ponds was the subject of state filed civil complaints threatened citizen law suits. Another benefit of lowering water levels was to provide contractors with a safer environment to work. DEB and DEP knew that the leaks in the risers were likely caused by cracks or failures in the grout between the joint of pipe below water. In August and September 2013, DEP and DEB began planning a work plan for dewatering the 1985 basin. On September 30, 2013, they began pumping water from the 1985 basin. After two days of pumping, a DEB engineer contacted an underwater pipe repair contractor to repair "a slow trickle out of the discharge of the riser pipes at two ash ponds." The contractor responded on October 22, 2013 with a proposal that included ash pond riser repairs. In January 2014, DEP began dewatering the 1978 pond with the same type of equipment and approach as the 1985 pond. Later in January 2014, DEP and DEB contracted with the underwater pipe repair contractor to repair the riser as well as accomplish other as basin closure work. While the contract specified a "complete by" date of December 31, 2014 but did not specify a start date. In March 2011, NCDENR employees from DWR and Division of Mineral and Land Resources inspected Cape Fear accompanied by DEB and DEP employees. They observed the dewatering in progress and took issue with DEP and DEB over whether or not the company had been authorized by DWR to discharge water from the basins using Godwin pumps (why is the type of pump an issue?). On March 19 and 20, 2014, the contractor performed a video inspection of the risers and observed the visibility in the 1985 riser was "next to nothing" because of turbidity and debris in the pipe. The contractor also observed a "slow trickle" of water into the 1978 riser even though the basin water level had been lowered below the level of some of the leaks. The contractor replaced and resealed the grout between the concrete sections of pipe in both risers. Between at least January 1, 2012 and January 24, 2014, DEP and DEB failed to properly maintain the risers in the 1978 and 1985 coal ash basins at Cape Fear in violation of the applicable NPDES permit.

Items 133 – 140 (pages 41 – 44) –Describes historical seeps and discharges from coal ash basins. DEP's and DEC's ash basins are earthen dams. Seeps developed in dam walls over time. Seeps are common in earthen dams. DEP, DEC, and DEB identified over 200 such distinct seeps in their 2014 (NPDES) permit modification applications. Not all seeps reach waters of the US, but some seepage is collected in engineered drains or channels to waters of the US. Other seeps flow across land surfaces into waters of US. All 14 of the plants listed in Item 12 had seeps of some form. Water from seeps may transport pollutants and water samples from seeps was acidic and contained metals. EPA issued June 7, 2010 interim guidance for NPDES permitting authorities on permitting discharges from coal as basins regarding point source discharges from seepage. "If seepage is discharged directly via a point source to waters of the US, the discharge must be addressed under the NPDES permit for the facility." Since at least 2010, all 14 DEC and DEP North Carolina coal plants had seeps that entered waters of the US through discrete conveyances. Wetlands and groundwater may be impacted by seepage. Since 2010, NPDES permits in North Carolina require groundwater monitoring at coal ash basins. Such monitoring at DEP and DEC plants showed exceedances of groundwater quality standards near the basins for metals, nitrates, sulfates, and TDS. From 2010 into 2014, DEP, DEC, and DEB referenced such seeps generally at first then more specifically about the engineered seeps. However, they did not begin gathering and providing more detailed data to NCDENR until after the 2014 Dan River Spill. After the Dan River spill, DEP, DEC, and DEB filed permit renewal or modification applications seeking to permit the point source

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discharge of seepage directly to waters of the US. The applications are pending at NCDENR (CHECK STATUS).

Items 141 – 149 (pages 44 – 47) – Describes issues with H.F. Lee Steam Electric Plant (aka, Goldsboro Plant) which began operation shortly after WWII and added units in 1952 and 1962. Coal fired units were retired in September 2012. Only one of the ash basins is still active and sits along the Neuse River. This basin includes a primary basin and a small secondary settling basin. The November 1, 2009 NPDES permit number NC0003417 authorized a discharge from the active ash basin and the other from the cooling water pond. A third outfall was authorized in 2010 from a combined cycle facility. The ash basin does not currently discharge through Outfall 001. Before the end of October 2010, DEP identified a seep on the east side of the ash basin near a seep that was identified and repaired in 2009 and 2010. The new seep was collected and channeled to a flowing ditch outside the basin. This seep was repaired in May 2011. Additional seeps in the same area flowed to the same ditch then into the Neuse River. The drainage ditch was not permitted under the existing NPDES permit. In 2014, DEP identified four seeps on the east side of the ash basin. After NCDENR Land Quality personnel observed a seep near the southeast corner of the ash pond dike, NCDENR personnel sampled water on February 20, 2013 in the unpermitted drainage ditch. The sample showed exceedances of state water quality standards for metals. Discharge from the drainage ditch was not authorized under the NPDES permit. On March 11, 2014, NCDENR samples the same drainage ditch and found exceedances of iron and manganese. From at least October 1, 2010 through December 30, 2014, H.F. Lee violated the NPDES permit with unpermitted discharges.

Items 150 – 155 (pages 47– 49) – Describes the issues with Riverbend Steam Station adjacent to Mountain Island Lake which is the primary drinking water supply for two counties. Riverbend began operations in 1929 and combustion units were retired in April 2013 and demolition was planned for after 2016. Two unlined coal ash ponds up to 80 feet high sit along Mountain Lake. The ash basins dams were designated as "Significant Hazard Potential" in the 2009 EPA Dam Safety Assessment. The two ash basins hold about 2.73 million tons of coal ash. NPDES Permit Number NC0004961 was issued on March 3, 1976, renewed regularly, and is set to expire on February 28, 2015. The permit has three permitted outfalls. From December 4 through 6, 2012, NCDENR personnel observed unpermitted discharges from the ash basin into the Catawba River. One of these discharges is Seep 12 (2014 permit modification) that flows to an engineered drain into the river. Prior to December 2012, Riverbend personnel created the unpermitted channel. From 2011 through 2013, the unpermitted seep discharged elevated levels of metals and sulfates into the Catawba River. Unpermitted discharges from Riverbend violated the NPDES permit from at least November 8, 2012 through December 30, 2014.

Items 156 – 161 (pages 49 – 50) – Describes the issues with DEP's Asheville Steam Electric Generating Plant. Asheville has two unlined coal ash basins, one built in 1964 and the other in 1982. Each basin is 45 acres and hold about 3 million tons of coal ash. The ash basins dams were designated as "High Hazard Potential" in the 2009 EPA Dam Safety Assessment. This means that "failure or mis-operation results will probably cause loss of human life." NPDES permit number NC0000396 was issued in 2005 and expired in 2010, but DEP filed a timely permit renewal on June 11, 2010. NCDENR has not issued a renewal so the plant continues under the 2005 version. On May 13, 2013, DEP requested authority to relocate the settling basin outfall from near the 1964 basin to 3,000 feet away in order to perform "stabilization work" on the 1964 ash pond impoundment. On March 11, 2013, NCDENR

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inspectors identified seeps from the 1964 basin toe drains and observed that the engineered seep continued to discharge into the French Broad River in violation of the NPDES permit. These unpermitted discharges occurred at Asheville from at least May 11, 2011 through December 30, 2014.

Items 162 – 165 (pages 51 – 52) – Describes bromide impacts from FGD systems at Belews Creek Steam Station and Cliffside Steam Station (now _____). To comply with Clean Air Act and North Carolina Clean Smokestack Act (year), DEC installed FGD equipment (scrubbers) to reduce SO2 and NOx. Other pollutants including bromides are collected in a gypsum slurry which ultimately goes to the ash basins. Some of the slurry may be diverted for reuse as wall board. Belews scrubbers became operational at the end of 2008. When bromides contact chlorine-based water treatment systems, trihalomethanes (THMs) can be formed. While there are no federal or state limits on bromides, there are limits on THMs under the Safe Drinking Water Act. Injested at levels above regulatory limits over many years, THMs can cause cancer among other adverse impacts.

Items 166 – 179 (pages 52 – 55) – Describes issues with discharge of Bromides at Belews. Beginning in 2008 or 2009, City of Eden noted increase in THMs in drinking water. Prior to installing FGD scrubbers at Belews, DEC reported bromide in its waste streams to NCDEQ. In 2009 NPDES permit modification application, DEC did not mention bromides because modification did not relate to bromides and there were no state or federal limitation on bromide discharges. In 2008 through 2009, DEC tested for bromides and other pollutants to evaluate effects of FGD wastewater. The confirmed the discharge of bromides into the Dan River from Belews – not a violation of the permit. In January 2011, Eden's consultant determined and increase in bromides contributed to increased TMHs in Eden's drinking water. After further testing to determine the source of the elevated TMHs, on May 10, 2011, Eden notified DEC of the problems with TMHs and requested bromide sampling data. During this period, EPA was considering lowering TMHs levels in Safe Drinking Water Act which motivated Eden's interest in TMHs who was at the upper limits of current standard. Eden's testing identified Belews at the source of increased bromides and shared this with DEC on June 7, 2011. DEC and DEB agreed with the assessment and attributed the source of the bromides to the FGD system at Belews. In mid-June 2011, DEC contacted City of Madison (closer to Belews than Eden) which also draws raw water from Dan River for its drinking water. Madison joined discussions with Eden and DEC about reducing bromide levels. Several discussion occurred between June 2011 and April 2012. DEC informed NCDENR of the increase in bromide levels during August 29, 2011 NPDES permit renewal in Outfalls 001 (into Belews Creek) and 003 (into Dan River). Largest concentration was 6.9 ppm. In October 2011, Eden notified DEC that Madison and Henry County Virginia which buys water from Eden violated its TMHs permit limit. On November 16, 2011, NCDENR's regional office me with DEC, DEB, Eden, and Madison about the bromide issue and all agreed that bromides were causing the TMHs exceedances. DEC said it was not aware of the connection between bromides and TMHs until the 2011 discussions with Eden. Since November 2011 meeting, DEC committed in writing to helping financially Eden and Madison to improve their water treatment systems.

Items 180 – 184 (pages 55 – 57) – Describes issues with discharge of Bromides at Cliffside. About the same time it was responding to Eden's initial complaints, DEC began monitoring bromide discharges at other locations using FGD scrubbers. In early August 2011, DEC identified the Cliffside facility as potential source of TMHs problem because of the relatively shallow Broad River and the close proximity of facilities drawing drinking water from the Broad River downstream. The last Cliffside

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NPDES permit was issued in January 2011 with no reference to bromides. DEC and DEB ***did not*** inform the downstream communities nor NCDENR of the discharge from Cliffside. As of the joint factual statement, the parties are not aware of any community reporting elevated levels of TMHs due to increased bromide levels from Cliffside, but acknowledge that it is a possibility. In 2013, DEC swapped one of the two wet FGD scrubbers for a spray dry absorber which reduced bromide discharge from Cliffside. The remaining wet scrubber runs only intermittently.

Items 185 – 192 (pages 57 – 58) – Describes issues with groundwater impacts from ash basins at L.V. Sutton Steam Station in New Hanover County. Sutton has two coal ash basins, one built in 1971 and the other in 1984. Flemington is near Sutton and has a history of water quality problems In 1978, an adjacent landfill (Superfund Site – WHICH ONE?) contaminated the city's drinking water and prompted the city to drill new wells. The new wells are down-gradient and near Sutton's ash basins. Since 1990, DEP monitored groundwater around Sutton because of boron plume emanating from the coal ash ponds. From at least 2010 through 2013, the monitoring wells at Sutton reported elevated levels of manganese, boron, sulfate, and TDS. In 2013, tests of Flemington's water quality tests showed exceedances of barium, manganese, sodium, and sulfate. In June and July 2013, Flemington concluded that the source of its elevated boron was Sutton's ash ponds. In October 2013, DEP agreed in writing to share the costs of extending a water line to Flemington.

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Document: Settlement Agreement
Date: September 29, 2015
Defendants: Duke Energy Progress and Duke Energy Carolinas (together, Duke Energy)
Plaintiff: NCDEQ (formerly NCDENR)

Affected Sites (14): Allen Steam Station (Gaston County), Asheville Steam Electric Generating Plant (Buncombe County), Belews Creek Steam Station (Stokes County), Buck Steam Station (Rowan County), Cape Fear Steam Electric Generating Plant (Chatham County), Dan River Steam Station (Rockingham County), H.F. Lee Steam Electric Generating Plant (Wayne County), Marshall Steam Station (Catawba County), Mayo Steam Station (Person County), Riverbend Steam Station (Gaston County), Rogers Energy Complex (formerly Cliffside in Cleveland and Rutherford Counties), Roxboro Steam Electric Generating Plant (Person County), L.V. Sutton Electric Plant (New Hanover County), and Weatherspoon Steam Electric Plant (Roberson County)

Relevant Documents:

(1) June 17, 2011 DEQ "Policy for Compliance Evaluations of Long-Term Permitted Facilities with No Prior Groundwater Monitoring Requirement." 2L Standards (??). Procedures for issuing a NOV and a flow chart for reporting exceedances of NC groundwater standards: (1) verify accuracy and significance of results, (2) distinguish from naturally occurring substances, and (3) evaluate other possible sources. See page 3.
(2) September 20, 2014 CAMA became effective. Required closure and dewatering of all ash ponds and monitoring/remediating groundwater quality. Tracks closely with 2011 Policy.
(3) February 25, 2015 NOV from DEQ set to DE for groundwater exceedance at Asheville Plant.
(4) March 10, 2015 DEQ assessed $25.1 million penalty against Sutton Plant for groundwater monitoring exceedances.
(5) April 9, 2015 DE submitted contested case request with NCOAH challenging the Sutton penalty.
(6) Section IIA of September 29, 2015 Settlement (page 6) references 15A NCAC 2L.0106 requires "accelerated remediation" at Sutton Plant by installing extraction wells to pump and treat groundwater contaminated by offsite migration. Required above and beyond coal ash impoundment closure obligations in CAMA. Wells required to continue operation until offsite constituents meet "2L" and no reasonable potential for further migration. DEQ allows DE to remove dry ash from basins under a construction stormwater permit.
(7) Section IIB of September 29, 2015 Settlement (page 6) also references "2L" and requires accelerated remediation at Asheville, Belews Creek, and H.F. Lee Plants as the only three other DE plants showing offsite groundwater impacts but no impacts to private wells.
(8) Section IIC of September 29, 2015 Settlement (page 7) requires DE to pay $7 million to DEQ in full settlement of all claims related to groundwater exceedances.
(9) Section IID of September 29, 2015 Settlement (page 7) requires DE to withdraw Sutton Petition.
(10) Section IIIA-B of September 29, 2015 Settlement (page 8) requires DEQ to withdraw the Sutton NOV, Sutton NORR, Asheville NOV, and the Penalty Assessment and to not issues any further such violations or penalties related to groundwater or ash basin closure and remediation.

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(11) Section IIIC-D of September 29, 2015 Settlement (page 8) prohibits DEQ from "materially" modifying groundwater monitoring conditions of NPDES permits. Limits groundwater standards and naturally occurring (background) to those in 2L standards.

(12) Section IIIE of September 29, 2015 Settlement (page 9) requires DEQ to follow up on inquiries and complaints about ash reuse projects and permits and to notify DE of responses.

(13) Section IV of September 29, 2015 Settlement (page 10) details legal provisions.

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ORDER GRANTING MOTION FOR PARTIAL SUMMARY JUDGEMENT
June 1, 2016

Cases deal with alleged violations of NPDES permits, 15 NCAC 2L Groundwater Rules, and Clean Water Act. Also discusses CAMA 2014 which became law on September 20, 2014 and Mountain Energy Act of 2015 which became effective on June 25, 2015. CCR impoundments at Riverbend, Dan River, Sutton, and Asheville were classified as "high priority." CAMA also required groundwater impacts assessments. CAMA did away with the grandfathering of disposal systems permitted before December 30, 1983. In this joint ruling, DEC and DEP agree to submit Site Analysis and Removal Plans for the four facilities by December 31, 2016.

Civil Action No. 13-CVS-9352 (DEC Riverbend Catawba) – From paragraph 12 on page 8 to paragraph 28 on page 15, Riverbend is retired and has two impoundments totaling about 69 acres. Item 19 directs DEC to excavate and remove all CCR and Coal Combustion Products from the Riverbend Impoundments and the Inactive Ash Areas (collectively, "Riverbend Removed Ash") to lined locations for disposal in a CCR landfill, industrial landfill, or municipal solid waste landfill or for use as structural fill or other beneficial use pursuant to applicable law, and thereafter stabilize and close the area where the Riverbend Impoundments and Inactive Ash Areas are located pursuant to applicable law. Excavation shall include all coal ash and such additional soil as is necessary for the protection of groundwater or as may be ordered by any regulatory agency. All Riverbend Removed Ash from the Riverbend Impoundments shall be removed by the statutory deadline directed by CAMA (presently August 1, 2019. Complete investigation and undertake corrective action to eliminate groundwater violations at or beyond the compliance boundary to the extent required by G.S. § 130A-309.211, the 2L Groundwater Rules, any other applicable laws and regulations, and pursuant to a Corrective Action Plan approved by DEQ in accordance with Paragraph 22 below. Close facility CCR impoundments. Dewater impoundments. Remove or permanently close pipes running through or under impoundments. Requires progress reports every six months. Check compliance boundaries shown in Exhibits.

Civil Action No. 13-CVS-14661 (DEC Dan River) – From paragraph 29 on page 15 to paragraph 43 on page 22, DEC owns Dan River Station in Rockingham County which is now retired as a coal plant but continues as a natural gas fired combined cycle plant. Dan River has one CCR impoundment receiving stormwater and another inactive CCR impoundment that failed in February 2014. Dan River holds NPDES permit number NC0003468 that regulates three external and one internal outfall. Item 34 directs DEC to excavate and remove all CCR and Coal Combustion Products from the Dan River Impoundments and the Inactive Ash Areas (collectively, "Dan River Removed Ash") to lined locations for disposal in a CCR landfill, industrial landfill, or municipal solid waste landfill or for use as structural fill or other beneficial use pursuant to applicable law, and thereafter stabilize and close the area where the Dan River Impoundments and Inactive Ash Areas are located pursuant to applicable law. Excavation shall include all coal ash and such additional soil as is necessary for the protection of groundwater or as may be ordered by any regulatory agency. All Dan River Removed Ash from the Dan River Impoundments shall be removed by the statutory deadline directed by CAMA (presently August 1, 2019) or other date as amended by CAMA but not later than January 1, 2026. Complete investigation and undertake corrective action to eliminate groundwater violations at or beyond the compliance boundary to the extent required by G.S. § 130A-309.211, the 2L Groundwater Rules, any other applicable laws and regulations, and

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pursuant to a Corrective Action Plan approved by DEQ in accordance with Paragraph 22 below. Close facility CCR impoundments and inactive ash areas should it later be determined to be a CCR surface impoundment C Sections 1311(a), 1342(a), and 1365(f).

Civil Action No. 13-CVS-4061 (DEP Sutton) – From paragraph 44 on page 22 to paragraph 57 on page 28, DEP owns Sutton Station in New Hanover County which is now retired as a coal plant but continues as a natural gas fired combined cycle plant. Sutton has one active impoundment receiving stormwater and another inactive CCR impoundment. Together, the impoundments contain about 7-16 million tons of ash and coal ash stored in an Inactive Ash Area to the south of the impoundments. Sutton's NDPES permit is number NC0001422 and discharges are allowed through Outfall 001 to the Cape Fear River and five other internal outfalls. Closure instructions…

Civil Action No. 13-CVS-11032 (DEP Asheville) – From paragraph 58 on page 28 to paragraph 71 on page 34, DEP owns Asheville Electric Generating Station in Buncombe County which is an actively operating steam electric generating station. Asheville has two coal ash settling ponds covering about 91 acres and store up to combined 900 million gallons. Discharges from Asheville are permitted under NPDES permit NC0000396. Closure instructions…

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CRIMINAL PLEA AGREEMENT US DISTRICT COURT
STATE OF NORTH CAROLINA, WAKE COUNTY, GENERAL COURT OF JUSTICE, SUPERIOR COURT DIVISION
Number: 13-CVS-11032

Plaintiff: NCDEQ DWR
Defendant: DEP
AMENDED ORDER GRANTING MOTION FOR PARTIAL SUMMARY JUDGEMENT
Date: June 9, 2017
Judge Ridgeway granted the motion for partial summary judgement over the objection of NCDEQ DWR. The order grants injunctive relief under GS Section 143-215.6C for alleged violations of GS Sections 143-215.1(a)(1) and (a)(6), alleged violations of the NPDES permits, alleged violations of groundwater standards (15A NCAC Subchapter 2L), alleged violations of CWA 33 USC Sections 1311(a), 1342(a), and 1365(f).

Subject Plants are: H.F. Lee, Cape Fear, and Weatherspoon. State wanted injunction to compel the: (1) abatement of violations of GS Sections 143-215.1(a)(1) and (a)(6), the NPDES permits, and groundwater standards (15A NCAC Subchapter 2L); (2) assessment of ash basins and cause of groundwater contamination beyond compliance boundary; and (3) corrective action to restore groundwater quality. Other Plaintiff-Intervenor wanted the same thing plus abating the unpermitted discharges from coal ash basins.

Section 5 of the order describes the provisions of CAMA regarding (1) prohibiting new or expanded coal ash basins, (2) three-tier risk classifications of impoundments with a schedule for closure (CCR impoundments at HF Lee, Cape Fear, and Weatherspoon are required to be closed by CAMA and this Order), (3) assessment of groundwater impacts from CCR impoundments and correction of groundwater impacts; (4) identification and assessment of all CCR discharges as well as corrective actions; and (5) submission of closure plans.

Sections 6-9 describes the actions taken by DEP to develop groundwater assessment plans (conditionally approved by DEQ), submit in 2014 new NPDES permit applications, submit analysis of CCR impoundment seeps, and conduct engineering and scientific analysis of these three plants. DEP concluded that the CCR impoundments should be dewatered, excavated, and contents removed to appropriate lined "storage" facilities or beneficially reused. Court concluded that these actions "have or will remedy the violations alleged in the Complaints."

Sections 13 – 27— Terms applicable to H.F. Lee in Wayne County which is retired from electric power production. H.F. Lee has four CCR impoundments (one active and three inactive). Coal ash is stored in the former ash disposal area which may or may not be determined a CCR Surface Impoundment. H.F. Lee's NPDES permit is NC0003417. Court orders excavation and removal of all CCR and CCP from the impoundments ***and*** the ash disposal area "to lined locations for disposal in a CCR landfill, industrial landfill, or MSW landfill or for use as structural fill or other beneficial use pursuant to applicable law, and thereafter stabilize and close the area where the HF Lee Impoundments and inactive ash area are located pursuant to applicable law." Excavation shall include all ash and additional soil necessary to protect groundwater. For structural fill or other beneficial use, Duke Energy Progress shall ensure that removed

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ash is not deposited on or below the land except in a lined facility. DEQ shall review and act on applications for such structural fill and beneficial use. DEP is required to complete assessment of and corrective action required by GS Section 130A-309.211, 2L Groundwater Rules, and other laws and regulations in accordance with approved corrective action plan. DEP with comply with NPDES permit and identify new discharges for inclusion in the NPDES permit. DEP shall dewater the impoundments and remove or permanently close all pipes running through or under impoundments. If determined to be a CCR surface impoundment, DEP shall close the inactive ash area. Dewatering of impoundments shall begin within one year of receiving permits followed by beginning excavation within three years of beginning the dewatering and ending excavation within 12 years of beginning dewatering. Inactive Ash Area shall begin excavation shall begin by April 4, 2026 and be completed by April 4, 2028. Court requires DEP to submit six-month progress reports. Requires submittal of and implementation of approved Groundwater Corrective Action Plan. DEP must comply with groundwater monitoring requirements and restore groundwater quality.

Sections 28 – 42— Terms applicable to Cape Fear Steam Station which is located in Chatham County and is retired from production. Cape Fear has five CCR impoundments built in 1956, 1963, 1970, 1978, and 1985. One of these still receives storm water. Discharges from a single outfall are permitted under NPDES permit number NC0003433. Court orders excavation and removal of all CCR and CCP from the impoundments and the ash disposal area "to lined locations for disposal in a CCR landfill, industrial landfill, or MSW landfill or for use as structural fill or other beneficial use pursuant to applicable law, and thereafter stabilize and close the area where the Cape Fear Impoundments and inactive ash area are located pursuant to applicable law." Excavation shall include all ash and additional soil necessary to protect groundwater. For structural fill or other beneficial use, Duke Energy Progress shall ensure that removed ash is not deposited on or below the land except in a lined facility. DEQ shall review and act on applications for such structural fill and beneficial use. DEP is required to complete assessment of and corrective action required by GS Section 130A-309.211, 2L Groundwater Rules, and other laws and regulations in accordance with approved corrective action plan. DEP with comply with NPDES permit and identify new discharges for inclusion in the NPDES permit. DEP shall dewater the impoundments and remove or permanently close all pipes running through or under impoundments. The 1956, 1963, and 1970 Cape Fear ash ponds shall begin excavation with five years of receiving the required permits and complete the excavation within 10 years of receiving the required permits. DEP shall begin dewatering the 1978 and 1985 ash ponds within one year of receiving the required permits, begin excavation within three years from start of dewatering, and complete the excavation within ten years of dewatering start. Court requires DEP to submit six-month progress reports. Requires submittal of and implementation of approved Groundwater Corrective Action Plan. DEP must comply with groundwater monitoring requirements and restore groundwater quality.

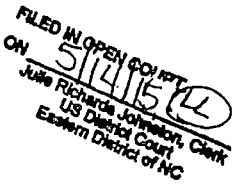
Sections 43 – 57 – Terms applicable to Weatherspoon which is located in Robeson County and is retired from electrical production. Weatherspoon has one CCR surface impoundment which has inactive ash area. The plant discharges are permitted under NPDES permit number NC0005363. Court orders excavation and removal of all CCR and CCP from the impoundments and the ash disposal area "to lined locations for disposal in a CCR landfill, industrial landfill, or MSW landfill or for use as structural fill or other beneficial use pursuant to applicable law, and thereafter stabilize and close the area where the Weatherspoon Impoundment is located pursuant to applicable law." Excavation shall include all ash and additional soil necessary to protect groundwater. For structural fill or other beneficial use, Duke Energy

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Progress shall ensure that removed ash is not deposited on or below the land except in a lined facility. DEQ shall review and act on applications for such structural fill and beneficial use. DEP is required to complete assessment of and corrective action required by GS Section 130A-309.211, 2L Groundwater Rules, and other laws and regulations in accordance with approved corrective action plan. DEP with comply with NPDES permit and identify new discharges for inclusion in the NPDES permit. DEP shall dewater the impoundment and remove or permanently close all pipes running through or under impoundments. The Weatherspoon impoundment shall begin excavation by April 4, 2026 and complete the excavation by April 4, 2028. Court requires DEP to submit six-month progress reports. Requires submittal and implementation of approved Groundwater Corrective Action Plan. DEP must comply with groundwater monitoring requirements and restore groundwater quality.

Sections 58 – 71 – Terms applicable to all three facilities – Order does not purport to address all requirements of CAMA, other applicable provisions of GS 130A, 143, or other applicable laws, statutes, and rules. Defendants are still required to comply with other existing or new statutes or rules or enforcement agreement between DEQ and EPA. Court maintains jurisdiction to enforce the order, modify the order, and resolve disputes. Entry of the order terminates all proceedings for these facilities and resolves all civil claims for injunctive relief. Should the Coal Ash Management Commission (now defunct – did the commission's authority devolve to the Environmental Management Commission?) determine excavation and movement of ash subject to this order at HF Lee, Cape Fear, or Weatherspoon is inappropriate or subject to a different remediation plan and that determination is upheld on appeal, a condition of Force Majeure shall exist. The court will hold additional proceedings to resolve this condition.

