EPA-600/2-75-022

August 1975

Environmental Protection Technology Series

EFFECTS OF TRANSIENT OPERATING CONDITIONS ON STEAM-ELECTRIC GENERATOR EMISSIONS

U.S. Environmental Protection Agency
Office of Research and Development
Washington, D. C. 20460

EPA-600/2-75-022

EFFECTS OF TRANSIENT OPERATING CONDITIONS ON STEAM-ELECTRIC GENERATOR EMISSIONS

by

J.S. McKnight

Research Triangle Institute
P.O. Box 12194
Research Triangle Park, N. C. 27709

Contract No. 68-02-1325, Task 10
ROAP No. 21BAV-002
Program Element No. 1AB013

EPA Project Officer: R.V. Hendriks

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, N. C. 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, D. C. 20460

August 1975

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Publication No. EPA-600/2-75-022

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ACKNOWLEDGMENTS

The cooperation of the electric utilities and the manufacturers of equipment used by the utilities has made this work easier. Messers. Joseph Greco, Robert Ezzell, and Robert Moultrie of the Tennessee Valley Authority, Andrew Winson of Georgia Power Company, Dennis Norton of Southern California Edison Company, Julian D'Amico of Duke Power Company, Robert Pollock of Carolina Power and Light Company, and Harry Lord and Lyman S. Gilbert of Environmental Data Corporation have contributed substantial time and effort in providing information which can be used in this report.

Dr. Jamshed A. Modi and Mr. Charles H. Gooding of RTI have done much of the work of this study. Dr. Forest O. Mixon has been the overall supervisor for this study.

Mr. R. V. Hendriks of the Industrial Environmental Research Laboratory of the Environmental Protection Agency has provided direction for the project and coordinated this work with the other projects of the Agency. The utility of this report is a result of his knowledge of the problems and missions which are faced by the regulator and the regulated.

CONCLUSIONS

Data were collected from a number of steam-electric generation plant operators to establish the relationship between atmospheric emissions and the operation of a generation plant under transient or upset conditions. Older, coal-fired steam generators that are equipped with a particulate-cleaning device as the only air pollution control equipment (i.e., no SO_x flue gas desulfurization system) are considered in the study. Emissions resulting from the transient operation of flue gas desulfurization systems are being investigated in other EPA-sponsored efforts.

A study of the operations involved in a steam-electric generation plant shows that transient conditions of operation affect the rate of emission of pollutants from the stack. Startups, shutdowns, load changes, fuel quality variations, electrostatic precipitator malfunctions, and other operating transients and equipment malfunctions are reviewed in the study. Conclusions about emission of particulates, visible emissions, and nitrogen oxides during these conditions that can be drawn from the collected data are presented in Table 1. The mass emission rate of sulfur oxides is in proportion to the fuel supplied to the boiler and to the sulfur content of the fuel; process variables do not affect the mass emitted. Therefore, the effects of transient conditions on sulfur oxide emissions are excluded from Table 1.

Adequate data obtained under carefully controlled and monitored conditions were not found to be available for the thorough characterization of the effect of transient conditions of operation on the rate of gaseous emissions from a steam generation plant. Few plants have continuous monitors of stack emissions that are necessary for seeing transient conditions. No continuous monitoring station was found that correlated the emissions with the boiler parameters.

Table 1. The effects of transient conditions of operation on stack emissions

Cause of transient condition	Effect on process control system	Manual or automatic compensation in the process control system	Frequency of occurrence	Duration of transient condition	Effect on stack emissions: Particulates	Effect on stack emissions: Oxides of nitrogen	Comments
STARTUPS							
Normal cold startup procedure for coal-fired boiler (hot startup is similar except oil-fired warmup is of shorter duration)	Nonoptimum combustion parameters; gradual load increase; delayed start of precipitator	Boiler and related equipment usually on manual control until fire is stabilized; excess air usually maintained high for better control of fire	12/yr for base-loaded plant to 50/yr for small peaking plant	a) First step: 1/2 - 5 hr of oil firing	No control, essentially all ash emitted, characteristic dark plume with oil	Low flame temperature, NO_x probably low	Gradual increase in fuel and air flow as boiler and turbine warm; unit is paralleled with system when turbine reaches rated speed.
				b) Second step: 0 - 8 hr oil and coal firing	No control, approximately 75% of coal ash emitted if precipitator is not energized, oil plume still present	Low load and temperature, NO_x probably low	Precipitator is energized when inlet gas temperature is above 135°C. Delaying energization until flue gas is above dew point avoids collection of wet ash which could foul wires and plates or plug hoppers.
				c) Third step: About 1 hr (total startup time usually is less than 8 hr)	Possible emission of unburned carbon due to nonoptimum combustion parameters	NO_x probably low	Pulverizer mills supply coal one at a time until flame is stabilized; oil firing stops after 2 or 3 mills are in operation.
Delay in energizing precipitator	Fly ash is not collected until precipitator is energized	None		Length of delay	Excessive emissions occur	None	Usual procedure is to energize precipitator after flue gas is above dew point; however, at least two operating companies energize when first coal is fired (see text).

