III. INDUSTRIAL PROCESS DESCRIPTION

This section describes the major industrial processes within the fossil fuel electric power generation industry, including the materials and equipment used and the processes employed. The section is designed for those interested in gaining a general understanding of the industry and for those interested in the interrelationship between the industrial process and the topics described in subsequent sections of this profile -- pollutant outputs, pollution prevention opportunities, and Federal regulations. This section does not attempt to replicate published engineering information that is available for this industry. Section IX lists available resource materials and contacts.

This section describes commonly used production processes, associated raw materials, the by-products produced or released, and the materials either recycled or transferred offsite. This discussion, coupled with schematic drawings of the identified processes, provide a concise description of where wastes may be produced in the process. This section also describes the potential fate (via air, water, and soil pathways) of these waste products.

III.A Industrial Processes in the Fossil Fuel Electric Generation Industry

The majority of the electricity generated in the United States today is produced by facilities that employ steam turbine systems.[14] Other fossil fuel prime movers commonly used include gas turbines and internal combustion engines. Still other power generation systems employ a combination of the above, such as combined-cycle and cogeneration systems. The numbers of these systems being built are increasing as a result of the demands placed on the industry to provide economic and efficient systems.

The type of system employed at a facility is chosen based on the loads, the availability of fuels, and the energy requirements of the electric power generation facility. At facilities employing these systems, other ancillary processes must be performed to support the generation of electricity. These ancillary processes may include such supporting operations as coal processing and pollution control, for example. The following subsections describe each system and then discuss ancillary processes at the facility.

III.A.1 Steam Turbine Generation

The process of generating electricity from steam comprises four parts: a heating subsystem (fuel to produce the steam), a steam subsystem (boiler and steam delivery system), a steam turbine, and a condenser (for condensation of used steam). Heat for the system is usually provided by the combustion of coal, natural gas, or oil. The fuel is pumped into the boiler's furnace. The boilers generate steam in the pressurized vessel in small boilers or in the water-wall tube system in modern utility and industrial boilers. Additional elements within or associated with the boiler, such as the superheater, reheater, economizer and air heaters, improve the boiler's efficiency.

Wastes from the combustion process include exhaust gases and, when coal or oil is used as the boiler fuel, ash. These wastes are typically controlled to reduce the levels of pollutants exiting the exhaust stack. Bottom ash, another byproduct of combustion, also is discharged from the furnace.

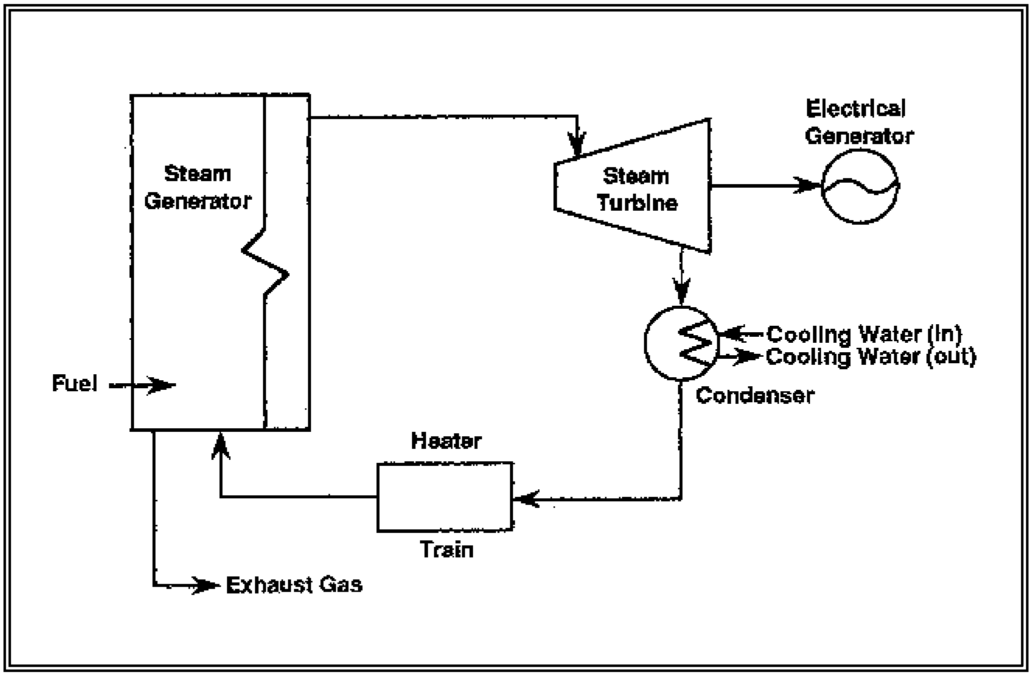
High temperature, high pressure steam is generated in the boiler and then enters the steam turbine. At the other end of the steam turbine is the condenser, which is maintained at a low temperature and pressure. Steam rushing from the high pressure boiler to the low pressure condenser drives the turbine blades, which powers the electric generator. Steam expands as it works; hence, the turbine is wider at the exit end of the steam. The theoretical thermal efficiency of the unit is dependent on the high pressure and temperature in the boiler and the low temperature and pressure in condenser. Steam turbines typically have a thermal efficiency of about 35 percent, meaning that 35 percent of the heat of combustion is transformed into electricity. The remaining 65 percent of the heat either goes up the stack (typically 10 percent) or is discharged with the condenser cooling water (typically 55 percent).

Low pressure steam exiting the turbine enters the condenser shell and is condensed on the condenser tubes. The condenser tubes are maintained at a low temperature by the flow of cooling water. The condenser is necessary for efficient operation by providing a low pressure sink for the exhausted steam. As the steam is cooled to condensate, the condensate is transported by the boiler feedwater system back to the boiler, where it is used again. Being a low-volume incompressible liquid, the condensate water can be efficiently pumped back into the high pressure boiler.

A constant flow of low-temperature cooling water in the condenser tubes is required to keep the condenser shell (steam side) at proper pressure and to ensure efficient electricity generation. Through the condensing process, the cooling water is warmed. If the cooling system is an open or a once-through system, this warm water is released back to the source water body. In a closed system, the warm water is cooled by recirculation through cooling towers, lakes, or ponds, where the heat is released into the air through evaporation and/or sensible heat transfer. If a recirculating cooling system is used, only a small amount of make-up water is required to offset the cooling tower blowdown which must be discharged periodically to control the build-up of solids. Compared to a once-through system, a recirculated system uses about one twentieth the water.[15] Figure 6 presents a typical steam generation process.

There are several types of coal-fired steam generators. A description of each follows. The classification of these generators is based on the characteristics of the coal fed to the burners and the mode of burning the coal. Coal-fired steam generation systems are designed to use pulverized coal or crushed coal. Before the coal is introduced to the burners, it must be processed, as discussed in Section III.A.6.

Figure 6: Steam Turbine Generation



Stoker-Fired Furnace

Stoker-fired furnaces are designed to feed coal to the combustion zone on a traveling grate. Stokers can be divided into three general groups, depending on how the coal reaches the grate of the stoker for burning. The three general types of stokers are (1) underfeed, (2) overfeed, and (3) spreader configurations. Table 12 presents the general characteristics of these three general types of stokers. Figure 7 presents a schematic of a stoker coal feeder.

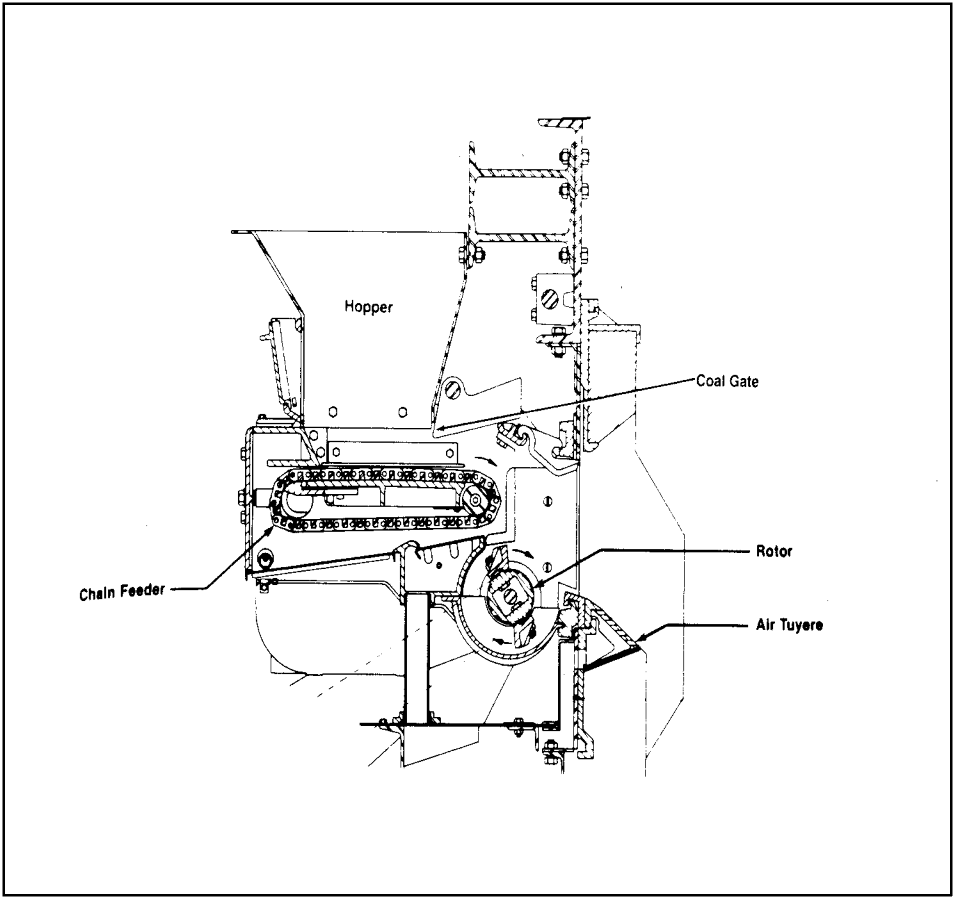
Table 12: Characteristics of Various Types of Stokers

Stoker Type and Subclass	Burning Rate * (BTU/hr/ft ^{2})	Characteristics
Spreader		
Stationary	450,000	Capable of burning a wide range of coals, best in handling fluctuating loads, high fly ash carry over, low load smoke.
Traveling grate	750,000	
Vibrating grate	400,000	
Overfeed		
Chain grate and traveling grate	600,000	Low maintenance but difficult in burning caking coals.
Vibrating grate	400,000	Low maintenance but difficult in burning weakly caking coals, smokeless operation.
Underfeed		
Single or double retort Multiple retort	400,000	Capable of burning caking coals and a wide range of coals, high maintenance, low fly ash carry over, suitable for continuous load operation.

* Maximum amount of British thermal units per hour per square foot of grate in the stoker.

Source: *Coal Handbook*, Robert Meyers (Ed.). Marcel Dekker, Inc. New York, NY, 1981 as referenced in *Wastes from the Combustion of Coal by Electric Utility Power Plants.* Report to Congress. US. Environmental Protection Agency, Office of Solid Waste. Washington, DC. February 1988. EPA/530-SW-88-002.

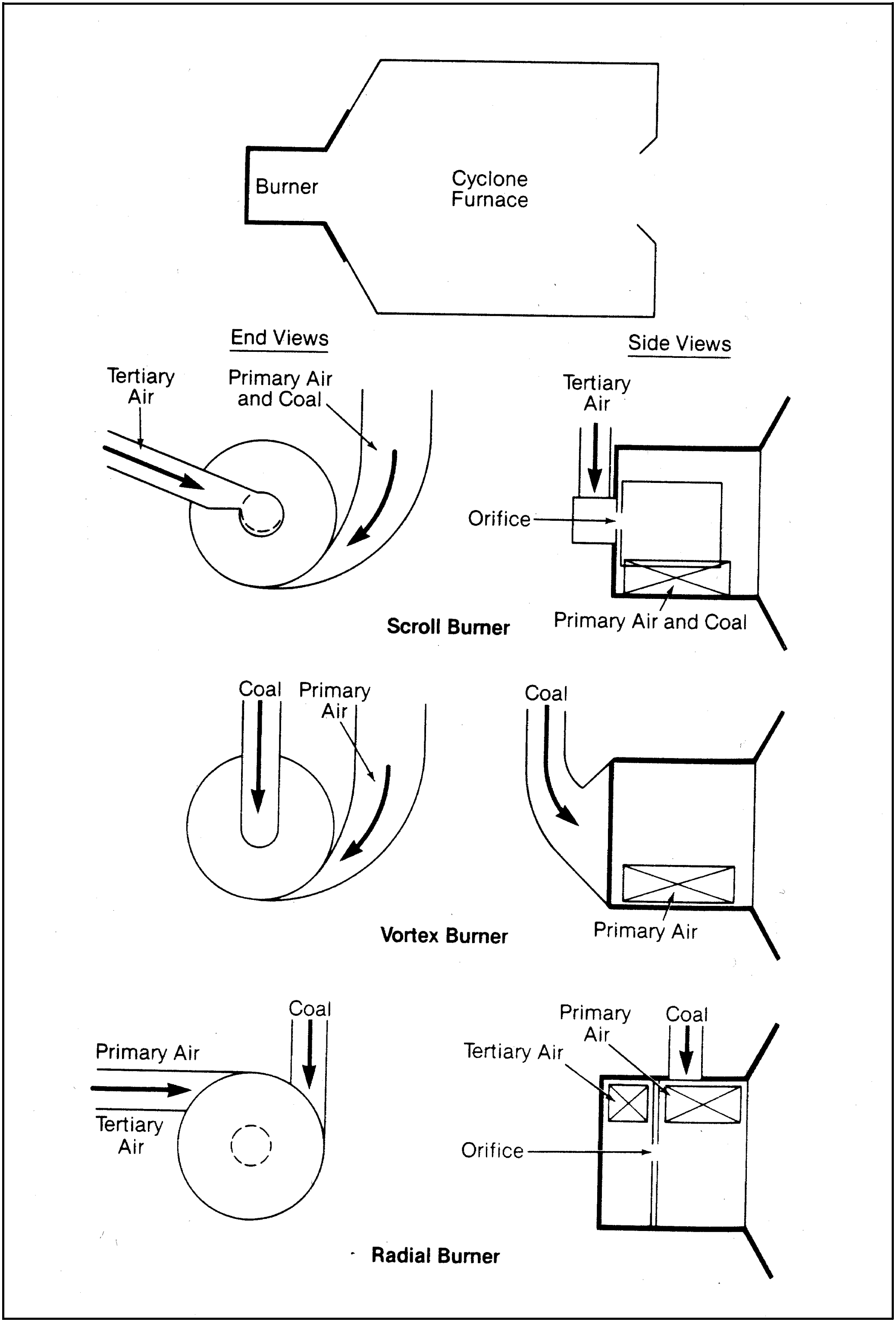
Figure 7: Stoker Coal Feeder



Source: *Standard Handbook of Power Plant Engineering*. Elliot, Thomas C. ed. McGraw-Hill, Inc. New York NY. 1989. Reproduced with permission of the McGraw-Hill Companies.

In a cyclone-fired furnace, fuel is fired under intense heat and air is injected tangentially to create a swirling motion as shown in Figure 8. The resulting hot gases exit through the cyclone bore into the cyclone in the furnace. Ash becomes a molten slag that is collected below the furnace. Coal is the primary cyclone fuel, but oil and gas are used as startup, auxiliary, and main fuels.

Figure 8: Typical Cyclone Coal Burners

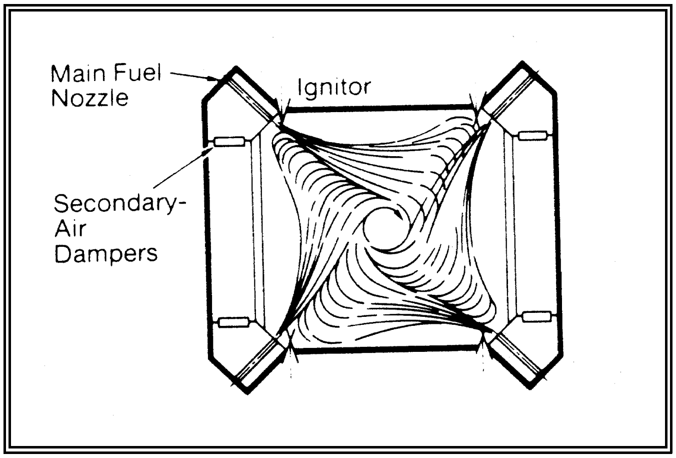


Source: *Steam, Its Generation and Use*; 40th Edition. Stultz and Kitto, eds. Babcock and Wilcox, Barbeton, OH. 1992. Reproduced with permission from the Babcock and Wilcox Co.

Tangential-Fired Furnace

In a tangential-fired furnace, both air and fuel are projected from the corners of the furnace along lines tangent to a vertical cylinder at the center. A rotating motion is created, allowing a high degree of mixing. This system provides great flexibility for multiple fuel firing (see Figure 9).[16]

Figure 9: Tangential Firing Pattern

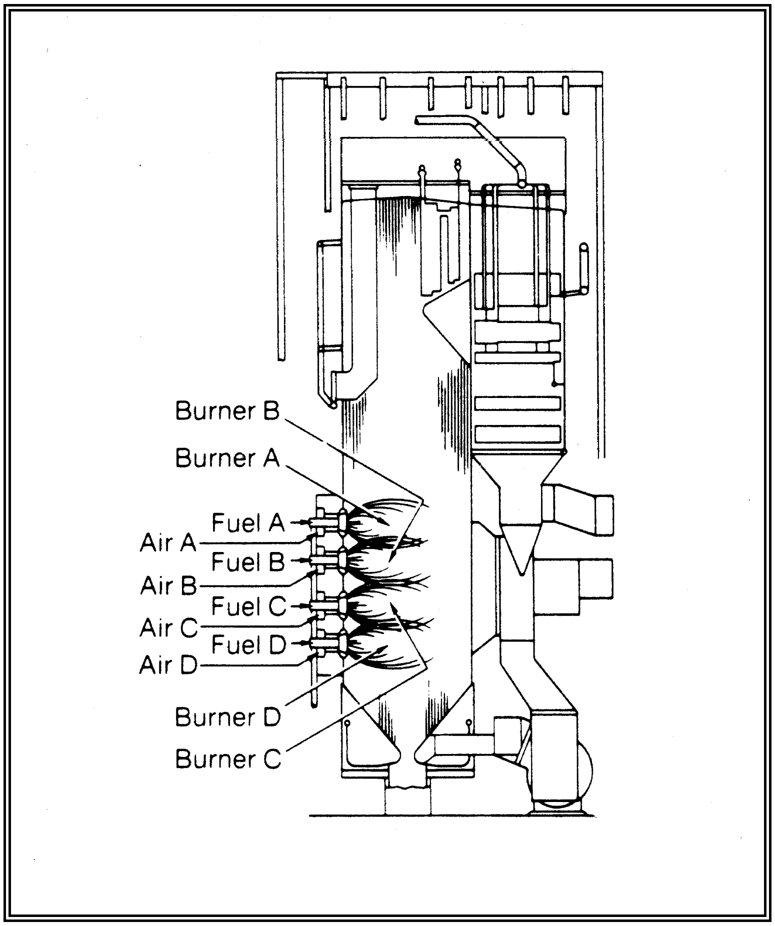


Source: *Standard Handbook of Power Plant Engineering*. Elliot, Thomas C. ed. McGraw-Hill, Inc. New York, NY. 1989. Reproduced with permission of the McGraw-Hill Companies.