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UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF NORTH CAROLINA
WESTERN DIVISION
No. 5:15-CR-67-H-2
No. 5:15-CR-68-H-2

UNITED STATES OF AMERICA	)	
	)	
v.	)	MEMORANDUM OF PLEA AGREEMENT
	)	
DUKE ENERGY CAROLINAS, LLC	)	

Pursuant to Rule 11(c)(1)(C) of the Federal Rules of Criminal Procedure, the United States of America, by and through the United States Attorneys for the Eastern District of North Carolina, the Middle District of North Carolina, and the Western District of North Carolina as well as the Environmental Crimes Section of the United States Department of Justice (collectively referred to herein as "the United States" or "the Government"), and the Defendant, DUKE ENERGY CAROLINAS, LLC (referred to herein as "the Defendant" or "DUKE ENERGY CAROLINAS") with the advice and concurrence of the Defendant's counsel, Julia S. Janson (Executive Vice-President, Secretary, and Chief Legal Officer, Duke Energy Carolinas, LLC) and James P. Cooney, III (Womble Carlyle Sandridge & Rice LLP) have agreed that the above-captioned case should be concluded in accordance with this Memorandum of Plea Agreement as follows:

1. This Memorandum constitutes the full and complete record of the Plea Agreement for criminal conduct in each of the prosecuting districts, that is, the Eastern District, Middle District, and Western District of North Carolina and as alleged in the following charging documents (hereinafter referred to collectively as the "Criminal Informations"):

United States v. Duke Energy Business Services LLC, and Duke Energy Progress, Inc., No. 5:15-CR-62-H;

United States v. Duke Energy Business Services LLC, Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., No. 5:15-CR-67-H; and

United States v. Duke Energy Business Services LLC, Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., No. 5:15-CR-68-H.

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There are no other agreements between the parties in addition to or different from the terms herein.

2. The United States and the Defendant agree:

a. That this Plea Agreement ("Agreement") is made pursuant to Rule 11(c)(1)(C) of the Federal Rules of Criminal Procedure ("Fed. R. Crim. P.") and that the sentence set forth herein is the appropriate disposition of this case. If the Court rejects this Agreement, it is further agreed that the Defendant may withdraw its plea and all of the parties may withdraw from this Agreement.

b. The parties further acknowledge that based upon the Joint Factual Statement, a copy of which is attached hereto as Exhibit A, the Court has sufficient information in the record to enable it to meaningfully exercise its sentencing authority. Accordingly, if acceptable to the Court, the parties agree to waive the presentence investigation and report pursuant to Fed. R. Crim. P. 32(c), and to request that the Defendant be sentenced at the time the guilty plea is entered.

c. The parties further agree and acknowledge that the Defendant's parent corporation, Duke Energy Corporation, shall guarantee all monetary penalties (criminal fine, restitution, community service, and mitigation) imposed upon the Defendant and the funding and performance due from the Defendant in connection with the nationwide and statewide environmental compliance plans under this Agreement as more fully set forth in the Guaranty Agreement, a copy of which is attached hereto at Exhibit B (without attachments) and fully incorporated herein by reference. The parties further agree and acknowledge that Duke Energy Corporation shall consent to the jurisdiction of the United States District Court for the Eastern District of North Carolina for the purpose of enforcing the Guaranty Agreement.

d. Pursuant to Fed. R. Crim. P. 11(c)(1)(C), the parties agree that the following sentence is warranted in this case:

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i. Criminal Fines: At the time of imposition of sentencing, the Defendant shall make a payment of Criminal Fines totaling $53.6 million ($53,600,000) as follows:

Dan River Violations

(1) $38 million ($38,000,000) for the negligent Clean Water Act discharge without a National Pollutant Discharge Elimination System ("NPDES") permit from the 48-inch stormwater pipe at Dan River Steam Station based upon a fine of twice the gross gain or loss pursuant to 33 U.S.C. § 1319(c)(1)(A) and 18 U.S.C. § 3571(c) and (d).

(2) $2 million ($2,000,000) for the negligent Clean Water Act failure to maintain the coal ash impoundments and related appurtenances (48-inch stormwater pipe) as required by the applicable NPDES permit for the Dan River Steam Station, a fine within the statutory penalty range of $2,500 to $25,000 per day of violation pursuant to 33 U.S.C. § 1319(c)(1)(A) and 18 U.S.C. § 3571(c) and (d).

(3) $9.5 million ($9,500,000) for the negligent Clean Water Act discharge without a NPDES permit from the 36-inch stormwater pipe at Dan River Steam Station, a fine within the statutory penalty range of $2,500 to $25,000 per day of violation pursuant to 33 U.S.C. § 1319(c)(1)(A) and 18 U.S.C. § 3571(c) and (d).

(4) $2 million ($2,000,000) for negligent Clean Water Act failure to maintain the coal ash impoundments and related appurtenances (36-inch stormwater pipe) as required by the applicable NPDES permit for the Dan River Steam Station, a fine within the statutory penalty range of $2,500 to $25,000 per day of violation pursuant to 33 U.S.C. § 1319(c)(1)(A) and 18 U.S.C. § 3571(c) and (d).

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Riverbend Violations

(5) $2.1 million ($2,100,000) for the negligent Clean Water Act discharge in violation of the applicable NPDES permit at Riverbend Steam Station, a fine within the statutory penalty range of $2,500 to $25,000 per day of violation pursuant to 33 U.S.C. § 1319(c)(1)(A) and 18 U.S.C. § 3571(c) and (d).

ii. Probation: A statutory-maximum term of five (5) years of probation is warranted. 18 U.S.C. § 3561(c)(2). Probation shall include the standard conditions of probation and the following special conditions, pursuant to 18 U.S.C. § 3563(a) and (b):

(1) Compliance with the Law: The Defendant shall not commit another federal, state, or local crime during the term of probation.

(2) Cooperation with Probation Office: The Defendant shall fully cooperate with the United States Probation Office. The Defendant shall answer truthfully all inquiries by the Probation Officer; shall provide full access to any of the Defendant's operating locations; shall give ten (10) days' prior notice of any intended change in principal business or mail address; and shall provide notice of any material change in the Defendant's economic circumstances that might affect the Defendant's ability to pay the fines and other financial obligations set forth herein.

(3) Nationwide Environmental Compliance Plan: Under the terms of its plea agreement, co-defendant Duke Energy Business Services LLC ("DEBS") is required to develop, adopt, implement, and fund a comprehensive nationwide environmental compliance plan ("NECP") during its term of probation, consistent with sentencing policies set forth in USSG §8D1.4 and which incorporates

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all of the agreed-upon obligations set forth in Paragraph 3(u)(v) of this Agreement. The Defendant shall take all steps necessary or required to assist DEBS in meeting this obligation.

(4) Statewide Environmental Compliance Plan: The Defendant, along with its co-defendants Duke Energy Progress, Inc. ("DEP") and DEBS, shall develop, adopt, implement, and fund a comprehensive statewide environmental compliance plan ("ECP-NC") during its term of probation, consistent with sentencing policies set forth in USSG §8D1.4 and which incorporates all of the agreed-upon obligations set forth in Paragraph 3(u)(vi) of this Agreement.

(5) Notice to Employees and Shareholders: Upon approval by the Court of the NECP and ECP-NC, the Defendant shall notify its employees of its criminal behavior, the NECP, and the ECP-NC. In addition, the Defendant shall cause a notice containing the same information to be sent to the shareholders of Duke Energy Corporation. Such notice shall be in a form prescribed by the Court-Appointed Monitor ("CAM") and at a time designated by the CAM.

(6) Community Service Payment: Pursuant to USSG §8B1.3 and in furtherance of the sentencing principles provided for under 18 U.S.C. § 3553(a), at the time of sentencing, the Defendant shall make a community service payment totaling $13.5 million ($13,500,000), through the National Fish and Wildlife Foundation ("NFWF"), to fund environmental projects, studies, and initiatives designed to benefit, preserve, and restore the riparian environment and ecosystems of North Carolina and Virginia affected by the Defendant's conduct, as set forth in Paragraph 3(aa) of this Agreement.

(7) Mitigation: In order to compensate for impacts to wetlands and other jurisdictional

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waters of the United States impacted as a result of the Defendant's conduct, including temporal and secondary effects, at its facilities in North Carolina with coal ash impoundments, the Defendant shall provide $5 million ($5,000,000) to an authorized wetlands mitigation bank or conservation trust, approved by the Court, for the purchase of riparian wetland and/or riparian land and/or restoration equivalent located in the Broad River Basin, French Broad River Basin, Cape Fear River Basin, Catawba River Basin, Dan River Basin, Yadkin-Pee Dee River Basin, Neuse River Basin, Lumber River Basin, and Roanoke River Basin as set forth in more detail in Paragraph 3(bb) of this Agreement.

iii. Payment Liability/Financial Assurances: The Defendant shall be liable for and pay all fines, restitution, community service, and mitigation payments and shall fund the NECP and ECP-NC, all as set forth herein. The Defendant shall further be liable for any additional restitution payments as determined by the CAM.

(1) Reservation of Funds by Defendant: The Defendant further shall record appropriate reserves on financial statements for the purpose of recognizing the projected obligation to retire its coal ash impoundments in North Carolina. This obligation is currently estimated at a total of $2.0 billion ($2,000,000,000) on the Defendant's balance sheet. Each year during the term of probation, beginning on the date that the Agreement is accepted by the Court and occurring by March 31 of each year thereafter, the Defendant shall cause the Chief Financial Officer of Duke Energy Corporation, as further directed under the Guaranty Agreement attached hereto, to certify to the United States and the CAM that the Defendant and Duke Energy Corporation have sufficient assets reserved to meet the obligations imposed by law or regulation or as may otherwise be necessary

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to fulfill the Defendant's obligations with respect to its coal ash impoundments within the State of North Carolina. If the CAM has any concerns regarding the assets available to meet obligations imposed by the Judgment in this case, the CAM shall immediately notify the Court and the parties.

(2) Reservation of Funds by Parent Company: The Defendant further shall cause its parent holding company, Duke Energy Corporation, to record appropriate reserves on its consolidated financial statements for the purpose of recognizing the projected obligation to retire all coal ash impoundments, including those in North Carolina. This obligation is currently estimated at a total of $3.4 billion ($3,400,000,000) on Duke Energy Corporation's balance sheet for all coal ash impoundments (including those owned by the Defendant and co-defendant DEP). Each year during the term of probation, beginning on the date that the Agreement is accepted by the Court and occurring by March 31 of each year thereafter, the Defendant shall cause the Chief Financial Officer of Duke Energy Corporation, as further directed under the Guaranty Agreement attached hereto, to certify to the United States and the CAM that the Defendant and Duke Energy Corporation have sufficient assets reserved to meet the obligations imposed by law or regulation or as may otherwise be necessary to fulfill the Defendant's obligations with respect to its coal ash impoundments within the State of North Carolina. If the CAM has any concerns regarding the assets available to meet obligations imposed by the Judgment in this case, the CAM shall immediately notify the Court and the parties.

(3) Security: Through the entire term of probation, the Defendant shall further maintain unused borrowing capacity in the amount of $250 million ($250,000,000) under the Master Credit Facility as security to

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meet its obligations under this Agreement for the closing and remediation of coal ash impoundments, as more fully set forth in Paragraph 3(k) of this Agreement. The Defendant shall certify this set aside to the CAM on an annual basis, or more frequently as the CAM requires. If the CAM has any concerns regarding the security available to meet the obligations imposed by the Judgment in this case, the CAM shall immediately notify the Court and the parties.

iv. Restitution for Counts of Conviction: Pursuant to 18 U.S.C. §§ 3663, 3663A, and 3563(b)(2), the Defendant shall make restitution to any victim in whatever amount the Court may order. Said restitution shall be due and payable immediately. Said restitution shall include at a minimum, as apportioned to this Defendant pursuant to 18 U.S.C. § 3664(h), restitution to be paid to the Clerk of the Court as follows:

(1) $63,309.45 to Virginia Beach, payable to:

City of Virginia Beach
c/o Department of Public Utilities
City of Virginia Beach
2405 Courthouse Drive
Virginia Beach, Virginia 23456
ATTN: **"Coal Ash Spill - Water Quality Sampling / CIP 5-967" as a reference**

(2) $125,069.75 to City of Chesapeake, VA (Lake Gaston sampling costs) payable to:

City of Chesapeake
c/o David Jurgens,
Director of Public Utilities
306 Cedar Rd, 2nd floor
Chesapeake, VA 23322

(3) and $31,491.11 to the United States Army Corps of Engineers payable to:

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FAO-USACE Wilmington
c/o Anita Bissette
69 Darlington Ave
Wilmington, NC 28406
(910-251-4803)

v. Restitution for Relevant Conduct to Be Paid During Term of Probation: Pursuant to 18 U.S.C. § 3663, the Defendant shall pay restitution as directed by the CAM through the claims process set forth in Paragraphs 3(x)(iii)-(vi) of this Agreement.

vi. Special Assessment: The Defendant shall pay special assessments, totaling $625.00, before or at the time of sentencing, and shall provide a receipt from the Clerk of Court for the Eastern District of North Carolina to the United States as proof of payment.

vii. Public Apology: Consistent with USSG §8D1.4(a), the Defendant and co-defendants DEBS and DEP shall place a full-page public apology in at least two national newspapers and three major North Carolina newspapers (one in Raleigh, one in Greensboro, and one in Charlotte) and on its publicly accessible company website.

3. The Defendant agrees:

a. Consent to Transfers: To consent to the entry of Rule 20 transfers for purposes of guilty pleas to the charges in the following matters:

i. United States v. Duke Energy Business Services LLC, Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., No. 1:15-CR-51-1 (MDNC); and

ii. United States v. Duke Energy Business Services LLC, Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., No. 3:15-CR-43-FDW (WDNC).

b. Restitution for Counts of Conviction: Pursuant to 18 U.S.C. §§ 3663, 3663A, and 3563(b)(2), to make restitution as ordered by the Court and as set forth in this Agreement. Said restitution shall be due and payable immediately. Said restitution shall include

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additional costs associated with the Dan River response as previously set forth in Paragraph 2(d)(iv) of this Agreement.

c. Restitution for Relevant Conduct to be Paid During Term of Probation: In addition to any order of restitution in connection with the counts of conviction, to make restitution to the following entities, as determined and directed by the CAM during the term of probation and pursuant to the agreed-upon claims process set forth in Paragraphs 3(x)(iii)-(vi):

i. City of Eden, North Carolina; Town of Madison, North Carolina; and other localities impacted by bromide discharges from the Belews Creek and Cliffside facilities

(1) For all costs, whenever incurred, associated with water treatment system upgrades resulting from the increase of trihalomethanes including, but not limited to, maintenance costs.

(2) All costs associated with investigating and responding to increased discharges of bromide and/or the increase of trihalomethanes.

ii. Other Local Governments with drinking water treatment systems impacted by bromide discharges from other facilities owned by the Defendant

(1) For all costs, whenever incurred, associated with water treatment system upgrades resulting from the increase of trihalomethanes including, but not limited to, maintenance costs.

(2) All costs associated with investigating and responding to increased discharges of bromide and/or the increase of trihalomethanes.

d. Crime Victims' Rights Act: Except as provided herein, at the time of the execution of this Agreement, the parties are not aware of any other

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victim as that term is defined by 18 U.S.C. §§ 3663, 3663A, and 3771. The Defendant understands that the United States intends to fully comply with all obligations under 18 U.S.C. § 3771, including victim notification and restitution provisions.

e. Appeal Waiver: To waive knowingly and expressly the right to appeal the conviction and whatever sentence is imposed on any ground, including any appeal pursuant to 18 U.S.C. § 3742, and further to waive any right to contest the conviction or the sentence in any post-conviction proceeding, including any proceeding under 28 U.S.C. § 2255, excepting an appeal or motion based upon grounds of ineffective assistance of counsel or prosecutorial misconduct not known to the Defendant at the time of the Defendant's guilty plea. The foregoing appeal waiver does not constitute or trigger a waiver by the United States of any of its rights to appeal provided by law.

f. Waiver of Rights to Records: To waive all rights, whether asserted directly or through a representative, to request or receive from the United States any records pertaining to the investigation or prosecution of this matter, except as provided in the Fed. R. Crim. P. This waiver includes, but is not limited to, rights conferred by the Freedom of Information Act and the Privacy Act of 1974.

g. Special Assessment: To pay a special assessment of $125.00 for each misdemeanor count pursuant to the provisions of 18 U.S.C. § 3013. The assessment shall be paid by the Defendant at sentencing. The Defendant or Defendant's counsel shall provide a check in payment of the said assessment directly to the Clerk of Court, U.S. District Court-EDNC.

h. Financial Statement: To complete and submit a financial statement under oath to the United States no later than two weeks prior to the entry of the guilty plea. The Defendant can satisfy this condition by submitting its most recent financial statement filed with the Securities and Exchange Commission.

i. Reservation of Funds by Defendant: To record appropriate reserves on financial statements for the

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purpose of recognizing the projected obligation to retire its coal ash impoundments in North Carolina, and, during each year during the term of probation, to certify that it has sufficient assets reserved to meet the obligations imposed by law and regulation as more fully set forth in Paragraph 2(d)(iii)(1) above. This obligation is currently estimated at a total of $2.0 billion ($2,000,000,000) on the Defendant's balance sheet.

j. Reservation of Funds by Parent Company: To cause its parent holding company, Duke Energy Corporation, to record appropriate reserves on its consolidated financial statements for the purpose of recognizing the projected obligation to retire all coal ash impoundments, including those in North Carolina, and during each year during the term of probation, to cause its parent holding company to certify that it has sufficient assets reserved to meet the obligations imposed by law and regulation as more fully set forth in Paragraph 2(d)(iii)(2) above. This obligation is currently estimated at a total of $3.4 billion ($3,400,000,000) on Duke Energy Corporation's balance sheet for all coal ash impoundments (including those owned by the Defendant and co-defendant DEP).

k. Security: Through the entire term of probation, to maintain unused borrowing capacity in the amount of $250 million ($250,000,000) under the Master Credit Facility as security to meet its obligations under this Agreement for the closing and remediation of coal ash impoundments, as more fully set forth in Paragraph 2(d)(iii)(3) of this Agreement. A copy of the certification for 2015 shall be filed with the Court at the time of entry of this Agreement.

l. Cooperation: The Defendant shall continue to cooperate fully with the United States, and with all other authorities and agencies designated by the United States, and shall truthfully disclose all information with respect to the activities of the Defendant and its present and former directors, officers, employees, agents, consultants, contractors, and subcontractors thereof, regarding the conduct underlying the Criminal Informations about which the Defendant has any knowledge or about

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which the United States shall inquire. This obligation of truthful disclosure includes the obligation of the Defendant to provide to the United States, upon request, any document, record, or other tangible evidence regarding the conduct underlying the Criminal Informations about which the United States shall inquire of the Defendant. Compliance with such cooperation requirements shall not be construed as requiring or effecting a waiver of the attorney-client privilege or work product protections.

m. Such cooperation set forth in Paragraph (l) above shall include but not be limited to: (a) promptly disclosing any and all related criminal or potentially criminal conduct of which the Defendant is currently aware; (b) promptly producing all documents requested by the federal government or by grand jury subpoena; (c) promptly making employees available to the investigation team upon request for interview or for testimony in any proceeding, subject to those employees' own legal rights; and (d) making reasonable efforts to ensure its employees provide full and truthful information.

n. If the Defendant, through its employees acting within the scope of their employment, provides false, incomplete, or misleading information or testimony, or fails to abide by any term of cooperation set forth in Paragraphs (l) and (m) above, this would constitute a material breach of this Agreement by the Defendant, and the Defendant shall be subject to prosecution for any federal criminal violation not barred by the applicable statute of limitations (or as waived pursuant to Paragraph 3(hh)) or other legal prohibition. Any information provided by the Defendant may be used against the Defendant in that prosecution.

o. Additionally, the Defendant agrees that in the event of the Defendant's material breach of this Agreement the following are admissible against the Defendant in any prosecution of or action against the Defendant: (i) any statements made by the Defendant, under oath, at the guilty plea hearing (before either a Magistrate Judge or a District Judge); (ii) the Joint Factual Statement supporting this Agreement; and

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(iii) any evidence derived from such statements. This includes the prosecution of the charges that are the subject of this Agreement or any charges that the United States agreed to dismiss or not file as part of this Agreement, but later pursues because of a material breach by the Defendant. Additionally, the Defendant knowingly and voluntarily waives any argument under the United States Constitution, any statute, Rule 410 of the Federal Rules of Evidence, Fed. R. Crim. P. 11(f) of the Federal Rules of Criminal Procedure, and/or any other federal rule, that the statements or any evidence derived from any statements should be suppressed or are inadmissible.

p. Compliance with the Law: Except as provided otherwise herein and in Paragraph (q) below, the Defendant agrees that it shall commit no new violations of federal, state, or local law, including those laws and regulations for which primary enforcement has been delegated to state authorities, and shall conduct its operations in accordance with the environmental laws of the United States and the State of North Carolina. If the Defendant learns of any such violations committed by its agents or employees during the term of probation, the Defendant shall notify the United States of the violations in accordance with the terms of the environmental compliance plans.

i. The Defendant understands that the Government shall not consider there to be a violation of the conditions of probation if the Defendant complies with federal environmental laws when there is a direct conflict between the state and federal environmental laws.

q. The Defendant shall comply with all federal, state, and other regulations relating to coal ash, and will have no new notices of violation, notices of deficiency, or other criminal, civil, or administrative enforcement actions based on conduct (including the failure to act) occurring after entry of the guilty plea.

i. The Defendant understands that it shall be considered a violation of the conditions of probation if the Defendant engages in the above

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conduct and such conduct or condition results in a final assessment (after conclusion of any appeals) in an amount greater than $5,000 and imposed after the entry of the guilty plea and which the CAM deems material. Any conduct or conditions resulting in a final assessment in an amount greater than $15,000 shall be presumed to be material.

ii. It shall not be considered a violation of probation if the enforcement action is based upon information disclosed by the Defendant in its 2014 Topographic Map and Discharge Assessment Plan(s) and/or its 2014 NDPES permit renewal application(s) for its facilities in North Carolina.

r. The Defendant shall comply with all legislative and regulatory mandates concerning closure of the coal ash impoundments which it operates, and shall complete full excavation and closure of all of the coal ash impoundments at its Dan River and Riverbend facilities in accordance with federal and state laws, including the United States Environmental Protection Agency's ("EPA") 2014 final rule governing the disposal of coal combustion residuals from electric utilities ("CCR Rule") and North Carolina's Coal Ash Management Act of 2014, by the dates dictated in those laws, currently the calendar year 2019. In so doing, the Defendant shall act diligently and in good faith to meet projected critical milestones in its closure plans for each site as set forth in the following documents: Duke Energy's Dan River Steam Station Coal Ash Excavation Plan dated November 13, 2014; and Duke Energy's Riverbend Steam Station Coal Ash Excavation Plan dated November 13, 2014 (collectively referred to as "Excavation Plans"), as may be amended with the approval of the North Carolina Department of Environment and Natural Resources ("DENR").

i. With respect to excavated coal ash, the removed ash shall be stored in a lined CCR landfill space or lined impoundment meeting all requirements established by applicable statute, law, and regulation, including but not limited to 40 CFR Part 258 (Subtitle D of RCRA). Nothing in this Paragraph shall prohibit the Defendant from the

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disposition of ash through beneficial reuse as contemplated by the CCR Rule.

ii. Every six months, or on a more frequent basis as determined by the CAM, the Defendant shall provide the CAM with a detailed description of its efforts to excavate coal ash and close all of the coal ash impoundments at Dan River and Riverbend and whether it has met the critical milestones set forth in the Excavation Plans in the time period since the last report. The Defendant shall also include the status of all permits and permit applications with any regulatory body, including but not limited to DENR. The Defendant shall also make such reports publicly available on its website.

(1) If the CAM has any concerns regarding whether the Defendant acted diligently or in good faith to meet its obligations under this provision, including the critical milestones set forth in the Excavation Plans, the CAM shall immediately notify the Court and the parties.

iii. The Defendant shall contemporaneously provide an executive summary of the report in subparagraph (ii) above to the United States Attorneys' Offices for the Eastern, Middle, and Western Districts of North Carolina; the Department of Justice - Environmental Crimes Section; the United States Environmental Protection Agency - Criminal Investigation Division; and the United States Environmental Protection Agency - Legal Counsel Division. Upon request, the Defendant shall provide the full report for inspection and review by any of the governmental parties.

(1) If the Government has any concerns regarding whether the Defendant acted diligently or in good faith to meet its obligation under this provision, including the critical milestones set forth in the Excavation Plans, the Government may elect to notify either the CAM or the Court, and may seek additional penalties as may be appropriate.

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iv. Six months prior to the end of the term of probation, the Defendant shall provide the Court, the CAM, and the Government with a full report of its efforts to excavate coal ash and to close all of the coal ash impoundments at Dan River and Riverbend and the anticipated completion date.

v. The Government may seek additional fines and penalties should the Defendant fail to comply with such legislative or regulatory mandates and closure requirements under this Paragraph unless the compliance is delayed by a "force majeure" as that term is defined herein. The parties recognize that a change in law making performance impossible may be raised under the "force majeure" clause herein, but final determination shall be made by the Court.

vi. The Defendant understands that the Government shall not consider there to be a violation of the conditions of probation if the Defendant complies with federal environmental laws when there is a direct conflict between the state and federal environmental laws. The Defendant, however, shall immediately notify the Court, the CAM, and the Government of the conflict of laws and the impact on excavation and closure plans.

s. Criminal Fine: The Defendant shall pay a total criminal fine in the amount of $53.6 million ($53,600,000), allocated as set forth in Paragraph 2(d)(i) above.

t. Stipulated Factual Basis for Fine: The Defendant stipulates that there is a factual basis for the imposition of a criminal fine in the amount of $53.6 million ($53,600,000) pursuant to 33 U.S.C. §§ 1319(c)(1)(A) and/or 18 U.S.C. § 3571(c) and (d) and that the payments made pursuant to Paragraph 2(d)(i) do not together exceed the statutory maximum fine available under each of the applicable statutes. The Defendant further waives any right to a jury or bench trial as to those payments.

u. Environmental Compliance Plans: As a special condition of probation, the Defendant shall cause, assist, and otherwise take all steps necessary to

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effectuate the obligation of co-defendant DEBS to develop, adopt, implement, and fund the NECP designed to ensure compliance with applicable environmental laws and regulations at all of the coal ash impoundments owned and operated (whether active or inactive) by any wholly-owned subsidiary of Duke Energy Corporation. In addition to requirements to be applied nationwide, the Defendant, along with co-defendants DEBS and DEP, shall develop, implement, and enforce the ECP-NC that also incorporates all of the requirements of the NECP. Both the NECP and the ECP-NC shall be filed with the Court as separate documents. Components of the NECP and the ECP-NC include, but are not limited to, the following:

i. Timing for Submission of NECP and ECP-NC: Defendant DUKE ENERGY CAROLINAS, along with its co-defendants DEBS and DEP, shall develop and adopt the NECP and ECP-NC within seventy (70) days of the selection of the CAM. The final NECP and ECP-NC shall be submitted to the Court with copies to the United States Probation Office; the United States Attorneys' Offices for the Eastern, Middle, and Western Districts; the Department of Justice - Environmental Crimes Section; the Environmental Protection Agency - Criminal Investigation Division; and the United States Environmental Protection Agency - Legal Counsel Division. The Court must approve both the NECP and ECP-NC.

(1) The United States acknowledges that two (2) wholly-owned subsidiaries of Duke Energy Corporation, Duke Energy Commercial Enterprises, Inc. (an indirect wholly-owned subsidiary) and Duke Energy SAM, LLC (a direct wholly-owned subsidiary) have entered into a purchase and sale agreement with a subsidiary of Dynegy Inc. in which Dynegy Inc. will acquire Duke Energy Ohio's unregulated Midwest generation business (which has been classified as Discontinued Operations on the Condensed Consolidated Statement of Operations). Approval is pending before the Federal Energy Regulatory Commission. Both of the subsidiaries handle coal ash.

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(2) If the sale above has not been closed at the time of the submission of the NECP to the Court for approval, it is expressly understood and agreed that these assets need not be included within the NECP with the following exception: if the sale is not closed within ninety (90) days of the approval of the NECP by the Court, the CAM may, at his/her option, require the NECP to be amended to include these subsidiaries.

ii. Best Efforts: Defendant DUKE ENERGY CAROLINAS, along with its co-defendants DEBS and DEP, shall use best efforts to comply with each and all of the obligations under both the NECP and ECP-NC.

(1) The requirement that the Defendant exercise "best efforts" to fulfill the obligation includes using commercially reasonable efforts to anticipate any potential "force majeure" event (as defined herein at Paragraph 3(y)) and to address the effects of any potential "force majeure" event: (a) as it is occurring, and (b) following the potential "force majeure" event, such that the delay is minimized to the greatest extent possible.

(2) If the CAM believes that the Defendant has not used "best efforts" to fulfill its obligations, the CAM shall provide written notice immediately to the Court and the parties.