Table 1. The effects of transient conditions of operation on stack emissions (con.)

Cause of transient condition	Effect on process control system	Manual or automatic compensation in the process control system	Frequency of occurrence	Duration of transient condition	Effect on stack emissions: Particulates	Effect on stack emissions: Oxides of nitrogen	Comments
SHUTDOWNS							
Normal shutdown procedure	Gradual decrease of fuel and air to boiler	Fuel to air ratio is kept in normal range; precipitator remains energized until stack gas reaches dew point; rapping continues until fly ash is removed from surfaces	12/yr for base-loaded plant to 50/yr for small plant	a) First step: 2 - 3 hours	Emissions decrease as load is reduced; excessive emissions occur if precipitator is deenergized too soon	Decreases as load is reduced	Boiler gradually and stepwise is dropped to about 1/3 to 1/2 load; then fuel flow is stopped, and precipitator is deenergized.
				b) Second step: 12 - 14 hours	If draft is used for cooling boiler, wisps of fly ash from boiler, duct work, and precipitator will be emitted from stack	None	Precipitator is not left on during boiler cooling because condensation would occur on wires and plates.
Turbine trip (emergency shutdown caused by malfunction in turbine, generator, output transformer, or other equipment or controls)	Immediate loss of load	Immediate closing of steam values blocking steam from turbine, fuel flow stopped, excess steam vented to atmosphere through relief valves	Rare, less than one/yr	a) First step: Steam vents for approximately 1 min. Fuel flow stops within a few seconds.	Vibrations caused by venting of steam could shake loose ash deposits causing puffs of particulates from stack	Emissions drop rapidly as fuel flow is stopped	Precipitator tripped after fuel flow stops.
				b) Second step: 12 - 14 hours	If draft is used for cooling boiler, wisps of fly ash from boiler and duct work will be emitted from stack.	None	Precipitator is not left on during boiler cooling because condensation would occur on wires and plates.
Fuel trip (emergency shutdown caused by malfunction in the boiler, fuel system, or other equipment or controls)	Immediate loss of fuel to boiler	Residual heat is used to generate steam and drive the turbine as long as possible, then load is dropped. Precipitator is operated as for normal shutdown.	Rare, 2/yr	a) First step: Fuel flow stops completely within a few seconds	Emissions drop rapidly as fuel flow is lost	Emissions drop rapidly as fuel flow is lost	Because fuel feed equipment occurs in multiple units, a plant rarely is tripped because of equipment failure in the fuel feed system. However, a deterioration in fuel quality, such as high moisture content, may make it difficult to maintain the furnace flame.
				b) Second step: 12 - 14 hours	If draft is used for cooling boiler, wisps of fly ash from boiler and duct work will be emitted from stack.	None	

Table 1. The effects of transient conditions of operation on stack emissions (con.)