Horizontal or Wall-Fired Furnace

In horizontal or wall-fired systems, pulverized coal and primary air are introduced tangentially to the coal nozzle. The degree of air swirl and the contour of the burner throat establish a recirculation pattern extending several throat diameters into the furnace. The hot products of combustion are directed back toward the nozzle to provide the ignition energy necessary for stable combustion. In this system, burners are located in rows on the front wall (see Figure 10) or both front and rear walls.[17]

Figure 10: Flow Pattern of Horizontal Firing



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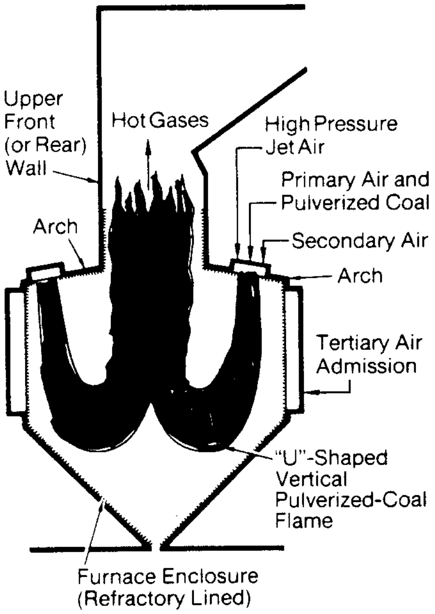
Arch-Fired Systems

Vertical-fired systems are used to fire solid fuels that are difficult to ignite, such as coals with moisture and ash-free volatile matter of less than 13 percent. In this system, the pulverized coal is discharged through a nozzle surrounded by heated combustion air. High-pressure jets are used to prevent fuel-air streams from short circuiting. The firing system produces a looping flame with hot gases discharging at the center (see Figure 11).[18]

Figure 11: Flow Pattern of Arch Firing



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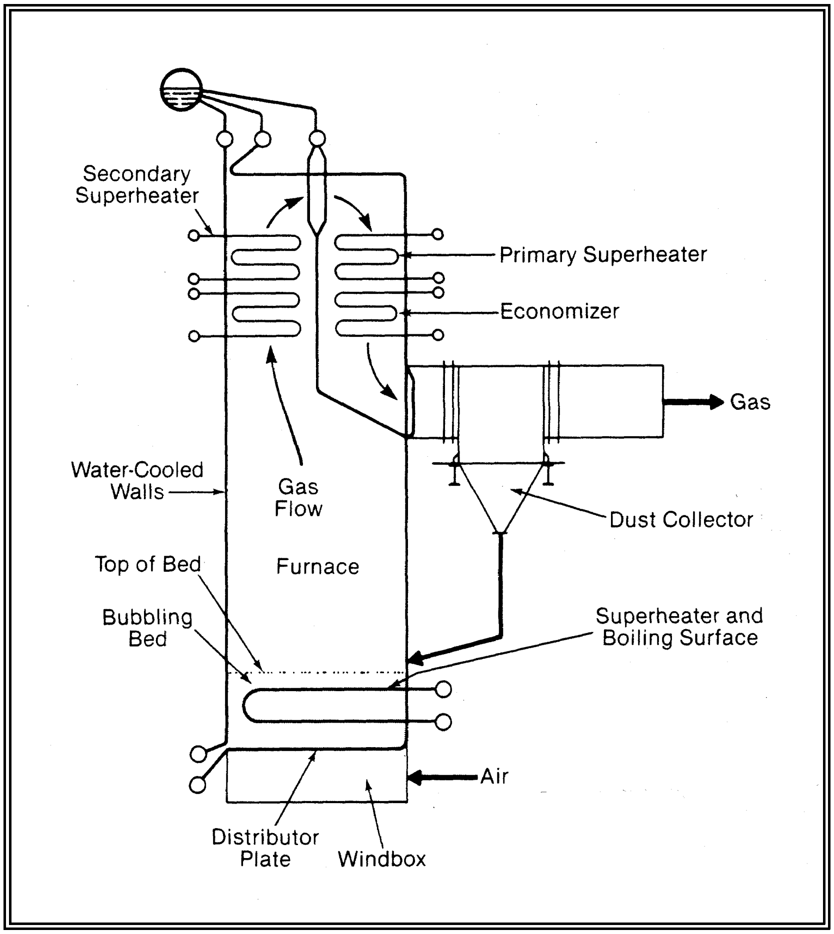
Fluidized-Bed Combustors

In fluidized-bed combustors, fuel materials are forced by gas into a state of buoyancy. The gas cushion between the solids allows the particles to move freely, thus flowing like a liquid. By using this technology, SO_2 and NO_X emissions are reduced because an SO_2 sorbent, such as limestone, can be used efficiently. Also, because the operating temperature is low, the amount of NO_X gases formed is lower than those produced using conventional technology.

Fluidized-bed combustors are divided into two categories: circulating fluidized-beds and bubbling fluidized-beds (see Figure 12). Fluidized-bed combustors can operate at atmospheric pressure or in a pressurized chamber. In the pressurized chamber, operating pressures can be 10 to 20 times the atmospheric pressure. Pressurized fluidized-bed furnaces provide significant gain in overall thermal efficiency over atmospheric fluidized-bed furnances. [19]

Figure 12: Typical Bubbling Fluidized-Bed Boiler



Source: Adapted from *Steam, Its Generation and Use*; 40th Edition. Stultz and Kitto, eds. Babcock and Wilcox, Barbeton, OH. 1992. Reproduced with permission from the Babcock and Will Cox. Co.

Fluidized-bed combustion allows for the use of high sulfur coals, high fouling and slagging fuels, and low British Thermal Unit (BTU) fuels. High ash coals burned in fluidized-beds require less preparation than in pulverized coal combustors. Additionally, fluidized-bed combustors require less maintenance than pulverized coal combustors.

III.A.2 Internal Combustion Generation

Internal combustion generating units, also known as diesel engines, have one or more cylinders in which fuel combustion occurs. Internal combustion generating units convert the chemical energy of fuels into mechanical energy in a design similar to an automobile engine. Attached to the shaft of the generator, the engine provides the mechanical energy to drive the generator to produce electricity. Internal combustion generating units for power plants are typically designed to operate on either four- or two-stroke cycles.

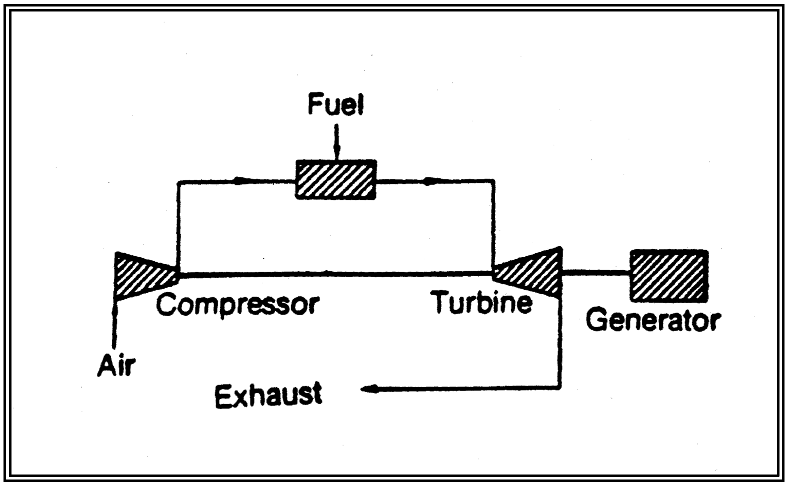
Internal combustion generators are small and range in capacity from 2 to 6 megawatts. They are more efficient than gas turbines.[20] In addition, capital costs are low, they are easily transported, and they can generate electricity almost immediately upon startup. For this reason, internal combustion generators are often used for small loads and for emergency power.[21]

III.A.3 Gas Turbine Generation

Gas turbine systems operate in a manner similar to steam turbine systems except that combustion gases are used to turn the turbine blades instead of steam. In addition to the electric generator, the turbine also drives a rotating compressor to pressurize the air, which is then mixed with either gas or liquid fuel in a combustion chamber. The greater the compression, the higher the temperature and the efficiency that can be achieved in a gas turbine. Exhaust gases are emitted to the atmosphere from the turbine. Unlike a steam turbine system, gas turbine systems do not have boilers or a steam supply, condensers, or a waste heat disposal system. Therefore, capital costs are much lower for a gas turbine system than for a steam system.

In electrical power applications, gas turbines are typically used for peaking duty, where rapid startup and short runs are needed. Most installed simple gas turbines with no controls have only a 20- to 30-percent efficiency. Figure 13 presents a schematic of a simple gas turbine system.

Figure 13: Simple Gas Turbine Cycle

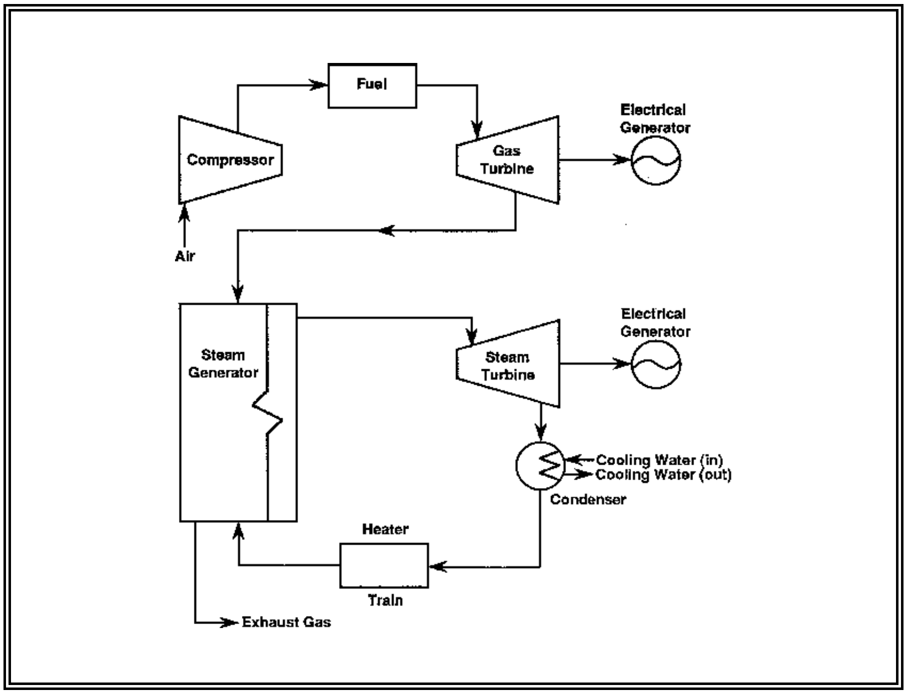


Source: *Standard Handbook of Power Plant Engineering*. Elliot, Thomas C. ed. McGraw-Hill, Inc. New York, N.Y. 1989.

III.A.4 Combined-Cycle Generation

Combined-cycle generation is a configuration using both gas turbines and steam generators. In a combined-cycle gas turbine (CCGT), the hot exhaust gases of a gas turbine are used to provide all, or a portion of, the heat source for the boiler, which produces steam for the steam generator turbine. This combination increases the thermal efficiency over a coal- or oil- fueled steam generator. The system has an efficiency of about 54 percent, and the fuel consumption is approximately 25 percent lower. Combined-cycle systems may have multiple gas turbines driving one steam turbine (see Figure 14).[22]

Figure 14: Combined Cycle with Heat Recovery



There are four major classifications of combined-cycle facilities:

- **Gas Turbine Plus Unfired Steam Generator**: A steam generator is installed at the discharge of a gas turbine to recover the heat in the gas turbine exhaust so as to create steam in the steam generator. The fuel is fired only in the gas turbine.

- **Gas Turbine Plus Supplementary-Fired Steam Generator**: A portion of the oxygen in the gas turbine exhaust is used to support further combustion in a supplementary firing system in the connecting duct between the gas turbine and the steam generator.

- **Gas Turbine Plus Furnace-Fired Steam Generator**: This generator is the same as the gas turbine plus supplementary-fired steam generator, except that essentially all of the oxygen from the gas turbine exhaust is used to support further combustion.

- **Supercharged Furnace-Fired Steam Generator Plus Gas Turbine**: A steam generator is placed between the air compressor and the gas turbine. The air compressor is used to pressurize the boiler where the fuel is fired. The products of combustion that have been cooled within the boiler are then discharged through a gas turbine.

In addition, integrated coal gasification combined-cycle (IGCC) units are combined systems that are in the demonstration stage, but are expected be in commercial operation by the year 2000. In an IGCC system, coal gas is manufactured and cleaned in a “gasifier” under pressure, thereby reducing emissions and particulates. The coal gas then is combusted in a CCGT generation system.

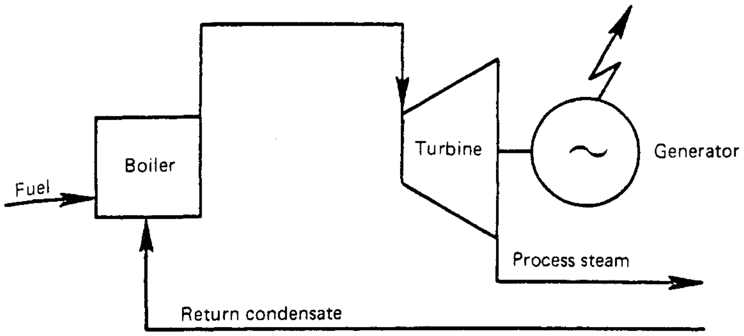
III.A.5 Cogeneration

Cogeneration is the merging of a system designed to produce electric power and a system used for producing industrial heat and steam. Cogeneration accounted for 75 percent of all nonutility power generation in 1995.[23] This system is a more efficient way of using energy inputs and allows the recovery of otherwise wasted thermal energy for use in an industrial process. Cogeneration technologies are classified as “topping cycle” and “bottoming cycle” systems, depending on whether electrical (topping cycle) or thermal (bottoming cycle) energy is derived first.

Most cogeneration systems use a topping cycle. This is shown as a steam turbine topping system in Figure 15. The process steam shown in Figure 15 is condensed as it delivers heat to an industrial process, and the resulting return condensate is returned back to the boiler as shown.

Facilities that cogenerate may be eligible for QF status under PURPA. To qualify, the facility must produce electric energy and “another form of useful thermal energy through sequential use of energy,” and meet certain ownership, operating, and efficiency criteria established by FERC (See 18 CFR Part 292). In a topping cycle system, the fuel is used to generate power with a steam boiler or gas turbine cycle combustor. The waste heat from the power generation process is then used in an industrial process.[24]

Figure 15: Cogeneration Plant Schematic



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III.A.6 Supporting Operations

Many operations associated with fossil fuel electric power generation facilities are not directly involved in the production of electricity but serve in a supporting role. This section discusses some of the major supporting processes.

Coal Processing

Fifty-seven percent of coal used in power plants is transported from mines by rail.[25] Coal is also transported by truck and barge. Once coal arrives at the plant, it is unloaded to live storage, dead storage, or directly to the stoker or hopper. Live storage is an enclosed silo or bunker next to conveyors leading to the pulverizer. Dead storage is exposed outdoors and is the backup supply. Coal unloading devices depend on the size and type of plant. Coal arriving by rail may be unloaded directly into the storage area or to conveyors leading directly to generation units. Coal arriving by barge is unloaded by buckets, which are part of coal towers or unloading bridges.[26] Coal shipped by truck generally needs little equipment for unloading.

Precautions must be taken in the transportation and storage of coal. In transporting coal during warmer months and in dry climates, dust suppression may be necessary. Dust suppression is typically accomplished through the use of water, oil, or calcium chloride ($CaCl_2$). In winter months, antifreeze chemicals are applied to the coal. Because coal oxidizes easily in open air, it should be stored in layered piles to minimize air flow. Hot areas should be removed from the pile to prevent fire; water should not be added to reduce the heat, since the water increases the air flow and, therefore, would increase the oxidation of the coal.

Coal may be cleaned and prepared before being either crushed or pulverized. Impurities in coal, such as ash, metals, silica, and sulfur, can cause boiler fouling and slagging. Coal cleaning can be used to reduce sulfur in the coal to meet sulfur dioxide (SO_2) emissions regulations. Cleaning the coal is a costly process that increases its fuel efficiency, yet reduces the size of the particles. Coal cleaning is typically performed at the mine by using gravity concentration, flotation, or dewatering methods. Some smaller stoker plants purchase pre-cleaned, pre-crushed coal.[27]

Coal is transported from the coal bunker or silo to be crushed, ground, and dried further before it is fired in the burner or combustion system. Many mechanisms can be used to grind the coal and prepare it for firing. Pulverizers, cyclones, and stokers are all used to grind and dry the coal. Increasing the coal's particle surface area and decreasing its moisture content greatly increases its heating capacity. Once prepared, the coal is transported within the system to the combustion system, or boiler. Devices at the bottom of the boilers catch ash and/or slag.

Air Pollution Control Processes

Air pollution control devices found in fossil fuel-fired systems (particularly steam electric power facilities) include particulate removal equipment, sulfur oxide (SO_X) removal equipment, and nitrogen oxide (NO_X) removal equipment. Particulate removal equipment includes electrostatic precipitators, fabric filters, or mechanical particulate collectors, such as cyclones. SO_X removal equipment includes sorbent injection technologies and wet and dry scrubbers. Both types of scrubbers result in the formation of calcium sulfate and sulfite as waste products. NO_X emission control systems include low NO_X burners and selective catalytic or non-catalytic reduction technologies. The selective catalytic and non-catalytic reduction technologies convert oxides of nitrogen into nitrogen gas and water.

Other Processes to Mitigate Environmental Impacts

Control technologies are used at many utility electric power generation facilities to mitigate the environmental impacts of cooling water intake structures. These technologies may include intake screening systems, passive intake system (physical exclusion devices), or fish diversion and avoidance systems. Technologies used to mitigate thermal pollution include cooling towers, cooling ponds or lakes, and sprinklers. Other control technologies may include recycling and reuse equipment for metals recovery; evaporators; and physical, chemical, and biological wastewater treatment.