(3) The final determination of whether the Defendant used "best efforts" shall be made by the Court with the advice of and recommendations from the CAM.

(4) If the Court concludes that the Defendant failed to exercise "best efforts" to fulfill an obligation of this Agreement, the Court may impose and the Government will be entitled to seek additional monetary penalties.

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iii. Selection and Funding of CAM:

(1) Funding: As part of the NECP and the ECP-NC, Defendant DUKE ENERGY CAROLINAS, along with its co-defendants DEBS and DEP, shall pay for a CAM who will be appointed by and report to the Court during the full period of probation.

(2) Qualifications: The object of the selection process for the CAM is to select the most qualified candidate to oversee implementation of the NECP, the ECP-NC, and the bromide claims process. Therefore, the CAM must have staff, or be able to retain staff, with the following experience: (a) expertise and competence in the regulatory programs under the United States and State of North Carolina environmental laws; (b) sufficient expertise and competence to assess whether the Defendant, DEBS, and DEP have adequate management systems in place to ensure regulatory compliance, document such noncompliance, and prevent future noncompliance; and (c) sufficient expertise and competence to review claims for reimbursement under the process for identifying, verifying, and providing restitution for claims relating to bromide discharges described herein.

(3) Nomination and Veto by Government: Within thirty (30) days of the entry of the Judgment, Defendant DUKE ENERGY CAROLINAS, along with its co-defendants DEBS and DEP, shall submit a list of three qualified candidates for the position of CAM from which the Court will select and appoint one of the candidates. Any nomination will include a detailed curriculum vitae or similar documentation setting forth the qualifications of the candidate. The Government shall have fifteen (15) days from the receipt of the nominations to file any reasonable objection to any or all of the proposed candidates. If the Government lodges an objection, then Defendant DUKE

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ENERGY CAROLINAS, along with its co-defendants DEBS and DEP, must nominate a replacement candidate(s). The Government again shall have the right to lodge any reasonable objection to any replacement candidate; and the Court may adjust the time frame for the nominations of the CAM as necessary to ensure that the best possible candidates are nominated.

(4) Court Selection: Upon receipt of a final list of candidates, the Court shall select one candidate as CAM by written order. In the event that the Court does not find any of the candidates satisfactory or if, during any point in the term of probation, the Court does not find the work of the selected CAM satisfactory, the Court may request Defendant DUKE ENERGY CAROLINAS, along with its co-defendants DEBS and DEP, to nominate additional candidates. The Court may adjust the time frame for the selection of the CAM as necessary to ensure that the best possible candidate is selected.

iv. Reporting by CAM: On an annual basis, or more often as the Court directs, the CAM shall provide reports in writing to the Court, through the United States Probation Office, demonstrating compliance with the NECP and the ECP-NC by DUKE ENERGY CAROLINAS, DEBS and DEP. The report shall include, among other things, a detailed description of: (1) all excavation, closure, and/or proper remediation of the coal ash impoundments located in North Carolina and addressed in the ECP-NC; and (2) all three co-defendants' compliance with all appropriate environmental laws and regulations in connection with the management of their coal ash impoundments in North Carolina and elsewhere.

(1) Public Access to Information: The CAM shall ensure, and the Defendant shall facilitate, the posting of copies of any environmental compliance audits, annual reports, and/or any other reports prepared pursuant to the

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NECP or ECP-NC on a company web page with public access.

- Subject to the approval of the CAM, the Defendant may redact confidential business information or any information it reasonably believes could impair the security of its operations before such audits or reports are posted for public access.

- The CAM shall inspect such proposed redactions to determine the propriety of the redactions.

- Notwithstanding the foregoing, unredacted copies shall be provided to the Court. The Defendant may seek to have the filings placed under seal to protect any information that the CAM has deemed to warrant redaction.

(2) The CAM will contemporaneously provide copies of the reports (as posted) to the United States Attorneys' Offices for the Eastern, Middle, and Western Districts of North Carolina; the Department of Justice - Environmental Crimes Section; the United States Environmental Protection Agency - Criminal Investigation Division; and the United States Environmental Protection Agency - Legal Counsel Division. If the reports contain redactions, any of these parties may inspect the redactions and challenge the propriety of the redactions. The Court shall be the final arbiter of any challenge.

v. Nationwide ECP: The NECP shall include, among other things:

(1) Organizational Funding: Co-Defendant DEBS shall maintain and fund the operation of all of the company compliance organizations created in the wake of the Dan River release, including: ABSAT, the Coal Combustion Products organization, and the

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National Ash Management Advisory Board. Subject to the approval of the CAM, DEBS may transfer operations and responsibilities between internal organizations or adjust funding of such organizations as appropriate, as long as the obligations of this Agreement are being met. To the extent necessary or required, the Defendant shall fund or otherwise pay for its proportionate share of the continued maintenance and operations of these compliance organizations.

(2) Compliance Officer ("CO"): The Defendant, and its co-defendants DEBS and DEP, each shall identify or establish a position at the Vice President level or higher who will liaise directly with the CAM. The Defendant's designated CO shall have, among other duties, the primary responsibility for ensuring compliance with applicable environmental requirements and requirements of the NECP and ECP-NC.

- The COs shall submit detailed reports discussing the development, implementation, and enforcement of the NECP and ECP-NC at intervals deemed necessary by the CAM. The first report shall also include an explanation of the current corporate structure responsible for the operation and control of the coal ash impoundments and the names of the individuals filling the relevant positions. With the concurrence of the CAM, the COs may elect to submit a joint report detailing the required information for all three co-defendants. Any changes to the corporate coal ash oversight structure shall be immediately forwarded to the CAM and included in the next regular report.

- Subject to the approval of the CAM, the Defendant may redact confidential business information or any information it reasonably believes could impair the

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security of its operations before such reports are posted for public access.

- The CAM shall inspect such proposed redactions to determine the propriety of the redactions.

- Notwithstanding the foregoing, unredacted copies shall be provided to the Court. The Defendant may seek to have the filings placed under seal to protect any information that the CAM has deemed to warrant redaction.

- The CAM will contemporaneously provide copies of the reports (as posted) to the United States Attorneys' Offices for the Eastern, Middle, and Western Districts of North Carolina; the Department of Justice - Environmental Crimes Section; the United States Environmental Protection Agency - Criminal Investigation Division; and the United States Environmental Protection Agency - Legal Counsel Division. If the reports contain redactions, any of these parties may inspect the redactions and challenge the propriety of the redactions. The Court shall be the final arbiter of any challenge.

(3) Environmental Audits: Within the first ninety (90) days of his or her appointment, the CAM shall establish a schedule for conducting environmental audits of each of Duke Energy Corporation's and its affiliates' wholly-owned or operated domestic facilities with Duke Energy Corporation or affiliate-managed or affiliate-controlled coal ash impoundments outside North Carolina on an annual basis.

- Each year the Defendant can request that the CAM accept any full environmental audit prepared by ABSAT or a similar organization in that same calendar year for its facilities subject to the audits under the NECP.

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- The CAM can reject any such request by the Defendant if the CAM concludes that the proposed environmental audit is not sufficiently comprehensive or not prepared by a competent organization.

- Copies of the environmental audit reports shall be posted on the Defendant's company webpage accessible to the public.

- Subject to the approval of the CAM, the Defendant may redact confidential business information or any information it reasonably believes could impair the security of its operations before such audits or reports are posted for public access.

- The CAM shall inspect such proposed redactions to determine the propriety of the redactions.

- Notwithstanding the foregoing, unredacted copies shall be provided to the Court and the United States Probation Officer. The Defendant may seek to have the filings placed under seal to protect any information that the CAM has deemed to warrant redaction.

- The CAM will contemporaneously provide copies of the reports (as posted) to the United States Attorneys' Offices for the Eastern, Middle, and Western Districts of North Carolina; the Department of Justice - Environmental Crimes Section; the United States Environmental Protection Agency - Criminal Investigation Division; and the United States Environmental Protection Agency - Legal Counsel Division. If the reports contain redactions, any of these parties may inspect the redactions to determine the propriety of the redactions. The Court shall be the final arbiter of any challenge.

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(4) Toll-Free Hotline/Electronic Mail Inbox: The Defendant, along with co-defendants DEBS and DEP, will establish and maintain a toll-free hotline that will be answered twenty-four (24) hours a day, seven (7) days a week, through which any person may report suspected violations of applicable environmental laws or regulations, or violations of the NECP or ECP-NC. The Defendant may utilize existing toll-free hotlines subject to approval by the CAM. In addition, the Defendant, along with co-defendants DEBS and DEP, shall create an electronic mail inbox accessible from its webpages and accessible through a share link, through which any employee of Duke Energy Corporation, its subsidiaries, or its affiliates, or any other person may report suspected violations of applicable environmental laws or regulations or violations of the NECP or ECP-NC.

- Co-defendant DEBS shall periodically apprise employees and the public of the availability of the toll-free hotline and electronic mail inbox by posting notices on the Internet, Intranet (known within Duke Energy Corporation as the "Portal"), by distributing notice via its electronic mail system, by providing notices in appropriate employee work areas, and by publication in community outlets.

- All reports to the toll-free hotline or electronic mail inbox of suspected violations of applicable environmental requirements, the NECP, or the ECP-NC shall promptly be provided to the appropriate CO for further action, and the appropriate CO shall maintain a record of the investigation and disposition of each such matter and disclose such matters in reports to the CAM.

(5) Environmental Training Program: The Defendant, along with co-defendants DEBS and

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DEP, shall adopt, implement, and enforce a comprehensive training program to educate all domestic employees of Duke Energy Corporation and its wholly-owned or operated affiliates on the environmental impact of coal ash impoundment operations and to be aware of the procedures and policies that form the basis of the NECP and ECP-NC.

- The goal of this training program is to ensure that every domestic employee of Duke Energy Corporation and its wholly-owned or operated affiliates understands applicable compliance policies and is able to integrate the compliance objectives in the performance of his/her job. The training shall include applicable notice and reporting requirements in the event of a release or discharge. Subject to the approval of the CAM, the Defendant may develop different training programs that are tailored to the employee's specific job description and responsibilities as long as the overall goal of the training requirement is met.

- Additionally, the Defendant and co-defendants DEBS and DEP shall provide training and written materials describing the safe and proper handling of pollutants, hazardous substances, and/or wastes.

- Copies of all written materials and training curricula shall be provided to the CAM.

vi. Statewide ECP: The ECP-NC, in addition to incorporating all of the requirements of the NECP, shall include, among other things, the following conditions:

(1) Point of Contact ("POC"): With respect to each of its facilities with coal ash impoundments in North Carolina, the Defendant and co-defendant DEBS shall identify or establish a POC for the CAM

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within each of the following three business services: (1) ABSAT; (2) Environmental, Health & Safety; and (3) Coal Combustion Products.

(2) Environmental Audits: Within the first ninety (90) days of his/her appointment, the CAM shall establish a schedule for conducting environmental audits of each of the Defendant's facilities with coal ash impoundments in North Carolina on an annual basis.

- Each year the Defendant can request that the CAM accept any full environmental audit prepared by ABSAT or a similar organization in that same calendar year for two of its facilities subject to the audits. The Defendant cannot make the request for the same facilities in consecutive years.

- The CAM can reject any such request by the Defendant if the CAM concludes that the proposed environmental audit is not sufficiently comprehensive or not prepared by a competent organization.

- Copies of the environmental audit reports shall be posted on the Defendant's company webpage accessible to the public.

- Subject to the approval of the CAM, the Defendant may redact confidential business information or any information it reasonably believes could impair the security of its operations before such audits or reports are posted for public access.

- The CAM shall inspect such proposed redactions to determine the propriety of the redactions.

- Notwithstanding the foregoing, unredacted copies shall be provided to the Court and

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the United States Probation Officer. The Defendant may seek to have the filings placed under seal to protect any information that the CAM has deemed to warrant redaction.

- The CAM will contemporaneously provide copies of the reports (as posted) to the United States Attorneys' Offices for the Eastern, Middle, and Western Districts of North Carolina; the Department of Justice - Environmental Crimes Section; the United States Environmental Protection Agency - Criminal Investigation Division; and the United States Environmental Protection Agency - Legal Counsel Division. If the reports contain redactions, any of these parties may inspect the redactions to determine the propriety of the redactions. The Court shall be the final arbiter of any challenge.

v. The Defendant shall ensure that any new, expanded, or reopened coal ash or coal ash wastewater impoundment facilities are lined to ensure no unpermitted discharges of coal ash or coal ash wastewater to any water of the United States. This includes all engineered, channelized, or naturally occurring seeps.

w. Recordkeeping of Coal Ash Impoundment Volumes: Every six months, the Defendant shall determine the volume of wastewater and coal ash in each of its wet-storage coal ash impoundments in North Carolina. Additional determinations shall be made following the conclusion of activities that significantly change the volumes of materials in the impoundments, including but not limited to temporary rerouting of waste streams other than sluiced coal ash to the ash impoundment, dredging, and dewatering. Written or electronic records of the volumes shall be maintained by the Defendant in a location(s) accessible to facility staff and to any of the Defendant's employees responsible for making environmental or emergency reports.

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x. Bromide Remediation Claims and Costs:

i. Identification: Within the first year of probation, or within ninety (90) days of the installation of a new Flue Gas Desulfurization ("FGD") scrubber system thereafter, the Defendant shall identify:

(1) all facilities operated by it in North Carolina that utilize or will utilize FGD scrubbers that will result in an increase in bromide discharge into surface waters; and

(2) all local governments that are downstream from such FGD scrubbers and draw water into water treatment facilities.

ii. Notification: Within the first year of probation, or within ninety (90) days of the installation of a new FGD scrubber system thereafter, the Defendant shall: (1) notify in writing the identified local governments of the increase or potential increase in bromide discharge; and (2) cooperate in studies of whether there has been or will be an impact on these water treatment facilities. The Defendant shall further advise the local government of the claims process established by the CAM, as described below. The Defendant will further note that the local government is not obligated to submit a claim through the process, is not bound by any recommendation of the CAM, and may pursue any civil and/or administrative remedies available to it. Copies of such correspondence shall be provided to the CAM, United States Probation Officer, and each of the prosecuting districts.

iii. Claims Process: The CAM shall establish a procedure by which local governments that are downstream of the Defendant's facilities with FGD scrubbers and experience increases in trihalomethanes at their water treatment facilities related to increases in bromide released by those facilities may submit evidence of these impacts and claims for restitution stemming from these impacts.

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(1) In these claims, the local governments bear the burden of proving by a preponderance of the evidence to the CAM that trihalomethanes have increased and that the Defendant's facility's discharge of bromide substantially contributed to the increase.

(2) The Defendant shall be permitted an opportunity to respond to any evidence or material submitted by local governments in this process.

(3) The CAM shall review proposed remediation actions and costs or anticipated costs associated with investigating, responding to, and remediating increased bromides and trihalomethanes for reasonableness in determining the correct amount of restitution. The CAM shall issue a written decision on every claim submitted. If the CAM determines that restitution to a local government in any amount is appropriate, the Defendant shall also reimburse the local government for costs associated with investigating and preparing its submission to the CAM, including reasonable attorneys' fees.

iv. Appeals Process: Once the written decision is issued, the Defendant or the local government may appeal the decision to the United States District Court. In such an appeal, the decision of the CAM shall be subject to a rebuttable presumption of correctness. If the Defendant unsuccessfully appeals a written decision of the CAM, the Defendant shall bear all of the costs of the appeal, including the costs of the CAM and the reasonable attorneys' fees of the local government, with the Court making the final determination of the reasonableness of such fees. If the Defendant is successful on appeal, the Defendant shall bear the costs of the CAM and the local government shall bear the costs of its attorneys' fees.

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v. Payment of Claims: Once the CAM has issued its written opinion, the Defendant shall pay the approved costs to the claimant within thirty (30) days of the opinion, unless it files an appeal to the United States District Court as provided above. If, after appeal, the Court concurs with the CAM's opinion approving such costs, the Defendant shall pay the approved costs to the claimant and submit proof of payment to the Court within thirty (30) days of the Court's opinion. Nothing in this subparagraph will bar the CAM or the Court from ordering a different payment schedule as appropriate.

vi. Deadline for Filing Claims: Local governments shall have until sixty (60) days prior to the end of the five-year (5-year) probationary term to submit a claim.

y. Force Majeure. For purposes of this Agreement, a "force majeure" is defined as any event arising from causes beyond the reasonable control of the Defendant, any entity controlled by the Defendant, or its contractors that delays or prevents performance of any obligation despite the best efforts to fulfill the obligation and includes but is not limited to war, terrorism, civil unrest, labor dispute, act of God, change in law making performance impossible, or act of a governmental or regulatory body delaying performance or making performance impossible, including, without limitation, any appeal or decision remanding, overturning, modifying, or otherwise acting (or failing to act) on a permit or similar permission or action that prevents or delays an action needed for the performance of any work such that it prevents or substantially interferes with the Defendant's ability to perform. Force majeure does not include financial inability to complete the work, increased cost of performance, or changes in business or economic circumstances.

i. If the Defendant seeks to rely on "force majeure" to excuse performance or timely performance with any term of this Agreement, the Defendant must apply to the CAM with copies of such application provided to the Government and the United States Probation Officer.

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ii. The final determination of "force majeure" shall be made by the Court with the advice and recommendation from the CAM.

iii. If the Court concludes that the Defendant's failure to fulfill an obligation of this Agreement was not excused by a "force majeure," the Court may impose and the Government will be entitled to seek additional monetary penalties.

z. Funding of NECP and ECP-NC: A failure to fund or implement the NECP or ECP-NC during its term of probation would constitute a breach of this Agreement by the Defendant, and the Defendant shall be subject to prosecution for any federal criminal violation not barred by the applicable statute of limitations (or as waived pursuant to Paragraph 3(hh)) or other legal prohibition. Any information provided by the Defendant may be used against the Defendant in such a prosecution.

aa. Community Service Payment: In addition to the community service payment made by co-defendant DEP, the Defendant, as guaranteed by Duke Energy Corporation and set forth in the Guaranty attached to this Agreement, shall pay $13.5 million ($13,500,000) to the National Fish and Wildlife Foundation ("NFWF"), a nonprofit organization established pursuant to 16 U.S.C. §§ 3701-3710, as community service by an organization. With respect to the work described in this Paragraph below, the Defendant shall assume no responsibilities or obligations other than making the payments described in Paragraph 3(aa)(i) below. The Defendant shall not seek any reduction in its tax obligations as a result of these community service payments nor shall the Defendant characterize, publicize, or refer to these payments as voluntary donations or contributions. Additionally, the Defendant shall not seek or take credit for any project performed using funds disbursed by NFWF pursuant to this Agreement in any related civil or administrative proceeding, including but not limited to, the Natural Resources Damages Assessment process.

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i. The Defendant will make the $13.5 million ($13,500,000) payment within sixty (60) days of entry of Judgment. Payments shall be made by certified check payable to the National Fish and Wildlife Foundation and mailed to the attention of its Chief Financial Officer at 1133 15th Street, NW, Suite 1100, Washington, DC 20005, and include a reference to the case number in this proceeding; or by electronic funds transfer in accordance with written instructions to be provided to the Defendant by NFWF at the time of transfer.

ii. NFWF shall use the money it receives from the Defendant pursuant to this Agreement for the benefit, preservation, restoration, and improvement of the water resources of North Carolina and Virginia that have been impacted by the operation of coal ash storage ponds owned by the Defendant. NFWF shall conduct or fund projects in the following federal districts, in the following amounts:

(1) Eastern District of North Carolina: $3.5 million ($3,500,000);

(2) Middle District of North Carolina: $3.5 million ($3,500,000);

(3) Western District of North Carolina: $3.5 million ($3,500,000); and

(4) Eastern District of Virginia and Western District of Virginia: $3 million ($3,000,000).

iii. The projects and initiatives considered by NFWF should include, but not be limited to: monitoring, study, restoration, and preservation of fish, wildlife, and plant resources; monitoring, study, clean up, remediation, sampling, and analysis of pollution and other threats to the riparian environment and ecosystem; research, study, planning, repair, maintenance, education, and public outreach relating to the riparian environment and ecosystem; environmental education and training

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relating to the protection and preservation of riparian resources; and the protection and support of public drinking water systems.

iv. The projects and initiatives considered by NFWF should be focused on the following river basins or watersheds: Broad River, Cape Fear River, Catawba River, Dan River, French Broad River, Lumber River, Roanoke River, Neuse River, and Yadkin River. NFWF shall make every effort to fund at least one project and/or initiative in each of the river basins or watersheds.

v. NFWF shall consult with appropriate state resource managers in North Carolina and Virginia, as well as federal resource managers, that have statutory authority for coordination or cooperation with private entities to help identify projects and maximize the environmental benefits of such projects. Specifically, NFWF should consult with the United States Environmental Protection Agency, the United States Fish and Wildlife Service, the United States Army Corps of Engineers, the North Carolina Department of Environment and Natural Resources, the North Carolina Wildlife Resources Commission, the Virginia Department of Environmental Quality, the Virginia Department of Conservation and Recreation, and the Virginia Department of Game and Inland Fisheries. NFWF shall further consult with localities as appropriate. NFWF is not bound by any recommendations from any of the state or federal agencies, resource managers, or localities consulted.

vi. Projects shall be identified and funding obligated within five (5) years of the date of entry of Judgment in this case.

vii. In identifying and selecting projects to receive funding pursuant to this Agreement and related Judgment, NFWF shall not incur liability of any nature in connection with any act or omission, made in good faith, in the administration of the funds or otherwise pursuant to this Agreement, excepting, however, liability resulting from

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NFWF's gross negligence or willful misconduct. In addition, if and to the extent NFWF grants funds to or contracts with any governmental entity to implement any project under this Agreement and related Judgment: (a) NFWF shall be deemed to act solely as an administrative agent in contracting for, granting to, and disbursing funds for any such project; and (b) NFWF shall not be deemed to incur liability of any nature in connection with the design, engineering, construction, operation, or maintenance of any such project, including, without limitation, any impact or consequences of any such project on fish, wildlife, plant, or other natural resources, personal injury, or property damage.

viii. NFWF's use of funds received pursuant to this Agreement and related Judgment shall be subject to the reporting requirements of 16 U.S.C. § 3706. In addition, NFWF shall report to the United States Probation Office and to the parties regarding the status and disposition of money it has received pursuant to this Agreement and related Judgment, on at least an annual basis, until all such money has been spent.

bb. Mitigation: Within ninety (90) days of sentencing, in order to mitigate impacts to wetlands and other jurisdictional waters of the United States impacted as a result of the Defendant's operation of coal ash impoundments and any relevant criminal conduct, including temporal and secondary effects, at its facilities in North Carolina with coal ash impoundments, and in addition to the mitigation payment made by its co-defendant DEP, the Defendant shall provide $5 million ($5,000,000), which represents its share after apportionment of a total $10 million ($10,000,000) payment, to an authorized wetlands mitigation bank for the purchase of wetland and/or riparian land and/or restoration equivalent located in the Broad River Basin, French Broad River Basin, Cape Fear River Basin, Catawba River Basin, Dan River Basin, Yadkin-Pee Dee River Basin, Neuse River Basin, Lumber River Basin, and Roanoke River Basin. This mitigation payment is in addition to, and does not replace, Duke Energy Corporation's public commitment to fund its $10 million

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($10,000,000) Water Resources Fund for environmental and other philanthropic projects along lakes and rivers in the Southeast.

i. Such wetland restoration shall be made through an authorized wetlands mitigation bank with no affiliation to any current or former employee of the North Carolina Department of Environment and Natural Resources in that employee's individual capacity.

ii. The Defendant, along with its co-defendants DEBS and DEP, shall provide a list of three (3) proposed mitigation banks from which the Court will select the mitigation bank to receive the funds. If the Defendant is unable after reasonable efforts to identify one or more mitigation banks, the Defendant may substitute one or more conservation trust funds within the State of North Carolina in its proposal as long as all other conditions of this section are being met.

iii. Such property must be purchased in the State of North Carolina by the selected authorized wetlands mitigation bank or conservation trust within four (4) years from the date of entry of Judgment.

iv. Such property shall be held by and titled in the name of a third-party (with no affiliation to the Defendant or any of the Defendant's sister or parent corporations).

v. Such property shall be held in permanent conservation status for the benefit of the citizens of North Carolina.

vi. The Defendant shall ensure that the selected authorized wetlands mitigation bank or conservation trust provides a full accounting of all mitigation property purchased to the Court and the CAM, and documentary evidence that the property has been placed in permanent conservation status.

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cc. No Credit in Civil or Administrative Proceedings: The Defendant shall not seek or take credit for any fine, restitution, community service payment, mitigation payment, or funding of the environmental compliance plan (including the costs associated with the hiring or payment of staff or consultants needed to assist the CAM) under this Agreement in any related civil or administrative proceeding, including, but not limited to, the Natural Resources Damages Assessment process.

dd. No Capitalization or Tax Deduction: The Defendant shall agree that: (1) it shall not capitalize into inventory or basis or take as a tax deduction, in the United States or elsewhere, any portion of the monetary payments (fine, restitution, community service, mitigation, or funding of the environmental compliance plans) made pursuant to this Agreement. Provided, however, that nothing in this Agreement shall bar or prevent the Defendant from appropriately capitalizing or seeking an appropriate tax deduction for restitution in connection with the remediation of bromide claims set forth in this Agreement or for costs which would have been incurred by the Defendant irrespective of the environmental compliance plans. Costs that would have been incurred irrespective of the environmental compliance plans include, by way of example only, costs for staffing and operating Central Engineering Services, ABSAT, Coal Combustion Products, or other similar organizations.

ee. No Rate Increase Based Upon Monetary Penalties: The Defendant shall not reference the burden of, or the cost associated with, compliance with the criminal fines, the restitution related to counts of conviction, the community service payments, the mitigation obligation, the costs of the clean-up in response to the February 2, 2014, release at Dan River Steam Station, and/or the funding of the environmental compliance plans in any request or application for a rate increase on customers. Provided, however, that nothing in this Agreement shall bar or prevent the Defendant from seeking appropriate recovery for restitution in connection with the remediation of bromide claims set forth in this Agreement or for costs which would have been incurred by the Defendant irrespective of the

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environmental compliance plans. Costs that would have been incurred irrespective of the environmental compliance plans include, by way of example only, costs for staffing and operating Central Engineering Services, ABSAT, Coal Combustion Products, or other similar organizations.

ff. Public Apology: Consistent with USSG §8D1.4(a), and in conjunction with its co-defendants DEBS and DEP, the Defendant shall place a full-page advertisement in at least two national newspapers and three major North Carolina newspapers (one in Raleigh, one in Greensboro, and one in Charlotte) and on its publicly accessible company website. The full page advertisement shall run within five (5) days of entry of the plea. The language of the public apology must be agreed upon by each of the federal districts and is appended to this Agreement as Exhibit C.

gg. The Defendant shall not reference this Agreement, any payments pursuant hereto, or other compliance herewith in any public relations, marketing, or advertising. The Defendant shall be permitted to make required disclosures under applicable securities laws.

hh. Tolling of Statute of Limitations: To ensure compliance with the terms of the Agreement, the Defendant waives any statute of limitations as of the date of this Agreement through the full term of Defendant's probation and until all of the Defendant's obligations under this Agreement have been satisfied with regard to any conduct relating to or arising out of the conduct set forth in the Criminal Informations.

ii. The Defendant waives any claim under the Hyde Amendment, 18 U.S.C. § 3006A (Statutory Note), for attorneys' fees and other litigation expenses arising out of the investigation or prosecution of this matter.

jj. The Defendant agrees to withdraw from and not to participate in any joint defense agreement, informal or formal, in connection with the defense by any person designated as a "target" or "subject" of, or indicted for, any potential criminal charges relating

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to the Clean Water Act violations in North Carolina that are the subject of this Agreement and any allegations of violations of Title 18 of which the Defendant is aware or becomes aware. The Defendant agrees to submit a written statement, signed by counsel and the appropriate corporate officer, reflecting this commitment to the United States prior to entry of this Agreement.

kk. Term of Supervised Probation: The Defendant and the Government agree that the Defendant shall be placed on organizational supervised probation for a period of five (5) years from the date of sentencing pursuant to 18 U.S.C. § 3561(c)(2) and USSG §§8D1.1 and 8D1.2.