Cause of transient condition	Effect on process control system	Manual or automatic compensation in the process control system	Frequency of occurrence	Duration of transient condition	Effect on stack emissions: Particulates	Effect on stack emissions: Oxides of nitrogen	Comments
LOAD CHANGES							
Normal cyclical variations in load	Quasi-steady state operation at slowly varying loads	Load changes gradually maintaining near optimum firing conditions so transient effects are believed to be negligible	Diurnal	Varies – change of 10% of maximum rated load requires 15-30 minutes	Precipitator efficiency normally improves at reduced load and deteriorates at overloading	Reduced at lower loads	Minimum output firing only with coal usually is 40% full-load output; at night, base-loaded units frequently are reduced to 50-60% full load so that intermediate-sized units will not have to be shut down.
Load reduction caused by disruption of fuel supply (caused by malfunction in feeders, burners, or other fuel cycle equipment or controls)	Fuel supply inadequate for load; excess air higher than normal	Load is shed; furnace draft is reduced to normal excess-air range; oil may be used as supplementary fuel until flame is stabilized	May be frequent if low quality fuel is being fired	Varies according to magnitude of load reduction; 1-15 minutes is typical range	Normally no transient effect; visible plume may result if oil is fired; when stabilized at lower load, emissions should be decreased	May increase if excess air is high; when stabilized at lower load, emissions should be decreased	Time of transient can vary greatly with design of boiler and control systems. Newer electronic controls normally are faster than pneumatic controls.
Failure of coal pulverizer mill	Reduction of fuel supplied to boiler; furnace temperature reduced	Fuel requirements supplied by remaining mills	Rate is related to fuel quality; high moisture causes clogging, rocks cause excessive wear	a) First step: 1 - 15 minutes to stabilize boiler	Slight decrease in rate of emissions because of a decrease in the rate of burning fuel	May decrease because of reduced furnace temperature; may increase because of increased excess air	Pulverizing mills grind coal better at lower supply rates, and the combustion of pulverized coal improves as the particle size becomes smaller. Therefore, the rate of fly ash emissions from a furnace and, consequently, the load on the precipitator increase if fewer pulverizers are used to grind a given amount of coal.
				b) Second step: After boiler is stabilized	May increase if same rate of fuel feed is maintained by fewer pulverizers (efficiency of one precipitator decreased by 1%)	No change	

Table 1. The effects of transient conditions of operation on stack emissions (con.)

Cause of transient condition	Effect on process control system	Manual or automatic compensation in the process control system	Frequency of occurrence	Duration of transient condition	Effect on stack emissions		Comments
					Particulates	Oxides of nitrogen	
LOAD CHANGES (con.)							
Load reduction caused by disruption of air supply (caused by malfunction of ID fan, FD fan, damper, or other draft equipment or controls)	Air supply inadequate for complete combustion	Load is shed; fuel flow is reduced until normal excess air range is achieved; oil may be used as supplementary fuel until flame is stabilized	Rare, less than one/yr	Varies according to magnitude of load reduction; 1-15 minutes is typical range	Lower gas flow rate tends to improve efficiency but unburned carbon may be emitted because of low air level; visible plume may result if oil is fired; when stabilized at lower load, emissions should be decreased	Decreased while excess air is low; when stabilized at lower load, emissions should be decreased	Time of transient can vary widely with design of boiler and control systems. Newer electronic controls are faster than pneumatic. If unit has only one ID fan or FD fan, a shutdown may be required. If the excess air is low, the emission of carbon monoxide is increased until excess air reaches normal range.
Forced load reduction caused by other reasons not directly limiting fuel or air flow (e.g., malfunction in feedwater, steam, or condensate system)	Load might be reduced slowly as with normal cyclical variations or abruptly with resultant nonoptimum firing conditions	Load is shed; fuel flow to air flow ratio could cycle until normal range is achieved at new load; oil may be used as supplementary fuel until flame is stabilized	Rare, maybe 4/yr	Varies according to magnitude of load reduction; 5 minutes to 1 hour is typical range	Unburned carbon may be emitted if excess air is low; visible plume may result if oil is fired; when stabilized at lower load, emissions should be decreased	Emissions may cycle higher with high excess air, lower with low excess air; when stabilized at lower load, emissions should be decreased	Time of transient can vary greatly with design of boiler and control systems. Newer electronic controls normally are faster than pneumatic controls; emission of carbon monoxide is also increased if excess air is lower than normal.
Abrupt increase in load	Fuel, steam, and air flow must be increased	Fuel flow to air flow ratio could cycle until normal range is achieved at new load	Less than 6/yr	Varies according to magnitude of load change; 5 min. to 1 hour is typical range	Unburned carbon may be emitted if excess air is low; emissions will be increased at higher load but not necessarily in excess of limits	Emissions may be higher with high excess air, lower with low excess air; when stabilized at higher load, emissions will be increased	Time of transient can vary greatly with design of boiler and control systems. Newer electronic controls normally are faster than pneumatic controls; emission of carbon monoxide is also increased if excess air is lower than normal.

Table 1. The effects of transient conditions of operation on stack emissions (con.)