III.B Raw Material Inputs and Pollution Outputs

The primary raw material used in fossil fuel electric power generation is the fossil fuel needed as the energy source to drive the prime mover (i.e., turbine). Fossil fuels employed in the United States predominantly include coal, petroleum, and gas. Other inputs include water (for cooling and steam generation) and chemicals used for equipment cleaning and maintenance. Pollution outputs include solid waste pollution, wastewater pollution, air pollution, and thermal pollution. The following subsection discusses the major sources of raw materials and the sources of emissions associated with the power generation industry.

III.B.1 Fossil Fuels and Other Raw Material Inputs

The major types of fossil fuels used for electricity generation in the United States are coal, petroleum, gas. Other fossil fuels used include petroleum coke, refinery gas, coke oven gas, blast furnace gas, and liquefied petroleum gas. These latter fuels are used much less frequently and, therefore, will not be discussed in this notebook.

Coal

Coal is the most abundant fossil fuel in the United States and the most frequently used energy source for U.S. electricity generation. More than one-half of all electricity generated by utilities comes from coal-fired facilities.[28] Although the use of coal has decreased since the 1970s, some areas of the country use coal almost exclusively.

Coals used for electric power generation are very heterogeneous and vary in content, depending on the location of the mine. The major chemical makeup, which includes carbon, hydrogen, and oxygen, also contains impurities, such as minerals and sulfur. These impurities are a major concern because they contribute to the pollutants produced during combustion of the coal.

Of all the fossil fuel used for electricity generation, coal requires the most extensive processing, handling, storage, and loading and unloading facilities. Coal firing requires the use of crushers, pulverizers, ash handling equipment, dust control, emissions control equipment, and soot blowers.

Petroleum

Petroleum, or crude oil, is the source of various fuel oils used as the energy source for power generation. As an energy source, petroleum accounts for less than five percent of all electricity receipts in the United States. However, numerous utilities in the New England States, New York, Florida, and Hawaii still rely on petroleum as an energy source.[29]

Most petroleum used for power generation is refined prior to use. Typical fuel oils include fuel oil numbers 4, 5, and 6 (heavy oil) and constitute the majority of all petroleum receipts at electric utilities. Smaller amounts of fuel oil number 2 (light oil) are used typically for startup and flame stabilization of the boilers.[30] Other less frequently used sources include topped crude, kerosene, and jet fuel.

Fuel oils used for electricity generation require special handling, storage, and loading and unloading facilities. Oil requires ash handling equipment, dust control, emissions control equipment, soot blowers, and, in some instances, warming and heating facilities.

Gas

Gas is used less than coal as a primary fuel source at power generation utilities. Gas is widely used for industrial electric power generation, however. Gas is used in those areas of the United States where it is readily accessible or in States in which environmental laws for air emissions are stringent (e.g., California). Many of the facilities that use gas also use petroleum in dual-fired generating units. The use of one fuel over the other is based on economics.

Natural gas must be treated to produce commercial fuel. Natural gas comprises primarily methane and ethane. Natural gas suitable for use as a fuel in power generation facilities must be at least 70-percent methane, 60-percent propane, or 25-percent hydrogen. The fuel may come in either a gaseous or liquid form.[31]

Gas has one advantage over other fuels in that it is a cleaner burning fuel. Therefore, some electric utilities use gas in order to comply with environmental regulations. Gas used for generating electricity requires relatively little special handling (piping) and may or may not require storage facilities.

Other Inputs

In addition to fossil fuels, electric power generation requires other material inputs. These inputs include (1) water for steam condensation and equipment cooling, (2) lime or limestone, as a sorbent for pollution control equipment, (3) chlorine and/or biocides to prevent biofouling of steam condensers and cooling towers, (4) chemical solvents, oils, and lubricants for equipment cleaning and maintenance.

III.B.2 Pollutant Outputs

Pollutants are generated as byproducts from the burning of fossil fuels to generate electricity. The combustion process releases highly regulated pollutants, such as NO_X, carbon monoxide (CO), particulate matter (PM), SO_2, volatile organic compounds (VOCs), organic hydrocarbons, and trace metals, into the air. Combustion waste, the majority of which is ash waste, is created during combustion processes using coal or oil for fuel. Non-combustion wastes, such as cooling, process, and storm waters, that are discharged from fossil fuel electric power generation facilities have the potential to release pollutants (e.g., chlorine, heavy metals, and thermal pollution) into surface waters. The following discussion highlights each of the waste streams created during the generation of fossil fuel electric power.

Air Emissions

Air emissions from the stack gases from coal- and oil-fired boilers include four of six criteria pollutants regulated through the National Ambient Air Quality Standards (NAAQS) under the Clean Air Act (CAA) as amended: NO_X, CO, SO_2, and PM. Amounts of SO_2 emitted depend largely on the amount of sulfur present in the coal or oil and the method used to generate steam.

Other emissions regulated by the CAA commonly contained in emission gases are total organic carbon (TOC) as methane, non-methane hydrocarbons (NMHC), and VOCs. Traces of lead, another criteria pollutant, and other metals and minerals are also found. These metals are present in the coal and oil. Sulfur is also found in these fuels (more in coal than in oil), and fly ash is the product of sulfur and other mineral materials that do not combust.

Fugitive dust from coal piles and fuel handling equipment is another source of particulates. In addition, fugitive emissions of VOCs can arise from coal piles during low temperature devolatilization. Thermal rise plumes are also discharged from cooling towers. These plumes contain such pollutants as heat and some trace materials in the water vapor.

Compared to a fossil-fueled steam turbine generating system with no air pollution controls, a gas-fired power generation system with no controls emits less tonnage of NO_X and SO_2 and trace amounts of TOC, particulate matter, and CO.

Combined-cycle gas turbines have virtually no SO_2 emissions because of the purity of natural gas. Because oil and coal are not used, solid waste is eliminated, and CO_2, NO_X, and thermal pollution are cut by 60 percent.

Cogeneration is considered a pollution prevention technology. Other benefits of cogeneration are reduced fuel consumption and lower air emissions. Because of their smaller size, however, cogeneration systems in the United States tend to have lower stack heights. Therefore, air emissions to the immediate atmosphere contribute to increased local pollution.

Combustion Wastes

Two principal wastes are associated with the combustion of fossil fuels: ash waste and flue gas desulfurization (FGD) wastes. The quantities of these wastes generated depend upon the fossil fuel burned.

Ash waste -Two types of ash are generated during combustion of fossil fuels: bottom ash and fly ash. Ash that collects at the bottom of the boiler is called bottom ash and/or slag. Fly ash is a finer ash material that is borne by the flue gas from the furnace to the end of the boiler. Bottom ashes are collected and discharged from the boiler, economizer, air heaters, electrostatic precipitator, and fabric filters. Fly ash is collected in the economizer and air heaters or is collected by the particulate control equipment. Coal-fired facilities generate the largest quantity of ash; gas facilities generate so little that separate ash management facilities are not necessary. Fly and bottom ash may be managed separately or together in landfills or in wet surface impoundments.

Ashes differ in characteristics depending upon the content of the fuel burned. For coal, the chemical composition of ash is a function of the type of coal that is burned, the extent to which the coal is prepared before it is burned, and the operating conditions of the boiler. These factors are very plant- and coal-specific. Generally, however, more than 95 percent of ash is made up of silicon, aluminum, iron, and calcium in their oxide forms, with magnesium, potassium, sodium, and titanium representing the remaining major constituents. Ash may also contain a wide range of trace constituents in highly variable concentrations. Potential trace constituents include antimony, arsenic, barium, cadmium, chromium, lead, mercury, selenium, strontium, zinc, and other metals.

Flue gas desulfurization waste - If coal or oil is the fuel source, the FGD control technologies result in the generation of solid wastes. Wet lime/limestone scrubbers produce a slurry of ash, unreacted lime, calcium sulfate, and calcium sulfite. Dry scrubber systems produce a mixture of unreacted sorbent (e.g., lime, limestone, sodium carbonates, calcium carbonates), sulfur salts, and fly ash. Sludges are typically stabilized with fly ash. Sludges produced in a wet scrubber may be disposed of in impoundments or below-grade landfills, or they may be stabilized and disposed of in landfills. Dry scrubber sludges may be managed dry or wet.

Non-Combustion Wastes

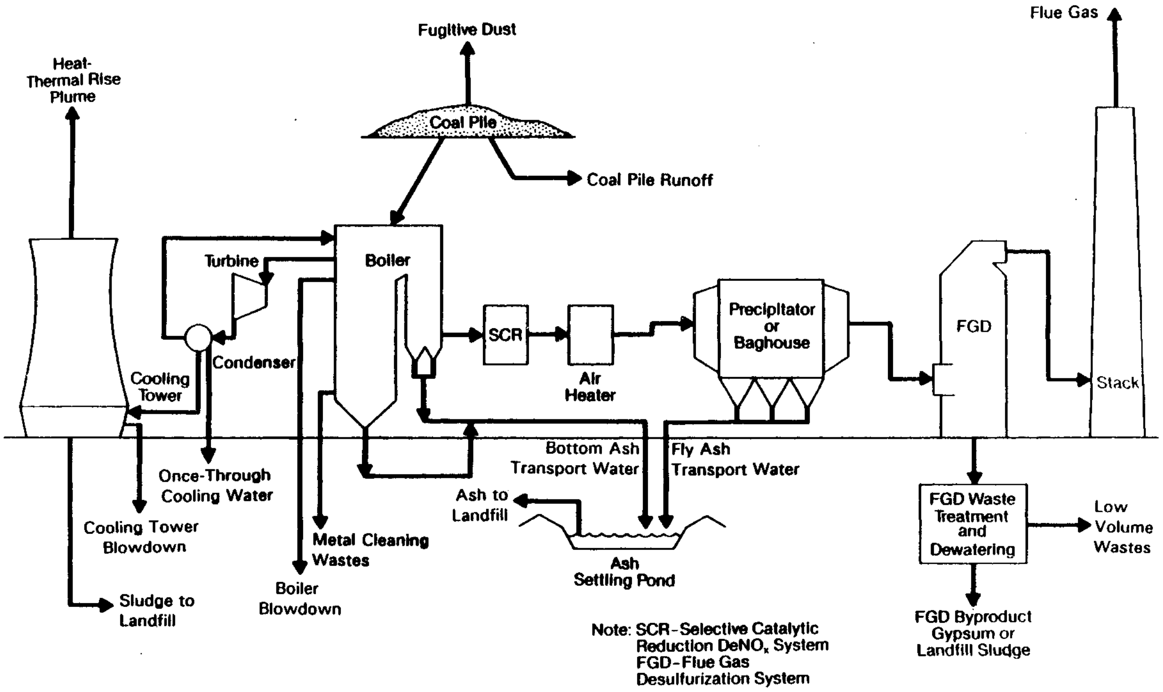
Non-combustion wastes can be categorized into contact and noncontact wastes. Contact wastes come in contact with combustion wastes and, therefore, contain the same constituents as the combustion wastes. In many cases, these contact wastes are managed with the combustion wastes. Non-contact wastes do not come in contact with ashes or FGD wastes and may be managed separately. Table 13 summarizes the typical waste streams, potential pollutants, and ways of managing these pollutants. Figure 16 shows where the waste streams are generated at a typical steam electric power plant.

Table 13: Summary of Typical Waste Streams and Pollutants Generated at Fossil Fuel Electric Power Generation Facilities Based on Fuel Type

Fuel Type	Wastes/Pollutant	Air Emissions	Combustion Wastes	Non-Combustion Wastes
Coal	Process wastes	Flue gas and heat - thermal rise plume.	Bottom ash, fly ash, and FGD wastes desulfurization, and fly ash.	*Contact*[†]*:* ash transport, gas-side boiler cleaning,* FGD blowdown, coal pile runoff, pyrite waste, floor drains. *Noncontact:* once-through cooling water,* cooling system blowdown,* boiler blowdown,* water-side boiler cleaning,* demineralizer regenerent.*
	Pollutants	SO_2, NO_X, CO_2, CO (more from small boilers), VOCs, TOC, PM, metals, sulfur.	Heavy metals, ferrous sulfate, sulfuric acid, sulfate, $CaSO_3$, and CaO.	Chlorine, organic chemicals, metals, pH, TSS, TDSS, ferrous sulfate, sulfuric acid, metals, pyrite.
Oil	Process wastes	Flue gas and heat - thermal rise plume.	Bottom ash and fly ash.	*Contact*[†]*:* ash transport, gas-side boiler cleaning,* FGD blowdown, floor drains. *Noncontact:* once-through cooling water,* cooling system blowdown,* boiler blowdown,* water-side boiler cleaning,* demineralizer regenerent.*
	Pollutants	Low SO_2, NO_X (as NO_X particulate), CO_2, sulfur, and PM compared to coal. Metals and TOC.	VOCs and heavy metals.	Chlorine, organic chemicals, metals, pH, TSS, TDSS, ferrous sulfate, sulfuric acid, metals.
Gas	Process wastes	Flue gas.	None.	*Contact*[†]*:* infrequent gas-side boiler cleaning,* floor drains. *Noncontact:* once-through cooling water,* cooling system blowdown,* boiler blowdown,* water-side boiler cleaning,* demineralizer regenerent.*
	Pollutants	Low No_X, and SO_2 compared to oil and coal. Thermal pollution is 60% less than coal.	None.	Chlorine, organic chemicals, metals, pH, TSS, TDSS, metals.

*** Waste streams at facilities with steam turbines. † In contact with combustion wastes.**

Figure 16: Waste Streams Generated at a Typical Fossil Fuel Electric Power Generation Plant



Source: Adapted from Steam, Its Generation and Use, 40th Edition. Stultz and Kitto, eds. Babcock and Wilcox, Barbeton, OH. 1992. Reproduced with permission from the Babcock and Wilcox Co.

Contact, Non-Combustion Wastes

Metal and boiler cleaning waste (gas-side) - Gas-side metal and boiler cleaning wastes are produced during maintenance of the gas-side of the boiler, including the air preheater, economizer, superheater, stack, and ancillary equipment. Residues from coal combustion (soot and fly ash) build up on the surfaces of the equipment and must be removed periodically. This buildup is typically removed with plain, pressurized water containing no chemical additives. Wastewaters are sometimes neutralized and metals precipitated. At coal plants, the wastewater is most often put into the ash ponds without treatment.

Ash transport wastewater - Ash produced from the combustion of coal or oil is typically collected in a sluice water that is then sent to settling ponds for disposal. The ash settling pond discharge may contain dissolved and suspended solids, heavy metals (nickel, iron, vanadium), organometalic compounds, and magnesium compounds when magnesium oxides are used for corrosion control.

Flue gas desulfurization blowdown - Blowdown from FGD systems is discharged when the recycled liquor begins to build up chlorine. The discharge contains calcium sulfate, calcium chloride, and sodium chloride. Depending upon fly ash carryover, the wastewater may contain metal ions.

Coal pile runoff - Open storage of coal allows contact with rain and/or other precipitation. These storm waters react with the minerals in the coal to produce a leachate contaminated with ferrous sulfate and sulfuric acid. The low pH of the leachate reacts with the coal, thereby accelerating dissolution of metals in the coal.

Pyrite waste - Coal mills or pulverizers reduce the size of the feed coal going into the boiler. During this process, various impurities, such as hard coal, rocks, and pyrites (an iron-based mineral), are mechanically separated from the feed stream. This solid waste is typically collected and fed into the bottom ash transport system and eventually co-disposed with the ash in either a landfill or an impoundment.

Floor drains - Floor and yard drains collect rainfall, seepage, leakage wastewaters from small equipment cleaning operations, process spills, and leaks. As a result, the pollutants found in the wastewaters are variable. The waste streams may contain coal dust, oil, and detergents.

<u>Noncontact, Non-combustion Wastes</u>

Once-through cooling water - When a steam turbine is used to drive the electric generator the process is called “steam electric.” Steam electric units require large amounts of cooling water for steam condensation and efficient thermal operation. The cooling water flow rate through the condenser is by far the largest process water flow, normally equating to about 98 percent of the total process water flow for the entire unit. In a once-through cooling water system, water is usually taken into the plant from surface waters, but sometimes ground waters or municipal supplies are used. The water is passed through the condenser where it absorbs heat and is then discharged to a receiving water. Chlorine, which is added intermittently to the cooling water to control biofouling, is a pollutant of concern in cooling water discharge. Heat is also a concern.

Cooling tower blowdown - Cooling water is recirculated when the water supply is inadequate to sustain a once-through system or when thermal discharges are regulated or undesirable. In a system that recirculates cooling water, heat from the water is transferred to the atmosphere via cooling towers, cooling ponds, or spray facilities. The recirculated water eventually builds up dissolved solids and suspended matter. Cooling tower blowdown (a percentage of the recirculated water) is discharged regularly and additional fresh makeup water is treated and added into the recirculating system to relieve this buildup of solids. Pollutants of concern in cooling tower blowdown discharges include chlorine, organic chemicals, and trace metals from biofouling and corrosion control.

Boiler blowdown - Water to make steam may be recirculated and eventually build up impurities in the boiler. This water is periodically purged from the system. Boiler blowdown is typically alkaline, is low in total dissolved solids, and contains chemical additives used to control scale and corrosion. Blowdown also contains trace amounts of copper, iron, and nickel.

Metal and boiler cleaning waste (water-side) - Metal cleaning wastes are produced during cleaning of the boiler tubes, superheater, and condenser located on the water-side or steam-side of the boiler. Scale and corrosion products build up in the boiler and must be removed with chemical cleaning using an acid or alkaline solution. The composition of the waste solvents depends on the construction material of the feedwater system, but largely consists of iron with lesser amounts of copper, nickel, zinc, chromium, calcium, and magnesium. Spent solvents may be treated in numerous ways: (1) neutralization and then discharge, (2) evaporation in other operating boilers onsite, (3) dedicated holding ponds, (4) mixing with rinsate and sending to ash impoundments, or (5) disposal offsite.

Demineralizer Regenerant - Boiler systems may require treatment of boiler makeup water prior to use. Ion exchange resins used in the treatment of the water accumulate cations and anions removed from the raw water. These resins are regenerated using a strong acid, such as sulfuric acid, or a strong base, such as sodium hydroxide. Regenerant wastes contain dissolved ions removed from the raw wastewater and excess acid or base. Often, the waste is directed into the ash impoundment for disposal or to a settling pond with other liquid wastes prior to discharge.

IV. WASTE RELEASE PROFILE

This section provides estimates and reported quantities of wastes released from the fossil fuel electric power generation industry. Currently, this information is not available from the Toxics Release Inventory (TRI) under the Emergency Planning and Community Right-to-Know Act (EPCRA). However, regulations promulgated on May 1, 1997, would require facilities that combust coal and/or oil for the purpose of generating power for distribution in commerce to begin reporting in 1999 (for the period from January 1 to December 31, 1998). Because TRI reporting is not currently required, other sources of waste release data have been identified for this profile.

This section comprises three subsections. The first section provides available data on releases of solid wastes from fossil fuel electric power generation facilities. The second section provides available data on releases to surface waters. A third section provides available data on releases of criteria pollutants and hazardous pollutants to the air.