4. The Defendant represents and/or acknowledges:

a. That the Defendant has had the assistance of an attorney in connection with the charges against it. That the attorney has carefully reviewed this Agreement with those persons designated by law and its bylaws to act on behalf of the Defendant (hereinafter referred to as "Designated Corporate Representative") and that this Agreement has been signed by a person authorized by law and the bylaws of the Defendant to execute agreements on behalf of the Defendant.

b. That its Designated Corporate Representative has reviewed and discussed the Criminal Informations filed in each of the federal districts involved in this matter with the Defendant's attorney and that the attorney has explained the Government's evidence to that Designated Corporate Representative.

c. That as a corporation, it is vicariously liable for the criminal acts of its employees acting within the scope of their employment for the benefit of the corporation.

d. That it understands that this Agreement does not provide or promise any waiver of any civil or administrative actions, sanctions, or penalties that may apply, including but not limited to fines; penalties; claims for damages to natural resources; suspension, debarment, listing to restrict rights and

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opportunities of the Defendant to contract with or receive assistance, loans, and benefits from United States agencies; licensing; injunctive relief; or remedial action to comply with any applicable regulatory requirement. The Defendant understands that this Agreement has no effect on any proceedings against any party not expressly mentioned herein, including the actual or potential criminal liability of any individuals.

e. Guaranty: That it has sought and obtained a guarantee of its obligations under this Agreement from its parent holding company, Duke Energy Corporation, a copy of which is attached hereto as Exhibit B and incorporated herein by reference. Duke Energy Corporation further consents to the jurisdiction of the United States District Court for the Eastern District of North Carolina for the purpose of enforcing the Guaranty Agreement.

f. Resolution: That it has filed with the Court prior to entry of this Agreement the original resolution from the board of directors (or equivalent written authorization as recognized by law) that gives the authority described in Paragraph 4(a) above to the Designated Corporate Representative and that authorizes such employee to execute this Agreement on behalf of the Defendant. A copy of the Resolution, attached hereto as Exhibit D, provides as follows:

i. The Defendant is a legally viable entity, authorized to plead guilty to the charges set forth in the Criminal Informations;

ii. The Defendant shall be bound by the specific terms of this Agreement;

iii. The parent corporation, Duke Energy Corporation, is authorized to guarantee all payments (criminal fine, restitution, community service, and mitigation), and funding and performance due from the Defendant in connection with its obligations under the NECP and ECP-NC under this Agreement, as set forth in the Guaranty Agreement.

iv. Any legal successor or assignee of Duke Energy Corporation shall remain liable, as the case may

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be, for the guarantee of the Defendant's payment obligations and the funding and performance of both the NECP and ECP-NC hereunder, and an agreement to so remain liable shall be included by Duke Energy Corporation in the terms of any sale, acquisition, or merger.

v. Any legal successor or assignee of the Defendant shall remain liable for the Defendant's obligations in this Agreement, and an agreement to so remain liable shall be included by the Defendant in the terms of any sale, acquisition, or merger of the Defendant with or by any other entity. Subject to the requirements of this subparagraph, nothing shall prevent the Defendant from undergoing a corporate reorganization or change in form. The Defendant shall record a copy of the Judgment with the Register of Deeds in each of the counties in North Carolina in which it owns and operates facilities with coal ash impoundments. Upon written request from the Defendant made only after fulfillment of all of the conditions of this Agreement and related Judgment, the Government shall take the necessary steps through the Register of Deeds to facilitate the removal of the notice of the Judgment.

5. The Defendant understands, agrees, and admits:

a. That as to each Count of the Criminal Informations to which the Defendant is pleading guilty, the charge, code section, elements, and applicable penalties are as follows:

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United States v. Duke Energy Business Services LLC,
Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc.,
No. 5:15-CR-67-H-2[1]

Violations at Dan River Steam Station

COUNT ONE

(1) Clean Water Act violation for the unpermitted discharge through the 48-inch stormwater pipe at the Dan River Steam Station and aiding and abetting

(2) Code Sections violated: 33 U.S.C. §§ 1311, 1319(c)(1)(A), and 1342; and
18 U.S.C. § 2

(3) Offense date: No later than February 2, 2014, through February 8, 2014

(4) Elements of the Offense:

First: The Defendant did discharge a pollutant, to wit, coal ash and coal ash wastewater;

Second: from a point source;

Third: into a water of the United States;

Four: the Defendant did so without a permit;

Five: the Defendant acted negligently in so doing; and

Six: the Defendant aided and abetted another in so doing.

(5) Maximum term of probation for a corporation: 5 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

[1]Counts Five and Six are captured by the Plea Agreement in United States v. Duke Energy Progress, Inc., No. 5:15-CR-62-H-2; No. 5:15-CR-67-H-3; and No. 5:15-CR-68-H-3.

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(6) Minimum term of probation for a corporation: 0 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

(7) Maximum fine: Pursuant to 18 U.S.C. § 3571(c) and (d), the greater of: not less than $2,500 nor more than $25,000 per day of violation (33 U.S.C. § 1319(c)(1)(A)); $200,000.00; or twice the gross gain or loss.

(8) Restitution pursuant to 18 U.S.C. §§ 3663, 3663A, and 3563(b)(2) as agreed to in Paragraphs 2(iv)-(v) and 3(b)-(c) above.

(9) Special assessment: $ 125.00

(10) Other penalties: Public Notice of Violation; Development of a Compliance Program; Community Service; and Remediation

COUNT TWO

(1) Clean Water Act violation for the failure to maintain the 48-inch stormwater pipe at the Dan River Steam Station and aiding and abetting

(2) Code Sections violated: 33 U.S.C. §§ 1319(c)(1)(A), and 1342; and 18 U.S.C. § 2

(3) Offense date: No later than January 2012, through February 2, 2014

(4) Elements of the Offense:

First: The Defendant did violate a condition of its NDPES permit issued by the State of North Carolina pursuant to the Clean Water Act; to wit, the requirement to properly maintain its equipment as more fully described in the Criminal Information;

Second: the Defendant acted negligently in so doing; and

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Third: the Defendant aided and abetted another in so doing.

(5) Maximum term of probation for a corporation: 5 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

(6) Minimum term of probation for a corporation: 0 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

(7) Maximum fine: Pursuant to 18 U.S.C. § 3571(c) and (d), the greater of not less than $2,500 nor more than $25,000 per day of violation (33 U.S.C. § 1319(c)(1)(A)); $ 200,000.00; or twice the gross gain or loss.

(8) Restitution pursuant to 18 U.S.C. §§ 3663, 3663A, and 3563(b)(2) as agreed to in Paragraphs 2(iv) - (v) and 3(b)-(c) above.

(9) Special assessment: $ 125.00

(10) Other penalties: Public Notice of Violation; Development of a Compliance Program; Community Service; and Remediation

COUNT THREE

(1) Clean Water Act violation for the unpermitted discharge through the 36-inch stormwater pipe at the Dan River Steam Station and aiding and abetting

(2) Code Sections violated: 33 U.S.C. §§ 1311, 1319(c)(1)(A) and 1342; and 18 U.S.C. § 2

(3) Offense date: No later than January 2012 through February 21, 2014

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(4) Elements of the Offense:

First: The Defendant did discharge a pollutant, to wit, coal ash and coal ash wastewater;

Second: from a point source;

Third: into a water of the United States;

Four: the Defendant did so without a permit;

Five: the Defendant acted negligently in so doing; and

Six: the Defendant aided and abetted another in so doing.

(5) Maximum term of probation for a corporation: 5 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

(6) Minimum term of probation for a corporation: 0 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

(7) Maximum fine: Pursuant to 18 U.S.C. § 3571(c) and (d), the greater of: not less than $2,500 nor more than $25,000 per day of violation (33 U.S.C. § 1319(c)(1)(A)); $200,000.00; or twice the gross gain or loss.

(8) Restitution pursuant to 18 U.S.C. §§ 3663, 3663A, and 3563(b)(2) as agreed to in Paragraphs 2(iv) - (v) and 3(b)-(c) above.

(9) Special assessment: $ 125.00

(10) Other penalties: Public Notice of Violation; Development of a Compliance Program; Community Service; and Remediation

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COUNT FOUR

(1) Clean Water Act violation for the failure to maintain the 36-inch stormwater pipe at the Dan River Steam Station and aiding and abetting

(2) Code Sections violated: 33 U.S.C. §§ 1319(c)(1)(A), and 1342; and 18 U.S.C. § 2

(3) Offense date: No later than January 2012, through February 6, 2014

(4) Elements of the Offense:

First: The Defendant did violate a condition of its NDPES permit issued by the State of North Carolina pursuant to the Clean Water Act; to wit, the requirement to properly maintain its equipment as more fully described in the Criminal Information;

Second: the Defendant acted negligently in so doing; and

Third: the Defendant aided and abetted another in so doing.

(5) Maximum term of probation for a corporation: 5 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

(6) Minimum term of probation for a corporation: 0 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

(7) Maximum fine: Pursuant to 18 U.S.C. § 3571(c) and (d), the greater of: not less than $2,500 nor more than $25,000 per day of violation (33 U.S.C. § 1319(c)(1)(A)); $200,000.00; or twice the gross gain or loss.

(8) Restitution pursuant to 18 U.S.C. §§ 3663, 3663A, and 3563(b)(2) as agreed to in Paragraphs 2(iv) - (v) and 3(b)-(c) above.

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(9) Special assessment: $ 125.00

(10) Other penalties: Public Notice of Violation; Development of a Compliance Program; Community Service; and Remediation

United States v. Duke Energy Business Services LLC, Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., No. 5:15-CR-68-H-2[2]

VIOLATIONS AT RIVERBEND STEAM STAITON

COUNT ONE

(1) Clean Water Act violation for the unpermitted discharge from a toe drain at the ash impoundment at Riverbend Steam Station and aiding and abetting

(2) Code Sections violated: 33 U.S.C. §§ 1311, 1319(c)(1)(A), and 1342; and 18 U.S.C. § 2

(3) Offense date: No later than November 8, 2012, through December 30, 2014

(4) Elements of the Offense:

First: The Defendant did discharge a pollutant, to wit, coal ash and coal ash wastewater;

Second: from a point source;

Third: into a water of the United States;

Four: the Defendant did so in violation of a permit;

[2] Count Two is captured by the Plea Agreement in United States v. Duke Energy Progress, Inc., No. 5:15-CR-62-H-2; No. 5:15-CR-67-H-3; and No. 5:15-CR-68-H-3.

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Five: the Defendant acted negligently in so doing; and

Six: the Defendant aided and abetted another in so doing.

(5) Maximum term of probation for a corporation: 5 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

(6) Minimum term of probation for a corporation: 0 years pursuant to 18 U.S.C. § 3561(c)(2) and USSG §8D1.2(a)(2)

(7) Maximum fine: Pursuant to 18 U.S.C. § 3571(c) and (d), the greater of: not less than $2,500 nor more than $25,000 per day of violation (33 U.S.C. § 1319(c)(1)(A)); $200,000.00; or twice the gross gain or loss.

(8) Restitution pursuant to 18 U.S.C. §§ 3663, 3663A, and 3563(b)(2) as agreed to in Paragraphs 2(iv) - (v) and 3(b)-(c) above.

(9) Special assessment: $ 125.00

(10) Other penalties: Public Notice of Violation; Development of a Compliance Program; Community Service; and Remediation

Total Statutory Penalties: 5 years of probation; a minimum fine of $45,740,000; a maximum fine of $115,375,000; and $625.00 special assessment.

6. The United States agrees:

a. That pursuant to Fed. R. Crim. P. 11(c)(1)(C), the sentence set forth in Paragraph 2 above is warranted.

b. That it reserves the right at sentencing to present any evidence and information pursuant to 18 U.S.C. § 3661, to offer argument or rebuttal, to recommend imposition of restitution, and to respond to any motions or objections filed by the Defendant.

c. That, subject to the reservations within this Agreement, the United States shall not further

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prosecute the Defendant, including all predecessors, successors, and assignees of the Defendant, for conduct constituting the basis for the Criminal Informations covered by this Agreement as set forth in the Joint Factual Statement or about which the United States Attorneys' Offices for the Eastern, Middle, and Western Districts and the Department of Justice - Environmental Crimes Section were otherwise aware of as of the date of this Agreement. This Agreement shall not apply to individuals. Should the Court determine that the Defendant has breached this Agreement, the Defendant will not be entitled to withdraw its plea of guilty, and the United States may prosecute the Defendant, and any predecessors, successors, and assignees of the Defendant for conduct constituting the basis for the Criminal Informations covered by this Agreement, notwithstanding the expiration of any applicable statutes of limitations following the signing of this Agreement. In any such prosecution, the United States may use the Defendant's admissions of guilt as admissible evidence against the Defendant.

d. That it will make known to the Court at sentencing the full extent of the Defendant's cooperation.

e. Pursuant to USSG §1B1.8, that self-incriminating information provided by the Defendant pursuant to this Agreement shall not be used against the Defendant in determining the applicable advisory Guideline range, except as provided by USSG §1B1.8 and except as stated in this Agreement. The United States may provide to the United States Probation Office any evidence concerning relevant conduct.

f. Notwithstanding the foregoing, the United States Attorneys' Offices for the Eastern, Middle, and Western Districts of North Carolina and the Department of Justice - Environmental Crimes Section further recognize that this Agreement does not provide or promise any waiver of any civil or administrative actions, sanctions, or penalties that may apply, including but not limited to: fines; penalties; claims for damages to natural resources; suspension, debarment, listing to restrict rights and opportunities of the Defendant to contract with or receive assistance, loans, and benefits from United

States agencies; licensing; injunctive relief; or remedial action to comply with any applicable regulatory requirement.

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DEQDANR00044686

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SO AGREED, THIS 20th DAY OF FEBRUARY, 2015.

THOMAS G. WALKER
U.S. Attorney
Eastern District of North Carolina
North Carolina

JOHN C. CRUDEN
Assistant Attorney General
Department of Justice
Environment and Natural
Resources Division

JILL WESTMORELAND ROSE
Attorney for the United States
Acting Under Authority
Conferred by 28 USC §515
Western District of North Carolina

CLIFTON T. BARRETT
Attorney for the United States
Acting Under Authority
Conferred by 28 USC §515
Middle District of North Carolina

ON BEHALF OF EACH PROSECUTING OFFICE:

BANUMATHI RANGARAJAN
Senior Litigation Counsel
Criminal Division
U.S. Attorney's Office - EDNC

LANA N. PETTUS
Senior Trial Attorney
Environmental Crimes Section
U.S. Department of Justice

SETH M. WOOD
Assistant U.S. Attorney
Appellate Division
U.S. Attorney's Office - EDNC

STEPHEN INMAN
Deputy Chief
Criminal Division
U.S. Attorney's Office - MDNC

ERIN C. BLONDEL
Assistant U.S. Attorney
Criminal Division
U.S. Attorney's Office - EDNC

JOANNA G. MCFADDEN
Assistant U.S. Attorney
Criminal Division
U.S. Attorney's Office - MDNC

JODI MAZER
Special Assistant U.S. Attorney
Criminal Division
U.S. Attorney's Office - EDNC

STEVEN R. KAUFMAN
Assistant U.S. Attorney
Criminal Division
U.S. Attorney's Office - WDNC

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SO AGREED, THIS 20 DAY OF FEBRUARY, 2015.

DUKE ENERGY CAROLINAS, LLC
Defendant

BY: _____
JULIA S. JANSON
Executive Vice-President,
Chief Legal Officer, and Corporate
Secretary
DUKE ENERGY CAROLINAS, LLC and
Authorized Designated Official for
DUKE ENERGY CAROLINAS, LLC

_____
JAMES P. COONEY, III
Womble Carlyle Sandridge & Rice LLP
Counsel for the Defendant

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The undersigned, Lynn J. Good, President and Chief Executive Officer of Duke Energy Corporation, the Guarantor, hereby acknowledges the terms and conditions of the foregoing Plea Agreement as they apply to the Guaranty set forth in Exhibit B.

SO ACKNOWLEDGED, THIS 20 DAY OF FEBRUARY, 2015.

DUKE ENERGY CORPORATION
Guarantor

BY: _____
LYNN J. GOOD
President and
Chief Executive Officer
DUKE ENERGY CORPORATION

_____
JAMES P. COONEY, III
Womble Carlyle Sandridge & Rice, LLP
Counsel for the Guarantor

APPROVED, this 14th day of May, 2015.

_____
UNITED STATES DISTRICT JUDGE

DEQDANR00044689

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UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF NORTH CAROLINA
WESTERN DIVISION
No. 5:15-CR-62-H
No. 5:15-CR-67-H
No. 5:15-CR-68-H

FILED
MAY 14 2015
JULIE RICHARDS JOHNSTON, CLERK
US DISTRICT COURT, EDNC
BY _____ DEP CLK

UNITED STATES OF AMERICA	)	
	)	
v.	)	JOINT FACTUAL STATEMENT
	)	
DUKE ENERGY BUSINESS SERVICES LLC	)	
DUKE ENERGY CAROLINAS, LLC	)	
DUKE ENERGY PROGRESS, INC.	)	

I. INTRODUCTION

Defendants Duke Energy Business Services LLC ("DUKE ENERGY BUSINESS SERVICES"), Duke Energy Carolinas, LLC ("DUKE ENERGY CAROLINAS"), and Duke Energy Progress, Inc. ("DUKE ENERGY PROGRESS"), (collectively referred to as "Defendants") and the United States of America, by and through the United States Attorneys for the Eastern District of North Carolina, the Middle District of North Carolina and the Western District of North Carolina and the Environmental Crimes Section of the United States Department of Justice (collectively referred to herein as "the United States" or "the government"), hereby agree that this Joint Factual Statement is a true and accurate statement of the Defendants' criminal conduct and that it provides a sufficient basis for the Defendants' pleas of guilty to the following charging documents and the terms of the Plea Agreements:

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United States v. Duke Energy Business Services, LLC, and Duke Energy Progress, Inc., No. 5:15-CR-62-H;

United States v. Duke Energy Business Services, LLC, Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., No. 5:15-CR-67-H; and

United States v. Duke Energy Business Services, LLC, Duke Energy Carolinas, LLC, and Duke Energy Progress, Inc., No. 5:15-CR-68-H.

The charges from the Middle District of North Carolina and the Western District of North Carolina have been transferred to the Eastern District of North Carolina for purposes of plea pursuant to Fed. R. Crim. P. 20. The Defendants' guilty pleas are to be entered pursuant to the Plea Agreements signed and dated this same day.

II. OVERVIEW AND BACKGROUND

Dan River Steam Station – Middle District of North Carolina

1. From at least January 1, 2012, DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES failed to properly maintain and inspect the two stormwater pipes underneath the primary coal ash basin at the Dan River Steam Station in Eden, North Carolina. On February 2, 2014, one of those pipes failed, resulting in the discharge of approximately 27 million gallons of coal ash wastewater and between 30,000 and 39,000 tons of coal ash into the Dan River. The coal ash travelled more than 62 miles downriver to the Kerr Lake Reservoir on the border of

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North Carolina and Virginia. Video camera inspections of the other pipe, conducted in the aftermath of the spill, revealed that the other pipe had also deteriorated, allowing coal ash wastewater to leak into the pipe, and that DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES had not taken appropriate action to prevent unauthorized discharges from the pipe.

Cape Fear Steam Electric Plant –
Middle District of North Carolina

2. DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES also failed to maintain the riser structures in two of the coal ash basins at the Cape Fear Steam Electric Plant, resulting in the unauthorized discharges of leaking coal ash wastewater into the Cape Fear River.

Asheville, Riverbend, & Lee Steam Stations –
Eastern and Western Districts of North Carolina

3. Additionally, DUKE ENERGY CAROLINAS' and DUKE ENERGY PROGRESS's coal combustion facilities throughout North Carolina allowed unauthorized discharges of pollutants from coal ash basins via "seeps" into adjacent waters of the United States. Three of those facilities include the Asheville Steam Electric Generating Plant, the H.F. Lee Steam Electric Plant, and the Riverbend Steam Station. At those facilities, discharges from naturally occurring seeps were channeled by DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES to flow through

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engineered drains and ditches into waters of the United States without obtaining or maintaining the necessary permits.

4. The Defendants' conduct violated the Federal Water Pollution Control Act (commonly referred to as the "Clean Water Act," or "CWA"). 33 U.S.C. §§ 1251 et seq. More specifically, the criminal investigation, conducted out of the Eastern District of North Carolina, revealed the following:

DEFENDANTS AND CORPORATE STRUCTURE

5. Duke Energy Corporation is an energy company headquartered in Charlotte, North Carolina.

6. Duke Energy Corporation is a holding company whose direct and indirect subsidiaries operate in the United States and Latin America. Duke Energy Corporation's wholly-owned subsidiaries include: DUKE ENERGY CAROLINAS; Progress Energy, Inc. ("Progress Energy"); DUKE ENERGY PROGRESS; and DUKE ENERGY BUSINESS SERVICES.

7. DUKE ENERGY CAROLINAS, a North Carolina limited liability company, is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina.

8. Progress Energy, a North Carolina corporation headquartered in Raleigh, North Carolina, is a holding company which holds, among other entities, DUKE ENERGY PROGRESS.

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9. DUKE ENERGY PROGRESS, a North Carolina corporation, is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Prior to the July 2, 2012, merger between Duke Energy Corporation and Progress Energy, Inc., DUKE ENERGY PROGRESS was known as Carolina Power & Light, Inc., d/b/a Progress Energy Carolinas.

10. "Progress Energy Carolinas" will refer to DUKE ENERGY PROGRESS before the merger.

11. DUKE ENERGY BUSINESS SERVICES provides shared services to all of Duke Energy Corporation's operating utilities nationwide, including: Legal Counsel; Central Engineering & Services; Environmental, Health & Safety; Ethics and Compliance; and Coal Combustion Products.

12. During the time period relevant to the charges, within the State of North Carolina, the Defendants and/or their predecessors owned and operated the following facilities with coal ash basins:

FACILITY	OWNER/ OPERATOR	NUMBER OF COAL ASH BASINS	ADJACENT WATERS OF THE UNITED STATES	FEDERAL JUDICIAL DISTRICT
Allen Steam Station (Gaston County)	Duke Energy Carolinas	2	Lake Wylie & Catawba River	WDNC
Asheville Steam Electric Generating Plant (Buncombe County)	Duke Energy Progress	2	French Broad River	WDNC

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Belews Creek Steam Station (Stokes County)	Duke Energy Carolinas	1	Belews Lake & Dan River	MDNC
Buck Steam Station (Rowan County)	Duke Energy Carolinas	3	Yadkin River & High Rock Lake	MDNC
Cape Fear Steam Electric Plant (Chatham County)	Duke Energy Progress	5	Cape Fear River	MDNC
Cliffside Steam Station (Rutherford & Cleveland Counties)	Duke Energy Carolinas	3	Broad River	WDNC
Dan River Steam Station (Rockingham County)	Duke Energy Carolinas	2	Dan River	MDNC
H.F. Lee Steam Electric Plant (Wayne County)	Duke Energy Progress	5	Neuse River	EDNC
L.V. Sutton Electric Plant (New Hanover County)	Duke Energy Progress	2	Cape Fear River & Sutton Lake[1]	EDNC
Marshall Steam Station (Catawba County)	Duke Energy Carolinas	1	Lake Norman	WDNC
Mayo Steam Electric Plant (Person County)	Duke Energy Progress	1	Mayo Lake	MDNC
Riverbend Steam Station (Gaston County)	Duke Energy Carolinas	2	Catawba River	WDNC
Roxboro Steam Electric Plant (Person County)	Duke Energy Progress	2	Hyco River	MDNC
Weatherspoon Steam Electric Plant (Robeson County)	Duke Energy Progress	1	Lumber River	EDNC

[1] While the parties agree that Sutton Lake receives wastewater from the L.V. Sutton Electric Plant, the status of Sutton Lake as a "water of the State" or "water of the United States" is part of ongoing federal civil litigation. See Cape Fear River Watch, Inc. v. Duke Energy Progress, Inc., 25 F.Supp.3d 798, 808-809 (2014). The Defendants do not concede that Sutton Lake is a jurisdictional water in this Joint Factual Statement.

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COAL COMBUSTION PLANTS AND COAL ASH BASINS

13. Power plants that generate electricity through the combustion of coal create a number of waste byproducts. Among those waste byproducts are "coal combustion residuals" or "CCRs." CCRs include fly ash, bottom ash, coal slag, and flue gas desulfurized gypsum. Fly ash and bottom ash are both commonly referred to as "coal ash." Coal ash contains various heavy metals and potentially hazardous constituents, including arsenic, barium, cadmium, chromium, lead, manganese, mercury, nitrates, sulfates, selenium, and thallium. Coal ash has not been defined, itself, as a "hazardous substance" or "hazardous waste" under federal law, although some constituents of coal ash may be hazardous in sufficient quantities or concentrations.

14. Coal ash basins (also known as "coal ash ponds," "coal ash impoundments," or "ash dikes") may be part of the waste treatment system at coal-fired power plants. Historically, the Defendants' coal ash basins were unlined earthen impoundments and typically operated as follows: Coal ash was mixed with water to form slurry. The coal ash slurry was carried through sluice pipe lines to the coal ash basin. Settling occurred in the coal ash basin, in which particulate matter and free chemical components separated from the slurry and settled at the bottom of the basin. Less contaminated water remained at the surface of the basin, from which it could eventually be

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discharged if authorized under relevant law and permits. In some instances, such as the Dan River Steam Station, water at the surface of the primary basin, flowed into a secondary basin, where further settling and treatment occurred before its discharge into a water of the United States.

15. Coal ash basins generally continued to store settled ash and particulate material for years or decades. From time to time, the Defendants dredged settled coal ash from the basins, storing the ash in dry stacks on plant property.

16. A total of approximately 108 million tons of coal ash are currently held in coal ash basins owned and operated by the Defendants in North Carolina. Duke Energy Corporation subsidiaries also operate facilities with coal ash basins in South Carolina (approximately 5.99 million tons of coal ash), Kentucky (approximately 1.5 million tons of coal ash), Indiana (approximately 35.6 million tons of coal ash), and Ohio (approximately 5.9 million tons of coal ash).

17. Each of the Defendants' facilities in North Carolina with coal ash basins sought and received permits to discharge treated coal ash wastewater through specified permitted outfalls into waters of the United States, including those listed in paragraph 12.

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III. LEGAL AND REGULATORY BACKGROUND

CLEAN WATER ACT

18. The Clean Water Act is a federal law enacted to "restore and maintain the chemical, physical, and biological integrity of the Nation's waters." 33 U.S.C. § 1251(a).

19. The Act prohibits the discharge of any pollutant into waters of the United States except in compliance with a permit issued pursuant to the CWA under the National Pollutant Discharge Elimination System ("NPDES") by the United States Environmental Protection Agency ("EPA") or by a state with an approved permit program. 33 U.S.C. §§ 1311(a) and 1342.

20. The Act defines "discharge of a pollutant" as "the addition of any pollutant to navigable waters from any point source." 33 U.S.C. § 1362(12). The term "pollutant" includes a wide range of materials, including solid waste and industrial waste. 33 U.S.C. § 1362(6). Coal ash and coal ash wastewater are pollutants.

21. A "point source" is a "confined and discrete conveyance, including . . . any pipe . . . from which pollutants are or may be discharged." 33 U.S.C. § 1362(14). Pipes and channelized ditches conveying stormwater or wastewater to surface waters are point sources.

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22. "Navigable waters" are defined in the Act as "waters of the United States." 33 U.S.C. § 1362(7). "Waters of the United States" include rivers and streams "which would affect or could affect interstate or foreign commerce including any such waters . . . [w]hich are or could be used by interstate or foreign travelers for recreational or other purposes . . . [and the] [t]ributaries of [such] waters." 40 C.F.R. § 122.2. The following rivers are "waters of the United States": (1) Broad River; (2) French Broad River; (3) Cape Fear River; (4) Catawba River; (5) Dan River; (6) Yadkin-Pee Dee River; (7) Neuse River; (8) Lumber River; (9) Roanoke River; (10) Hyco River; (11) all tributaries of those rivers, including the South Fork of the Catawba River and Crutchfield Branch; and (12) all lakes and reservoirs exchanging water with those rivers, including, but not limited to, Belews Lake, Lake Norman, Mayo Lake, High Rock Lake, Sutton Lake,[2] and Kerr Reservoir.

23. Permits regulating discharges of pollutants (other than dredge and fill material) to waters of the United States are issued under the NPDES permit program. See 33 U.S.C. § 1342. Under the NPDES permit program, persons or entities who wish to discharge one or more pollutants must apply for an permit from the proper state or federal agency. See 40 C.F.R. § 122.21. A "permit" is "an authorization, license, or equivalent

[2] See note 1, supra.