Cause of transient condition	Effect on process control system	Manual or automatic compensation in the process control system	Frequency of occurrence	Duration of transient condition	Effect on stack emissions		Comments
					Particulates	Oxides of nitrogen	
FUEL QUALITY VARIATIONS							
Fuel supply reaches bunker turnover point	Coal quality parameters may change abruptly, upsetting optimum firing conditions	May cause transient cycling of fuel flow rate or excess air	2/day	Varies from unnoticeable transition to upset of perhaps 15 minutes duration	Probably no affect unless ash content changes drastically; see "Excessive ash in coal" below	Emissions may cycle as fuel to air ratio cycles, lower emissions with low excess air and higher emissions with high excess air	Coal is filled into a bunker in batches. The bunker turnover print is the time at which a new batch of coal first reaches the boiler.
Excessive moisture in coal	Clogging of bunkers, feeders, or mills	Load may have to be dropped; older units often put on manual control; oil is used as supplementary fuel to stabilize flame	Usually related to weather conditions, such as rainy season	As long as several days	Normally no effect; visible plume may result if oil is fired	Emissions will decrease with load reduction	See also "Load reduction, disruption of fuel supply" above.
Excessive ash in coal	Fuel system may be unable to provide sufficient fuel for full-load operation	Unit may have to operate at less than full load if problem is severe	Possible with change of source for fuel	Until fuel quality returns to normal	Higher inlet particulate loading on precipitator may result in excessive emissions	None	Not likely to be noticeable as a short-term transient problem.
Ash with increased slagging tendencies	Slag tends to build up on furnace walls and reduce heat transfer to tubes	May have to increase excess air to control wall deposits	Possible with change of source for fuel	Until fuel quality returns to normal	Emissions may be increased if draft is increased appreciably; emissions may be increased or decreased by changes in flue gas temperature	Emissions will increase since higher gas temperature will occur as heat transfer to tubes is reduced; increasing excess air to control slagging will also increase emissions	

Table 1. The effects of transient conditions of operation on stack emissions (con.)

Cause of transient condition	Effect on process control system	Manual or automatic compensation in the process control system	Frequency of occurrence	Duration of transient condition	Effect on stack emissions: Particulates	Effect on stack emissions: Oxides of nitrogen	Comments
FUEL QUALITY VARIATIONS (con.)							
Variation in sulfur content	Change the resistivity of the fly ash	Electrostatic field intensity in precipitator for optimum collection efficiency may change	Possible with change of source for fuel	Until fuel quality returns to normal	Efficiency of collection will change	None	
Variation in chemical content of ash	May change the resistivity and particle size of fly ash	Electrostatic field intensity in precipitator for optimum collection efficiency may change	Possible with change of source for fuel	Until fuel quality returns to normal	Efficiency of collection may change	None	

Table 1. The effects of transient conditions of operation on stack emissions (con.)

Cause of transient condition	Effect on process control system	Manual or automatic compensation in the process control system	Frequency of occurrence	Duration of transient condition	Effect on stack emissions: Particulates	Effect on stack emissions: Oxides of nitrogen	Comments
ELECTROSTATIC PRECIPITATOR MALFUNCTIONS (frequency of occurrence given as bus section unavailability in percent of operating time)							
Failure in power supply (transformer or rectifier)	Loss of service of bus section(s) supplied	Stop power to power supply	1 - 25%, but usually < 4% for all failures taken together	Replacement may take one week if spare is available	Emissions increase, magnitude depends on configuration of precipitator	None	Must shut down boiler to repair if problem is internal; otherwise, repair can be made with boiler in service. The power supply usually is repaired at the factory in several weeks. On some precipitators the power supply is difficult to reach for replacement.
Electrode short to ground: (1) at bushing, (2) at ash hopper	Equivalent to loss of power supply; total loss of performance of bus section(s)	Disconnect bus section from power supply	Usually < 1%	Until repair	Emissions increase, magnitude depends on configuration of precipitator	None	(1) Must shut down boiler to repair (2) May have to shut down boiler to repair
Broken electrode	Normally will short out entire bus section	Disconnect bus section from power supply	0 - 7%, usually < 1%	Until repair	Emissions increase, magnitude depends on configuration of precipitator	None	Must shut down boiler to repair
Inability to remove ash from hoppers	Reentrainment of ash, possible short of electrode (*see above*)	Use sledgehammer to jar hopper walls or stir ash with rods through access ports	0 - 3%, usually < 1%	Until ash flow can be restored, usually < 1 hr	Emissions increase	None	May have to shut down boiler to repair; problem may be caused by burning coal with higher ash content than precipitator was designed to handle.
Failure of rappers or vibrators	Buildup of ash on wires or plates	None	1 - 10%, usually < 2%	Until repair, usually several hours	Emissions are reduced for a few hours because reentrainment of ash is reduced; eventually emissions increase because of ash caking on wires or plates	None	Repair can be made with the boiler on line.
Failure in control circuits	Loss of service for bus sections affected	Stop power to precipitator	0 - 1%, usually < 0.2%	Until repair, usually several hours	Emissions increase	None	