IV.A Available Solid Waste Release Data for the Fossil Fuel Electric Power Generation Industry

As described previously, the primary solid waste releases from coal- and oil-fired steam electric facilities are fly ash and bottom ash produced during the combustion process. An increasing number of facilities must condition flue gases to remove sulfur compounds, which results in the generation of another solid waste typically referred to as FGD sludge. The following tables present aggregated ash and FGD sludge generation estimates for utility and nonutility steam electric facilities.

Table 14 presents the estimated quantity of fly and bottom ash (combined) for utility boilers in 1994. Coal ash figures have been derived from 1994 DOE, EIA Form EIA-767 utility survey responses. These responses are compiled by the Edison Electric Institute (EEI) in their *Power Statistics Database.*[32] The oil ash figures were developed by the Electric Power Research Institute (EPRI) based on utility-provided estimates, as well as extrapolations based on oil consumption and particulate collection efficiencies for individual plants. Gas-fired facilities are not presented in the table because gas combustion does not generate measurable quantities of particulate ash. In general, coal-fired utilities produce ash at approximately 10 percent of the fuel consumption rate. This high rate of production confirms that ash management can represent an important operational consideration at coal plants. In contrast, oil-fired utilities produce much less than 0.1 percent of the total ash produced by the coal-fired facilities. This figure reflects the low ash content of oil compared with coal, the typically lower requirements for particulate collection devices at coal-fired facilities, the small average particle size of oil ash, and the small contribution that oil currently makes to total U.S. electricity generation.

Table 14: Generation and Disposition of Utility Fly and Bottom Ash, 1994 (thousand short tons)

Fuel Type	Number of Plants	Quantity Sold	Quantity Removed by Contractor	Quantity Landfilled	Quantity Ponded	Quantity Used Onsite, Given Away, or Disposed of in Other Ways	Total Quantity Collected for the Record Year (1994)
Coal[*]	404	12,122	8,762	24,849	19,929	4,014	69,676
Coal/Gas	32	830	546	636	133	83	2,228
Coal/Nuclear	2	279	0	0	26	29	334
Coal/Oil	26	368	401	303	470	180	1,722
Coal/Oil/Gas	2	1	41	45	0	0	87
Coal/Wood	1	0	0	0	0	0	0
Subtotal Coal	**467**	**13,600**	**9,750**	**25,833**	**20,558**	**4,306**	**74,047**
Oil[**]	73	n/a	n/a	n/a	n/a	n/a	23
Totals	**540**	**13,600**	**9,750**	**25,833**	**20,558**	**4,306**	**74,070**

[*] Coal ash values provided in EEI *Power Statistics Database (1994 Data)*. Prepared by Utility Data Institute, McGraw-Hill, Washington, DC. 1995. Plants include only those reporting coal as primary or secondary fuel. Includes 88 facilities reporting zero waste generation: 26 facilities reported zero fuel consumption and 62 facilities did not exceed the capacity and/or ash generation reporting thresholds for the DOE EIA 767 Survey.

[**] Oil ash values are for 1995. Source: *Oil Combustion By-Products -- Chemical Characteristics and Management Practices: Draft Report.* Electric Power Research Institute, Palo Alto, California. March 1997.

Table 14 also indicates the range of management options employed by utilities in managing coal ash. While the figure varies considerable between operators and sites, roughly one-third of all U.S. utility coal ash finds its way to some type of beneficial use project. Of the material remaining in traditional disposal environments, the majority is managed in onsite impoundments or landfills. These units vary in size, design, and environmental controls, depending on the age, the State, and the operator.

Table 15 presents similar findings for utility FGD sludge generation and management. Again, the data reflect utility responses to the Form EIA-767, as compiled by EEI in the *Power Statistics Database*. Note that there are no oil-fired utility boilers equipped with FGD scrubbers. The quantity of FGD sludge generated at a given plant is a function of the sulfur content of the coal consumed, the total quantity of coal consumed, the type of scrubber

Table 15: Generation and Disposition of Utility FGD Sludge, 1994 (thousand short tons)

Fuel Type	Number of Plants	Quantity Sold	Quantity Removed by Contractor	Quantity Landfilled	Quantity Ponded	Quantity used onsite, given away, or disposed of in other ways	Total Quantity Collected for the record year (1994)
Coal	71	118	759	8,286	4,082	708	13,953
Coal/Gas	4	106	6	479	0	5	596
Coal/Nuclear	0	0	0	0	0	0	0
Coal/Oil	2	18	5	55	0	0	78
Coal/Oil/Gas	1	0	0	33	0	0	33
Coal/Wood	0	0	0	0	0	0	0
Totals	**78**	**242**	**770**	**8,853**	**4,082**	**713**	**14,660**

Source: EEI *Power Statistics Database (1994 Data)*. Prepared by Utility Data Institute, McGraw-Hill, Washington, DC. 1995.

employed, the efficiency of reaction of the scrubber, and other factors. The majority of FGD sludge is managed in onsite landfills or impoundments.

Table 16 presents an estimate of the 1990 coal ash generation by nonutility fossil fuel combustors, broken out by major industrial category. Based on EPA Office of Air and Radiation’s 1990 *Particulate Inventory Database (Version 3)*, the ash figures are derived from the estimated 1990 coal consumption and coal ash content for the boiler population. The table includes all coal combustors permitted as major sources of criteria pollutants under the CAA and, therefore, includes many combustors that do not produce electricity. The electric generators, however, may be expected to represent the largest of the nonutility combustors and the greatest portion of the fuel usage by that population, such that the estimates shown provide at least a fair picture of the ability of the population to generate ash.

Compared with the utility coal ash estimates presented above, the nonutility universe represents only roughly 5 percent of the total U.S. ash generation. This fact reflects the generally small boiler size and the small aggregate coal consumption represented by nonutility combustors. Two industry categories, paper and chemicals manufacturing, represent 50 percent of all nonutility coal consumption, with only five industry categories accounting for more than 80 percent of all nonutility coal consumption.

Table 16: Estimated Nonutility Generation of Coal Ash, 1990

Standard Industrial Classification	Number of Facilities	Number of Boilers	Total Capacity (MMBTU)	Estimated Ash Generation (1,000 tons)
2600-2699, Paper and Allied Products	139	243	61,348	1,189
2800-2899, Chemicals and Allied Products	116	276	54,031	1,025
3300-3399, Primary Metals Industries	45	85	20,344	500
2000-2099, Food and Kindred Products	94	151	21,391	402
4900-4999, Electric, Gas, and Sanitary Services	29	83	30,234	392
3700-3799, Transportation Equipment	57	162	14,581	125
2200-2299, Textile Mill Products	58	101	7,272	107
1400-1499, Mining and Quarrying of Non-Metallic Minerals, Except Fuels	7	15	6,620	76
3800-3899, Measuring, Analyzing, and Controlling Instruments	1	3	1,976	66
3000-3099, Rubber and Miscellaneous Plastic Products	20	37	3,779	63
TOTALS (Top Ten Ash Producing SIC Categories)	**566**	**1,156**	**221,576**	**3,945**
Percentage of Total Universe	**76**	**79**	**89**	**93**
TOTALS (Complete Nonutility universe)	**749**	**1,467**	**249,437**	**4,263**

Source: *Nonutility Fossil Fuel Combustion: Sources and Volumes - Revised Draft Report.* Prepared for U.S.EPA, Office of Solid Waste by Science Applications International Corporation, McLean, VA. December 1996.

As discussed previously, steam electric facilities may generate a variety of other solid wastes. These may include boiler and cooling water treatment wastes, coal mill rejects, boiler cleaning wastes, and a variety of smaller waste streams incidental to power generation of ancillary activities. At coal plants, these waste streams typically are small compared with ash and sludge generation. At oil- and gas-fired plants, they may represent the largest solid wastes present at the site. Unfortunately, available data sources do not provide credible estimates of the total quantity of these materials generated at utility and nonutility steam electric sites.

IV.B Available Water Release Information for the Fossil Fuel Electric Power Generation Industry

The EPA Office of Water, Office of Science and Technology, Engineering and Analysis Division, has collected water release data in evaluating the need for revisions to the 1982 Effluent Limitations Guidelines and Standards for the Steam Electric Point Source Category. The EPA has identified 53 chemicals (29 priority and 24 nonconventional) as pollutants of interest in wastewaters discharged from steam electric power generation facilities. These pollutants were identified in the EPA Permit Compliance System (PCS) database. The PCS is a computerized information management system maintained by the EPA Office of Enforcement. The PCS contains data on permit conditions, monitoring, compliance, and enforcement data for facilities regulated by the National Pollutant Discharge Elimination System (NPDES) Program. The information contained in the database is generally limited to only those facilities that have been classified as “major” by EPA based on factors such as effluent design flow and physical, chemical, and locational characteristics of the discharge. Information on facilities designated as “minor” is not required to be entered into the PCS database.

The data collected included 1992 records of pollutant releases from facilities with primary SIC codes 4911 and 4931. Approximately 512 facilities were identified in PCS as “major” steam electric facilities. Please note that facilities that use nuclear energy to drive steam turbines are also covered in the universe evaluated under this study. An option in the PCS system called Effluent Data Statistics (EDS) was used to generate the annual loading values. For the purposes of the effluent guideline study, the EDS-derived data were subjected to numerous refinements in an attempt to overcome limitations in the database. These refinements included review of the data by monitored facilities, as arranged by the Utility Water Act Group (UWAG) and the EEI. The industry still contends, however, that the loadings of pollutants in these data are over estimated.[33] Therefore actual loadings cannot be provided in this Sector Notebook.

Table 17 provides a list of the pollutants found in the 1992 PCS data for steam electric effluents.

Table 17: List of Pollutants Reported in 1992 PCS Data from Steam Electric Facilities *

Priority Pollutant	Pollutant	Priority Pollutant	Pollutant
	Iron	X	Trichloromethane
	Chlorine	X	Beryllium
	Aluminum		Ethylene glycol
	Boron		Nitrosomorpholine, N-
	Fluoride	X	Mercury
	Boric Acid	X	Pentachlorophenol
X	Zinc	X	Silver
	Barium	X	Thallium
	Magnesium	X	Antimony
X	Copper		Molybdenum
	Ammonia		Benzonitrile
	Iron Sulfate		Titanium
	Manganese		Polychlorinated biphenyls, NOS
X	Chromium, trivalent	X	Dichloromethane
X	Nickel	X	Tetrachloroethane
X	Lead		Dibenzofuran
X	Arsenic	X	Toluene
X	Chromium		Xylene
X	Selenium		Lithium
	Bromine	X	Benzene
	Hydrogen Sulfide	X	Ethylbenzene
X	Chromium, hexavalent	X	Phenanthrene
X	Cadmium	X	Pyrene
	Vanadium	X	PCB-1254
X	Cyanide	X	PCB-1260
X	Phenol	X	Chlorophenol, 2-
	Hydrazine		

* Based on estimated data supplied by members (representing 80 facilities) of the electric utility industry.

Source: *Preliminary Data Summary for the Steam Electric Point Source Category*. U.S. Environmental Protection Agency, Office of Water, Washington, D. C. July 1996. (EPA-921-R-96-010).

IV.C Available Air Emissions Data for the Fossil Fuel Electric Power Generation Industry

Three existing sources of data for estimating the releases to the air from the fossil fuel electric power generation industry were identified. The following sections discuss the available data and associated limitations.

IV.C.1 Annual Emissions Estimated by the Department of Energy, Energy Information Administration

Emissions data for traditional utility steam electric facilities that generate 10 or more megawatts electricity using fossil fuels are derived or obtained directly from information collected in an annual survey by the DOE EIA. This survey (Form EIA-767) is a restricted-universe census used to collect boiler-specific data from almost 900 electric utility power plants. The emissions are calculated based on fuel consumption data and using emission factors from the EPA report AP-42, *Compilation of Air Pollutant Emission Factors* and reduction factors for control equipment, where applicable. The CO_2 emissions are estimated using additional information about fuel quality. Table 18 provides the estimated 1995 emissions for utility fossil fuel steam electric generating units that generate 10 or more megawatts electricity.

Table 18: Estimated 1995 Emissions From Fossil Fuel Steam Electric Generating Units at Electric Utilities by Fuel Type (thousand short tons)

Fuel	Net Generation (thousand megawatts)	SO_2	NO_X	CO_2
Coal	1,652,914	11,248	6,508	1,752,527
Gas	307,306	1	533	161,969
Petroleum	60,844	321	92	50,878

Source: *Electric Power Annual 1995, Volume 2.* Energy Information Administration, Department of Energy, Washington, DC. DOE/EIA-0348(95)/2. December 1996.

As indicated in the table, the majority of the emissions from utility fossil fuel steam electric generating units come from coal-burning facilities. This is due in part because there is more coal-fired capacity than other fossil-fueled capacity in use. SO_2 emissions are higher in coal-burning facilities due to the higher sulfur content in coals than in other fuels. The average sulfur content in coals ranges from 0.3 percent in the West to approximately 2.5 percent in the East. Petroleum burned at utility power plants ranges from almost no sulfur to about 3.5 percent. The amount of sulfur contained in natural gas is relatively small.

The Form EIA-767 does not collect data for facilities employing internal combustion engines, gas turbines, or combined-cycle systems or steam electric plants generating less than 10 megawatts electricity. The EIA conducted a study in 1991 to estimate air emissions from these generating units, using a methodology similar to that used on the larger steam electric facilities. The study indicated that emissions of SO_2, $NO_{X,}$, and CO_2 are less than 0.1, 1.2, and 1.1 percent, respectively, of total utility air emissions.[34]

The EIA collects similar fuel consumption and quality information for nonutility power producers. However, EIA provides only aggregate statistics on estimated emissions for all fuels (fossil and renewable energy sources) and does not separate out emissions for fossil-fueled facilities. These statistics are not provided in this document since the capacity of nonutility generation using nonrenewable energy sources is large.

IV.C.2 AIRS Database Annual Estimated Releases for the Electric Power Generation Industry

The Aerometric Information Retrieval System (AIRS) is an air pollution data delivery system managed by the Technical Support Division in EPA's Office of Air Quality Planning and Standards (OAQPS), located in Research Triangle Park, North Carolina. The AIRS is a national repository of data related to air pollution monitoring and control. It contains a wide range of information related to stationary sources of air pollution, including the emission of a number of air pollutants that may be of concern within a particular industry. States are the primary suppliers of data to AIRS. Data are used to support monitoring, planning, tracking, and enforcement related to implementation by EPA staff, the scientific community, other countries, and the general public. The following criteria pollutant emissions and estimated TRI pollutant release data for the fossil fuel electric power generation industry were extracted from this database.

AIRS Estimated Criteria Pollutant Emissions

The AIRS database contains data on criteria pollutants: CO, NO_X, particulate matter (PM) of 10 microns or less (PM10), total particulate emissions (PT), SO_2, and VOCs. Criteria pollutant releases for the fossil fuel electric power generation industry were accessed using SIC codes 4911 and 4931. It should be noted that accessing the data using SIC codes does not allow the segregation of emissions for facilities that use fossil fuels from facilities that use nuclear, renewable, or a combination of fuels. Therefore, the annual emissions taken from the AIRS database will overestimate the emissions from the fossil fuel subsector of the power generation industry. Table 19 presents the criteria pollutant data available for this industry. Pollutant releases for other industries are also included in the table.

Table 19: Annual Air Pollutant Releases (tons/year)

Industry Sector	CO	NO_2	PM_{10}	PT	SO_2	VOC
Metal Mining	4,670	39,849	63,541	173,566	17,690	915
Nonmetal Mining	25,922	22,881	40,199	128,661	18,000	4,002
Lumber and Wood Production	122,061	38,042	20,456	64,650	9,401	55,983
Furniture and Fixtures	2,754	1,872	2,502	4,827	1,538	67,604
Pulp and Paper	566,883	358,675	35,030	111,210	493,313	127,809
Printing	8,755	3,542	405	1,198	1,684	103,018
Inorganic Chemicals	153,294	106,522	6,703	34,664	194,153	65,427
Organic Chemicals	112,410	187,400	14,596	16,053	176,115	180,350
Petroleum Refining	734,630	355,852	27,497	36,141	619,775	313,982
Rubber and Misc. Plastics	2,200	9,955	2,618	5,182	21,720	132,945
Stone, Clay and Concrete	105,059	340,639	192,962	662,233	308,534	34,337
Iron and Steel	1,386,461	153,607	83,938	87,939	232,347	83,882
Nonferrous Metals	214,243	31,136	10,403	24,654	253,538	11,058
Fabricated Metals	4,925	11,104	1,019	2,790	3,169	86,472
Electronics and Computers	356	1,501	224	385	741	4,866
Motor Vehicles, Bodies, Parts and Accessories	15,109	27,355	1,048	3,699	20,378	96,338
Dry Cleaning	102	184	3	27	155	7,441
Transportation	128,625	550,551	2,569	5,489	8,417	104,824
Metal Casting	116,538	11,911	10,995	20,973	6,513	19,031
Pharmaceuticals	6,586	19,088	1,576	4,425	21,311	37,214
Plastic Resins and Synthetic Fibers	16,388	41,771	2,218	7,546	67,546	74,138
Textiles	8,177	34,523	2,028	9,479	43,050	27,768
Fossil Fuel ElectricPower Generation	366,208	5,986,757	140,760	464,542	13,827,511	57,384
Ship Building and Repair	105	862	638	943	3,051	3,967

Source: U.S. EPA Office of Air and Radiation, AIRS Database, 1997.

AIRS Estimated TRI Pollutant Emissions

Data were collected from the AIRS database by the EPA Office of Pollution Prevention and Toxics, Environmental Assistance Division, Toxics Release Inventory Branch in support of the TRI expansion project discussed previously. The data set that was downloaded included the most recent data available for each facility up to and including 1995 data. The data presented in Table 20 are estimates of TRI releases based on air releases reported in the AIRS Facility Subsystem (AFS) from facilities within SIC codes 4911 and

4931. The data contain quantities of directly reported TRI chemicals, as well as quantities of additional TRI chemicals extrapolated from reported releases of PM and VOCs. The PM and VOC releases were matched with chemical profiles contained in the SPECIATE database (Version 1.5). The SPECIATE is a computerized format of the EPA Air Emissions Species Manual and is available for download from the Clearing House of Inventory and Emissions Factors (CHIEFs). The data presented are based only on apportionment of "original" species profiles in the SPECIATE database -- those species profiles that were developed specifically for the source of the release where it has been applied. Despite the use of only the highest quality profiles in the SPECIATE database, these data should only be used as a preliminary indication of potential releases and not as actual air releases. These data have been provided for illustrative purposes only and should not be used in comparisons with other release data.