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control document issued by EPA or an 'approved State' to implement the requirements of [the CWA]." "Permit" does not include a "draft permit" or a "proposed permit" which has not yet been the subject of final agency action. 40 C.F.R. § 122.2 (emphasis added). Thus, an application for a permit does not provide the applicant with authority or permission to discharge under the Act.

24. States can seek approval from EPA to administer and enforce the CWA NPDES permit program. 33 U.S.C. § 1342(b). EPA's approval of a state program does not affect the United States' ability to enforce the Act's provisions. 33 U.S.C. § 1342(i).

25. On October 19, 1975, EPA approved the State of North Carolina's application to administer the NPDES Program. 40 Fed. Reg. 51493-05 (Nov. 5, 1975).

26. NPDES permits typically contain, among other things, effluent limitations; water quality standards; monitoring and reporting requirements; standard conditions applicable to all permits; and special conditions where appropriate. See 33 U.S.C. § 1342; 40 C.F.R. §§ 122.41-122.50.

27. All of DUKE ENERGY CAROLINAS' and DUKE ENERGY PROGRESS's facilities with coal ash basins in North Carolina are required to comply with the following Standard Conditions,

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incorporated into their NPDES permit. See also 40 C.F.R. § 122.41.

a. The Permittee shall take all reasonable steps to minimize or prevent any discharge or sludge use or disposal in violation of this permit with a reasonable likelihood of adversely affecting human health or the environment. Standard Conditions, Section B(2) ("General Conditions").

b. The Permittee shall at all times properly operate and maintain all facilities and systems of treatment and control (and related appurtenances) which are installed or used by the Permittee to achieve compliance with the conditions of this permit. Standard Conditions, Section C(2) ("Operation and Maintenance of Pollution Controls").

IV. FACTUAL BASIS FOR PLEA AND RELEVANT CONDUCT

DAN RIVER STEAM STATION

28. DUKE ENERGY CAROLINAS owns and operates the Dan River Steam Station ("DAN RIVER"), located on the Dan River in the Roanoke River Basin near Eden, North Carolina. DAN RIVER began operating in 1949 as a coal combustion plant. The coal combustion unit at DAN RIVER was retired in 2012. DUKE ENERGY CAROLINAS now operates a combined cycle natural gas facility to generate steam and electricity at DAN RIVER.

29. In 1956, the first coal ash basin at DAN RIVER was constructed to store existing and future coal ash. This basin is commonly referred to as the "Primary Ash Basin."

30. Two stormwater pipes run under the Primary Ash Basin: a 48-inch stormwater pipe and a 36-inch stormwater pipe. Both

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were designed to carry stormwater from the site to the Dan River.

31. The 48-inch stormwater pipe predates the Primary Ash Basin. As installed in 1954, the 48-inch stormwater pipe was composed of galvanized corrugated metal pipe ("CMP").

32. From 1968 to 1969, the Primary Ash Basin was expanded over the original outfall of the 48-inch stormwater pipe. When the Primary Ash Basin was expanded, the 48-inch stormwater pipe was extended using reinforced concrete. After the expansion, the 48-inch stormwater pipe was a total of 1130 feet in length, of which approximately 786 feet was corrugated metal pipe and approximately 344 feet was reinforced concrete pipe ("RCP").

33. The 36-inch stormwater pipe is composed of reinforced concrete pipe that is approximately 600 feet in length.

34. Between 1976 and 1977, the expanded Primary Ash Basin was divided to form a second basin, commonly referred to as the "Secondary Ash Basin."

35. The Primary Ash Basin has a surface area of approximately 27 acres and a total storage capacity of approximately 477 acre-feet (or 155,431,132 gallons). The Secondary Ash Basin has a surface area of approximately 12 acres and a total storage capacity of approximately 187 acre-feet (or 60,934,277 gallons). In 2013, the basins contained a total of

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approximately 1,150,000 cubic yards (or 232,270,130 gallons) of coal ash.

36. In a 2009 EPA Dam Safety Assessment, it was noted that the Primary and Secondary coal ash basins were:

> Classified as a significant hazard potential structure due to the environmental damage that would be caused by misoperation or failure of the structure.

DAN RIVER STEAM STATION NPDES PERMIT

37. On January 31, 2013, the State of North Carolina, through its Department of Environment and Natural Resources ("DENR") - Division of Water Resources ("DWR"), issued a new NDPES permit to DUKE ENERGY CAROLINAS. Effective March 2013, NPDES Permit NC0003468 ("the Dan River Permit"), and authorized the discharge of wastewater from specified outfalls at DAN RIVER.

38. The Dan River Permit required, among other things, that the facility meet the dam design and dam safety requirements set forth in North Carolina regulations at 15A NCAC 2K.

39. Pursuant to 15A NCAC 2K.0301, dams such as the Primary Ash Basin at DAN RIVER are subject to annual safety inspections by state authorities.

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40. In 2006, DUKE ENERGY CAROLINAS, with the assistance of DUKE ENERGY BUSINESS SERVICES, applied for a NDPES stormwater permit for the 48-inch and the 36-inch pipes. As of February 2, 2014, DENR had not issued DUKE ENERGY CAROLINAS an individual or general NDPES stormwater permit for either the 48-inch or 36-inch pipe.

41. A NPDES stormwater permit is different than the NPDES permit issued for the discharge of wastewater from a treatment system. Stormwater permits generally do not allow the discharge of wastewater or particulates from coal ash basins or other industrial processes.

42. Neither the 48-inch nor the 36-inch stormwater pipe was a permitted outfall under the Dan River permit for wastewater. Neither DUKE ENERGY CAROLINAS nor any predecessor received authorization pursuant to the CWA and NPDES program to discharge wastewater from the coal ash basins or coal ash stored in those basins from either the 48-inch or 36-inch stormwater pipe under the Primary Coal Ash Basin at DAN RIVER.

1979 DOCUMENTED PROBLEMS WITH STORMWATER PIPES

43. In 1979, DUKE ENERGY CAROLINAS (at that time called Duke Power Company) inspected the 48-inch stormwater pipe through its Design Engineering and Station Support group. Although no major leaks were identified, engineers noted water

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leaking into the pipe. Repairs to the 48-inch stormwater pipe were undertaken in response to this inspection.

44. Also in 1979, the Design Engineering and Station Support group inspected the 36-inch stormwater pipe. Twenty-two joints in the 36-inch pipe were noted for major leaks. DUKE ENERGY CAROLINAS/Duke Power Company employees recommended that the company repair the leaks or reroute the drain lines, noting that the discharges could be violations of EPA regulations. Repairs to the 36-inch stormwater pipe were undertaken in response to this inspection.

INSPECTIONS OF DAN RIVER COAL ASH BASINS AND DUKE ENERGY'S RESPONSE TO RECOMMENDATIONS

45. Pursuant to the requirements of North Carolina's dam safety laws, from 1981 through 2007, DUKE ENERGY CAROLINAS/Duke Power Company hired consultants to perform inspections of the coal ash basins at DAN RIVER every five years. The consultants generated reports containing their observations and recommendations that were provided to and reviewed by DUKE ENERGY CAROLINAS/Duke Power Company. In the same time period and pursuant to the same laws, DUKE ENERGY CAROLINAS/Duke Power Company performed its own annual inspections of the coal ash basins. DUKE ENERGY CAROLINAS/Duke Power Company also performed less-detailed monthly inspections of the coal ash basins.

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46. In 1981, Engineering Firm #1 conducted the first of five independent inspections of DAN RIVER's ash basins. The report clearly identified the 48-inch pipe as part CMP/part RCP and the 36-inch pipe as RCP. (See Appendix, Diagram 1).

47. The 1981 report made the following recommendation, among others:

> The culverts which pass beneath the primary basin may become potential sources of problems, particularly as they age. As noted previously, there seemed to be more water leaving the 52/36-inch culvert than entering it. It is recommended that within the next several months the flow rate at each of the culverts be established, then checked at 6-month intervals thereafter. If there is a significantly greater flow of water leaving the pipes than entering them, the pipes should be inspected for leakage, as was done in 1979, and any needed repairs implemented.

48. The original schematic drawings in the 1981 report were maintained on site at DAN RIVER.

49. A 1984 Annual Inspection report prepared by DUKE ENERGY CAROLINAS/Duke Power Company recommended that "[f]low in the culverts beneath the primary basin should continue to be monitored at six month intervals" and that "[t]he corrugated metal pipe at the west end of the basin should be monitored in future inspections for further damage from seepage flow."

50. A 1985 Annual Inspection report prepared by DUKE ENERGY CAROLINAS/Duke Power Company clearly identified the 48-inch stormwater pipe as CMP. At least one of the engineers who participated in the 1985 annual inspection continues to work for

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DUKE ENERGY BUSINESS SERVICES, although currently in a different capacity, and, in fact, conducted two inspections of the Primary and Secondary Ash Basins in 2008.

51. In 1986, Engineering Firm #1 conducted the "Second Five-Year Independent Consultant Inspection of the Ash Dikes" at DAN RIVER. The report clearly identified the 48-inch pipe as part CMP/part RCP and the 36-inch pipe as RCP. Employees of DUKE ENERGY CAROLINAS/Duke Power Company accompanied the consultant during field inspections.

52. The 1986 report repeated the recommendation noted in 1981:

> The monitoring program appears adequate, except it would be desirable to quantitatively (rather than qualitatively) monitor the inflow and outflow at the 52/36-inch diameter culvert, as recommended in the 1981 inspection report, to check for joint leakage. It would also be desirable to do quantitative monitoring of inflow and outflow of the 48-inch diameter culvert that also passes beneath the ash basin; part of this culvert is constructed of corrugated metal pipe which would be expected to have less longevity of satisfactory service than the reinforced concrete pipes.
>
> . . .
>
> It is recommended that quantitative monitoring of inflow and outflow be done at the culverts which pass under the ash basin to check for potential leakage. It is recommended that this monitoring be done at 6-month intervals. If there is a significant difference between inflow and outflow, or whenever there is some cause to suspect leakage, the inside of the culverts should be inspected for leakage.

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53. In the 1986 Annual Inspection report, engineers for DUKE ENERGY CAROLINAS/Duke Power Company asked the DAN RIVER personnel to perform the following tasks:

> Quantitatively monitor the inflow and outflow at the two culverts that pass under the ash basin. Instructions are provided on the attached form and tables. Monitoring should begin within thirty days after the installation of V-notched weirs at the inlets and continue at six-month intervals. Random tests at various depths of flow should be made using a bucket and stop watch to verify flow rates given in the attached tables before beginning the monitoring schedule. Results of these tests should be transmitted to Design Engineering.

54. DUKE ENERGY CAROLINAS did not install V-notched weirs at the inlets. Flow monitoring, while apparently performed between 1991 and 1998, was not reported on the requested forms.

55. In 1991, Engineering Firm #2 performed the Third Five-Year Independent Consultant Inspection of the ash basins at DAN RIVER. The report noted that the two stormwater pipes passed under the Primary Ash Basin, but incorrectly identified the entire length of the 48-inch pipe as RCP. During the review process and prior to submission to the North Carolina Utilities Commission, engineers for DUKE ENERGY CAROLINAS/Duke Power Company did not correct the error. This erroneous description of the 48-inch stormwater pipe was repeated in the 1998, 2001 and 2007 Five-Year Independent Consultant Inspection reports produced by Engineering Firms #1 and #3 and not corrected by DUKE ENERGY CAROLINAS/Duke Power Company.

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56. The 1991 report repeated the prior monitoring recommendations:

> As was previously recommended, the inflow and outflow of the drainage pipes extending under the ash basins should be monitored for the quantity flowing in versus that flowing out and the turbidity of the discharge. If a disparity becomes evident or if there is evidence of turbidity, the pipes should be checked for leaks.

57. The 1998 Fourth Independent Consultant Inspection report prepared by Engineering Firm #1 made the following recommendation for monitoring of the stormwater pipes:

> The outflow of the drainage pipes extending under the primary ash basins to the river should be monitored for turbidity of the discharge, which would be indicative of soil entrance into the pipes through leaks under the basin. The appearance of turbidity would make it advisable to perform a TV camera inspection of the pipe to help determine if the leak or leaks are a threat.

58. The recommendation in the 1998 report was repeated in identical language in the 2001 and 2007 Five-Year Inspection reports prepared by Engineering Firm #1 and #3, respectively.

59. In the 2007 Sixth Five-Year Independent Consultant Inspection report, Engineering Firm #3 noted that DUKE ENERGY CAROLINAS engineers had not performed annual inspections since 2001, and also had not performed monthly inspections in 2003. The firm expressed concern over the qualifications of the DUKE ENERGY CAROLINAS employees assigned to perform monitoring. Engineering Firm #3 recommended "that Duke reinstitute more

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clearly defined engineering responsibility for the receiving and plotting of data from the dikes at the individual stations."

60. After 2008, DUKE ENERGY CAROLINAS installed a metal platform over rip rap (large rocks) along the outer wall of the coal ash basin to better enable employees to access the river bank near the outfalls of the 48-inch and 36-inch stormwater pipes. However, DUKE ENERGY CAROLINAS employees were still unable to view the 36-inch stormwater pipe outfall.

61. A 2009 EPA Dam Safety Assessment, prepared for EPA by an engineering contractor, restated the recommendations of the Sixth Five-Year Independent Consultant Inspection report and recommended that DUKE ENERGY CAROLINAS complete the implementation of those recommendations as described in the Sixth Five-Year Independent Consultant Inspection Report. Based on information received from DUKE ENERGY CAROLINAS, the EPA Dam Safety Assessment reported that "[v]isual monitoring of the outflow from the drainage pipes that go under the Primary Basin is performed on a monthly basis." EPA's contractor observed that during its field inspection in May 2009, the outflow from the 48-inch and 36-inch pipes was clear.

62. The last monthly inspection of the stormwater pipes occurred on January 31, 2014. The form created by DUKE ENERGY CAROLINAS for recording observations during the monthly inspections did not provide any specific space for reporting

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observations of the stormwater pipes and the DUKE ENERGY CAROLINAS employee who performed the inspection did not independently record any observations of the pipes on the form for the January 31, 2014, inspection. According to the DUKE ENERGY CAROLINAS employee who performed the January 31, 2014, she did not observe turbidity in the water flowing from the 48-inch stormwater pipe. She could not see the discharge from the 36-inch stormwater pipe due to the location of the outfall in relation to her observation point on the scaffolding.

63. Between 1999 and 2008, and again from January 2013 through January 31, 2014, DUKE ENERGY CAROLINAS employees did not perform any visual inspections of the 36-inch stormwater pipe.

64. Between 1999 and 2008, during the months from May to September, DUKE ENERGY CAROLINAS employees were generally not able to conduct visual inspections of the flow from the 48-inch pipe because it was too difficult to access the end of the pipe from land as the result of vegetative growth and the presence of snakes.

65. Each of the DUKE ENERGY CAROLINAS employees responsible for monitoring the flow from the stormwater pipes from 1991 to December 2012 was aware that the 48-inch stormwater pipe was composed of corrugated metal.

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ADDITIONAL DUKE ENERGY DOCUMENTATION THAT THE 48-INCH STORMWATER PIPE WAS CMP

66. On or about January 22, 2014, Engineering Firm #4 finished a draft document titled "Design Report - DRAFT Ash Basin Closure - Conceptual Design for Dan River Steam Station." Appendix 4 of the Report identifies the 48-inch stormwater pipe as "CMP," although that information was not separately stated in the body of the report. In preparing the report, Engineering Firm #4 engineers relied on documentation provided by DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES, including a 2008 schematic of the Primary Ash Basin that correctly identified the 48-inch stormwater pipe as CMP. Engineers with DUKE ENERGY BUSINESS SERVICES' Central Engineering office worked with Engineering Firm #4 in the preparation of the conceptual design and reviewed the draft documents but did not notice the labeling of the 48-inch stormwater pipe in Appendix 4.

67. A 2009 schematic entitled "Rough Grading - Overall Grading Plan for Dan River Combined Cycle" provided to DUKE ENERGY CAROLINAS by one of its contractors also identified the 48-inch stormwater pipe as CMP.

68. As of the date of the Dan River spill, record-keeping and information-sharing practices at DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES did not ensure that information such as the actual composition of the 48-inch pipe was

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communicated from employees with knowledge to engineers and employees making budget decisions. Additionally, engineers in DUKE ENERGY BUSINESS SERVICES, with responsibility for DAN RIVER, had not sufficiently reviewed the records available to them and, therefore, continued to operate under the erroneous belief that the 48-inch pipe was made entirely of RCP.

RECOMMENDATION FOR CAMERA INSPECTIONS
BY DUKE ENERGY PROGRAM ENGINEERING

69. From at least 2011 through February 2014, DUKE ENERGY BUSINESS SERVICES had a group of engineers assigned to support fossil impoundment and dam inspections. The group was known as "Program Engineering."

70. In May 2011, a Senior Program Engineer and a Program Engineer with responsibilities covering DAN RIVER, recommended that the budget for DAN RIVER include camera inspections of the pipes within the Primary and Secondary Ash Basins. The estimated total cost for the camera inspection of four pipes, including the 48-inch stormwater pipe, within the Primary and Secondary Coal Ash Basins was $20,000.

71. DUKE ENERGY CAROLINAS did not provide funding for the camera inspection.

72. Upon learning that the camera inspection was not funded, the DAN RIVER Station Manager called the Vice-President

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of Transitional Plants and Merger Integration, who was in charge of approving the budget at DAN RIVER and other facilities. The Station Manager told the Vice-President that DAN RIVER needed the camera inspections, that the station did not know the conditions of the pipes, and that if one of the pipes failed, there would be environmental harm. The request was still denied.

73. In May 2012, the Senior Program Engineer and the Program Engineer again recommended that the budget for DAN RIVER include camera inspections of the 48-inch and 36-inch stormwater pipes underneath the Primary Ash Basin, along with two additional pipes within the Primary and Secondary Ash Basins. The estimated total costs for the camera inspection was $20,000. The reason noted on the budget request form was "internal recommendation due to age of piping system."

74. By e-mail dated May 30, 2012, the Senior Program Engineer indicated his intention to eliminate the camera survey budget line item for stormwater pipes at DAN RIVER in light of the anticipated closure of the basins.

75. In response to the Senior Program Engineer's May 30, 2012, email, the DAN RIVER Equipment Owner, employed by DUKE ENERGY BUSINESS SERVICES and responsible for monitoring the Primary Ash Basin wrote, in part:

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> I would think with the basin closing you would want to do the camera survey. I don't think the drains have ever been checked and since they go under the basin I would like to ensure that we are eliminating any risk before closing the basins.

76. In response to the Senior Program Engineer's May 30, 2012, email, another DUKE ENERGY BUSINESS SERVICES employee advised:

> I don't know if this changes your opinion, but [it] isn't likely that the ash basin will close in 2013. We have to submit a plan to the state at least one year prior to closure and we haven't even begun to prepare that.

77. On a date unknown but sometime between May 2012 and July 2012, at an in-person meeting, a DUKE ENERGY BUSINESS SERVICES Program Engineer asked the Vice-President of Transitional Plants and Merger Integration whether camera inspections of the stormwater pipes would be funded. The Vice-President said no.

78. In June 2012, preliminary engineering plans for closing the DAN RIVER coal ash basins called for the removal of both the 48-inch and 36-inch pipes. However, between 2012 and 2014, there was no set date for closing and no formal closure plan had been submitted to DENR. In December 2012, the DAN RIVER ash basin closure was not projected to be completed until 2016.

79. DUKE ENERGY CAROLINAS did not provide funding for the camera inspections of the stormwater pipes and no camera

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inspections were performed prior to February 2, 2014. If a camera inspection had been performed as requested, the interior corrosion of the elbow joint in the 48-inch pipe would likely have been visible.

80. From at least January 1, 2012, through February 2, 2014, DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES failed to take reasonable steps to minimize or prevent discharge of coal ash to the Dan River that would adversely affect the environment and failed to properly operate and maintain the DAN RIVER coal ash basins and the related stormwater pipes located beneath the Primary Coal Ash Basin, thus, negligently violating the DAN RIVER NPDES permit.

FEBRUARY 2014 DISCHARGES INTO THE DAN RIVER

81. On February 2, 2014, a five-foot long elbow joint within the sixty-year-old corrugated metal section of the 48-inch pipe under the Primary Ash Basin at DAN RIVER failed, resulting in the release of coal ash wastewater and coal ash into the Dan River.

82. Later inspection of the elbow joint, after its retrieval from the Dan River, revealed extensive corrosion of the metal of the elbow joint initiating at the bottom center of the elbow. The parties disagree about some of the factors that contributed to the extensive corrosion. Nevertheless, the age of the pipe was at or beyond the reasonably expected serviceable

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life for CMP under similar conditions. Ultimately, the combination of the corrosion and the weight of the coal ash basin over the elbow joint caused it to buckle, fail, and be pushed through the end of the 48-inch stormwater pipe into the Dan River.

83. Between approximately 1:30 p.m. and approximately 2:00 p.m. on February 2, 2014, a security guard at DAN RIVER noticed that the level of the wastewater in the Primary Ash Basin had dropped significantly.

84. The security guard immediately notified DUKE ENERGY CAROLINAS employees in the control room for the adjacent natural gas-powered combined cycle plant. The DUKE ENERGY CAROLINAS Shift Supervisor on duty went to the Primary Ash Basin and observed a large sinkhole. The Shift Supervisor saw only residual water and mud left in the basin. The Shift Supervisor alerted other DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES employees in order to begin response efforts.

85. After the initial discovery of the sinkhole in the Primary Ash Basin on February 2, 2014, an employee who responded to the site circulated photographs of the Primary Ash Basin to other DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES employees via e-mail at approximately 3:49 p.m.

86. Photographs attached to the 3:49 p.m. e-mail reflected the status of the basin. **(See Appendix, Photographs 1 – 4).**

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87. From on or about February 2, 2014, through February 8, 2014, the unpermitted discharge of approximately 27 million gallons of coal ash wastewater and between 30,000 and 39,000 tons of coal ash into the Dan River occurred through the 48-inch pipe from the Primary Coal Ash Basin.

88. According to the U.S. Fish and Wildlife Service, coal ash from the release traveled more than 62 miles down the Dan River, from the Middle District of North Carolina, through the Western District of Virginia, and into the John H. Kerr Reservoir in the Eastern District of North Carolina and Eastern District of Virginia.

89. On or about February 8, 2014, DUKE ENERGY CAROLINAS sealed the outfall of the 48-inch pipe, halting the discharge of coal ash wastewater and coal ash into the Dan River.

DISCHARGES FROM THE 36-INCH STORMWATER PIPE

90. On February 6, 2014, an interior video inspection of the 36-inch stormwater pipe revealed: (1) infiltration of wastewater occurring through a number of joints; (2) water jets from pressurized infiltration at three joints; (3) separation in one joint near the outfall point; (4) cracks running lengthwise through several pipe segments; and (5) sections of ponding water indicating irregular vertical alignment.

91. Analysis of water samples from the 36-inch pipe revealed that the line was releasing wastewater that contained

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elevated levels of arsenic. On February 14, 2014, the arsenic concentration in the effluent at the outfall of the 36-inch pipe was 140 ug/L. On February 17, 2014, the arsenic concentration in the effluent at the same point was 180 ug/L. The North Carolina water quality standard for the protection of human health for arsenic is 10 ug/L and the water quality standard for the protection of freshwater aquatic life is 50 ug/L.

92. Discharge of contaminated wastewater continued from the 36-inch pipe between February 6, 2014, and February 21, 2014. The nature of the wastewater infiltration into the 36-inch stormwater pipe and DUKE ENERGY CAROLINAS employees' visual and auditory confirmation of flow from the 36-inch pipe indicates that discharge from the 36-inch pipe began a significant period of time before February 6, 2014. The discharge began at least as early as January 1, 2012, continued until February 21, 2014, and was not authorized by a NPDES permit.

93. On February 21, 2014, DUKE ENERGY CAROLINAS sealed the 36-inch stormwater pipe.

RESPONSE COSTS FOR DAN RIVER RELEASE

94. Thus far, DUKE ENERGY CAROLINAS and federal, state, and local governments have spent over $19 million responding to the spill.

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95. Drinking water intakes in the Dan River watershed, including those for the Cities of Danville, Virginia Beach, and Chesapeake and for the Halifax County Service Authority in Virginia were temporarily closed and were required to undertake additional monitoring for contamination. Monitoring results indicated that the water treatment plants along the Dan River were able to adequately treat and remove the coal ash and related contaminants from the spill.

96. The North Carolina Department of Health and Human Services issued an advisory against consuming fish from or recreational contact with the Dan River from the point of the spill to the North Carolina – Virginia border from February 12, 2014, to July 22, 2014.

97. DUKE ENERGY CAROLINAS has reimbursed many entities for their expenditures in the aftermath of the spill. Nonetheless, at least two localities and one federal agency have not yet been fully reimbursed. Those entities and their expenditures are: (1) Virginia Beach, $63,309.45; (2) Chesapeake, Virginia, $125,069.75; and (3) the United States Army Corps of Engineers, $31,491.11.

CAPE FEAR STEAM ELECTRIC PLANT

98. DUKE ENERGY PROGRESS (formerly "Progress Energy Carolinas") owns the Cape Fear Steam Electric Plant ("CAPE

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FEAR"), located adjacent to the Cape Fear River, just south of the confluence of the Haw and Deep Rivers and approximately two miles southeast of Moncure, North Carolina.

99. CAPE FEAR has a total of five coal ash basins. Three of the basins, constructed in 1956, 1963, and 1970 have been inactive for many years. Two of the basins, constructed in 1978 and 1985 continued to receive coal ash slurry and other forms of wastewater through at least November 2011.

100. The 1978 ash basin had a storage capacity of 880 acre-feet (approximately 286,749,258 gallons), a surface area of 43 acres, and a maximum structural height of 27 feet. The 1978 ash basin included a "riser," also known as a "stand pipe," used under normal operation to allow the passive and permitted discharge of wastewater treated by settlement from the basin. The riser was constructed of vertically stacked 18-inch diameter concrete pipe sections.

101. The 1985 ash basin had a storage capacity of 1764 acre-feet (approximately 574,801,921 gallons), a surface area of 65 acres, and a maximum structural height of 28 feet. The 1985 ash basin included a riser constructed of vertically stacked 48-inch diameter concrete pipe sections.

102. In a 2009 EPA Dam Safety Assessment, both the 1978 and 1985 coal ash basins at CAPE FEAR were classified as having "significant hazard potential," as previously defined.

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103. By December 2011, DUKE ENERGY PROGRESS/Progress Energy Carolinas ceased electric power generation at CAPE FEAR. As a result of the cessation of operation, coal ash slurry was no longer received by the 1978 or 1985 coal ash basin, although each basin continued to receive rainwater or stormwater.

INSPECTIONS OF CAPE FEAR ASH BASINS, MONITORING RECOMMENDATIONS, AND DETECTION OF LEAKING RISERS

104. DUKE ENERGY PROGRESS/Progress Energy Carolinas engaged outside firms to perform annual and five-year inspections of the coal ash basins at CAPE FEAR, as required by state law.

105. On or about May 1, 2008, Engineering Firm #3, hired by DUKE ENERGY PROGRESS/Progress Energy Carolinas, conducted an annual inspection of the CAPE FEAR coal ash basins and generated a report of its observations, conclusions, and recommendations. The report was submitted to DUKE ENERGY PROGRESS/Progress Energy Carolinas and reviewed by the plant manager and environmental coordinator for CAPE FEAR.

106. The 2008 annual inspection report described the condition of the risers in the 1978 and 1985 coal ash basins as "marginal" and estimated that the risers were "likely to develop problems" in two to five years from the date of the report. The report further recommended that DUKE ENERGY PROGRESS/Progress Energy Carolinas perform its own inspections of the risers in

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the 1978 and 1985 ash basins by boat, in order to better assess the condition of the risers.

107. The recommendation to inspect the risers using a boat was repeated in annual reports produced by engineering firms and submitted to DUKE ENERGY PROGRESS/Progress Energy Carolinas in 2009 and 2010, and to DUKE ENERGY PROGRESS in 2012 and 2013.

108. At no time from May 1, 2008, until March 2014 did DUKE ENERGY PROGRESS/Progress Energy Carolinas perform inspections of the risers in the 1978 or 1985 ash basins by boat.