Table 1. *The effects of transient conditions of operation on stack emissions (con.)*

Cause of transient condition	Effect on process control system	Manual or automatic compensation in the process control system	Frequency of occurrence	Duration of transient condition	Effect on stack emissions: Particulates	Effect on stack emissions: Oxides of nitrogen	Comments
MISCELLANEOUS OPERATING TRANSIENTS AND EQUIPMENT MALFUNCTIONS							
Soot blowing	Increases particulate load to precipitator	None	Every 8 hr or more often	5 - 15 minutes for intermittent blowing	Emissions will increase unless precipitator is designed to handle the increased loading	No transient effect but cleaning surfaces reduces NO_x by improving heat transfer and lowering gas temperature	Rate varies with boiler; some blow soot on automatic cycle almost continuously; some blow soot at the discretion of the operator.
Failure of soot blowing system	Excessive accumulations on surfaces reduce heat transfer	If efficiency of boiler is significantly affected, more fuel will be required to maintain load	1 per 3 months for retractable blowers, 1/week to 1/day for wall blowers	Until repair	May increase because of higher gas flow rate; may increase or decrease because of higher gas temperature	May increase because of higher gas temperature	Wall boilers can be removed and repaired while a boiler is in service. A bearing failure is the most frequent trouble with a retractable blower; on some boilers it cannot be repaired while the furnace is in service.
Accumulation of clinkers in bottom arch of boiler	Heat transfer to water wall tubes is reduced	If efficiency of boiler is significantly affected, more fuel will be required to maintain load	2/yr with poor quality of coal	Until repair when boiler is out of service	May increase because of higher gas flow rate; may increase or decrease because of higher gas temperature	May increase because of higher gas temperature	Problem exists when burning coal of high ash content and low ash fusion temperature. Boiler should be inspected for clinkers whenever out of service.
Malfunction of burner tilt mechanism	Partial loss of steam temperature control; more limited flame control	None	1/yr	Until repair, about 4 hr	None	Depends on number of burners affected and the tilt. NO_x emissions in *tangentially* fired boilers are usually lowest when burners are horizontal.	

Table 1. The effects of transient conditions of operation on stack emissions (con.)

Cause of transient condition	Effect on process control system	Manual or automatic compensation in the process control system	Frequency of occurrence	Duration of transient condition	Effect on stack emissions		Comments
					Particulates	Oxides of nitrogen	
MISCELLANEOUS OPERATING TRANSIENTS AND EQUIPMENT MALFUNCTIONS (con.)							
Motor failure in rotating (Ljungstrom) air preheater	Primary and secondary air temperature is reduced; flame temperature is reduced; flue gases not cooled by air preheater	Put spare motor into operation if available, usually unit must be shut down	Rare	Until spare motor is put into operation or main motor is repaired	Higher volumetric flow rate through precipitator will increase emissions; in cold-side precipitator increase in gas temperature of 200 - 300° will tend to increase collection efficiency	Emissions are reduced because of lower flame zone temperatures	If spare motor is not available, shutdown of boiler is required to prevent warping of air preheater from thermal stress
Movement of personnel in precipitator during shutdown	Draft blows fly ash out stack	None		As long as personnel move about precipitator	Fly ash emissions occur with no input fuel	None	Fly ash emissions during such an episode are unavoidable and insignificant.
Boiler tube failure	Possible loss of steam pressure	None	Several/yr	Until repair	Possible increase because of poor conditions of combustion during shutdown		Small leaks in upper furnace (reheater or superheater) tubes may be tolerated for several days. However, a wall tube failure in the lower furnace usually requires an immediate shutdown.