IV.C.3 Hazardous Air Pollutant Emissions Estimates for Fossil Fuel Electric Utility Steam Generating Units

Estimates of hazardous air pollutant (HAP) emissions from fossil fuel electric utility steam generating units have been developed by OAQPS and are reported in a report entitled, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units - Interim Final Report* (Volumes 1-3).[35] These estimates are based on emissions test data from 52 units obtained from extensive emission tests by the EPRI, DOE, the Northern States Power Company, and EPA. The testing program covered a wide range of facility types with a variety of control scenarios. Therefore, the data are considered to be generally representative of fossil fuel utility steam electric generating units as a whole. This study estimated the average annual emissions for each of 684 power plants. A total of 67 HAPs were identified in the emission testing program as potentially being emitted from these facilities.

It should be noted that the report states that because of the small sample sizes for specific boiler types and control scenarios, there are uncertainties in the data. Therefore, the data for individual plants may either underestimate or overestimate the actual emissions. According to the report, the average annual emissions estimates will be roughly within a factor of plus or minus three of the actual annual emissions. However, it is recognized that the analysis had numerous limitations, such as not including data on potential upsets or unusual operating conditions, and it is possible that the range of uncertainty is greater. Tables 21, 22, and 23 present data on estimated inorganic HAPs from coal-fired, oil-fired, and gas-fired utility steam electric facilities. Tables 24, 25, and 26 present data on estimated organic HAPs from coal-fired, oil-fired, and gas-fired utility steam electric facilities.

Table 20: Estimated Releases of TRI Chemicals *		
CAS NO.	Chemical Name	Total Releases (pounds per year)
71556	1,1,1-Trichloroethane (Methyl chloroform)	52,923,638
79005	1,1,2-Trichloroethane	422,954
95636	1,2,4-Trimethylbenzene	264,682
106934	1,2-Dibromoethane (Ethylene dibromide)	1,820,797
95501	1,2-Dichlorobenzene	22,292
107062	1,2-Dichloroethane (Ethylene dichloride)	35,222,942
106990	1,3-Butadiene	7,443,883
541731	1,3-Dichlorobenzene	672
106467	1,4-Dichlorobenzene	378,018
112345	2-(2-Butoxyethoxy)ethanol	103,100
124174	2-(2-Butoxyethoxy)ethanol acetate	0
111900	2-(2-Ethoxyethoxy)ethanol	885,978
111773	2-(2-Methoxyethoxy)ethanol	0
111762	2-Butoxyethanol	21,929,191
110805	2-Ethoxyethanol	998,125
111159	2-Ethoxyethyl acetate	111,202
109864	2-Methoxyethanol	60
90437	2-Phenylphenol	8,507
101779	4,4'-Methylenedianiline	43
75070	Acetaldehyde	2,010,699
107028	Acrolein	1,528,324
79107	Acrylic acid	3,657
107131	Acrylonitrile	783,041
7429905	Aluminum (fume or dust)	75,792,629
7664417	Ammonia	43,518,590
62533	Aniline	311,982
120127	Anthracene	139,265
7440360	Antimony	1,789,097
7440382	Arsenic	9,329,119
1332214	Asbestos (friable)	8,123
7440393	Barium	1,435,995
56553	Benz(a)anthracene	1,839
71432	Benzene	149,967,605
218019	Benzo(a)phenanthrene	1,609
50328	Benzo(a)pyrene	1,381
100447	Benzyl chloride	0
7440417	Beryllium	10,997
92524	Biphenyl	85,493
7726956	Bromine	949,230
141322	Butyl acrylate	11,240
123728	Butylaldehyde	110,921
7440439	Cadmium	13,733,816

Table 20 (continued): Estimated Releases of TRI Chemicals *

CAS NO.	Chemical Name	Total Releases (Pounds per Year)
75150	Carbon disulfide	27,330,674
56235	Carbon tetrachloride	81,376
7782505	Chlorine	71,501,754
108907	Chlorobenzene	171,894
75456	Chlorodifluoromethane (HCFC-22)	162,070
75003	Chloroethane (Ethyl chloride)	31,182,710
67663	Chloroform	13,340
74873	Chloromethane (Methyl chloride)	178,484
126998	Chloroprene	57,294
75729	Chlorotrifluoromethane (CFC-13)	9,053
7440473	Chromium	2,632,999
7440484	Cobalt	211,262
7440508	Copper	3,058,579
8001589	Creosote	0
1319773	Cresol (mixed isomers)	239,994
98828	Cumene	725,684
110827	Cyclohexane	96,418,561
108930	Cyclohexanol	6,031
84742	Dibutyl phthalate	1,248,555
75718	Dichlorodifluoromethane (CFC-12)	97,414
75092	Dichloromethane (Methylene chloride)	1,414,455,336
76142	Dichlorotetrafluoroethane (CFC-114)	5,847
131113	Dimethyl phthalate	669,536
106898	Epichlorohydrin	66,000
140885	Ethyl acrylate	117,509
100414	Ethylbenzene	68,347,539
74851	Ethylene	53,298,159
107211	Ethylene glycol	76,627
75218	Ethylene oxide	541,571
7782414	Fluorine	6,068,173
50000	Formaldehyde	61,211,875
64186	Formic acid	467,279
76131	Freon 113 [Ethane, 1,1,2-trichloro-1,2,2,-trifluoro-]	7,587,241
7647010	Hydrochloric acid	5,809,931
78842	Isobutyraldehyde	109,758
67630	Isopropyl alcohol (mfg-strong acid process)	32,059,970
7439921	Lead	72,091,837
108383	m-Xylene	32,874,142
108316	Maleic anhydride	324,171
7439965	Manganese	2,969,118
7439976	Mercury	394,924
67561	Methanol	44,028,966

Table 20 (continued): Estimated Releases of TRI Chemicals *

CAS NO.	Chemical Name	Total Releases (Pounds per Year)
96333	Methyl acrylate	0
78933	Methyl ethyl ketone	91,926,327
108101	Methyl isobutyl ketone	20,020,683
80626	Methyl methacrylate	16,208
74953	Methylene bromide	52,241
101688	Methylenebis(phenylisocyanate) (MBI)	130
101688	Methylenebis(phenylisocyanate) (MDI)	130
76153	Monochloropentafluoroethane (CFC-115)	6,199
68122	N,N-Dimethylformamide	2,700,310
71363	n-Butyl alcohol	12,653,277
110543	n-Hexane	107,548,181
91203	Naphthalene	434,275
7440020	Nickel	7,884,920
7697372	Nitric acid	214,564
98953	Nitrobenzene	0
95476	o-Xylene	41,115,640
106423	p-Xylene	2,327,391
85018	Phenanthrene	84,032
108952	Phenol	15,017,545
7723140	Phosphorus (yellow or white)	7,980,941
85449	Phthalic anhydride	2,491,887
123386	Propionaldehyde	49,400
115071	Propylene (Propene)	45,955,707
75569	Propylene oxide	183,593
78922	sec-Butyl alcohol	990,420
7782492	Selenium	173,886
7440224	Silver	289,686
100425	Styrene	28,155,503
7664939	Sulfuric acid	1,320,503
75650	Tert-Butyl alcohol	4,660
127184	Tetrachloroethylene (Perchloroethylene)	14,623,885
7440280	Thallium	<1
108883	Toluene	421,985,085
79016	Trichloroethylene	27,838,379
75694	Trichlorofluoromethane (CFC-11)	1,315,878
7440622	Vanadium (fume or dust)	7,256,367
108054	Vinyl acetate	1,011,166
75014	Vinyl chloride	10,200,715
1330207	Xylene (mixed isomers)	191,013,108
7440666	Zinc (fume or dust)	20,353,738

* Data in this table should not be used for comparison with other environmental data from other sources. It is only provided for illustrative purposes. Please note the limitations of the data explained in the text.

Table 21: Median Emission Factors Determined From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Inorganic HAPs From Coal-Fired Units[*]

Coal-Fired Units: Inorganic HAPs	Number of Stack Factors: PM Control[**]	Median Stack Factor: PM Control (lb/trillion Btu)[***]	Number of Stack Factors: PM and SO_2 Control[**]	Median Stack Factor: PM and SO_2 Control (lb/trillion Btu)[**]	Estimated Total 1990 Emissions (tons)	Estimated Total 2010 Emissions (tons)
Antimony	7	1.4	4	0.13	11	14
Arsenic	21	2.9	8	0.9	54	62
Beryllium	12	0.45	5	0.14	6.6	7.6
Hydrogen Chloride	15	21,000	9	1,290	137,000	150,000
Hydrogen Cyanide (HCN)[†]	All HCN factors were combined	Number of Factors: 5	Median Factor: 28 lb/trillion Btu		240	320
Hydrogen Fluoride	14	4,200	6	106	19,500	25,600
Cadmium	18	0.72	9	1	1.9	2.3
Chromium	22	8.4	10	4	70	83
Cobalt	10	2.7	6	1	21	27
Lead	21	4.8	9	5.8	72	83
Manganese	21	15	9	15	180	232
Mercury	20	3.9	10	3.4	51	65
Nickel	21	8.3	10	5.2	48	57
Phosphorous (P)[††]	All P Factors were Combined	Number of Factors: 10	Median Factor 31 lb/trillion Btu		270	350
Selenium	19	62	9	8	190	230

[*] Compounds are listed in the following sequence: inorganic, organic, and dioxin/furan/polycyclic aromatic hydrocarbons (PAHs). Median emission factors were determined from organic HAP concentrations at the stack, control device outlet, or boiler outlet when at least one of typically three measured flue gas concentrations was detected.

[**] Stack factors for inorganic HAPs were taken from test reports when at least one of typically three measured flue gas concentrations was detected. These factors were not used to develop the estimated emissions.

[***] Since the inorganic emissions were not directly estimated from stack factors, total emissions of inorganic HAPs projected with the computer program and from median stack factors will vary.

[†] Nationwide hydrogen cyanide emissions were detected from stack emission factors and not from emission median factors.

[††] Nationwide phosphorous emissions were detected from stack emission factors and not from emission median factors.

Source: *Study of Hazardous Air Pollutant Emission from Electric Utility Steam Generating Units--Interim Final Report, Volumes 1-3.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. EPA-453/R-96-013b. October 1996.

Table 22: Median Emission Factors Determined From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Inorganic HAPs From Oil-Fired Units [*]

Oil-Fired Units: Inorganic HAPs	Number of Stack Factors: PM Control [**]	Median Stack Factor: PM Control (lb/trillion Btu)[***]	Number of Stack Factors: No PM Control [**]	Median Stack Factor: No PM Control (lb/trillion Btu) [***]	Estimated Total 1990 Emissions (tons)	Estimated Total 2010 Emissions (tons)
Arsenic	2	0.32	8	5.3	5	2.5
Beryllium	2	0.33	4	0.21	0.45	0.23
Cadmium	1	0.32	9	1.6	1.7	0.87
Chromium	4	3.7	8	5.7	4.7	2.4
Cobalt	2	6.1	3	27	20.3	10.3
Hydrogen Chloride	4	2900	2	2300	2870	1456
Hydrogen Fluoride	3	230	2	140	144	73
Lead	3	2.6	8	9	10.6	5.3
Manganese	3	15	9	16	9.5	4.8
Mercury	3	0.24	3	0.48	0.25	0.13
Nickel	4	180	9	410	389	197
Phosphorous (P)[†]	All P Factors were Combined	Number of Factors: 3	Median Factor 110 lb/trillion Btu		68	34
Selenium	1	1.4	8	3.8	1.7	0.84

[*] Compounds are listed in the following sequence: inorganic, organic, and dioxin/furan/polycyclic aromatic hydrocarbons (PAHs). Median emission factors were determined from organic HAP concentrations at the stack, control device outlet, or boiler outlet when at least one of typically three measured flue gas concentrations was detected.

[**] Stack factors for inorganic HAPs were taken from test reports when at least one of typically three measured flue gas concentrations was detected. These factors were not used to develop the estimated emissions.

[***] Since the inorganic emissions were not directly estimated from stack factors, total emissions of inorganic HAPs projected with the computer program and from median stack factors will vary.

[†] Nationwide phosphorous emissions were detected from stack emission factors and not from emission median factors.

Source: *Study of Hazardous Air Pollutant Emission from Electric Utility Steam Generating Units--Interim Final Report Volumes 1-3.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. EPA-453/R-96-013b. October 1996.

Table 23: Median Emission Factors Determined From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Inorganic HAPs From Gas-Fired Units [*]

Gas-Fired Units: Inorganic HAPs	Number of Stack Factors: No PM Control	Median Stack Factor: No PM Control (lb/trillion Btu)	Estimated Total 1990 Emissions (tons)	Estimated Total 2010 Emissions (tons)
Arsenic	2	0.14	0.16	0.25
Cadmium	1	0.044	0.054	0.086
Chromium	2	0.96	1.2	1.9
Cobalt	1	0.12	0.14	0.23
Lead	2	0.37	0.44	0.68
Manganese	2	0.3	0.37	0.59
Mercury	2	<0.38	0.0016	0.0024
Nickel	2	2.3	2.3	3.5
Phosphorous	1	2.2	1.3	2

[*] Compounds are listed in the following sequence: inorganic, organic, and dioxin/furan/polycyclic aromatic hydrocarbons (PAHs). Median emission factors were determined from organic HAP concentrations at the stack, control device outlet, or boiler outlet when at least one of typically three measured flue gas concentrations was detected.

Source: *Study of Hazardous Air Pollutant Emission from Electric Utility Steam Generating Units--Interim Final Report Volumes 1-3*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. EPA-453/R-96-013b. October 1996.

Table 24: Median Emission Factors From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Organic HAPs From Coal-Fired Units

Coal-Fired Units: Organic HAP	Number of Emission Factors	Median Emission Factor (lb/trillion Btu)	Computer Program: 1990 Total Tons	Computer Program: 2010 Total Tons
1,1,2-Trichloroethane	1	4.7	40	53
2-chloroacetophenone	3	0.29	2.4	3.2
2,4 -Dinitro toluene	3	0.015	0.13	0.17
Acetaldehyde	12	6.8	58	76
Acetophenone	7	0.68	5.8	7.7
Acrolein	6	3.3	28	37
Benzene	20	2.5	21	28
Benzyl chloride	1	0.0056	0.048	0.063
Bis(2-ethylhexyl) phthalate	9	4.1	35	46
Bromoform	1	6.6	57	75
Carbon disulfide	8	4.3	37	48
Carbon tetrachloride	2	3.3	28	37
Chlorobenzene	2	3.2	27	36
Chloroform	2	3.2	28	36
Cumene	1	0.29	2.5	3.2
Dibutyl phthalate	5	2.8	24	32
Ethylbenzene	5	0.40	3.5	4.6
Ethylchloride	1	2.4	20	27
Methylchloroform	4	3.4	29	38
Ethylenedichloride	3	3.1	27	35
Formaldehyde	15	4.0	35	45
Hexane	2	0.82	6.9	9.1
Hexachlorobenzene	1	0.079	0.68	0.89
Isophorone	2	24	200	270
Methylbromide	6	0.88	7.7	10
Methylchloride	3	5.9	51	67
Methylethylketone	6	8.0	69	90
Methyliodide	1	0.40	3.4	4.5
Methylisobutyl ketone	3	4.9	42	53
Methylmethacrylate	1	1.1	9.3	12
Methyltertbutylether	1	1.4	12	16
Methylenechloride	5	13	110	150

Table 24 (continued) : Median Emission Factors From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Organic HAPs From Coal-Fired Units

Coal-Fired Units: Organic HAP	Number of Emission Factors	Median Emission Factor (lb/trillion Btu)	Computer Program: 1990 Total Tons	Computer Program: 2010 Total Tons
n-nitrosodimethylamine	1	0.68	5.9	7.7
Naphthalene	11	0.77	6.6	8.7
n,p-cresol	2	0.68	5.8	7.6
o-cresol	3	1.7	14	19
p-cresol	1	0.95	8.2	11
perylene	1	0.075	0.65	0.85
Pentachlorophenol	1	0.0082	0.070	0.093
Phenol	10	6.1	52	69
Phthalicanhydride	1	4.9	42	56
Propionaldehyde	4	10	89	120
Quinoline	1	0.053	0.46	0.61
Styrene	7	3.1	27	35
Tetrachloroethylene (Perchloroethylene)	5	3.1	27	35
Toluene	17	3.6	31	41
Trans 1,3-dichloropropene	1	4.7	40	53
Trichloroethylene	1	3.1	27	35
Vinyl acetate	1	0.42	3.5	4.6
Vinylidnechloride	2	9.7	84	110
Xylene	2	4.7	40	53
o-xylene	5	0.82	6.9	9.1
m,p-xylene	8	1.5	13	17
Total TEQ[*] for 2,3,7,8-tetra-chlorodibenzo-p-dioxin	-	-	1.5 x 10^{-4}	2.0 x 10^{-4}
2,3,7,8-tetrachloride-benzo-p-dioxin	4	1.6 x 10^{-6}	1.4 x 10^{-5}	1.9 x 10^{-5}
1,2,3,7,8-pentachlorodi-benzo-p-dioxin	3	4.3 x 10^{-6}	3.7 x 10^{-5}	4.8 x 10^{-5}
1,2,3,4,7,8-hexachlorodi-benzo-p-dioxin	4	9.7 x 10^{-6}	8.3 x 10^{-5}	1.1 x 10^{-4}
1,2,3,6,7,8-hexachlorodi-benzo-p-dioxin	4	5.8 x 10^{-6}	5.0 x 10^{-5}	6.6 x 10^{-5}
1,2,3,7,8,9-hexachlorodi-benzo-p-dioxin	4	7.3 x 10^{-6}	6.3 x 10^{-5}	8.3 x 10^{-5}
1,2,3,4,6,7,8-heptachlorodi-benzo-p-dioxin	9	5.7 x 10^{-6}	4.9 x 10^{-5}	6.5 x 10^{-5}
Heptachlorodi-benzo-p-dioxin	6	1.1 x 10^{-4}	9.2 x 10^{-4}	1.2 x 10^{-3}
Hexachlorodi-benzo-p-dioxin	8	2.4 x 10^{-5}	2.1 x 10^{-4}	2.7 x 10^{-4}
Octachlorodi-benzo-p-dioxin	6	5.8 x 10^{-5}	5.0 x 10^{-4}	6.6 x 10^{-4}
Pentachlorodi-benzo-p-dioxin	6	9.8 x 10^{-6}	8.5 x 10^{-5}	1.1 x 10^{-4}

Table 24 (continued) : Median Emission Factors From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Organic HAPs From Coal-Fired Units