109. At some time during the summer of 2011, but on a date unknown, the DUKE ENERGY PROGRESS/Progress Energy Carolinas Environmental Coordinator and the NPDES Subject Matter Expert responsible for CAPE FEAR visited the site. During their visit, they became aware that the risers in the 1978 and 1985 coal ash basins were leaking. During the fall of 2011, but on a date unknown, they informed DUKE ENERGY PROGRESS/Progress Energy Carolinas management that repairs were needed on the risers. No additional inspection or monitoring of the risers was undertaken by DUKE ENERGY PROGRESS/Progress Energy Carolinas as a result of their observations prior to March 2014.

110. The 2012 Five-Year Independent Consultant Report, produced on January 26, 2012, by Engineering Firm #4, noted that the skimmer located at the top of the riser in the 1978 ash basin was corroded and tilted. The skimmer was designed to

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prevent debris from being discharged from the basin or clogging the riser.

111. Photographs included with the 2012 Five-Year Independent Consultant Report show the skimmer on the riser in the 1978 coal ash basin sitting askew. **(See Appendix, Photographs 5 & 6).**

112. Photographs included with the 2012 Five-Year Independent Consultant Report show the skimmer on the riser in the 1985 coal ash basin. **(See Appendix, Photograph 7).**

113. Annual inspection reports for 2012 and 2013 also reported that the riser in the 1978 ash basin was damaged, deteriorated, and tilted. The annual reports recommended that DUKE ENERGY PROGRESS/Progress Energy Carolinas replace or repair the skimmer on the riser in the 1978 ash basin.

114. At no time from January 26, 2012, through March 2014 did DUKE ENERGY PROGRESS/Progress Energy Carolinas repair or replace the skimmer on the riser in the 1978 coal ash basin.

115. The annual inspection report produced on or about June 24, 2013, by Engineering Firm #4 and submitted to DUKE ENERGY PROGRESS noted that a "trickle of flow" was observed at the outfalls leading from the risers in the 1978 and 1985 ash basins which the report concluded indicated possible leakage.

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DEWATERING OF THE ASH BASINS AND REPAIR OF RISERS

116. During the summer of 2013, on a date unknown, an employee of DUKE ENERGY BUSINESS SERVICES contacted a contractor specializing in diving and underwater pipe repair and mentioned the possible need for riser repair at CAPE FEAR. The contractor was not engaged at that time and no schedule for the potential work was discussed.

117. Also during the summer of 2013, DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES were engaged in planning for the closure of the coal ash basins at CAPE FEAR. On or about July 11, 2013, consulting engineers assisting DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES in planning for ash basin closure produced and provided to DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES a "site investigation plan" that included plans for locating, inspecting, and determining the composition of risers and discharge pipes for each ash basin.

118. As part of the ongoing planning for ash basin closure, DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES sought to eliminate the need for NPDES permits for CAPE FEAR, in keeping with its "Ash Basin Closure Strategy." This strategy would reduce continuing operation and maintenance costs at the plant while ash basin closure was pending. DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES knew that in order to eliminate

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the NPDES permits, the coal ash basins would have to be in a "no flow" state. To reach that state, DUKE ENERGY PROGRESS needed to eliminate the riser leaks at the 1978 and 1985 coal ash basins as well as lower the level of the contents of the ash basins to prevent water from overtopping the risers during a 25-year rain event. These requirements were discussed by a number of DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES employees during the summer of 2013, including the DUKE ENERGY BUSINESS SERVICES NPDES Subject Matter Expert and the DUKE ENERGY BUSINESS SERVICES Director of Plant Demolition and Retirement.

119. Also as part of the ongoing planning for ash basin closure at CAPE FEAR, DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES recognized that dewatering the ash basins was a necessary and time-consuming part of the process of closing an ash basin. DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES further believed that dewatering the coal ash basins would "lessen hydrostatic pressure" and "over a relatively brief time reduce and/or eliminate seepage." At the time, seepage was the subject of threatened citizen law suits, a series of state-filed civil complaints, and significant public concern.

120. DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES also believed that dewatering the 1978 and 1985 coal ash basins prior to repairing the risers would provide a safer environment

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for contractors performing repair work. DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES employees knew that the leaks in the risers were likely being caused by cracks or failures in the grout between the concrete pipe sections that were underwater. The employees did not know how far underwater the leaks or grout failures were or how many sections of the pipe would need repair. Because the risers were filled with air but surrounded by water, underwater repair of the risers could be hazardous to the divers due to a phenomenon known as "differential pressure." DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES employees believed that removing the standing water from the 1978 and 1985 basins to at or below the level of the leaking portions of the risers would eliminate the risk from differential pressure.

121. Beginning on or about August 16, 2013, and continuing through on or about September 30, 2013, employees and contractors for DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES began developing a work plan for pumping water from the 1985 ash basin at CAPE FEAR.

122. On or about September 30, 2013, DUKE ENERGY PROGRESS employees began pumping water from the 1985 ash basin at CAPE FEAR, using a Godwin pump and hoses.

123. On or about October 2, 2013, two days after pumping began at the 1985 ash basin, a DUKE ENERGY BUSINESS SERVICES

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engineer assigned to the plant retirement program emailed a representative of a contracting company specializing in underwater pipe repair. In the email, the engineer indicated that there were "several potential opportunities at [the] Cape Fear plant that we would like you to look at." The engineer went on to describe one of the opportunities as:

> Ash pond riser repairs. Two ponds' risers leak. There is a slow trickle out of the discharge of the concrete riser pipes at two ash ponds. We may elect to stop the leak. Could you provide a ballpark for providing the investigation and repair services? Could you also describe what the process would be?

124. On or about October 22, 2013, the underwater pipe repair contractor submitted to DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES a project estimate titled "Abandonment of Intakes and Leak Sealing" that included four tasks, including "Ash Pond Riser Repairs."

125. On or about January 13, 2014, DUKE ENERGY PROGRESS began dewatering operations at the 1978 coal ash basin at CAPE FEAR, using a Godwin pump and hoses similar to those used at the 1985 coal ash basin, as well as the same work plan.

126. On or about January 24, 2014, DUKE ENERGY PROGRESS signed a contract, through DUKE ENERGY BUSINESS SERVICES, acting as its agent, with the underwater pipe repair contractor for various projects at CAPE FEAR relating to plant decommissioning and coal ash basin closure, as addressed in the October 22,

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2014, project estimate. One of the projects was repair work on the risers in the 1978 and 1985 coal ash basins. The contract specified that work under the contract would "start on or about January 27, 2014 and shall be completed no later than December 31, 2014." The contract did not identify specifically when the work would begin on the risers.

127. On or about March 11, 2014, DENR officials from both the DWR and the Division of Mineral and Land Resources visited CAPE FEAR to perform an inspection. The DENR officials were accompanied by several DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES employees during their inspection. DENR observed the Godwin pumps at the 1985 and 1978 ash basins along with obvious signs of a significant drop in the water level in the coal ash basins and disturbances in the surface of the coal ash in the basins. **(See Appendix, Photographs 8 - 10).**

128. At the conclusion of the DENR inspection on March 11, 2014, a dispute arose between DENR officials and DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES employees over whether DUKE ENERGY PROGRESS had been authorized by DENR-DWR to discharge water from the coal ash basins using Godwin pumps.

129. On or about March 19 and 20, 2014, an employee of the underwater pipe repair contractor performed video inspections of the risers in the 1978 and 1985 coal ash basins. The contractor observed that in the discharge pipe leading from the riser in

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the 1985 coal ash basin, the visibility in one area was "next to nothing." The visibility was negatively impacted by turbidity and debris in the pipe. The contractor observed a "slow trickle" of water intruding into the riser in the 1978 coal ash basin. At the time of the camera inspections, the water level in both coal ash basins had already been lowered below the uppermost joints of the risers and, thus, below the level of some of the leaks.

130. No other camera inspections were conducted of the risers between 2008 and March 19, 2014.

131. On or about March 19 and 20, 2014, employees and agents of the underwater pipe repair contractor replaced and resealed the grout between the concrete pipe sections of the risers in the 1978 and 1985 coal ash basins. **(See Appendix, Photographs 11 through 14).**

132. Between at least January 1, 2012, and January 24, 2014, DUKE ENERGY PROGRESS and DUKE ENERGY BUSINESS SERVICES failed to properly maintain the risers in the 1978 and 1985 coal ash basins at CAPE FEAR in violation of the applicable NPDES permit.

HISTORICAL SEEPS AND DISCHARGES FROM COAL ASH BASINS

133. DUKE ENERGY CAROLINAS' and DUKE ENERGY PROGRESS's coal ash basins are comprised of earthen dams. Over time, "seeps" developed in the dam walls. "Seeps" occur when water, often

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carrying dissolved chemical constituents, moves through porous soil and emerges at the surface. Seeps are common in earthen dams. The Defendants have identified nearly 200 distinct seeps at the Defendants' coal ash basins throughout North Carolina in permit modification applications filed in 2014. Not all seeps necessarily reach waters of the United States. However, some of the discharge from seeps is collected and moved through engineered drains or channels to waters of the United States. Other seeps are simply allowed to flow across land surfaces to waters of the United States. Each of the facilities listed in the table at paragraph 12 had seeps of some form.

134. Water from seeps may transport pollutants. Wastewater sampled from various seep locations at DUKE ENERGY CAROLINAS and DUKE ENERGY PROGRESS coal ash basins in 2014 was found to contain constituents including aluminum, arsenic, barium, boron, chloride, chromium, copper, fluoride, lead, manganese, nickel, selenium, thallium, and zinc, and was additionally found to be acidic.

135. On June 7, 2010, EPA issued interim guidance to assist NPDES permitting authorities with establishing appropriate permit requirements for wastewater discharges from coal ash basins at power plants. In the guidance, EPA advised with respect to point source discharges of seepage:

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> If the seepage is directly discharged to waters of the United States, it is likely discharged via a discrete conveyance and thus is a point source discharge. Seepage discharges are expected to be relatively minor in volume compared to other discharges at the facility and could be inadvertently overlooked by permitting authorities. Although little data are available, seepage consists of [coal combustion residuals] including fly ash and bottom ash and fly ash transport water and [flue-gas desulfurization] wastewater. If seepage is discharged directly via a point source to a water of the U.S., the discharge must be addressed under the NPDES permit for the facility.

136. Since at least 2010, seepage from DUKE ENERGY CAROLINAS' and DUKE ENERGY PROGRESS's coal ash basins at certain of their 14 coal-fired power plants in North Carolina entered waters of the United States through discrete conveyances.

137. Wetlands may also suffer impacts from the operation of coal-fired plants. Coal ash basins were historically sited near rivers and are, therefore, often located in or near riparian wetlands and some coal ash basins have hydrologic connections to wetlands via groundwater or seeps.

138. Since 2010, as part of the NPDES permitting process in North Carolina, coal-fired plants are required to monitor groundwater to assure natural resources are protected in accordance with federal and state water quality standards. Monitoring of groundwater at coal ash basins owned by DUKE ENERGY CAROLINAS and DUKE ENERGY PROGRESS has shown exceedances of groundwater water quality standards for pollutants under and near the basins including arsenic, boron, cadmium, chromium,

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iron, manganese, nickel, nitrate, selenium, sulfate, thallium, and total dissolved solids.

139. At various times between 2010 and 2014 the Defendants included general references to seeps in correspondence and permit applications with DENR and disclosed more detailed information concerning certain seeps, including engineered seeps (i.e., man-made channels). The Defendants did not begin gathering and providing detailed, specific, and comprehensive data concerning seeps, and particularly seeps discharging to waters of the United States, at each of the North Carolina coal ash basins to DENR until after the DAN RIVER spill in 2014.

140. After the coal ash spill at DAN RIVER in 2014, DUKE ENERGY CAROLINAS and DUKE ENERGY PROGRESS, with the assistance of DUKE ENERGY BUSINESS SERVICES, filed NPDES permit renewal and/or modification applications seeking authorization for certain seeps that discharged, via a point source, directly to a water of the United States. These applications are currently pending as DENR considers the impacts of the seeps and discharges on the receiving waters of the United States.

H.F. LEE STEAM ELECTRIC PLANT

141. DUKE ENERGY PROGRESS owns the H. F. Lee Steam Electric Plant ("LEE"), which is located in Goldsboro, North Carolina. LEE (formerly known as the "Goldsboro Plant") began operation

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shortly after World War II and added additional coal-fired combustion units in 1952 and 1962. The plant retired the coal-fired units in September of 2012.

142. LEE used several coal ash basins in the past. Only one of the remaining coal ash basins still contains water and ash sluiced from LEE (the "active coal ash basin"). The active ash basin sits on the north side of the Neuse River. (See Appendix, Photograph 15).

143. The active coal ash basin is triangle-shaped and includes a primary basin and a small secondary settling basin. The treatment system is designed so that water discharges from the primary basin into the secondary basin and from the secondary basin into the Neuse River.

144. The NPDES permit No. NC0003417 for LEE, effective November 1, 2009, authorized two discharges into the Neuse River — one from the active coal ash basin ("Outfall 001") and one from the cooling water pond ("Outfall 002"). A 2010 modification of the 2009 permit also authorized a third outfall ("Outfall 003") from a combined cycle generation facility. Water does not currently discharge from the active coal ash basin into the Neuse River via Outfall 001.

145. Beginning at a time unknown but no later than October 2010, DUKE ENERGY PROGRESS/Progress Energy Carolinas identified a seep on the eastern embankment of the active coal ash basin.

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This seep was adjacent to an area of seepage that was identified and repaired in 2009 and 2010. This seep in 2010 collected and flowed to a "flowing ditch" outside of the active coal ash basin. This seep was repaired in May of 2011.

146. Additional seeps on the eastern side of the active coal ash basin also flowed into the same drainage ditch as the seep identified in October 2010. The drainage ditch discharged into the Neuse River at latitude 35.379183, longitude -78.067533. The drainage ditch was not an authorized outfall under the NPDES permit. In 2014, DUKE ENERGY PROGRESS identified the GPS coordinates of four seeps on the eastern side of the coal ash basin as: latitude 35.380510, longitude -78.068532; latitude 35.382767, longitude -78.069655; latitude 35.386968, longitude -78.071942; and latitude 35.379492, longitude -78.067718.

147. On February 20, 2013, DENR personnel sampled water in three locations from the drainage ditch. This sampling occurred after DENR personnel from the Land Quality Section observed a seep near the southeast corner of the ash pond dike. The seep collected in the unpermitted discharge ditch and flowed into the Neuse River. Water quality analysis of samples from the drainage ditch showed exceedances of state water quality standards for chloride, arsenic, boron, barium, iron, and manganese. This discharge of wastewater into the Neuse River

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from the drainage ditch at LEE was not authorized under the NPDES permit.

148. On March 11, 2014, DENR personnel again sampled wastewater from the drainage ditch referenced previously. The ditch showed exceedances for iron and manganese.

149. Unpermitted discharges, in violation of the applicable NPDES permit, occurred at LEE from at least October 1, 2010, through December 30, 2014.

RIVERBEND STEAM STATION

150. DUKE ENERGY CAROLINAS owns and operates the Riverbend Steam Station ("RIVERBEND"), located in Gaston County, North Carolina, approximately 10 miles from the city of Charlotte and immediately adjacent to Mountain Island Lake, on a bend in the Catawba River. Mountain Island Lake is the primary source of drinking water for residents of Gaston and Mecklenburg Counties.

151. RIVERBEND began commercial operation in 1929 and its combustion units were retired in April 2013, with plans to demolish it after 2016. It has two unlined coal ash basins along Mountain Island Lake, with dams reaching up to 80 feet in height. The RIVERBEND dams are designated in a 2009 EPA Dam Safety Assessment as "Significant Hazard Potential," as previously defined. RIVERBEND contains approximately 2,730,000 million tons of stored coal ash.

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152. The RIVERBEND NPDES permit, No. NC0004961, was issued on March 3, 1976, and has been renewed subsequently, with the current NPDES Permit expiring on February 28, 2015. The RIVERBEND NPDES permit allows the facility to discharge wastewater to the Catawba River from three "permitted outfalls" in accordance with the effluent limitations and monitoring requirements regarding flow, suspended solids, oil and grease, fecal coliform, copper, iron, arsenic, selenium, mercury, phosphorus, nitrogen, pH, and chronic toxicity, as well as other conditions set forth therein. Wastewater from the coal ash basin was to be discharged, after treatment by settling, through one of the monitored and permitted outfalls.

153. On December 4 through December 6, 2012, DENR conducted inspections of RIVERBEND and discovered unpermitted discharges of wastewater from the coal ash basin into the Catawba River. Among the unpermitted discharges at RIVERBEND is a seep identified in a 2014 permit modification application as Seep 12, an engineered drain to discharge coal ash contaminated wastewater into the river. RIVERBEND Seep 12 is located at latitude 35.36796809, longitude -80.95935079. **(See Appendix, Photographs 16 through 18)**. At some time unknown, but prior to December 2012, one or more individuals at RIVERBEND created the unpermitted channel that allowed contaminated water from the coal ash basin to be discharged into the river.

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154. The unpermitted seep resulted in documented unpermitted discharges from 2011 through 2013 containing elevated levels of arsenic, chromium, cobalt, boron, barium, nickel, strontium, sulfate, iron, manganese, and zinc into the Catawba River.

155. Unpermitted discharges, in violation of the applicable NPDES permit, occurred at RIVERBEND from at least November 8, 2012, through December 30, 2014.

ASHEVILLE STEAM ELECTRIC GENERATING PLANT

156. DUKE ENERGY PROGRESS owns and operates the Asheville Steam Electric Generating Plant ("ASHEVILLE"), in Buncombe County, North Carolina.

157. ASHEVILLE is a coal-powered electricity-generating facility in the Western District of North Carolina. It has two unlined coal ash basins, one constructed in 1964 and the other constructed in 1982. The basins, each approximately 45 acres in size, hold a total of approximately 3,000,000 tons of coal ash waste. (See Appendix, Photograph 19). The basins were each characterized in the 2009 EPA Dam Safety Assessment as "High Hazard Potential," meaning that "failure or mis-operation results will probably cause loss of human life."

158. The ASHEVILLE NPDES permit, number NC0000396, was issued in 2005 and expired in 2010. Progress Energy Carolinas (now DUKE ENERGY PROGRESS) filed a timely permit renewal

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application on June 11, 2010. DENR has not yet issued a new permit and ASHEVILLE continues to operate under the terms of the 2005 NPDES permit.

159. On May 13, 2011, DUKE ENERGY PROGRESS/Progress Energy Carolinas sought authority to relocate the settling basin and permitted discharge outfall at ASHEVILLE from its original location near the 1964 coal ash basin to a location approximately 3,000 feet away, latitude 35.47367 and longitude -82.504, in order to allow "stabilization work" on the 1964 ash pond impoundment.

160. On March 11, 2013, DENR staff inspected ASHEVILLE and identified seeps flowing from toe drains at the 1964 coal ash basins. The engineered seep from the 1964 coal ash basin has continued to discharge pollutants. This engineered seep is not authorized under the applicable NPDES permit. Engineered seeps from the 1964 coal ash basin are located at latitude 35.468319, longitude -82.549104 and latitude 35.466943, longitude -82.548502. These engineered seeps discharge through the toe drain to the French Broad River.

161. Unpermitted discharges, in violation of the applicable NPDES permit, occurred at ASHEVILLE from at least May 31, 2011, through December 30, 2014.

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BROMIDE IMPACTS FROM FGD SYSTEMS

162. As described above, DUKE ENERGY CAROLINAS owns and operates Belews Creek Steam Station ("BELEWS") in Stokes County, North Carolina, and Cliffside Steam Station ("CLIFFSIDE") in Rutherford and Cleveland Counties, North Carolina.

163. As part of its efforts to comply with the Clean Air Act and North Carolina Clean Smokestacks Act, DUKE ENERGY CAROLINAS installed Flue Gas Desulfurization ("FGD") "scrubbers" to significantly reduce or eliminate certain air pollutants, such as sulfur dioxide and nitrogen oxide at several coal-fired facilities. FGD scrubbers isolate certain pollutants from coal combustion emissions into the air and ultimately divert those pollutants, including bromides, into a gypsum slurry that is eventually routed to the facility's coal ash basins. At times, portions of the slurry may be diverted for reuse in products such as wall board.

164. FGD installation was completed and the scrubbers at BELEWS became fully operational at the end of 2008.

165. When bromide comes into contact with chlorine-based water treatment systems, it can contribute to the formation of compounds known as trihalomethanes ("THMs"). There are no general federal or state water limits for the discharge of bromides to surface water. However, there are state and federal limits for total trihalomethanes ("total THMs") under the Safe

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Drinking Water Act. If ingested in excess of the regulatory limits over many years, THMs may cause adverse health effects, including cancer.

DISCHARGE OF BROMIDES AT BELEWS

166. Beginning in 2008 or 2009, the City of Eden ("Eden"), downstream from BELEWS, noted an increase in total THMs in its drinking water.

167. Prior to the installation of the FGD scrubbers, DUKE ENERGY CAROLINAS reported to DENR in its BELEWS NPDES permit applications that bromide occurred in its waste stream at a level too low to detect. When BELEWS applied for a NPDES permit modification in 2009, it made no new disclosures concerning bromide levels because the modification did not relate to bromide and there were no federal or state limitations for bromide discharge.

168. DUKE ENERGY CAROLINAS tested for bromides, as well a number of other potential pollutants, at BELEWS in 2008-2009 to evaluate the effects of the FGD wastewater treatment system. Those test results showed that bromides were discharged from BELEWS into the Dan River. This did not violate the NDPES permit for the facility.

169. In consultation with an outside contractor, in January 2011, Eden determined that an increase in bromides contributed

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to the increase in total THMs it had witnessed beginning in 2008-2009.

170. In early 2011, Eden tested the water entering its water treatment facility from the Dan River and performed water tests upstream to determine the source of the bromides.

171. On May 10, 2011, Eden notified DUKE ENERGY CAROLINAS that it was having difficulty with increasing levels of total THMs in its treated drinking water and requested DUKE ENERGY CAROLINAS' bromide sampling data from the outflow of BELEWS. An impending reduction in the threshold for total THMs (required by an EPA rule promulgated under the Safe Drinking Water Act) triggered Eden's particular interest in the pollutant, especially given that Eden was at the upper limit of the then-permissible total THM range.

172. As a result of the water testing, Eden identified the source of the increased bromides as BELEWS, which discharges into the Dan River. Eden shared this information and its test results with DUKE ENERGY CAROLINAS on June 7, 2011.

173. Shortly thereafter, DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES internally agreed that the increased bromides very likely came from BELEWS and, combined with a number of other factors, had likely caused the THM increase at Eden. DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES

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also agreed internally that the increased bromides were likely the result of the FGD scrubber system.

174. In mid-June 2011, DUKE ENERGY CAROLINAS contacted the Town of Madison ("Madison"), which also draws water from the Dan River and processes that water for drinking and which is closer to BELEWS than Eden. DUKE ENERGY CAROLINAS informed Madison of its findings and Madison asked to be part of the discussions with Eden about reducing bromide levels. DUKE ENERGY CAROLINAS and DUKE ENERGY BUSINESS SERVICES employees met with Eden and Madison several times between June 2011 and April 2012 to discuss reducing total THMs in their drinking water.

175. DUKE ENERGY CAROLINAS informed DENR of the increase in bromide levels in its effluent when it filed its NPDES permit renewal application for BELEWS on August 29, 2011. In the application, DUKE ENERGY CAROLINAS listed bromide as a pollutant present in outfalls 001 (into Belews Lake) and 003 (into Dan River). The largest concentration of bromide was listed as 6.9 mg/L from Outfall 003, which translates to 6.9 parts per million (ppm) or 6907 parts per billion (ppb). This bromide result appears to have been taken from a sample of water collected in January 2011 and analyzed after Eden had brought the issue to DUKE ENERGY CAROLINAS' attention.

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176. At the time DUKE ENERGY CAROLINAS filed its NPDES permit renewal application for BELEWS, none of the previous permits had placed any restrictions or limits on bromides.

177. In mid-October 2011, Eden informed DUKE ENERGY CAROLINAS that Madison had violated its limit on total THMs. DUKE ENERGY CAROLINAS was also informed that Henry County, Virginia, (which purchases Eden's water) violated its total THM limit. Dan River Water (another purchaser of Eden's water) also violated its total THM limit.

178. On November 16, 2011, DENR's Winston-Salem Regional Office held a meeting with DUKE ENERGY CAROLINAS, DUKE ENERGY BUSINESS SERVICES, Eden, and Madison regarding the bromide issue. All participants agreed that the total THM problem was caused by bromides entering the Dan River from BELEWS. DUKE ENERGY CAROLINAS was not aware of the relationship between bromides and THMs until Eden brought the matter to DUKE ENERGY CAROLINAS' attention in 2011.

179. Since the November 2011 meeting, DUKE ENERGY CAROLINAS has entered into written agreements with Eden and Madison to assist them with a portion of the costs of modifying and modernizing their water treatment systems.

DISCHARGE OF BROMIDES AT CLIFFSIDE

180. Beginning at about the time DUKE ENERGY CAROLINAS responded to Eden's initial complaints regarding the bromide

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discharge at BELEWS, DUKE ENERGY CAROLINAS conducted an initiative to monitor bromide discharge at other locations employing FGD scrubbers.

181. As a result of this initiative, in or about early August 2011, DUKE ENERGY CAROLINAS also internally identified the CLIFFSIDE facility in western North Carolina as one that could pose a potential THM problem in light of the relatively shallow river (the Broad River) into which CLIFFSIDE discharged and the presence of relatively close downstream facilities that drew drinking water from the Broad River.

182. The last CLIFFSIDE NPDES permit was issued in January 2011 and did not reference bromide.

183. DUKE ENERGY CAROLINAS AND DUKE ENERGY BUSINESS SERVICES informed neither downstream communities nor DENR regarding this discharge from CLIFFSIDE. As of the date of this joint factual statement, the parties are not aware of a community downstream from CLIFFSIDE that has reported elevated levels of total THMs due to an increase in bromide discharge from the facility, but acknowledge the possibility that one or more communities may have been affected.

184. In 2013, DUKE ENERGY CAROLINAS installed a spray dry absorber for one of the two FGD scrubber units at the CLIFFSIDE facility which reduced the bromide discharge from CLIFFSIDE.

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The other FGD scrubber unit at CLIFFSIDE operates only intermittently.

SUTTON FACILITY

185. DUKE ENERGY PROGRESS owns and operates the L.V. Sutton Steam Station ("SUTTON") in New Hanover County, North Carolina. SUTTON houses two coal ash basins, one constructed in 1971 and one constructed in 1984.

186. Located near SUTTON is the community of Flemington. Flemington's water supply has a history of water-quality problems. In 1978, an adjacent landfill, designated as a "Superfund" site, contaminated Flemington's drinking water and caused authorities to construct new wells.

187. Flemington's new wells are located near SUTTON's coal ash basins. They are located down-gradient from the SUTTON coal ash basins, meaning groundwater ultimately flows from the coal ash basins toward the Flemington wells.

188. DUKE ENERGY PROGRESS/Progress Energy Carolinas has monitored groundwater around SUTTON since 1990. Monitoring particularly focused on a boron plume emanating from the coal ash ponds.

189. From at least 2010 through 2013, the groundwater monitoring wells at SUTTON reported unnaturally elevated levels of some constituents, including manganese, boron, sulfate, and total dissolved solids.

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190. Flemington's public utility also tested its water quality. Those tests showed exceedances of barium, manganese, sodium, and sulfate in 2013.

191. In June and July 2013, Flemington's public utility concluded that boron from SUTTON's ash ponds was entering its water supply. Tests of water from various wells at and near SUTTON from that period showed elevated levels of boron, iron, manganese, thallium, selenium, cadmium, and total dissolved solids.

192. In October 2013, DUKE ENERGY PROGRESS entered into an agreement with the Cape Fear Public Utility Authority to share costs for extending a municipal water line to the Flemington community.

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SO AGREED, THIS 20th DAY OF FEBRUARY, 2015.