RECOMMENDATIONS

To obtain a precise knowledge of the effects of transient conditions of operation on the emission of gaseous pollutants from a fossil-fuel-fired steam-electric generation plant, an experimental program must be organized that monitors both the emissions of pollutants and the parameters of boiler operation. Because each boiler has its own characteristic behavior, the extrapolation of performance from one boiler to another is difficult, especially if the boilers are different in size. Therefore, an extensive program of continuous monitoring is necessary for the accumulation of data adequate for statistical analysis of transient conditions.

Utility companies may be willing to cooperate in the establishment of a monitoring program. The utility company would gain experience in the operation of monitors and learn more about control of its equipment for the creation of optimum conditions of operation with respect to energy conversion and the emission of pollutants.

1.0 INTRODUCTION

Air pollution standards generally are based upon control of a specified percentage of emissions during steady-state operation of a control system. Periods of startup, shutdown, and malfunctions of process and air pollution control equipment generally are not subject to meeting a prescribed standard (ref. 1).

However, these periods of transient operating conditions are becoming recognized as contributing to the accumulation of pollutants in the ambient atmosphere and as the cause for short-term, localized accumulations of high concentrations of pollutants. Regulatory agencies are beginning to recognize the need to place greater emphasis on insuring that process sources minimize both the number of emission-causing malfunctions and the emissions when malfunctions do occur (ref. 2). This enforcement effort is being taken in one or more of the following approaches:

1. Requirements to report malfunctions and steps taken to minimize emissions during these occurrences;
2. Review of design and proposed maintenance of critical equipment in proposed new plants;
3. Litigation against sources that, in the opinion of the regulatory agency, continue to have abnormally high occurrences of malfunctions.

In order to supplement this effort, information is required to identify malfunctions, to determine emissions during their occurrence, to determine how and when they occur in practice, and to identify methods for their prevention and minimization. With this information, specific strategies can be developed to reduce environmental problems created by process and equipment malfunctions.

This report focuses on developing information on the malfunction of fossil-fuel-fired steam-electric generators. More specifically, the report focuses on older coal-fired steam generators that are equipped with a particulate-cleaning device as the only air pollution control equipment (i.e., no SO_x flue gas desulfurization system). These generators, usually 100-500 MW in electrical output capacity, are frequently being used to provide the cycling portion of the diurnal variation in power generated by electrical utilities. In such use, they are subject to operating in a transient mode a large percentage of the time. Newer, base-loaded generators are of more efficient and reliable design than the older plants. However, the effects of transient conditions on emissions from the newer plants should be similar to the effects for the older plants.

2.0 THE FOSSIL-FUEL-FIRED STEAM-ELECTRIC GENERATION PLANT

The stationary source of air pollution considered in this report is the fossil-fuel-fired steam-electric generation plant. The fossil fuel, either coal, oil, or natural gas, is burned in a furnace to produce heat; the heat vaporizes water to steam in a boiler; the steam is used to drive a turbine; and the turbine drives an alternator, which generates electricity.

The principal emissions from a fossil-fuel-fired electric generator are soot, particulates, and the oxides of nitrogen and sulfur. When a generator is equipped with a particulate collection device, soot is a significant emission only during conditions of poor combination in the furnace. Particulate emissions are not a concern when the fuel is oil or natural gas because of the negligible ash content of these fuels. The use of coal with an ash content of 5-16 percent as a fuel requires the use of an electrostatic precipitator to control the emission of fly ash. Since 1970 most older coal-fired electric generators have been equipped with precipitators of 95 percent collection efficiency or better. New coal-fired electric generators are being equipped with precipitators whose collection efficiency is better than 99 percent.

The emission of the oxides of nitrogen is a function of the conditions of combustion in the boiler. All fossil fuels produce about the same rate of emissions of oxides of nitrogen.

The rate of emissions of the oxides of sulfur depends upon the sulfur content of the fuel. Natural gas contains a negligible amount of sulfur, oil contains 0.1-4.4 percent sulfur, and coal contains 014-5.5 percent sulfur. Devices that collect sulfur oxides from stack gases are not considered in this study.

The electric generators of principal concern in this report are the older coal-fired generators, usually 100-500 Mw in electrical output capacity, which are being used for providing the cycling portion of the diurnal variation in power generated by electric utilities. Newer, base-loaded generators are of more efficient and reliable design than the older plants. However, the effects of transient conditions on emissions for the newer plants should be similar to the effects for the older plants. Oil-fired and gas-fired generators are not considered in detail because they are easier to control and are less subject to the upset conditions found in coal-fired plants.