Coal-Fired Units: Organic HAP	Number of Emission Factors	Median Emission Factor (lb/trillion Btu)	Computer Program: 1990 Total Tons	Computer Program: 2010 Total Tons
Tetrachloride-benzo-p-dioxin	9	7.1 x 10^{-6}	6.1 x 10^{-5}	8.0 x 10^{-5}
2,3,7,8-tetrachloride-benzofuran	8	3.9 x 10^{-6}	3.4 x 10^{-5}	4.5 x 10^{-5}
1,2,3,7,8-pentachlorodi-benzofuran	5	2.4 x 10^{-6}	2.1 x 10^{-5}	2.8 x 10^{-5}
2,3,4,7,8-pentachlorodi-benzofuran	5	1.0 x 10^{-5}	9.0 x 10^{-5}	1.2 x 10^{-4}
1,2,3,4,7,8-hexachlorodi-benzofuran	6	1.3 x 10^{-5}	1.1 x 10^{-4}	1.5 x 10^{-4}
1,2,3,6,7,8-hexachlorodi-benzofuran	5	4.0 x 10^{-6}	3.4 x 10^{-5}	4.5 x 10^{-5}
1,2,3,7,8,9-hexachlorodi-benzofuran	4	8.5 x 10^{-6}	7.3 x 10^{-5}	9.6 x 10^{-5}
2,3,4,6,7,8-hexachlorodi-benzofuran	5	1.6 x 10^{-5}	1.4 x 10^{-4}	1.8 x 10^{-4}
1,2,3,4,6,7,8-heptachlorodi-benzofuran	8	2.0 x 10^{-5}	1.7 x 10^{-4}	2.2 x 10^{-4}
1,2,3,4,7,8,9-heptachlorodi-benzofuran	4	1.7 x 10^{-4}	1.5 x 10^{-3}	2.0 x 10^{-3}
Heptachlorodi-benzofuran	8	2.4 x 10^{-5}	2.1 x 10^{-4}	2.7 x 10^{-4}
Hexachlorodi-benzofuran	8	1.9 x 10^{-5}	1.6 x 10^{-4}	2.1 x 10^{-4}
Octachlorodi-benzofuran	10	1.7 x 10^{-5}	1.4 x 10^{-4}	1.9 x 10^{-4}
Pentachlorodi-benzofuran	9	1.8 x 10^{-5}	1.6 x 10^{-4}	2.1 x 10^{-4}
Tetrachloride-benzofuran	10	1.2 x 10^{-5}	1.0 x 10^{-4}	1.3 x 10^{-4}
1-methylnaphthalene	2	0.0085	0.076	0.1
2-chloronaphthalene	2	0.04	0.35	0.46
2-methylnaphthalene	6	0.024	0.2	0.26
Acenapthene	6	0.008	0.07	0.09
Acenapthylene	5	0.0042	0.036	0.047
Anthracene	4	0.0042	0.036	0.047
Benz(a)anthracene	4	0.0021	0.018	0.002
Benzo(a)pyrene	6	0.001	0.0088	0.012
Benzo(e)pyrene	1	0.0012	0.01	0.014
Benzo(b)fluoranthene	1	0.0081	0.07	0.092
Benzo(b+k)fluoranthene	1	0.0016	0.014	0.018
Benzo(k)fluoranthene	1	0.0036	0.031	0.04
Benzo(g,h,i)perylene	2	0.0032	0.028	0.036
Biphenyl	1	0.34	3.1	4
Chrysene	4	0.0026	0.022	0.03
Dibenzo(a,h)anthacene	1	0.0003	0.003	0.004
Fluoranthene	6	0.007	0.06	0.082

Table 24 (continued) : Median Emission Factors From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Organic HAPs From Coal-Fired Units

Coal-Fired Units: Organic HAP	Number of Emission Factors	Median Emission Factor (lb/trillion Btu)	Computer Program: 1990 Total tons	Computer Program: 2010 Total tons
Fluorene	5	0.013	0.11	0.15
Indeno(1,2,3-c,d)pyrene	2	0.0064	0.054	0.072
Phenanthrene	7	0.032	0.031	0.36
Pyrene	4	0.009	0.081	0.103

[*] Toxic equivalent emissions.

Source: *Study of Hazardous Air Pollutant Emission from Electric Utility Steam Generating Units--Interim Final Report, Volumes 1-3.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. October 1996. EPA-453/R-96-013b.

Table 25: Median Emission Factors From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Organic HAPs From Oil-Fired Units

Oil-Fired Units: Organic HAPs	Number of Emission Factors	Median Emission Factor (lb/trillion Btu)	Computer Program: 1990 Total Tons	Computer Program: 2010 Total Tons
Acetaldehyde	1	8.2	5	2.6
Benzene	6	1.4	0.88	0.45
Ethylbenzene	2	0.49	0.29	0.15
Formaldehyde	9	30	19	9.5
Methylchloroform	3	7.6	4.6	2.4
Methylenechloride	2	32	20	10
Naphthalene	4	0.33	0.21	0.1
Phenol	2	24	15	7.5
Tetrachloroethylene (Perchloroethylene)	1	0.55	0.34	0.17
Toluene	6	8	4.9	2.5
Vinyl acetate	2	5.2	3.2	1.6
o-Xylene	1	0.84	0.51	0.26
m,p-Xylene	2	1.4	0.82	0.42
Total TEQ[*] for 2,3,7,8-tetra-chlorodibenzo-p-dioxin	--	--	1.1×10^{-5}	5.4×10^{-6}
2,3,7,8-tetrachloride-benzo-p-dioxin	1	6.5×10^{-6}	4.5×10^{-6}	2.0×10^{-6}
1,2,3,7,8-pentachlorodi-benzo-p-dioxin	2	5.8×10^{-6}	3.5×10^{-6}	1.8×10^{-6}
1,2,3,4,7,8-hexachlorodi-benzo-p-dioxin	1	1.2×10^{-5}	7.6×10^{-6}	3.9×10^{-6}
1,2,3,6,7,8-hexachlorodi-benzo-p-dioxin	2	5.4×10^{-5}	3.3×10^{-6}	1.7×10^{-6}
1,2,3,7,8,9-hexachlorodi-benzo-p-dioxin	2	8.3×10^{-6}	5.1×10^{-6}	2.6×10^{-6}
1,2,3,4,6,7,8-heptachlorodi-benzo-p-dioxin	2	2.0×10^{-5}	1.2×10^{-5}	6.2×10^{-6}
Heptachlorodi-benzo-p-dioxin	2	2.0×10^{-5}	1.2×10^{-5}	6.2×10^{-6}
Hexachlorodi-benzo-p-dioxin	2	8.1×10^{-6}	5.0×10^{-6}	2.5×10^{-6}
Octachlorodi-benzo-p-dioxin	1	2.3×10^{-5}	1.4×10^{-5}	7.3×10^{-6}
Pentachlorodi-benzo-p-dioxin	2	5.8×10^{-6}	3.5×10^{-6}	1.8×10^{-6}
Tetrachloride-benzo-p-dioxin	2	5.7×10^{-6}	3.4×10^{-6}	1.8×10^{-6}
2,3,7,8-tetrachloride-benzofuran	2	4.6×10^{-6}	2.9×10^{-6}	1.4×10^{-6}
1,2,3,7,8-pentachlorodi-benzofuran	2	4.3×10^{-6}	2.6×10^{-6}	1.3×10^{-6}
2,3,4,7,8-pentachlorodi-benzofuran	2	4.8×10^{-6}	3.0×10^{-6}	1.5×10^{-6}
1,2,3,4,7,8-hexachlorodi-benzofuran	2	6.1×10^{-6}	3.7×10^{-6}	1.9×10^{-6}
1,2,3,6,7,8-hexachlorodi-benzofuran	2	3.8×10^{-6}	2.3×10^{-6}	1.2×10^{-6}

Table 25 (continued): Median Emission Factors From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Organic HAPs From Oil-Fired Units

Oil-Fired Units: Organic HAPs	Number of Emission Factors	Median Emission Factor (lb/trillion Btu)	Computer Program: 1990 Total Tons	Computer Program: 2010 Total Tons
1,2,3,7,8,9-hexachlorodi-benzofuran	2	5.8×10^{-6}	3.5×10^{-6}	1.8×10^{-6}
2,3,4,6,7,8-hexachlorodi-benzofuran	1	4.8×10^{-6}	3.0×10^{-6}	1.4×10^{-6}
1,2,3,4,6,7,8-heptachlorodi-benzofuran	1	9.4×10^{-6}	5.7×10^{-6}	3.0×10^{-6}
1,2,3,4,7,8,9-heptachlorodi-benzofuran	1	1.0×10^{-5}	6.2×10^{-6}	3.2×10^{-6}
Heptachlorodi-benzofuran	1	1.5×10^{-6}	8.8×10^{-7}	4.4×10^{-7}
Hexachlorodi-benzofuran	2	9.6×10^{-6}	5.8×10^{-6}	3.0×10^{-6}
Octachlorodi-benzofuran	1	1.0×10^{-5}	6.2×10^{-6}	3.2×10^{-6}
Pentachlorodi-benzofuran	2	7.3×10^{-6}	4.4×10^{-6}	2.2×10^{-6}
Tetrachloride-benzofuran	2	5.0×10^{-6}	3.1×10^{-6}	1.5×10^{-6}
2-methylnaphthalene	4	0.017	0.01	0.0052
Acenaphthene	2	0.38	0.22	0.11
Acenaphthylene	1	0.017	0.01	0.0052
Anthracene	2	0.015	0.0093	0.0047
Benz(a)anthracene	3	0.03	0.018	0.0092
Benzo(b+k)fluoranthene	2	0.033	0.02	0.01
Benzo(g,h,i)perylene	2	0.021	0.013	0.0065
Chrysene	3	0.021	0.013	0.0066
Dibenzo(a,h)anthracene	2	0.0081	0.005	0.0025
Fluoranthene	6	0.016	0.0097	0.0049
Fluorene	5	0.021	0.013	0.0065
Indeno(1,2,3-c,d)pyrene	2	0.024	0.014	0.0073
Nitrobenzofluoranthene	1	0.015	0.0092	0.0047
Nitrochrysene/benzanthracene	1	0.016	0.0098	0.005
Phenanthrene	9	0.025	0.015	0.0077
Pyrene	6	0.037	0.022	0.011

[*] Toxic equivalent emissions

Source: *Study of Hazardous Air Pollutant Emission from Electric Utility Steam Generating Units--Interim Final Report, Volumes 1-3.* U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. October 1996. EPA-453/R-96-013b.

Table 26: Median Emission Factors From Test Report Data, and Total 1990 and 2010 HAP Emissions, Projected With the Emission Factor Program for Organic HAPs From Gas-Fired Units

Gas-Fired Units: Organic HAPs	Number of Emission Factors	Median Emission Factor (lb/trillion Btu)	Computer Program: 1990 Total Tons	Computer Program: 2010 Total Tons
Benzene	1	1.4	1.8	2.7
Formaldehyde	8	35.5	55	83
Naphthalene	2	0.7	0.66	1
Toluene	2	10	13	19
2-methylnaphthalene	2	0.026	0.025	0.038
Fluoranthene	1	0.0028	0.0034	0.0055
Fluorene	1	0.0026	0.0034	0.0051
1-phenanthrene	2	0.013	0.016	0.024
Pyrene	1	0.0049	0.0061	0.0094

Source: *Study of Hazardous Air Pollutant Emission from Electric Utility Steam Generating Units--Interim Final Report, Volumes 1-3*. U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. October 1996. EPA-453/R-96-013b.

V. POLLUTION PREVENTION OPPORTUNITIES

The best way to reduce pollution is to prevent it in the first place. Some companies have creatively implemented pollution prevention techniques that improve efficiency and increase profits while at the same time minimizing environmental impacts. This can be done in many ways, such as reducing material inputs, re-engineering processes to reuse byproducts, improving management practices, and employing substitution of toxic chemicals. Some smaller facilities are able to actually get below regulatory thresholds just by reducing pollutant releases through aggressive pollution prevention policies.

The Pollution Prevention Act of 1990 established a national policy of managing waste through source reduction, which means preventing the generation of waste. The Pollution Prevention Act also established as national policy a hierarchy of waste management options for situations in which source reduction cannot be implemented feasibly. In the waste management hierarchy, if source reduction is not feasible the next alternative is recycling of wastes, followed by energy recovery, and waste treatment as a last alternative.

In order to encourage these approaches, this section provides both general and company-specific descriptions of some pollution prevention advances that have been implemented within the fossil fuel electric power generation industry. While the list is not exhaustive, it does provide core information that can be used as the starting point for facilities interested in beginning their own pollution prevention projects. This section provides summary information from activities that may be, or are being implemented by this sector. When possible, information is provided that gives the context in which the technique can be used effectively. Please note that the activities described in this section do not necessarily apply to all facilities that fall within this sector. Facility-specific conditions must be carefully considered when pollution prevention options are evaluated, and the full impacts of the change must examine how each option affects air, land and water pollutant releases.

Coal is considered the primary energy source for power generation now and in the future. Coal is relatively abundant and inexpensive. However, environmental impacts associated with coal combustion, most notably, acid rain, represent a cost to the environment and human health. This section emphasizes technologies for coal-fired electric power generation plants, but includes pollution prevention practices that apply to other fossil fuel electric plants as well. Many of the technologies and practices may be employed in existing plants, in the repowering of existing plants, and in the design and construction of new plants.

V.A Pollution Prevention Technologies in the DOE Clean Coal Technology Demonstration Program

The DOE is charged with protecting the Nation's energy interests. In recognition of the vital role of coal as a sustainable energy source, DOE vigorously researches and promotes ways to reduce the environmental impacts associated with coal combustion under the Clean Coal Technology Demonstration (CCT) Program. Specific goals of the CCT Program include (1) increasing the efficiency of electricity production and (2) enhancing the efficient and cost effective use of U.S. coal reserves, while ensuring achievement of national and environmental goals.

One way in which the CCT Program progresses towards these goals is by building a portfolio of advanced, coal-based technology demonstration projects. Included in the portfolio are technologies that result in improved efficiency with fewer environmental consequences. The technologies demonstrated under the CCT Program include commercially viable processes, as well as projects whose commercial viability is still being explored. These technologies may be categorized as (1) power systems, (2) environmental control devices, and (3) clean coal processing. Pollution prevention technologies being demonstrated under the CCT Program are included under the categories labeled "power systems" and "clean coal processing." Technologies categorized as "environmental control devices" may not be considered pollution prevention technologies; however, they may enable the recovery of pollutants for subsequent reuse/resale in products.

A brief discussion of emerging power systems and coal processing technologies being demonstrated under the CCT Program is provided below. DOE's *Clean Coal Technology Demonstration Program, Program Update 1995* (April 1996) provides a more detailed discussion.

V.A.1 Emerging Technologies

Pollution prevention opportunities in advanced coal-fired power systems are realized by the increase in overall efficiency of the combustion (electricity produced per amount of fuel) resulting in the reduction of environmental pollutants released. Efficiency of a technology is determined by the portion of energy in fuel that is converted into electricity. Thus, the process of combustion and heat transfers are critical variables. In considering advanced technologies, one must consider the environmental transfer of wastes from one media to another. Unless the transfer represents a more manageable form of the waste, there may be little or no environmental gain.

A brief description of power system technologies is provided below. While none of the technologies described are currently commercially viable, they may be in the future. Table 27 summarizes demonstration projects for power system technologies funded by DOE and participating companies.

Table 27: Summaries of Clean Coal Technologies Under DOE's Clean Coal Technology Demonstration Program

Demonstration: Pressurized Fluidized-Bed Combustion Combined-cycle, Tidd Project-The Ohio Power Company

Status*: Completed on the 70 MW scale, future testing on 340 MW scale planned.*
Size*: 55 MW steam turbine, 15 MW gas turbine*
Efficiency: *Combustion efficiency of 99.6%. Heat rate efficiency of 33.2 percent*
Environmental Benefits: *SO_2 removal of up to 95%. Resulting NO_X emissions of 0.15-0.33lb/million Btu.*

Demonstration: Integrated Gasification Combined-cycle Repowering Project

Status: *Currently still in design stage.*
Size: *65 MW*
Projected Efficiency: *Heat efficiency of approximately 43%.*
Environmental Benefits: *Expected CO_2 reduction, improved efficiency over coal-fired plant with flue gas desulfurization.*

Demonstration: Indirect Fired Cycle-Repowering, Pennsylvania Electric Co. Warren Station, Unit No. 2

Status*: Currently still in design stage.*
Size: *62.4 MW*
Projected Heat Rate: *9,650 BTU/KWh (31.3% improvement over existing).*
Environmental Benefits: *Eliminates the need for hot gas cleanup systems.*

Demonstration: Coal Diesel Combined-Cycle Project, Arthur D. Little, Inc.

Status: *Currently in design stage.*
Size: *14 MW*
Projected Efficiency: *Heat efficiency of approximately 48%.*
Environmental Benefits: *Emissions reductions to levels of 50%-70% below NSPS.*

Demonstration: Slagging Combustor, Heavy Clean Coal Project, Alaska Industrial Development and Export Authority, Golden Valley Electric Association

Status*: Currently in construction stage.*
Size: *50 MW*
Projected Efficiency: *Projected SO_2 removal of 90%, NO_X emissions/million BTU emissions of less than 0.015 lb/million BTU, particulates of 0.0015 lb/million BTU.*
Environmental Benefits: *SO_2, NO_X, particulates emissions reductions.*

Fluidized-Bed Combustion

Fluidized bed combustion (FBC) technology includes three designs: atmospheric, pressurized, and two-stage bubbling bed. Although FBC technology is not yet widespread in the industry, it allows any kind of fuel to be burned while controlling the emission of SO_2 without the use of a flue gas scrubbing device. In the FBC process, a sorbent, such as crushed limestone, is introduced with pulverized coal in the combustion chamber. Air forced into the combustion chamber suspends the coal-limestone mixture. Sulfur, released from the coal, combines with the sorbent to form a solid waste that is relatively easy to handle and dispose of. The advantage of FBC technology is that it creates a turbulent environment conducive to a high rate of combustion and a high rate of sulfur capture and allows for lower operating temperatures than conventional boilers. Because operating temperatures are below the threshold of thermally induced NO_X formation, NO_X emissions are reduced. In addition, the operating temperature tends to be below the ash fusion range for coal, resulting in less wastes present in fireside wash waters and less frequent cleaning requirements.

Integrated Gasification Combined-cycle

In the IGCC, coal is converted into a gaseous fuel, purified, and combusted in a gas turbine generator to produce electricity. The constituents react to produce a fuel gas. Heat from the exhaust gas is recovered and used to generate steam, which produces additional electricity. Gasification is a process in which coal is introduced to a reducing atmosphere with oxygen or air and steam. In some systems, a limestone sorbent is added to the gasifier for sulfur removal. The environmental advantages of IGCC include:

- High efficiency
- Removal of nitrogen, sulfur, and particulates prior to the addition of combustion air, thereby lowering the volume of gas requiring treatment
- Sulfur in the gas is in the form of hydrogen sulfide, which is removable to a greater extent than SO_2
- NO_X removal of more than 90 percent
- Reduced CO_2 emissions compared to traditional coal-fired boilers.

Currently, gas cleanup in IGCC requires the gas to be cooled; however, hot gas cleanup systems are being developed that will remove 99.9 percent of the sulfur and result in a saleable sulfur product. The IGCC system is well suited for repowering because it can use the existing steam turbine, electrical generator, and coal-handling facilities in most cases.