THOMAS G. WALKER
U.S. Attorney
Eastern District of North Carolina
North Carolina

JOHN C. CRUDEN
Assistant Attorney General
Department of Justice
Environment and Natural
Resources Division

JILL WESTMORELAND ROSE
Attorney for the United States
Acting Under Authority
Conferred by 28 USC §515
Western District of North Carolina

CLIFTON T. BARRETT
Attorney for the United States
Acting Under Authority
Conferred by 28 USC §515
Middle District of North Carolina

ON BEHALF OF EACH PROSECUTING OFFICE:

BANUMATHI RANGARAJAN
Senior Litigation Counsel
Criminal Division
U.S. Attorney's Office - EDNC

LANA N. PETTUS
Senior Trial Attorney
Environmental Crimes Section
U.S. Department of Justice

SETH M. WOOD
Assistant U.S. Attorney
Appellate Division
U.S. Attorney's Office - EDNC

STEPHEN INMAN
Deputy Chief
Criminal Division
U.S. Attorney's Office - MDNC

ERIN C. BLONDEL
Assistant U.S. Attorney
Criminal Division
U.S. Attorney's Office - EDNC

JOANNA G. MCFADDEN
Assistant U.S. Attorney
Criminal Division
U.S. Attorney's Office - MDNC

JODI MAZER
Special Assistant U.S. Attorney
Criminal Division
U.S. Attorney's Office - EDNC

STEVEN R. KAUFMAN
Assistant U.S. Attorney
Criminal Division
U.S. Attorney's Office - WDNC

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SO AGREED, this the 20 day of February, 2015.

DUKE ENERGY CAROLINAS, LLC.
Defendant

BY: _____
JULIA S. JANSON
Executive Vice-President,
Chief Legal Officer, and
Corporate Secretary

Authorized Designated Official for
Duke Energy Carolinas, LLC

_____
JAMES P. COONEY, III
Womble Carlyle Sandridge & Rice LLP
Counsel for the Defendant

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SO AGREED, this the 20 day of February, 2015.

DUKE ENERGY PROGRESS, INC.
Defendant

BY: _____
JULIA S. JANSON
Executive Vice-President,
Chief Legal Officer, and
Corporate Secretary

Authorized Designated Official for
Duke Energy Progress, Inc.

_____
JAMES P. COONEY, III
Womble Carlyle Sandridge & Rice LLP
Counsel for the Defendant

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SO AGREED, this the 20 day of February, 2015.

DUKE ENERGY BUSINESS SERVICES, INC.
Defendant

BY: _____
JULIA S. JANSON
President and Chief Legal Officer

Authorized Designated Official for
Duke Energy Business Services, LLC

_____
JAMES F. COONEY, III
Womble Carlyle Sandridge & Rice LLP
Counsel for the Defendant

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United States v. Duke Energy Business Services LLC, et al.

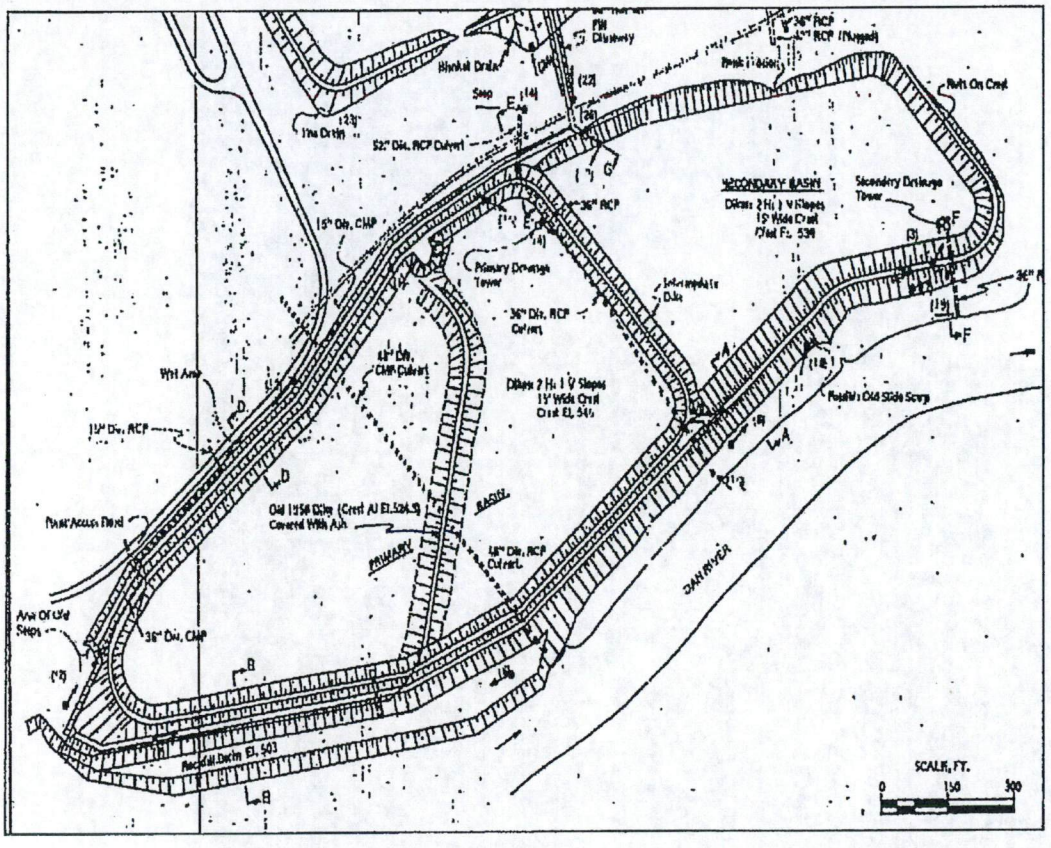
APPENDIX

TO JOINT FACTUAL STATEMENT

February 20, 2015

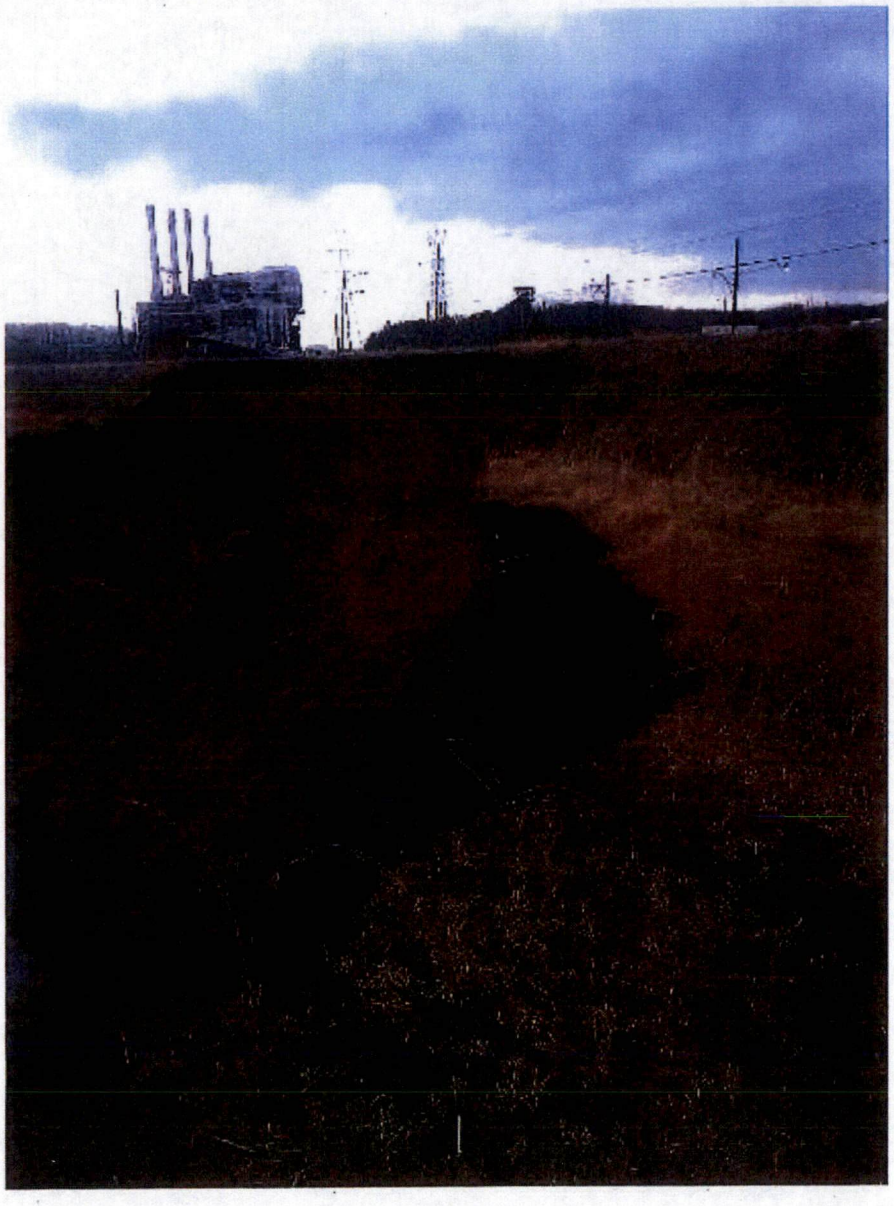
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Diagram 1. Engineering Firm #1, Report of Safety Inspection - Duke Power Dan River Steam Station Ash Dikes, at Fig. 4 (1981).



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Photograph 1. Photograph of DAN RIVER coal ash basin during spill, attached to 2/2/2014, 3:49 p.m. e-mail from Duke Energy Business Services employee.



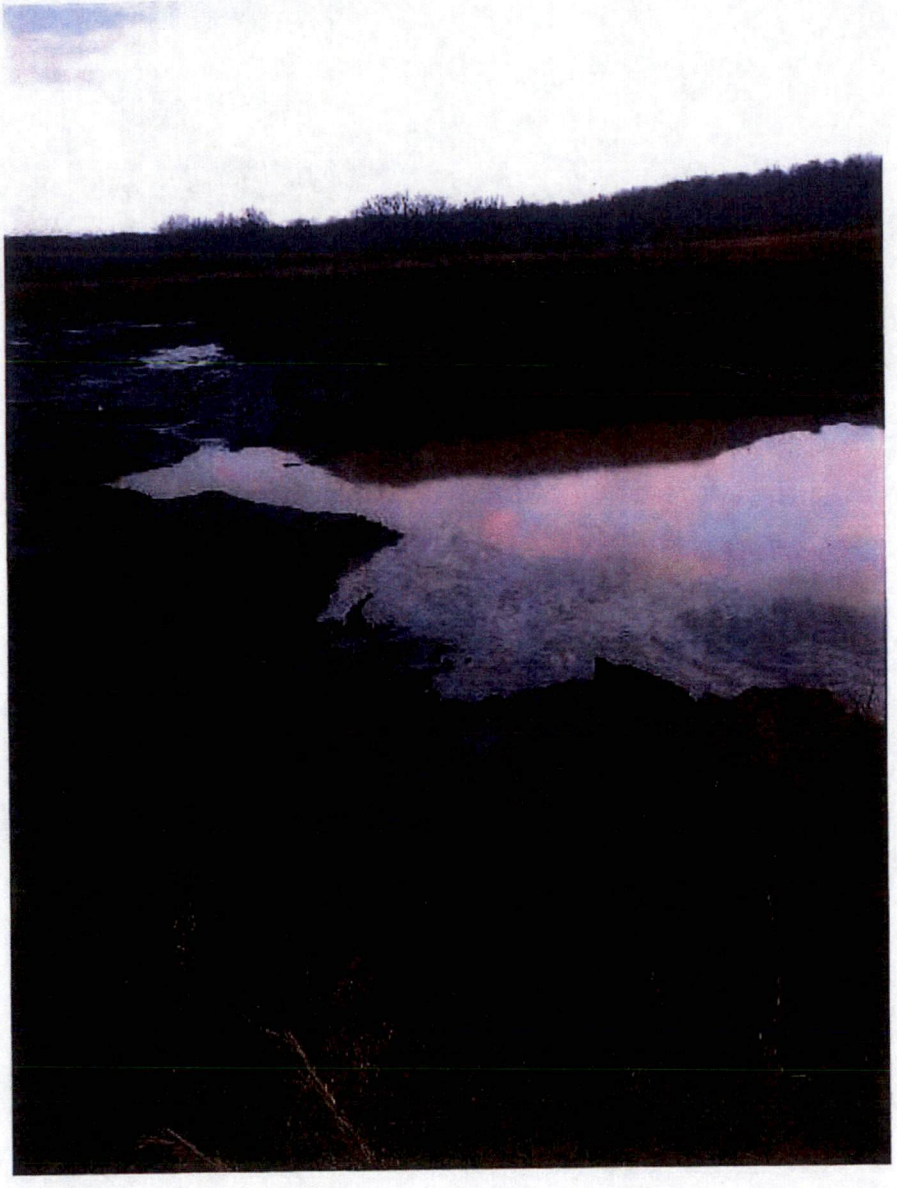
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Photograph 2. Photograph of DAN RIVER coal ash basin during spill, attached to 2/2/2014, 3:49 p.m. e-mail from Duke Energy Business Services employee.



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Photograph 3. Photograph of DAN RIVER coal ash basin during spill, attached to 2/2/2014, 3:49 p.m. e-mail from Duke Energy Business Services employee.



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Photograph 4. Photograph of DAN RIVER coal ash basin during spill, attached to 2/2/2014, 3:49 p.m. e-mail from Duke Energy Business Services employee.

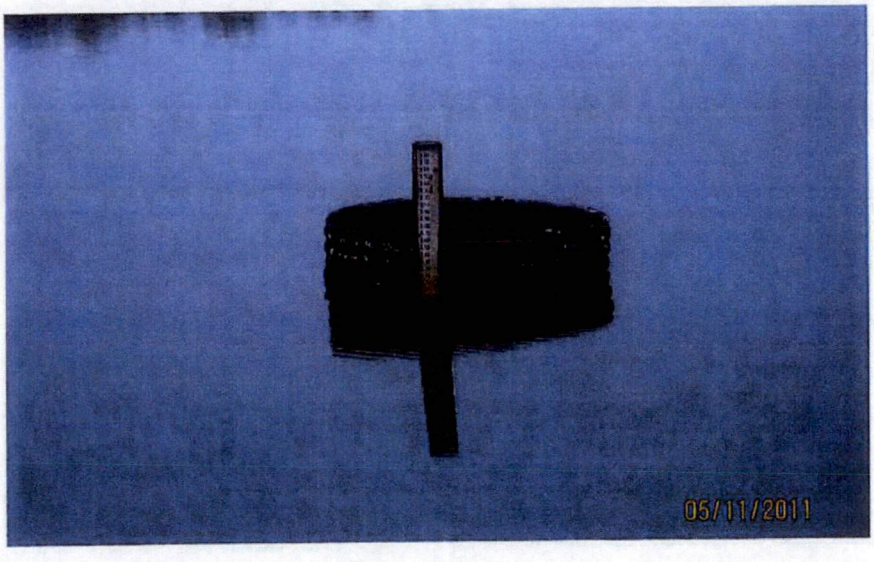


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Photograph 5. Riser in CAPE FEAR 1978 coal ash basin from 2012 Five Year Independent Consultant Report.



Photograph 6. Riser in CAPE FEAR 1978 coal ash basin from 2012 Five Year Independent Consultant Report.

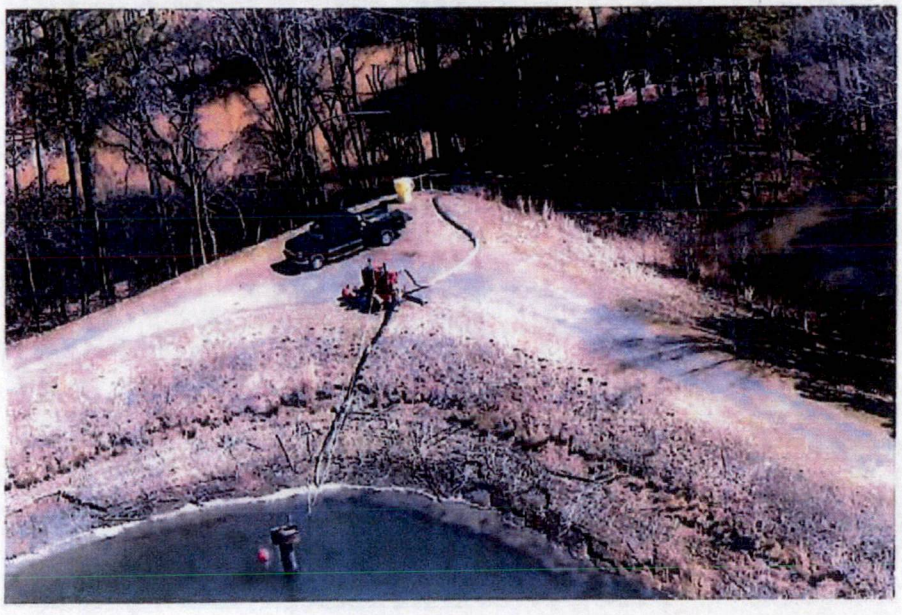


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Photograph 7. Riser in CAPE FEAR 1985 coal ash basin from 2012 Five Year Independent Consultant Report.

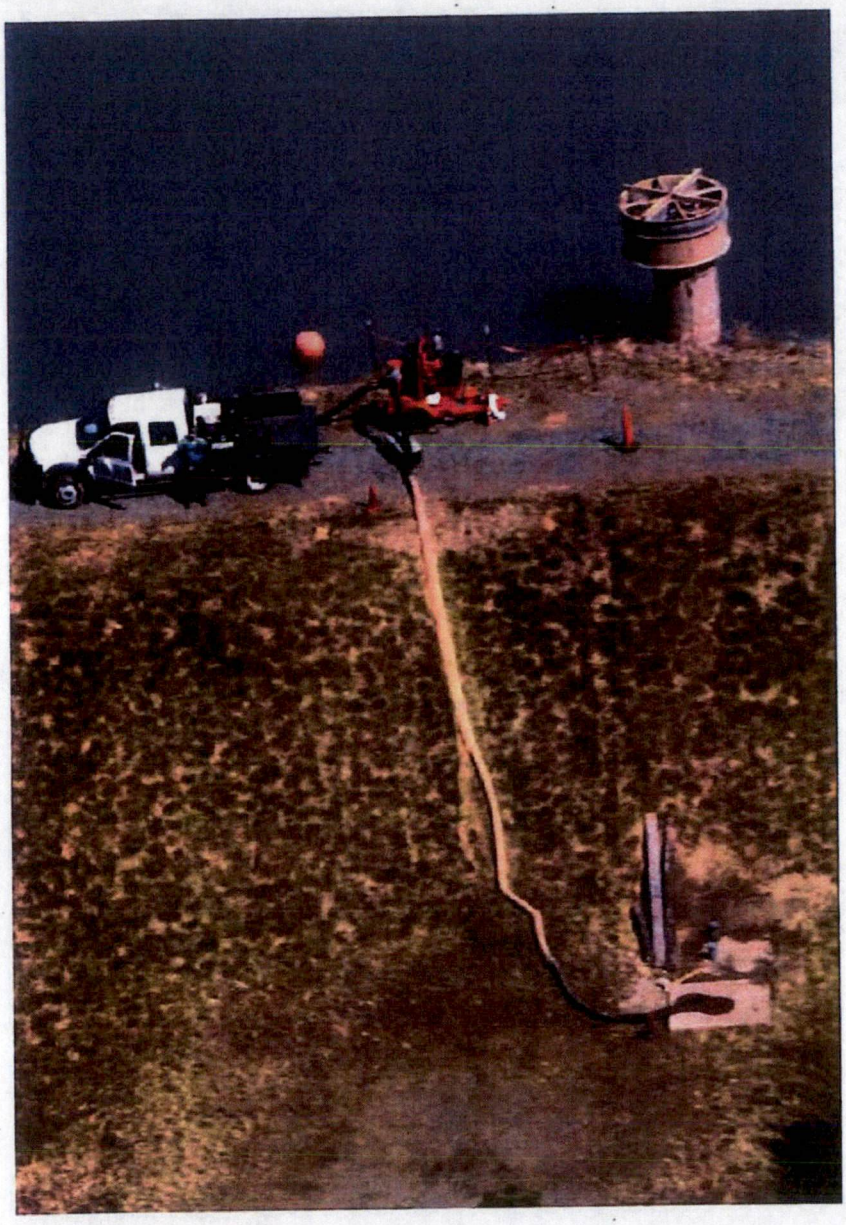


Photograph 8. 3/11/14 aerial photograph of CAPE FEAR 1978 coal ash basin with Godwin pump and truck.



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Photograph 9. 3/11/14 aerial photograph of CAPE FEAR 1985 coal ash basin with Godwin pump and truck.

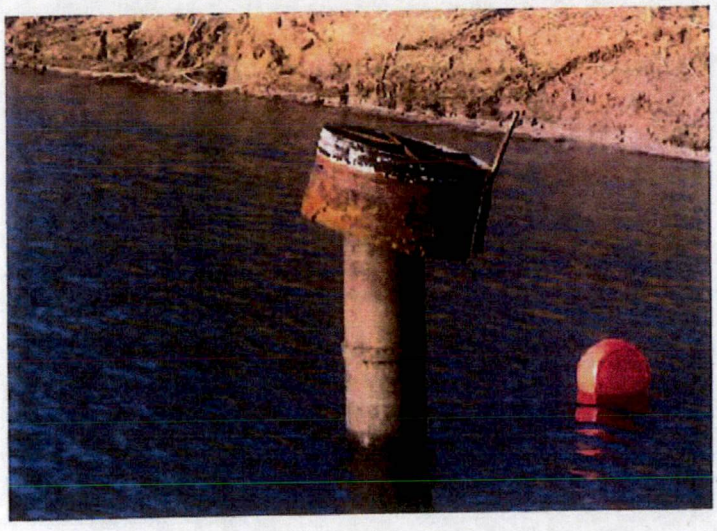


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Photograph 10. 3/11/14 aerial photograph of CAPE FEAR 1985 coal ash basin with Godwin pump and truck.



Photograph 11. 3/19/14 photograph of CAPE FEAR 1978 coal ash basin riser, prior to repair work.



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Photograph 12. 3/19/14 photograph of CAPE FEAR 1985 coal ash basin riser, prior to repair work.



Photograph 13. 3/19/14 photograph of old grout on CAPE FEAR coal ash basin riser.



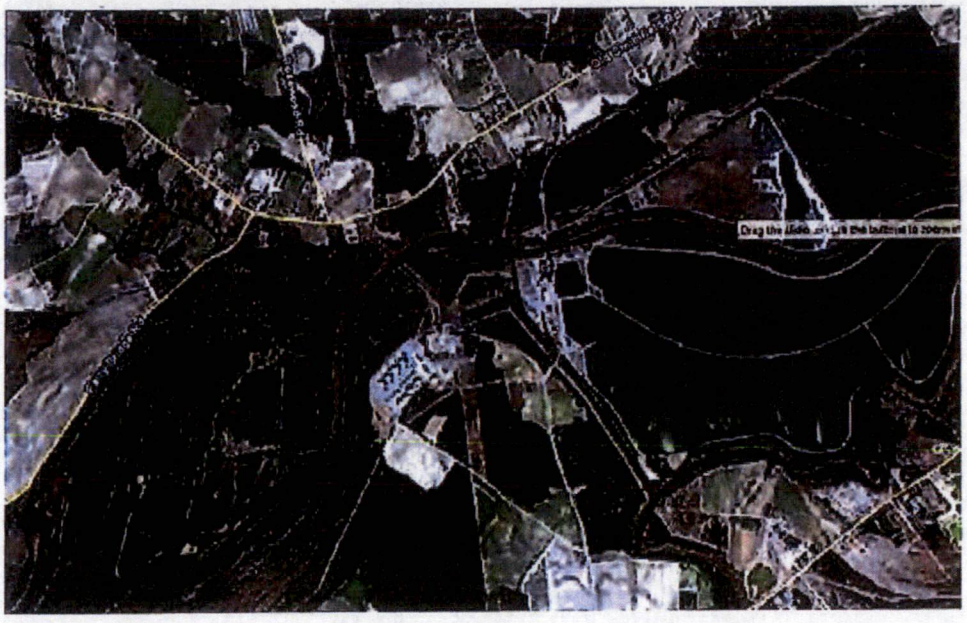
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Photograph 14. 3/19/14 photograph of new grout on CAPE FEAR coal ash basin riser.



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Photograph 15. Aerial Photograph of LEE from 2011 EPA Dam Safety Assessment report.



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Photograph 16. Aerial photograph depicting location of RIVERBEND Seep 12.



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Photograph 17. Photograph of RIVERBEND Seep 12.



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Photograph 18. Photograph of RIVERBEND Seep 12.



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Photograph 19. Aerial photograph of ASHEVILLE.



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[Please note: The removal of Exhibit DJW-5.2.1 reflects the testimony of the witness during the hearing in this matter.]

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STATE OF NORTH CAROLINA
COUNTY OF MECKLENBURG

IN THE GENERAL COURT OF JUSTICE
SUPERIOR COURT DIVISION

Civil Action No. 13-CVS-9352

STATE OF NORTH CAROLINA ex rel. NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, DIVISION OF WATER RESOURCES,
Plaintiff,
v.

CATAWBA RIVERKEEPER FOUNDATION, INC.,
Plaintiff-Intervenor,
v.

DUKE ENERGY CAROLINAS, LLC,
Defendant.

Civil Action No. 13-CVS-14661

STATE OF NORTH CAROLINA ex rel. NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY,
Plaintiff,
v.

DAN RIVER BASIN ASSOCIATION, ROANOKE RIVER BASIN ASSOCIATION, SOUTHERN ALLIANCE FOR CLEAN ENERGY, and WATERKEEPER ALLIANCE,
Plaintiff-Intervenors,
v.

DUKE ENERGY CAROLINAS, LLC,
Defendant.

STATE OF NORTH CAROLINA
COUNTY OF WAKE

IN THE GENERAL COURT OF JUSTICE
SUPERIOR COURT DIVISION

Civil Action No. 13-CVS-4061

STATE OF NORTH CAROLINA ex rel. NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY, DIVISION OF WATER RESOURCES,
Plaintiff,
v.

SIERRA CLUB, MOUNTAINTRUE, and WATERKEEPER ALLIANCE,
Plaintiff-Intervenors,
v.

DUKE ENERGY PROGRESS, LLC,
Defendant.

Civil Action No. 13-CVS-11032

STATE OF NORTH CAROLINA ex rel. NORTH CAROLINA DEPARTMENT OF ENVIRONMENTAL QUALITY,
Plaintiff,
v.

SIERRA CLUB, WATERKEEPER ALLIANCE, and CAPE FEAR RIVER WATCH, INC.,
Plaintiff-Intervenors,
v.

DUKE ENERGY PROGRESS, LLC,
Defendant.

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ORDER GRANTING MOTION FOR PARTIAL SUMMARY JUDGMENT

THIS CAUSE came on before the Hon. Paul Ridgeway, Superior Court Judge presiding pursuant to designation under Rule 2.1 of the General Rules of Practice, on Motion of the Defendants for Partial Summary Judgment. After reviewing the Motion, the Responses, the materials attached, and the pleadings in this matter, this Court is of the opinion that the Motion for Partial Summary Judgment should be GRANTED as set forth in this Order.

Findings of Undisputed Fact and Conclusions of Law

1. These are civil enforcement actions brought by the State of North Carolina and joined in by Plaintiff-Intervenors against the Defendants for injunctive relief. The Plaintiff and Plaintiff-Intervenors submitted separate Complaints which, together, seek injunctive relief under G.S. §143-215.6C for alleged violations of G.S. §§143-215.1(a)(1) and (a)(6), alleged violations of the National Pollutant Discharge Elimination System ("NPDES") permits, alleged violations of the groundwater standards established (at the time of the Complaint) by 15A N.C. Admin. Code Subchapter 2L ("2L Groundwater Rules"), and, in the case of Plaintiff-Intervenors' Complaints, alleged violations of various provisions of the Clean Water Act, 33 U.S.C. §§1311(a), 1342(a), and 1365(f) as set forth in those Complaints.

2. As to the plants that are the subject of this Motion (Riverbend Steam Station, Dan River Steam Station, Sutton Plant, and Asheville Electric Generating Plant), the State of North Carolina sought the identical injunctive relief as set forth in the various Complaints: (1) abatement of the violations of G.S. § 143-215.1, the NPDES permits and 2L Groundwater Rules, (2)

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assessment of the ash basins and specifically assessment of whether exceedances in groundwater constituents beyond the compliance boundary were naturally occurring or a result of the coal ash basins, and (3) corrective action to restore groundwater quality.