2.1 LOCATION AND SIZES OF FOSSIL-FUEL-FIRED STEAM-ELECTRIC GENERATION PLANTS

Most electric generation plants in the United States are fired by fossil fuels. The local cost of fuel and pollution abatement requirements determines what type of fuel is used. Throughout the Appalachians and the Southeast, coal is used because of the availability, low transportation costs, and lack of difficulty in meeting pollution abatement requirements. In the Northeast, oil is the principal fuel because of the high cost of transporting coal and the stringent pollution abatement procedures required near large cities. In the Southwest, natural gas is used for fuel because of the availability. On the Pacific coast, fuel oil is used because of the pollution problems.

The first steam-electric generation plant that used turbines exclusively was the Fisk Street Station of the Commonwealth Edison Company, Chicago. The plant commenced operations in 1903 with two turbines, rated at 5 MW, each driven by eight 500 hp boilers. Upon completion, the Station contained eighty 500 hp boilers, four turbines rated at 5 MW, and six turbines rated at 8 MW (ref. 3). By 1925 generation units of 60 MW were being placed in service, by 1956 generation units of 500 MW were being placed in service, and today units of 1,600 MW have been placed in service.

Boilers are designed for a lifetime of 30-40 years. Because most generation units smaller than 100 MW were placed in service more than 40 years ago, generators in service today are 100 - 1,600 MW in size.

2.2 FUELS AND COMBUSTION

The combustion of fuel is the source of all air pollution that comes from a plant. The amount of pollution resulting from combustion varies considerably with the type of fuel. However, no fuel now being used for combustion in an electric generation plant can be burned without pollution of the atmosphere.

Most steam-electric generation plants burn fossil fuels. The fossil fuels were created by the fossilization of organic matter in the earth over a long period of time. The fossil fuels are coal, oil, and natural gas. Coal is the fuel that is used most frequently to fire steam-electric generators. Oil or natural gas sometimes is used because of advantageous conditions of supply or the need for significantly lower pollution.

Other fuels that are used to fire steam-electric generation plants are urban wastes (usually as a supplementary fuel) and wood wastes, especially in the wood-processing industries. Because these fuels are used infrequently, they will not be discussed further.

2.2.1 Coal

Coals are classified under four major categories and several subcategories. The major categories are lignite, subbituminous, bituminous, and anthracite. Table 2 shows typical ranges of analysis of

Table 2. Typical range of coal analyses

Rank	Anthracite	Bituminous	Subbituminous	Lignite
Analysis:				
Moisture, %	2-5	2-15	15-30	25-45
Volatile matter, %	5-12	18-40	30-40	25-30
Fixed carbon, %	70-90	40-75	35-45	20-30
Ash, %	8-20	3-25	3-25	5-30
Heating Value, 10^3 Btu/lb	12-14.5	10-14	8-10.5	5.5-8
Sulfur, %	<1	0.5-5	0.5-3	0.5-2.5
Nitrogen, %	0.5-1	1-2	1-1.5	0.5-1.5

these four categories. Lignite has a distinct woody or clay-like structure, a moisture content of 30-45 percent, and a low heating value of 5,500 to 8,000 Btu per pound. Upon drying, lignite disintegrates into flakes. Lignite is increasing in commercial importance as supplies of high grade coal are depleted. Subbituminous coal, although of higher quality than lignite, also has a high moisture content and a relatively low heating value. Anthracite is a hard, smokeless coal that has less than 8 percent volatile matter and is generally slow to ignite.

Bituminous coals are the principal fuels for power generation in the United States because of their availability and favorable price. These coals have a wide variation in volatile matter content. The bituminous coals of low volatility have a low moisture content and high heating value and produce little smoke when burned, whereas the bituminous coals of high volatility have a high moisture content and can produce an objectionable amount of smoke unless properly burned in a furnace of sufficient size to burn the volatile gases.

The ash residue remaining after the combustion of coal may be in a variety of forms: small, dry particles; chunks of slag; or a pool of molten ash. The form of the ash residue depends on the fusion characteristics of the ash and on the temperature and method of combustion.