Indirect-Fired Cycle

An indirect-fired cycle operates such that coal or biomass combustion products do not come in direct contact with gas turbine components. Instead, heated gases pass on the shell side of an air heater. On the tube side of the air heater, compressed gas is heated and passes through a gas turbine. The environmental advantage is that this eliminates the need for hot gas cleanup since the corrosive and abrasive fuel products do not come into direct contact with the turbines. Heat is recovered from air heater exhaust and is used to produce steam, which powers a steam turbine. In addition, corrosive gas products do not come into direct contact with the turbine, thereby eliminating the need for hot gas cleanup. Although the technology is still in the design stage, the efficiency is expected to be 20 percent greater than that of a pulverized coal plant. Furthermore, SO_2 reductions of 90 percent, as well as reduced NO_X and particulate emissions, are expected.

Integrated Gasification Fuel Cell

An integrated gasification fuel cell system consists of a coal gasifier with a gas cleanup system, a fuel cell, an inverter, and a heat recovery system. Coal gas, made through the reaction of steam, oxygen, and limestone, is introduced to a fuel cell composed of an anode and a cathode and separated by an electrolytic layer. The fuel cell converts the chemical energy of the gas to direct current electrical energy and generates heat, and an inverter converts direct current to alternating current. A heat recovery system delivers heat to a bottoming steam cycle for further generation of electricity. Pollution prevention is realized by improved emissions reduction associated with the gas cleanup system and solid waste reduction.

Coal-Fired Diesel

Diesel generators are modified to accept a coal/water slurry as a fuel source. Environmental control systems are typically installed to remove NO_X, SO_2, and particulates. The advantage of a coal-fired diesel system is that it is well suited to small generators (below 50 megawatts). In addition, it is estimated to result in emissions reduction of 50 percent below New Source Performance Standards. Similarly, coal-oil mixture technology can replace up to 50 percent of fuel oil with pulverized coal for burning in conventional oil or gas burners.

Slagging Combustor

In a slagging combustor, coal is burned at very high combustion temperatures outside the furnace cavity, and combustion gasses pass into the boiler, where heat exchange takes place. In a conventional boiler, the ash enters the boiler and collects on boiler tubes, thus decreasing the efficiency of heat exchange. Alternatively, the high temperature of the slagging combustor causes ash to form slag, which is collected in cyclones. The advantage of the slagging combustor is that it prevents a loss in heat exchange efficiency that would occur from ash accumulation on boiler tubes.

V.A.2 Coal Processing for Clean Fuels

Pollution prevention entails removal of the pollutants from coal in the precombustion stage. This is accomplished through coal cleaning, whereby pollutants are removed without altering the solid state of the coal, or by conversions (gasification or liquefaction), which represent transformations in the state of the coal.

Coal Cleaning

Most coal cleaning occurs at the mouth of the mine. The cleaning method depends on the size of the coal pieces. Typically, coal is cleaned by pulsing currents of water through a bed of coal in a jig to separate the impurities from the coal. Coal cleaning can be achieved through physical, biological, or chemical means. Physical cleaning is the most common method and involves the separation of coals to obtain coals with lower ash content. A lower ash content helps in meeting particulate emissions standards and results in lower operating and maintenance costs associated with ash handling. Coal cleaning can also reduce the trace metal content, thus reducing trace metal content in ashes. Furthermore, cleaning is effective in removing sulfur from coal. This is sulfur that may otherwise end up as SO_2 emissions. There is a tradeoff between sulfur reduction and energy recovery.[36] It should be noted, however, that a reduction in energy recovery is associated with sulfur removal.

A study cited in a report written by the Virginia Department of Environmental Quality compared two FBC conceptual plant designs using mine-run coal versus washed coal. The washed coal facility reduced SO_2 emissions by more than 50 percent on the basis of equivalent heat input and sulfur removal. The NO_X emissions from the washed coal are about one-third lower in comparison to mine-run coal based on equivalent heat input. In addition, the washed coal facility was physically smaller, had lower installation costs, required less storage area for limestone and ash, used less water, and generated less high-volume wastes.

Coal Gasification

Gasification is the process of converting coal to a gaseous fuel—coal gas—followed by chemical cleaning. Coal gas has the benefit of burning as cleanly as natural gas. The process entails coal gas reacted with steam and an oxidant in a reducing atmosphere. If air is the oxidant, a low-BTU gas results; if oxygen is the oxidant, a medium-BTU gas results.

Mild Gasification

In mild gasification, coal is heated in a oxygen-free reactor, which produces gaseous, solid, and liquid products. The environment in the reactor drives off the condensed, volatile hydrocarbons and leaves behind carbon. The benefit of mild gasification is that it produces multiple fuels and feedstocks using medium temperature treatment of coal.

Coal Liquefaction

Hydrogen added to coal increases the fuel's ratio of hydrogen to carbon to a level similar to that of petroleum-based fuels. Coprocessing is a liquefaction process, whereby heavy petroleum residue combined with coal produces a liquid fuel. The liquids can be cleaned of sulfur and ash prior to use as a fuel and have higher thermal efficiencies (60-70 percent range), high product yield, and potentially marketable byproducts, such as gasoline.

V.B Other Pollution Prevention Technologies

Cogeneration

Cogeneration is the production of electricity and heat from a single power plant unit. Because of the heat recovery aspect, cogeneration itself is a pollution prevention strategy. In cogeneration, heat that would otherwise be released from a steam turbine, gas turbine, or diesel engine is recaptured and used to heat buildings or other industrial processes or to generate additional electricity. In fact, whereas the typical efficiency at a fossil fuel electric plant is around 33 to 38 percent, cogenerators can obtain up to 80-percent efficiency because of the heat recaptured. The heat recovered comes mainly from the flue gases.[37]

Cogeneration plants were originally industrial applications. They are still used primarily to provide power for industries, hotels, universities, etc., yet they are increasingly being designed for larger capacities and are competing with utilities for power production. Cogeneration plants may be owned by an industrial company, supplying its own power, or they may be owned by small entrepreneurial companies. Besides size requirements, factors such as type of fuel to burn, methods of recapturing heat, and control of emissions, should be considered when evaluating cogeneration as a power source.

DOE's Office of Industrial Technology (OIT) has several projects underway to promote cogeneration, which is a commercially available technology. For example, OIT teamed up with Riegel Textile Corporation to design and test an innovative 4.3 MW high-back-pressure steam cogeneration system using a modified coal-fired boiler. The turbine exhaust (225 psig at 570 degrees Fahrenheit) is hot enough to be used for process heating and can also be used to drive an existing low-pressure turbine to generate additional electricity. In 1994, 17 such systems were in operation.[38]

Repowering

Repowering is a way in which power generation facilities can improve and increase both the production and efficiency of standard thermal generating facilities. Repowering options include expanding a unit's size or changing the type or quality of the fuel used. In most cases, it involves partial or complete replacement of the steam supply system and usually a more or less complete retention, refurbishment, and reuse of the turbine/generator. Many of the technologies listed above are appropriate for repowering.

Fuel Cells

Natural gas fuel cell (NGFC) energy systems improve gas utilization and efficiency. Like batteries, fuel cells are based on the principles of electrochemistry, except that they consume fuel to maintain the chemical reaction. The most common electrochemical reaction in a fuel cell is that of hydrogen with oxygen. The oxygen is usually derived from the air, and the hydrogen is usually obtained by steam-reforming fossil fuel. Natural gas is the most common fuel; however, other fuels can be used: peaked-shaved gas, air-stabilized gas from local production such as landfills, propane, or other fuels with high methane content. Fuel Cells, being electrochemical, are more efficient than combustion systems. In addition, emissions are reduced from typical gas systems because there is no combustion of fossil fuel. Although many fuel cells are being researched, developed, and demonstrated around the world, only one system is commercially available at this time. It is a 200 kW phosphoric acid fuel cell system.[39]

Because emissions are reduced, State and local air quality regulating agencies have begun to grant and/or consider exemptions from air quality permitting requirements. For example, after extensive emissions testing, the South Coast Air Quality Management District has granted NGFC's exemption in the Los Angeles area. Exemptions have also been granted by the Santa Barbara Air Quality Management District, the Bay Area Air Quality

Management District, and the State of Massachusetts. These exemptions may create economic incentives to install NGFC systems to avoid permitting fees and violation fines, or to take advantage of emissions credits. A Federal incentive program is being managed by the DOE Morgantown Energy Technology Center to reduce the cost of the fuel cell by $1,000 per kW.[40]

Additional information on this technology may be obtained from the North American Fuel Cell Owner Group (NAFCOG), an independent users group comprised of owners and operators of NGFCs.

V.C Other Pollution Prevention and Waste Minimization Opportunities

In addition to the technologies discussed previously, several other pollution prevention methods can be employed. Some of the methods are common solutions applicable to a wide range of facilities; others are more tailored to site-specific situations. Some of the methods are relatively simple, whereas others require more technological modifications. This section includes not only physical tasks, but management and training steps that foster pollution prevention.

V.C.1 Process or Equipment Modification Options

Fuel Sources

As discussed under the CCT Program, the initial fuel source may be examined as a potential pollution prevention opportunity. Clean coal technologies remove the pollutants prior to the major processes of electrical generation. But on a case-by-case basis, one can also consider the option of using fuels that are naturally lower in pollutants. Low-sulfur coals produce less SO_2 emissions, and there is less pollution associated with coal pile runoff. However, a tradeoff exists in that most low-sulfur coal in the United States is “low rank” (i.e., it has a higher ash and moisture content). Several operational difficulties stem from switching from high-rank to low-rank coal. Nonetheless, processing techniques to improve the BTU and remove sulfur from low-rank coals are being developed. For example, SynCoal (Western Energy Company) is a technology that produces a fuel with a 0.5 percent sulfur content, a moisture content of greater than 5 percent, a heating value of 11,800 Btu per pound, and ash content of approximately 9 percent.

Another related technology that has been researched extensively is co-firing using refuse derived fuel (RDF) pellets and coal in power plants. In 1992, DOE’s OIT, in cooperation with several organizations, operated a power plant with a mixture of coal and up to 25 percent RDF pellets. The project found that the mixture resulted in reduced acid gas emissions. The CAA amendments of 1990 allow the combustion of up to 30 percent municipal solid waste in coal plants. The results of this project are facilitating commercialization of the co-combustion technology.

Cooling Water

Cooling water is used in steam turbine electric power plants and is circulated through the condenser to condense the steam left after the generation of electricity. The resulting condensate can then be pumped back into the high-pressure boiler. Cooling systems may be once-through, where cooling water is discharged into a receiving water body after use, or recirculating, which involves the use of cooling towers, lakes, or ponds. Scaling of heat exchange equipment and piping occurs from cooling water contact and reduces the efficiency of the equipment. To prevent scaling, chemical additives, such as polyphosphates, polyester, phosphates, and polyacrylates, are added to cooling water. In the past, cooling tower treatment chemicals contained hexavalent chromium. Recent regulations have restricted the use of chrome-based treatment to reduce the associated public health and environmental impacts. As a result, industry has switched to non-chrome treatment chemicals.

Corrosion, fostered through aeration of cooling water in cooling towers, is another problem. A number of different chemicals such as zinc, molybdate, silicate, polyphosphate, aromatic azole, carboxylate, and sometimes chromate are added to cooling water for corrosion control. Fouling and biological growth are commonly controlled through the addition of polyester, phosphates, polyacrylates, non-oxidizing biocides, chlorine, and bromine.

Pollution prevention opportunities for cooling water address minimizing chemical additives and conserving water. Table 28 presents a few general pollution prevention recommendations for reducing cooling tower emissions.

First and foremost, a facility can determine the optimum chemicals for the prevention of biologic growth and corrosion. In general, chlorinated biocides are less toxic than brominated biocides, and polyphosphate and organo-phosphate inhibitors are less toxic than chromate corrosion inhibitors. Another possible means to reduce the need for chemical additives for control of scaling is magnetic water conditioning.

Widespread attention has focused on ozone treatment in lieu of common biocide use. Ozone acts to rupture bacterial cells through oxidation. Reductions in scaling, biofouling, and overall toxics may be realized from ozone. It has been successful mainly in once-through cooling water systems for power plants. Drawbacks in the use of ozone treatment include (1) the potential for corrosion in cooling towers, unless careful dosing is practiced to maintain the oxidation-reduction potential rate and (2) ozone treatments have been shown to exhibit rapid fouling on high temperature surfaces such as would be found in recirculating systems. In addition, health and safety issues associated with worker exposure to ozone must be considered.

Table 28: Pollution Prevention Opportunities for Reducing Cooling Tower Emissions

Pretreat makeup water: Pretreating the makeup water to cooling towers reduces the chemical treatment requirements for scale and corrosion control and can increase the number of times cooling water may be recycled before blowdown.

Use inert construction materials: Polyethylene, titanium, and stainless steel are relatively nonreactive compared to carbon steel and require lesser quantities of scale and corrosion inhibitors.

Install automatic bleed/feed controllers and bypass feeders: By installing this equipment on the cooling towers, facilities have reduced volumes of cooling tower chemicals, as well as energy costs, labor, and water.

Recirculate the cooling water: When possible, cooling tower water should be recirculated instead of cycling once-through the system.

Use chlorinated biocides: Facilities can use chlorinated biocides instead of brominated biocides to reduce the toxicity of biocides.

Sources: *Fact Sheet: Eliminating Hexavalent Chromium from Cooling Towers.* City of Los Angeles Board of Public Works, Hazardous and Toxic Materials Office. Undated; *Fact Sheet: Water and Chemicals Reduction for Cooling Towers*. North Carolina Department of Environmental Health and Natural Resources, Pollution Prevention Program. May 1987; *Pollution Prevention/Environmental Impact Reduction Checklist for Coal-Fired Power Plants*. U.S. Environmental Protection Agency, Office of Federal Activities. Undated.

Fireside Washes

In the combustion of fossil fuels, products of incomplete combustion will rise with gas and collect on boiler tubes and heat transfer units. Fireside wastes consist primarily of bottom ash and damaged refractory brick, which may be contaminated with heavy metals from the ash. As the buildup increases, the heat exchange efficiency decreases. Periodically, the buildup is removed by applying a large volume of water to the boiler surfaces. The wash water contains trace metals (nickel, chromium, iron, vanadium, and zinc), calcium, sodium, chlorides, nitrates, sulfates, and organics contained in suspended soot. The resulting waste is a wet ash sludge. This sludge may be co-managed for disposal with large volume combustion waste (fly ash, bottom ash, FGD sludge) or managed separately with other low-volume wastes and treated through physical or chemical precipitation, as well as pond evaporation.

Soot blowers use steam, air, or water to clean fireside fouled heat transfer surfaces. The removed soot and ash deposits are either reintroduced into the combustion process, redeposited for easier removal, or captured by particulate control equipment. Sonic horns generate sound waves that cause the heat transfer surface to vibrate and dislodge soot and ash. Manual cleaning includes brushing, sweeping, and vacuuming.

Abrasive cleaning methods remove contaminants by blasting a compound at the substrate. Typical blasting compounds are sand, walnut shells, or carbon dioxide pellets. The abrasive cleaning technology field is changing rapidly. New materials that may remove soot and ash without damaging the boiler tubes and refractory include plastic beads, sodium bicarbonate, and, potentially, liquid CO_2.

Table 29 provides some examples of pollution prevention opportunities for fireside washes.

Table 29: Pollution Prevention Options for Fireside Washes

Options	Comments
Use cleaner fuels	Natural gas is the cleanest burning fossil fuel, but availability limits widespread use. Cleaner burning fuel oils and coals are available but may be cost-prohibitive.
Use alternative cleaning methods	Soot blowers and sonic horns may be used to reduce the need for washing. Dry ash has higher potential for reuse. Abrasives may be used but add to waste created.
Recycle or reuse fireside wastes	Lime sludge from treatment may be sold to copper smelters. Vanadium recovery from fuel oil ash may be feasible. Coal ash can be used as a substitute for cement in concrete or as structural fill.

Source: *Industrial Pollution Prevention Handbook*. Freeman, Harry M., ed. McGraw Hill, Inc. 1995.

Boiler Chemical Cleaning Wastes

The purpose of boiler cleaning is to remove scale from the inside (water side) of boiler tubes. The waste generated contains spent cleaning solution and the scaling components: copper, iron, zinc, nickel, magnesium, and chromium. Certain cleaning agents target certain types of boilers and deposits. Boiler cleaning wastewaters may be difficult to treat and, in some cases, fall under the jurisdiction of the Resource Conservation and Recovery Act (RCRA) as a hazardous waste.

One way to minimize the volume of boiler cleaning wastes is to optimize the cleaning frequency. Specific practices that help to optimize cleaning frequency include:

- Maintaining records of operations
- Conducting biweekly chemical analysis to define normal cycle chemistry
- Sampling tubes annually

- Determining the location and/or type of deposits through ultrasonic imaging, thermocouples, removable test strips, and fiberscopic inspections.

Controlling the chemistry of the boiler feed water is a significant way to control the rate of scaling. Generally, boiler water is treated through fine filtration, chemical treatment, reverse osmosis, and/or ion exchange to remove minerals. Other constituents in the boiler water targeted for removal may include oxygen and carbon dioxide.

While most utilities use hydrazine and morpholine in the chemical treatment of boiler feed water, an elevated oxygen treatment process has been demonstrated that results in the accumulation of a finer-grained, more unified, magnetite layer that necessitates less frequent cleaning. To create this condition, oxygen or hydrogen peroxide is added to condensate at a pH of 7 to 7.5, oxygen and ammonia are added at a pH of 8 to 8.5, and ammonia is added at a pH of 9 or greater, until ammonia concentrations of 250 parts per billion are reached.

The boiler cleaning frequency may be decreased by reducing the amount of oxygen entering the boiler due to leaks in the system. Leaks can be corrected through inspection and replacement of seals on steam cycle components. Maintenance schedules and monitoring techniques are effective practices in preventing leaks. Furthermore, maintaining high quality performance of the oxygen deaerators will also help to prevent oxygen ingress.