3. As to these same plants, the various Plaintiff-Intervenors requested separate relief from the State of North Carolina, but relief that was substantively identical across Plaintiff-Intervenors Complaints in Intervention for each of the facilities. The Plaintiff-Intervenors sought injunctive relief under the 2L Groundwater Rules for exceedances of any constituents that were not naturally occurring and were caused by the coal ash basins, sought an assessment of those exceedances as specified in the 2L Groundwater Rules, sought implementation of any corrective actions required by the 2L Groundwater Rules, asked that the Defendants conduct sampling and testing of seeps for purposes of characterizing their constituents, and requested abatement of alleged unpermitted discharges from the coal ash basins under the Clean Water Act and the coordinate provisions of North Carolina law.

4. On August 20, 2014, the General Assembly ratified Session Law 2014-122, which includes the Coal Ash Management Act of 2014, portions of which are codified as Part 2I of Article 9 of Chapter 130A of the General Statutes (collectively "CAMA 2014"); this was permitted to become law by the Governor without signature on September 20, 2014. On June 15, 2015, the General Assembly enacted the Mountain Energy Act of 2015, which was ratified as Session Law 2015-110 and which became effective on June 24, 2015 ("2015

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Mountain Energy Act"), which, among other things, amended CAMA 2014. As used herein, "CAMA" shall refer to CAMA 2014, as amended by the 2015 Mountain Energy Act.

5. CAMA amended and enacted a number of North Carolina Statutes relevant to the relief sought by the State of North Carolina and the Plaintiff-Intervenors.

a. G.S. §130A-309.210 was enacted to prohibit the construction of new coal combustion residuals surface impoundments[1] or the expansion of such existing impoundments after October 1, 2014;

b. The coal combustion residuals surface impoundments at the Riverbend Steam Station, at the Dan River Steam Station, at the Sutton Plant, and at the Asheville Electric Generating Plant were classified as "high priority"

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[1] CAMA enacts G.S. §130A-309.201 to define a "coal combustion residuals surface impoundment" as a "topographic depression, excavation or diked area that is (i) primarily formed from earthen materials; (ii) without a base liner approved for use by Article 9 of Chapter 130A of the General Statutes or rules adopted thereunder for a combustion products landfill or coal combustion residuals landfill, industrial landfill, or municipal solid waste landfill; and (iii) designed to hold accumulated coal combustion residuals in the form of liquid wastes, wastes containing free liquids, or sludges, and that is not backfilled or otherwise covered during period of deposition. 'Coal combustion residuals surface impoundment' shall only include impoundments owned by a public utility, as defined in G.S. 62-3. 'Coal combustion residuals surface impoundment' includes all of the following: (a) An impoundment that is dry due to the deposited liquid having evaporated, volatilized, or leached. (b) An impoundment that is wet with exposed liquid. (c) Lagoons, ponds, aeration pits, settling ponds, tailing ponds, and sludge pits, when these structures are designed to hold accumulated coal combustion residuals. (d) A coal combustion residuals surface impoundment that has been covered with soil or other material after the final deposition of coal combustion residuals at the impoundment."

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and required to be closed in conformity with the closure and permitting provisions of CAMA by no later than August 1, 2019;[2]

c. CAMA enacted G.S. §130A-309.211 to require the assessment and, where appropriate, corrective action as to groundwater impacted by the coal ash basins at the facilities operated by the Defendants by, among other things, requiring: (1) the preparation and implementation of an approved Groundwater Assessment Plan, (2) the preparation and submission of a Groundwater Assessment Report, and (3) the preparation and implementation of any necessary Groundwater Corrective Action Plan which provides for the restoration of groundwater quality. In addition, N.C.G.S. § 143-215.1(k) was amended to eliminate the distinction between disposal systems that were permitted after 30 December 1983 and those permitted prior to that date. This provision of CAMA was recently held to have rendered moot this Court's declaratory ruling that the 2L Groundwater Rules required immediate action to eliminate the source or sources of groundwater contamination, as requested by the Plaintiff-Intervenors under those rules. The Supreme Court held that that case "ha[d] been rendered moot as a matter of both law and fact by virtue of the enactment of the revised version of N.C.G.S. § 143-215.1(k)," *Cape Fear River Watch, et al. v. N.C. Envtl. Mgmt. Comm'n*, 368 N.C. 92, 100, 772 S.E.2d 445,

[2] On June 24, 2015, the Governor signed the "Mountain Energy Act of 2015," Session Law 2015-110, which amended this section as to the Asheville Steam Generating Plant. It provides that if Duke Progress receives a certificate of public convenience and necessity for the construction of a new natural-gas fired generating facility, and if Duke Progress issues a notice that it will permanently cease operation of the coal fired units at Asheville no later than January 31, 2020, then the closing date for the coal ash basins at Asheville will be no later than August 1, 2022.

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450 (2015), which "eliminate[d] the distinction between facilities that were permitted before 30 December 1983 and facilities that were permitted after that date by providing that all permitted facilities, 'without regard to the date that the system was first permitted,' are subject to the corrective action requirements of Rule .0106(d)." Id. at 98, 772 S.E.2d at 449. The Environmental Management Commission has initiated the process of adopting conforming amendments into the 2L Groundwater Rules.

d. CAMA enacted G.S. § 130A-309.212 to require the identification and assessment of all discharges from CCR impoundments, the implementation of corrective action to prevent unpermitted discharges from CCR impoundments, and preparation of a plan for the identification of new discharges.

e. Defendants agree to submit by December 31, 2016, Site Analysis and Removal Plans for the four facilities that are the subject of this Order. For purposes of this Order, such Site Analysis and Removal Plans shall include the following topics or documents: (1) a description of the facility and its history, including a description of all on-site CCR surface impoundments; (2) a site map showing the CCR surface impoundments, topography, potential receptors within 2,640 feet of the compliance boundary, and monitoring locations; (3) hydrogeologic, geologic, and geotechnical investigation results; (4) groundwater modeling; (5) any planned beneficial use of CCR on-site; (6) drawings, schematics, and specifications; (7) construction quality assurance and quality control programs; (8) management of stormwater and wastewater; (9) final disposition of CCR from the site, including information on any CCR disposed

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of or beneficially used offsite; (10) necessary permits; (11) post-closure monitoring and care for the CCR surface impoundments; and (12) closure project milestones[3].

6. Defendants have submitted groundwater assessment plans for each of the four facilities addressed in this Order. DEQ conditionally approved the plans, requiring that certain changes be addressed in the groundwater assessment reports. Defendants have now submitted the groundwater assessment reports to DEQ, and they are currently under review.

7. In addition, during 2014, new NPDES permit applications were submitted to the DEQ for the coal ash basins at these plants. As part of this process, the Defendants have submitted analyses of all seeps associated with the coal ash basins that the Defendants have identified, sampled and tested the seeps, and provided a characterization of the chemicals found in the seeps (as sought by the relief requested by the Plaintiff-Intervenors).

8. As a result of these actions and statutory changes requiring further action, the Court finds that an Order on relief as to these facilities is appropriate, and the actions already taken together with those required by this Order (including dewatering, excavating and removing the contents of the coal ash basins) have remedied, or will remedy, the violations alleged in the Complaints.

9. This Court further finds that the issues alleged in the various Complaints with regard to unpermitted discharges, and with regard to violations

[3] This Order does not make a determination regarding whether Defendants are required under CAMA to submit Closure Plans for these four facilities, nor does this Order attempt to select from among the elements listed by the legislature in G.S. §130A-309.214(a)(4) to be included in a Closure Plan.

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of NPDES permits and groundwater standards at these facilities will be remedied by compliance with the provisions of this Order and the provisions of CAMA applicable to the four plants included in this Order. This Order does not resolve any issue with regard to: (1) any claims that may be pursued by DEQ pursuant to a joint enforcement agreement between DEQ and the United States Environmental Protection Agency, (2) any seeps that are determined to be waters of the United States, or (3) whether any seeps can be addressed through NPDES permitting.

Order on Relief

10. This Court has jurisdiction over the subject matter and the parties to these actions pursuant to G.S. 7A-245 and 143-215.6C. DEQ brought the Actions based on its reasonable cause to believe that Duke Energy Carolinas, LLC ("Duke Energy Carolinas") and Duke Energy Progress, LLC. ("Duke Energy Progress") have violated or might violate provisions of G.S. 143-215.1 and the 2L Groundwater Rules.

11. Venue in the Riverbend Action and the Dan River Action is proper in Mecklenburg County under G.S. 1-79 and 143-215.6C. Venue in the Asheville Action and the Sutton Action is proper in Wake County under G.S. 1-79 and 143-215.6C.

Specific Facility Terms

Riverbend Steam Station

12. Duke Energy Carolinas owns the Riverbend Station, located in Gaston County, which has been retired, in that it is no longer used for the production of electricity.

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13. The Riverbend Station has two coal ash settling Impoundments totaling about 69 acres ("Riverbend Impoundments") and as further identified on **Exhibit A**. The Riverbend Impoundments no longer receive sluice water, which was water that was used to transport to the Riverbend Impoundments the coal ash produced when the Riverbend Station was generating electricity.

14. The Riverbend Station also has coal ash stored in the Ash Storage and Cinder Storage areas located immediately south and west of the Riverbend Impoundments and indicated on the attached map marked as **Exhibit A** (collectively, "Inactive Ash Areas").

15. The Riverbend Impoundments are Coal Combustion Residual ("CCR") Surface Impoundments as defined in G.S. § 130A-309.201(6). Upon evaluation by DEQ and full adjudication of any challenges to DEQ's evaluation, to the extent provided by applicable law, the Inactive Ash Areas may or may not be determined to be CCR Surface Impoundments as defined in G.S. § 130A-309.201(6).

16. The Riverbend Station holds NPDES Permit No. NC0004961 that authorizes and regulates discharges from permitted outfalls from the Riverbend Impoundments ("Riverbend NPDES Permit") into Mountain Island Lake, a lake of the Catawba River created in 1924 by damming the Catawba River.

17. Mountain Island Lake is approximately 12 miles north of Charlotte, North Carolina. Mountain Island Lake provides drinking water to over three-quarters of a million people served by the Charlotte-Mecklenburg, Mount Holly, and Gastonia water systems.

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18. The Riverbend NPDES Permit currently authorizes discharges through the following outfalls:

a. Outfall 001, for discharge of once-through cooling water to Mountain Island Lake;

b. Outfall 002, for discharges from the Riverbend Impoundments to Mountain Island Lake; and

c. Outfall 002A, which discharges yard sump overflows to Mountain Island Lake.

19. Duke Energy Carolinas shall comply with the following requirements:

a. Excavate and remove all CCR and Coal Combustion Products from the Riverbend Impoundments and the Inactive Ash Areas (collectively, "Riverbend Removed Ash") to lined locations for disposal in a CCR landfill, industrial landfill, or municipal solid waste landfill or for use as structural fill or other beneficial use pursuant to applicable law, and thereafter stabilize and close the area where the Riverbend Impoundments and Inactive Ash Areas are located pursuant to applicable law. Excavation shall include all coal ash and such additional soil as is necessary for the protection of groundwater or as may be ordered by any regulatory agency. All Riverbend Removed Ash from the Riverbend Impoundments shall be removed by the statutory deadline directed by CAMA (presently August 1, 2019, or other date specified in any subsequent amendment of the CAMA deadline), or earlier as otherwise may be directed by other applicable law, but, in any event, no later than January 1, 2026. All

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Riverbend Removed Ash from the Inactive Ash Areas shall be removed no later than January 1, 2026, or earlier if otherwise required by DEQ pursuant to applicable laws and regulation. If the Inactive Ash Areas are found by DEQ to be CCR Surface Impoundments, they shall be removed by the statutory deadline directed by CAMA (presently August 1, 2019, or other date specified in any subsequent amendment of the CAMA deadline), or earlier as otherwise may be directed by other applicable law, but, in any event, no later than January 1, 2026.

b. Defendant shall ensure that the Riverbend Removed Ash transferred for disposal is transferred to a lined CCR landfill, industrial landfill, or municipal solid waste landfill meeting applicable permitting, siting, construction and engineering requirements established by applicable law, statute or regulation. The Defendant shall take all necessary steps to ensure that the disposal or reuse of the Riverbend Removed Ash shall meet the requirements specified in **Exhibit B**, and Defendant will ensure any application for a permit submitted to DEQ shall comply with the requirements specified in Exhibit B. **DEQ neither endorses nor objects to the inclusion of Exhibit B in this Order.** DEQ shall review, and approve or deny any application for the disposal of Riverbend Removed Ash in accordance with applicable State statutes and regulations. If Riverbend Removed Ash is used as structural fill or in another beneficial use, such as lined mine reclamation, Defendant shall ensure that it is not deposited on the surface or subsurface of the land except in a lined facility and that any application for such use submitted to DEQ shall meet the requirements set forth in **Exhibit B**. DEQ shall review, and approve or deny any

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application for the use of Riverbend Removed Ash as structural fill or other beneficial use in accordance with applicable State statutes and regulations.

c. During the removal process, sample the Riverbend Removed Ash in accordance with the protocol attached as **Exhibit C** and such other protocols or procedures as specified by any regulatory agency.

d. Complete investigation and undertake corrective action to eliminate groundwater violations at or beyond the compliance boundary to the extent required by G.S. § 130A-309.211, the 2L Groundwater Rules, any other applicable laws and regulations, and pursuant to a Corrective Action Plan approved by DEQ in accordance with Paragraph 22 below.

e. Comply with the terms and conditions of the NPDES Permit, and any modified or new NPDES permit issued for this facility, pending closure of the Riverbend Impoundments and Inactive Ash Areas.

f. Comply with and implement an approved Plan for Identification of New Discharges in accordance with G.S. § 130A-309.212(d), attached to and included as a part of any modified or new NPDES permit issued for the facility.

g. Dewater the Riverbend Impoundments pursuant to the terms and limitations of a NPDES permit and in compliance with the requirements in s.3(c) of S.L. 2014-122 and G.S. § 130A-309-214.

h. Remove or permanently close all pipes currently running through or beneath the Impoundments pursuant to an approved plan.

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20. Duke Energy Carolinas shall otherwise close the Impoundments and Inactive Ash Areas should they later be determined to be CCR Surface Impoundments (after evaluation by DEQ and full adjudication of any challenges to DEQ's evaluation, to the extent provided by applicable law) at Riverbend in accordance with the standards and procedures contained in Section 3(c) and all applicable provisions of CAMA and the regulations that are cited therein, including the submission of a Site Analysis and Removal Plan as set forth in paragraph 5(e), as well as the additional provisions contained in this Order.

21. Commencing six months after the entry of this Order, and continuing every six months thereafter until one year after the removal of the Riverbend Removed Ash has been completed, Duke Energy Carolinas shall provide a written report to the Court summarizing its actions under this Order including (1) the amount of ash removed during the previous six-month period, (2) the results of all monitoring, (3) the progress of excavation, dewatering and closure, (4) all significant activities performed pursuant to this Order during the previous six-month period, and (5) the destination and/or intended use of the Riverbend Removed Ash. Duke Energy Carolinas may utilize reports to other federal or state courts or agencies to meet this reporting requirement or any portion of this reporting requirement.

22. Within the timeframes and as required by § 3(c) of CAMA and G.S. 130A-309.211(b), Duke Energy Carolinas shall submit a proposed Groundwater Corrective Action Plan to DEQ for its review and approval. The Corrective Action Plan will be designed to address any groundwater contamination as required by

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§ 3(c) of CAMA, G.S. § 130A-309.211, the 2L Groundwater Rules, and any other applicable laws, statutes, or regulations, but, at a minimum, to prevent contaminants from the coal ash sites from violating the 2L Groundwater Rules at or beyond the compliance boundary. For purposes of clarity, the current compliance boundary is shown on the map attached as **Exhibit D.** The actual compliance boundary is under regulatory review by DEQ and may be modified in the future, such as through permit modification or the purchase by Duke Energy Carolinas of additional property; provided, however, that Duke Energy Carolinas, for purposes of its obligation to address groundwater contamination, will treat the compliance boundary as not extending beyond the closest shoreline of rivers or lakes.

23. No later than thirty (30) days from DEQ's approval of the Groundwater Corrective Action Plan, Duke Energy Carolinas shall begin implementation of the plan in accordance with the plan's schedules.

24. Notwithstanding the preceding paragraph, Defendants must comply with all applicable requirements for groundwater monitoring and assessment, and corrective action to restore groundwater quality in accordance with CAMA and the 2L Groundwater Rules.

25. Following the removal of the ash, Defendant must investigate and remediate soil and groundwater impacted by the Riverbend Impoundments and

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Inactive Ash Areas in conformance with the requirements of CAMA and the 2L Groundwater Rules, and as otherwise required by law.[4]

26. Within thirty (30) days of the entry of this Order, the Plaintiff-Intervenors shall have the right to sample any of the alleged unpermitted discharges. The Plaintiff-Intervenor representatives must be given access no later than five (5) days following notice and will be accompanied at all times while at the Facility for these purposes. The Plaintiff-Intervenors shall split samples with Duke Energy Carolinas and DEQ upon request.

27. The terms of this Order define Duke Energy Carolina's minimum obligations regarding closure. Any Site Analysis and Removal Plan submitted by Duke Energy Carolinas shall not be inconsistent with this Order.

28. A decision by any agency on the Site Analysis and Removal Plan for the Riverbend Steam Station that is final under the North Carolina Administrative Procedure Act and otherwise appealable under applicable law may be challenged by Duke Energy and/or any of the Plaintiff-Intervenors by filing a contested case in the Office of Administrative Hearings, but only to the extent it is inconsistent with this Order.

Dan River Steam Station

29. Duke Energy Carolinas owns the Dan River Station, located in Rockingham County, which has ceased using coal to generate electricity, although Duke Energy Carolinas has constructed and is now operating a natural gas powered combined cycle electric generating station at this site.

[4] This Order does not address whether or under what circumstances, if any, a compliance boundary may be eliminated or the obligations of the parties upon elimination of a compliance boundary.

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30. The Dan River Station has one Impoundment receiving stormwater and one inactive Impoundment (which was the subject of a release in February, 2014), which together currently contain approximately 2,620,000 tons of ash as set forth in **Exhibit E**.

31. The Dan River Impoundments are CCR Impoundments as defined in G.S. 130A-309.201(6).

32. The Dan River Station also has coal ash stored in the Ash Storage areas as indicated on the attached map marked as **Exhibit E** (collectively, "Inactive Ash Areas"). Upon evaluation by DEQ and full adjudication of any challenges to DEQ's evaluation, to the extent provided by applicable law, the Inactive Ash Areas may or may not be determined to be CCR Surface Impoundments as defined in G.S. § 130A-309.201(6).

33. The Dan River Station holds NPDES Permit No. NC0003468 ("Dan River NPDES Permit") that authorizes and regulates discharges from the following permitted outfalls:

a. Outfalls 001, 002, and 002A; and

b. Outfall 001A as an internal outfall discharging low volume waste sources.

34. Duke Energy Carolinas shall comply with the following requirements:

a. Excavate and move all CCR and CCP from the Dan River Impoundments and the Inactive Ash Areas ("Dan River Removed Ash") to lined locations for disposal in a CCR landfill, industrial landfill, or municipal solid waste

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landfill or for use as structural fill or other beneficial use pursuant to applicable law, and thereafter stabilize and close the area where the Dan River Impoundments and Inactive Ash Areas are located pursuant to applicable law. Excavation shall include all coal ash and such additional soil as is necessary for the protection of groundwater or as may be ordered by any regulatory agency. All Dan River Removed Ash from the Dan River Impoundments shall be removed by the statutory deadline directed by CAMA (presently August 1, 2019, or other date specified in any subsequent amendment of the CAMA deadline), or earlier as otherwise may be directed by other applicable law, but, in any event, no later than January 1, 2026. All Dan River Removed Ash from the Inactive Ash Areas shall be removed no later than January 1, 2026, or earlier if otherwise required by DEQ pursuant to applicable laws and regulation. If the Inactive Ash Areas are found by DEQ to be CCR Surface Impoundments, they shall be removed by the statutory deadline directed by CAMA (presently August 1, 2019, or other date specified in any subsequent amendment of the CAMA deadline), or earlier as otherwise may be directed by other applicable law, but, in any event, no later than January 1, 2026.

b. Defendant shall ensure that the Dan River Removed Ash transferred for disposal is transferred to a lined CCR landfill, industrial landfill, or municipal solid waste landfill meeting applicable permitting, siting, construction and engineering requirements established by applicable law, statute or regulation. The Defendant shall take all necessary steps to ensure that the disposal or reuse of the Dan River Removed Ash shall meet the requirements

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specified in **Exhibit B**, and Defendant will ensure any application for a permit submitted to DEQ shall comply with the requirements specified in Exhibit B. **DEQ neither endorses nor objects to the inclusion of Exhibit B in this Order.** DEQ shall review, and approve or deny any application for the disposal of Dan River Removed Ash in accordance with applicable State statutes and regulations. If Dan River Removed Ash is used as structural fill or in another beneficial use, such as lined mine reclamation, Defendant shall ensure that it is not deposited on the surface or subsurface of the land except in a lined facility and that any application for such use submitted to DEQ shall meet the requirements set forth in **Exhibit B**. DEQ shall review, and approve or deny any application for the use of Dan River Removed Ash as structural fill or other beneficial use in accordance with applicable State statutes and regulations.

c. During the removal process, sample the Dan River Removed Ash in accordance with the protocol attached as **Exhibit C** and such other protocols or procedures as specified by any regulatory agency.

d. Complete investigation and undertake corrective action to eliminate groundwater violations at or beyond the compliance boundary to the extent required by G.S. § 130A-309.211, the 2L Groundwater Rules, any other applicable laws and regulations, and pursuant to a Corrective Action Plan approved by DEQ in accordance with Paragraph 37 below.

e. Comply with the terms and conditions of the NPDES Permit, and any modified or new NPDES permit issued for this facility, pending closure of the Dan River Impoundments and Inactive Ash Areas;

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f. Comply with and implement an approved Plan for Identification of New Discharges in accordance with G.S. § 130A-309.212(d), attached to and included as a part of any modified or new NPDES permit issued for the facility.

g. Dewater the Dan River Impoundments pursuant to the terms and limitations of a NPDES permit and in compliance with the requirements in s.3(c) of S.L. 2014-122 and G.S. § 130A-309-214.

h. Remove or permanently close all pipes currently running through or beneath the Impoundments pursuant to an approved plan.

35. Duke Energy Carolinas shall otherwise close the Impoundments and Inactive Ash Areas should they later be determined to be CCR Surface Impoundments (after evaluation by DEQ and full adjudication of any challenges to DEQ's evaluation, to the extent provided by applicable law) at Dan River in accordance with the standards and procedures contained in Section 3(c) and all applicable provisions of CAMA and the regulations that are cited therein, including the submission of a Site Analysis and Removal Plan as set forth in paragraph 5(e), as well as the additional provisions contained in this Order.

36. Commencing six months after the entry of this Order, and continuing every six months thereafter until one year after the removal of the Dan River Removed Ash has been completed, Duke Energy Carolinas shall provide a written report to the Court summarizing its actions under this Order including (1) the amount of ash removed during the previous six-month period, (2) the results of all monitoring, (3) the progress of excavation, dewatering and closure, (4) all

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significant activities performed pursuant to this Order during the previous six-month period, and (5) the destination and/or intended use of the Dan River Removed Ash. Duke Energy Carolinas may utilize reports to other federal or state courts or agencies to meet this reporting requirement or any portion of this reporting requirement.

37. Within the timeframes and as required by § 3(c) of CAMA and G.S. 130A-309.211(b), Duke Energy Carolinas shall submit a proposed Groundwater Corrective Action Plan to DEQ for its review and approval. The Corrective Action Plan will be designed to address any groundwater contamination as required by § 3(c) of CAMA, G.S. § 130A-309.211, the 2L Groundwater Rules, and any other applicable laws, statutes, or regulations, but, at a minimum, to prevent contaminants from the coal ash sites from violating the 2L Groundwater Rules at or beyond the compliance boundary. For purposes of clarity, the current compliance boundary is shown on the map attached as **Exhibit E.** The actual compliance boundary is under regulatory review by DEQ and may be modified in the future, such as through permit modification or the purchase by Duke Energy Carolinas of additional property; provided, however, that Duke Energy Carolinas, for purposes of its obligation to address groundwater contamination, will treat the compliance boundary as not extending beyond the closest shoreline of rivers or lakes.

38. No later than thirty (30) days from DEQ's approval of the Groundwater Corrective Action Plans, Duke Energy Carolinas shall begin implementation of the plans in accordance with the plans' schedules.

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39. Notwithstanding the preceding paragraph, Defendant must comply with all applicable requirements for groundwater monitoring and assessment, and corrective action to restore groundwater quality in accordance with CAMA and the 2L Groundwater Rules.

40. Following the removal of the ash, Defendant must investigate and remediate soil and groundwater impacted by the Dan River Impoundments and Inactive Ash Areas in conformance with the requirements of CAMA and the 2L Groundwater Rules, and as otherwise required by law.[5]

41. Within thirty (30) days of the entry of this Order, the Plaintiff-Intervenors shall have the right to sample any of the alleged unpermitted discharges. The Plaintiff-Intervenor representatives must be given access no later than five (5) days following notice and will be accompanied at all times while at the Facility for these purposes. The Plaintiff-Intervenors shall split samples with Duke Energy Carolinas and DEQ upon request.

42. The terms of this Order define Duke Energy Carolina's minimum obligations regarding closure. Any Site Analysis and Removal plan submitted by Duke Energy Carolinas shall not be inconsistent with this Order.

43. A decision by any agency on the Site Analysis and Removal Plan for the Dan River Steam Station that is final under the North Carolina Administrative Procedure Act may be challenged by Duke Energy Carolinas

[5] This Order does not address whether or under what circumstances, if any, a compliance boundary may be eliminated or the obligations of the parties upon elimination of a compliance boundary.

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and/or any of the Plaintiff-Intervenors by filing a contested case in the Office of Administrative Hearings, but only to the extent it is inconsistent with this Order.

Sutton Plant

44. Duke Energy Progress owns the Sutton Station, located in New Hannover County, which has ceased using coal to generate electricity, although Duke Energy Progress has constructed and is now operating a natural gas powered combined cycle electric generating station at the same site.

45. The Sutton Station contains one Impoundment and one inactive Impoundment ("Sutton Impoundments"), which currently contain approximately 7,160,000 tons of ash, and coal ash stored in areas located to the south of the Sutton Impoundments ("Inactive Ash Areas") as set forth in **Exhibits F** and G.

46. The Sutton Impoundments are CCR Impoundments as defined in G.S. 130A-309.201(6). Upon evaluation by DEQ and full adjudication of any challenges to DEQ's evaluation, to the extent provided by applicable law, the Inactive Ash Areas may or may not be determined to be CCR Surface Impoundments as defined in G.S. § 130A-309.201(6).

47. The Sutton Station holds NPDES Permit No. NC0001422 ("Sutton NPDES Permit") that authorizes and regulates discharges from the following permitted outfalls:

a. Outfall 001, for discharges to the Cape Fear River;

b. Outfall 002, for "internal" discharges from the old ash pond;

c. Outfall 003, for Chemical Metal Cleaning Waste;

d. Outfall 004, for "internal" discharges from the new ash pond;

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e. Outfall 005, for low-volume waste water from the new combined cycle generating facility;

f. Outfall 006, for discharges from the combined cycle auxiliary boiler.

48. Duke Energy Progress shall comply with the following requirements:

a. Excavate and remove all CCR and CCP from the Sutton Impoundments and the Inactive Ash Areas ("Sutton Removed Ash") to lined locations for disposal in a CCR landfill, industrial landfill, or municipal solid waste landfill or for use as structural fill or other beneficial use pursuant to applicable law, and thereafter to stabilize and close the area where the Sutton River Impoundments and Inactive Ash Areas are located. Excavation shall include all coal ash and such additional soil as is necessary for the protection of groundwater or as may be ordered by any regulatory agency. All Sutton Removed Ash from the Sutton Impoundments shall be removed by the statutory deadline directed by CAMA (presently August 1, 2019, or other date specified in any subsequent amendment of the CAMA deadline), or earlier as otherwise may be directed by other applicable law, but, in any event, no later than January 1, 2026. All Sutton Removed Ash from the Inactive Ash Areas shall be removed no later than January 1, 2026, or earlier if otherwise required by DEQ pursuant to applicable laws and regulation. If the Inactive Ash Areas are found by DEQ to be CCR Surface Impoundments, they shall be removed by the statutory deadline directed by CAMA (presently August 1, 2019, or other date specified in any