Another effective pollution prevention technique is determining the optimum frequency of boiler cleanouts. Utilities should clean the boilers based on the actual deposit thickness instead of according to a predetermined schedule. According to a survey performed by EPRI, one California utility monitors both scale thickness and composition by means of small, retrievable test strips placed inside the boiler. Base unit boilers are now cleaned about once every 72 months, and cycling units are cleaned once every 48 months. Other California utilities report cleaning schedules as often as once every 24 months.[41]

On-line cleaning involves boiler cleaning while the boiler remains in operation. This can be done by injection of a sodium poly-acrylate additive into the boiler feedwater to a concentration of 400 mg/L. The most critical outer layer of magnetite is removed, but an inner layer remains. This method requires less cleaning time than traditional boiler cleaning, uses less hazardous chemicals, and results in a more easily handled waste. The drawbacks of on-line cleaning include the risk of contaminating the steam turbine, less deposits removed, and potentially poor copper removal. Cost savings associated with the use of this technology at a 300-MW unit have been estimated to be $25,000 to $30,000 per year.[42]

Sodium bicarbonate-based blast media can be used in association with specifically designed delivery systems to meet a wide range of cleaning needs, including general facility maintenance (e.g., floor cleaning, paint stripping and boiler tube cleaning). Sodium bicarbonate blasting is becoming increasingly common in the electric utility industry.[43]

In areas where water costs are high, utilities may choose to reuse their boiler chemical cleaning wastewater as makeup for cooling towers, fly ash scrubbers, or flue gas desulfurization systems.[44] Also, depending on the composition of the chemical cleaning sludge, it may be economically feasible to recycle the sludge for its metal content. Arizona Electric Power Cooperative (AEPCO), Incorporated, for example, uses this cleaning material, rather than face potentially expensive disposal costs. The EPA, the Arizona Department of Environmental Quality, the California Department of Toxic Substances Control, and the Occupational Safety and Health Administration approved the use of by products from chemical cleaning from AEPCO's boilers. AEPCO sells the by-product to Pacific Gas & Electric Company for hydrogen sulfide gas abatement at its Geysers Power Plant, a geothermal power generation facility.[45]

Table 30 lists pollution prevention opportunities for boiler cleaning wastes.

Fly Ash

Fly ash is typically collected in the flue of the combustion unit and transported to a centralized containment area for treatment and storage. Both wet ash transport and dry collection are commonly practiced. Some facilities use wet ash, creating a slurry as the mechanism for transport. The disadvantage of wet ash transport is that it increases the volume of the ash waste and it must eventually be separated out and treated. In contrast, a dry process control electrostatic precipitator avoids the added volume due to water and allows the collection of a dry product for recycling and/or beneficial reuse.

Chemical Substitutions

Several process modifications described previously have required material substitution (e.g., switching fuels). However, material substitutions are not

Table 30: Pollution Prevention Options for Boiler Cleaning Wastes

Options	Comments
Improve boiler water supply	Regenerate ion exchange resins promptly. Install reverse osmosis equipment ahead of ion exchange systems to reduce mineral loading and reduce regeneration frequency.
Control boiler water chemistry	Use hydrazine to control dissolved oxygen and morpholine to control carbon dioxide.
Reduce contaminant ingress	Improve equipment seals to prevent air and cooling water leaks into the boiler.
Base cleaning on fouling	Use coupons to measure scale buildup and schedule cleaning accordingly.
Use on-line cleaning	Sodium polyacrylate injection may be used to remove deposits without having to shut down boiler. Further research required.
Reuse wastewater	Wastewater may be used for cooling tower makeup or as feedwater to ash scrubbers and flue gas desulfurization units. Some pretreatment and/or segregation may be required.
Reuse lime sludge	Sludges from lime treatment of chemical cleaning wastes may be sold to copper smelters for reuse.
Control H_2S	Ethylenediamine-tetraacetic acid (EDTA)-based cleaning processes can produce Fe-EDTA, which is an effective chelating agent for H_2S control.

Source: Adapted from *Industrial Pollution Prevention Handbook.* Freeman, Harry M., ed. McGraw Hill, Inc. 1995.

limited to major processes. Sometimes, toxic chemicals are used unnecessarily on a wide-scale basis for a variety of operations and maintenance activities (e.g., cleaning, lubrication). By substituting less toxic chemicals, a facility can avoid unnecessary risks associated with worker exposure and the potential for release into the environment. The first step in determining the viability of material substitutions is to inventory the chemicals used at the site. The chemical can be evaluated as to its hazard potential, its necessity, and possible alternatives. For example, San Diego Gas and Electric Company determined several different solvents onsite could be replaced by just a few different solvents. By eliminating the wide array of solvents, the company is now able to install a solvent recovery unit, which will reduce the amount of solvent waste.

V.C.2 Inventory Management and Preventative Maintenance for Waste Minimization

Fossil fuel electric power generation facilities, like many industrial facilities, use solvents and other chemicals for everyday operations. Everyday operations include parts washing, lubricating, general cleaning, and degreasing application during plant and equipment maintenance activities. Often, chemical wastes generated by these operations are made up of out-of-date, necessary, off-specification, and spilled or damaged chemical products. Actual costs for materials used include not only the cost of the original product, but also the costs of disposal. Inventory management and preventative maintenance are ways these facilities can decrease the amounts of chemical wastes generated in a cost-effective manner.

There are two categories of inventory management including inventory control and material control. Inventory control includes techniques to reduce inventory size, reduce toxic and/or hazardous chemical use, and increase current inventory turnover. Material control includes the proper storage and safer transfer of materials. Proper material control will ensure that materials are used efficiently to reduce waste and preserve the ability to recycle the wastes.

Corrective and preventative maintenance can reduce waste generation. A well run preventative maintenance program will serve to identify the potential for releases and correct problems before material is lost and/or considered a waste. New or updated equipment can use process materials more efficiently, producing less waste. Table 31 provides examples of inventory management and preventative maintenance waste minimization techniques that can be used at fossil fuel electric power generation facilities.

V.C.3 Potential Waste Segregation and Separation Options

Fossil fuel electric power generation facilities can reduce their waste disposal costs by carefully segregating their waste streams. In particular, facilities should segregate RCRA nonhazardous wastes from hazardous wastes to reduce the quantity of waste that must be disposed of as a hazardous waste. For example, facilities should segregate used oil from degreasing solvents because uncontaminated used oil can be recycled or fed into the boiler as a supplemental fuel. Oil contaminated with polychlorinated biphenyls (PCBs) should be segregated from other used oils. Absorbent material that is not fully saturated with oils, etc., should be stored separately from saturated material so that it can be reused. Recycling companies typically offer a higher price for segregated recyclables (e.g., clean office paper, scrap metal) than mixed waste streams.

Table 31: Inventory Management and Preventative Maintenance Waste Minimization Opportunities

Inventory Management

Inventory Control

- Purchase only the quantity of material needed for the job or a set period of time
- Evaluate set expiration date on materials, especially for stable compounds, to determine if they could be extended.
- Search the inventory at other company sites for available stock before ordering additional material
- Purchase material in the proper quantity and the proper container size. If large quantities are needed, purchase in bulk. If the material has a short shelf-life or small quantities are needed, purchase in small containers
- If surplus inventories exist, use excess material before new material are ordered
- Contact supplier to determine if surplus materials can be returned. If not, identify other potential users or markets
- Evaluate whether alternative, non-hazardous substitutes prior to purchase and checked for acceptance at the facility.

Material Control

- Reduce material loss through improved process operation, increased maintenance and employee training to identify sources of loss
- Handle and manage wastes to allow recycling.

Maintenance Programs

Operational and Maintenance Procedures

- Reduce raw material and product loss due to leaks, spills, and off-specification products
- Develop employee training procedures on waste reduction
- Evaluation the need for operational steps and eliminate practices that are unnecessary
- Collect spilled or leaked material for re-use whenever possible
- Consolidate like chemicals and segregate wastes to reduce the number of different waste streams and increase recoverability.

Preventive Maintenance Programs

- Perform maintenance cost tracking
- Perform scheduled preventive maintenance and monitoring
- Monitor closely “Problem” equipment or processes that are known to generate hazardous waste (e.g., past spills).

Source: Adapted from “ComEd Operation and Maintenance Manual” and “Pollution Prevention Success” Fact Sheets. Received From Edison Electric Institute. July 1997.

V.C.4 Recycling Options

With the exception of cooling water and used oil, fly ash represents the greatest waste component at fossil fuel plants. For this reason, recycling options for fly ash present a significant opportunity for pollution prevention. Typical uses include incorporating fly ash into construction materials, such as asphalt or cement. However, new uses are being found every day. Table 32 lists existing and potential marketable uses for fly ash. More information about the production and use of fly ash and other coal combustion materials can be obtained from the American Coal Ash Association.[46]

Table 32: Current and Potential Uses for Fly Ash

Current Uses for Fly Ash
Flowable fill
Soil stabilization
Lightweight aggregate building material
Roofing materials
Roofing granules
Plastics, paint
Filter cloth precoat for sludge dewatering
Pipe bedding
Structural fills
Concrete and block Portland cement
Mine reclamation
Agricultural enhancement
Road paving: as a sub-base or fill material under a paved road
Potential Uses for Fly Ash
Ingredient of golf ball coverings
Flue gas reactants
An additive to sewage sludge for use as a soil conditioner
An alkali reactivity minimizer in concrete aggregate
The footprint of a structure, a paved parking lot, sidewalk, walkway, or similar structure

The Carolina Power and Light (CP&L) is successful in selling 80 to 100 percent of the fly ash generated at three coal-fired power plants. The CP&L estimates capital costs to be $1 to $2/ton of fly ash and operation and maintenance costs to be $3 to $4/ton of fly ash. The ash sales revenues have resulted in reduced disposal costs. Duke Power has experienced similar success. Duke Power has sold more than 230,000 tons of fly ash and 65,400 tons of bottom ash for use in concrete production. Other markets for the fly ash included plastic manufacturing and asphalt production. In addition, Duke Power donated 30,000 tons of bottom ash to the State of North Carolina to use as a base in road construction.

It should be noted that uses for fly ash vary greatly according to market conditions and transportation costs. In addition, for most uses, the ash must have a low carbon content. However, available commercial technologies can separate the ash into carbon-rich and carbon-poor fractions.

Pollution prevention associated with boiler blowdown was discussed previously; however, boiler blowdown water may potentially be recycled and used as makeup to cooling tower waters and flashing blowdown to generate additional steam. This is accomplished through the regeneration of demineralizer waters.

Sulfur is produced through the cleaning of fuels and ores and the use of clean scrubbers. Recycling options include the following:

- Substituting sulfur for Portland cement and water to act as a binding agent to produce a durable, acid-resistant concrete
- Using sulfur in protective coatings to improve the resistance of conventional building materials to chemical and other stresses; fabric can be impregnated with sulfur and additive materials to produce flexible or rigid lining materials
- Using sulfur as an asphalt extender or as an asphalt replacement to totally eliminate the need for asphalt.

The FGD units can produce sulfur, sulfuric acid, gypsum, or some non-saleable sludge material. Select FGD units can produce saleable materials, as indicated in the following examples:

- Gypsum can be processed into a quality gypsum grade for resale to wall board producers or sold for use in cement manufacturing.
- Sodium sulfate and sulfuric acid can be produced for resale.
- An electron beam scrubbing system can be used to produce ammonium sulfate and ammonium nitrate for sale as a fertilizer supplement.
- A pozzolanic stabilization reaction process can be implemented where lime-based reagent is added to scrubber sludge and fly ash to create a mineral product suitable for roadway base course. (Pozzolans are siliceous or siliceous/aluminous materials that, when mixed with lime and water, form cementitious compounds.)

V.C.5 Facility Maintenance Wastes

In addition to the wastes associated with the power production operations, fossil fuel electric power generation facilities also generate wastes from support operations, such as facility and equipment maintenance, storage areas, transportation, and offices. Pollution prevention techniques can greatly reduce many of these waste streams for relatively little cost.

Table 33 highlights several basic pollution prevention options for equipment and facility maintenance. All of the options involve the use of commercially available equipment that is already in widespread use. In addition to the options described in Table 33, common pollution prevention options include:

- Establishing preventive maintenance programs for equipment
- Testing fluids prior to changing them
- Purchasing equipment to enable recycling of antifreeze, solvents, and oil/water mixtures
- Purchasing longer lasting/reusable absorbent materials and rags

- Laundering rags offsite instead of disposing of them
- Using steam cleaning equipment or sodium bicarbonate blast systems for general facility cleaning
- Purchasing electric-powered vehicles for onsite use
- Upgrading bulk storage equipment and spill prevention practices
- Improving spill containment equipment and equipment for transferring fluids
- Using low- or no-VOC paints for facility maintenance and restricting color choices
- Recycling office paper, cardboard, plastics, scrap metals, wood products, etc.
- Purchasing products with recycled content
- Finding alternatives to replace ozone depleting substances (e.g., refrigerants, fire suppression, degreasers)
- Practicing integrated pest management to reduce the use of pesticides in grounds maintenance operations
- Using less toxic products for custodial operations.

Table 33: Pollution Prevention Opportunities For Facility Maintenance Wastes

Options	Comments
Rotating Equipment Maintenance	
Use high quality fluids	While costing more initially, high quality fluids may last twice as long in service.
Routinely monitor fluid condition	Waste fluid generation can be reduced by switching to a replacement schedule based on fluid condition. Low-cost testing services can provide detailed information.
Use nonleak equipment	Use dry disconnect hose couplings, self sealing lock nuts, and elastomeric flange gaskets to reduce oil leakage. Canned or magnetically driven pumps, bellow valves, and bellow flanges are also effective.
Clean and recycle dirty fluids	Dirty fluids may be cleaned for extended use by small filtration devices. More complex systems may use centrifugation or vacuum distillation.
Use waste oils as boiler fuel	This depends on boiler size, PCB content, and halogen content of the waste oil. Would not apply to synthetic hydraulic fluids.
Facility Maintenance	
Eliminate use of hazardous materials	Major accomplishments have been made in this area, including eliminating the use of PCBs, asbestos insulation, chromium-based cooling water treatment chemicals, and leaded paints.
Replace tricarboxylic acid (TCA) and chlorofluorocarbons (CFCs) with non-ODS cleaners	Petroleum distillate and D-limonene blends are effective cleaners for electrical equipment. Detergents are good for general purpose cleaning but must be kept out of yard drains and oil water separators.
Use high transfer efficiency painting equipment	Brushes, rollers, and hand mitts are very efficient but labor-intensive. Airless spray is common for field use since a source of clean, dry air is not required.
Use an enclosed cleaning station	Several air districts mandate the use of enclosed gun cleaners and prohibit the spraying of cleanup solvent into the air.
Avoid the removal of leaded paint	Removal of lead-based paint should only be performed when the paint fails to provide adequate protection. Use wet blasting or vacuum collective devices to prevent the generation of leaded paint dust.

Source: *Industrial Pollution Prevention Handbook*. Freeman, Harry M., ed. McGraw-Hill, Inc. 1995.

V.C.6 Storm Water Management Practices

An important pollution prevention consideration at fossil fuel electric power generation plants is the management of runoff. Coal pile runoff is perhaps the most significant. Coal pile runoff results from precipitation coming into contact with coal storage piles. The most effective way to eliminate coal pile runoff is to store coal indoors. In many instances, this is not feasible, at which point, pollution prevention turns to managing runoff. A facility's storm water pollution prevention plan should address storm water controls (e.g., dikes, levies) and the potential for reuse of storm water. Coal-handling areas also represent potential for coal pollutants to contaminate storm water. Table 34 lists practices that can prevent pollutants in coal from contaminating storm water.

Table 34: Common Pollution Prevention Practices for Managing Runoff at Coal Storage and Handling Areas [47]

- Consider rail transport of coal over barge transport, because the potential impacts to water are lessened.
- Cover coal off-loading areas, crushers, screens, and conveyors to reduce dust emissions.
- Cover coal storage piles or store in silos to prevent contact with precipitation and to minimize dust.
- Spray coal piles with anionic detergents. This will reduce the acidic content of the pile by reducing bacterial oxidation of sulfide minerals.
- Configure a storm water collection system based on slopes, collection ditches, diversions and storage, and treatment ponds.
- If settling ponds exist, consider recycling the dredgings.

Some of the practices listed in the table are applicable to fly ash storage and handling areas, as well as coal pile runoff. For example, if dry ash transport is employed, covers will prevent dust and contact with precipitation. Other areas of concern with respect to storm water pollution prevention include fuel and chemical handling and storage areas where there is potential for spills. Table 35 provides some recommended practices that apply to these areas. Ideally, these practices should be addressed in a facility's storm water pollution prevention plan.

Table 35: Storm Water Pollution Prevention Opportunities at Fossil Fuel Electric Power Generation Facilities

Areas of Concern	Storm Water Pollution Prevention Opportunities
Fuel Oil Unloading Areas	• Use containment curbs to contain spills • Station personnel familiar with spill prevention and response procedures at areas during deliveries to ensure quick response for leaks or spills • Use spill and overflow protection technologies
Chemical Unloading/Loading Areas	• Use containment curbs to contain spills • Cover area • Station personnel familiar with spill prevention and response procedures at areas during deliveries to ensure quick response for leaks or spills
Miscellaneous Loading/Unloading Areas	• Use grading, berming, and curbing to minimize runon • Locate equipment and vehicles so leaks can be controlled in existing containment and flow diversion system • Cover area
Liquid Storage Tanks	• Use dry cleanup methods • Use containment curbs to contain spills • Use spill and overflow protection technologies
Large Bulk Fuel Storage Tanks	• Use containment curbs to contain spills
Oil-Bearing Equipment Storage Areas	• Use level grades and gravel surfaces to retard flow and limit spread of spills • Collect storm water in perimeter ditches
Ash-Loading Areas	• Establish procedures to reduce or control tracking of ash or residue from ash loading areas • Clear ash from building floor and immediately adjacent roadways of spillage, debris, and excess water before each loaded vehicle departs
Areas Adjacent to Disposal Ponds	• Reduce ash residue, which can be tracked onto access roads traveled by residue trucks or residue handling vehicles • Reduce ash residue on exit roads leading into and out of residue-handling areas
Material Storage Areas	• Use level grades • Collect runoff in graded swales or ditches • Implement erosion protection measures at steep outfall sites • Provide cover for material

Source: Preamble to NPDES Storm Water Multi-Sector General Permit for Industrial Activities (60 *FR* 50974 Friday, September 29, 1995).

V.C.7 Training and Supervision Options

While the major pollution prevention gains are achieved through process controls and reuse/recycling, many day-to-day common sense practices are relatively easy and inexpensive to incorporate. Through training, these practices can become effective means of pollution prevention. Examples of proactive employee behavior includes training for careful use and disposal of cleaners and detergents to prevent them from entering floor and yard drains. If these substances do enter the drains, they may interfere with oil/water separators. Good housekeeping will ensure optimum performance of these treatment units.

V.C.8 Demand-Side Management Programs

In the past, electric utilities have implemented demand-side management (DSM) programs to achieve two basic objectives: energy efficiency and load management. Through these demand-side programs, the utilities have successfully reduced toxic air emissions and achieved cost effectiveness for both the utility and the consumer, mainly by deferring the need to build new power plants.[48] The energy efficiency goal has been achieved primarily by reducing the overall consumption of electricity from specific end-use devices and systems by promoting high-efficiency equipment and building design.

With the advent of deregulation and restructuring in the utility power generation industry, DSM programs appear to be diminishing. The industry is reducing DSM spending and experiencing a reduction in the rate of growth on energy savings. Among other factors, the potential for restructuring could affect the utilities interest in energy savings or may create new types of DSM activities.