Coal used for fuel commonly is analyzed by two methods, the proximate analysis and the ultimate analysis. The proximate analysis determines the energy content and the percent by mass of moisture, ash, volatile matter, and a fixed carbon. The ultimate analysis determines the mass percent of carbon, hydrogen, nitrogen, oxygen, sulfur, and ash. In the ultimate analysis, the hydrogen and oxygen contained in the moisture in the fuel may be reported separately as moisture.

2.2.2 Fuel Oil

Fuel oils are divided into five standard grades on the basis of specific gravity and viscosity. Analysis results often report specific gravity, viscosity, heating value, and percent by mass of sulfur, hydrogen, carbon, and ash. Table 3 reports typical analyses for the five grades. Numbers 1 and 2 fuel oils are distillates. Because the distillate oils are obtained by the condensation of the hydrocarbon vapors from crude stills, they are essentially free of ash. The distillate oils are used as fuel in domestic and light industrial applications and for starting a boiler that burns coal. Numbers 4, 5, and 6 fuel oils are the residual oils obtained after distillation that contain the ash that was present in the crude oil. Number 6 oil, also called Bunker C oil, is the primary fuel oil used in large-scale power generation. Compared to coal, number 6 fuel oil contains a small amount of ash, but it may be high in sulfur content.

2.2.3 Natural Gas

Natural gas is a generic term applied to underground accumulations of gaseous fuels of widely varying composition. Typical constituents are 85-95 percent methane, 0-5 percent nitrogen, and negligible sulfur,

Table 3. Typical range of fuel oil analyses

	Distillate oil		Residual oil		
Grade	No.1	No.2	No.4	No.5	No.6
Analysis					
Gravity. °API	35-42	30-35	23-25	18-22	12-16
Viscosity, Saybolt sec.	-	33-37	45-125	150-700	900-9000
Heating value, 10^3 Btu/gal	134-138	136-144	143-146	145-149	149-152
Sulfur, %	0.1-0.3	0.2-0.8	1-3	1-3	1-5
Hydrogen, %	12-14	12-14	11-12	10-12	10-12
Carbon, %	86-88	86-88	86-88	86-88	85-88
Nitrogen, %	<0.01	<0.01	0.1-0.5	0.1-0.5	0.1-0.5
Ash, %	0.01	0.01	0.01-0.1	0.01-0.1	0.01-0.3

with the remainder consisting of ethane, propane, and other hydrocarbons. The specific gravity of natural gas relative to air varies from about 0.6 to 0.7, and the heat content is typically 1,000 to 1,100 Btu/ft^3.

Of all fossil fuels, natural gas is the cleanest and easiest to burn in a steam generator. The gas is piped directly to the plant, where storage and handling are minimal. Complete combustion can be obtained with a low level of excess air and no smoke emissions. However, natural gas now is in very short supply, and the cost of firing with natural gas is prohibitively high for electric utilities except under unusual conditions of a favorable supply or requirements for low emissions.

2.2.4 Combustion Parameters

Depending on the conditions of combustion and its completeness, mixtures of complex hydrocarbon compounds contained in fossil fuels are converted to a series of intermediate substances and combustion products. Under ideal conditions of complete combustion, carbon is converted to carbon dioxide (CO_2), hydrogen to water vapor (H_2O), and sulfur primarily to sulfur dioxide (SO_2). These combinations of carbon, hydrogen, and sulfur with oxygen occur in definite proportions, with the oxygen being provided in the air supplied to the boiler. In theory, the amount of air required to burn a given amount of a particular fuel can be predicted from an analysis of the fuel. This amount of air, called "theoretical air," is the minimum amount of air required to burn the fuel completely. In practice, because of inadequate mixing and insufficient time for the chemical reactions to reach equilibrium, boilers are supplied with excess air to insure a close approach to complete combustion. Excess air normally is expressed as a percentage of theoretical air. Table 4 shows the amount of excess air required by various fuels when burned in a furnace designed for the particular fuel. The amount of excess air must be restricted to the minimum amount necessary to insure essentially complete combustion because the flow of hot gases up the stack represents a loss of thermal energy and a consequent decrease in the efficiency of the boiler.

Table 4. Usual amount of excess air supplied to fuel-burning equipment

Fuel	Type of furnace or burners	Normal excess air % by weight
Pulverized coal	Completely water-cooled furnace for slag-tap or dry-ash removal	15-20
	Partially water-cooled furnace for dry-ash removal	15-40
Crushed coal	Cyclone furnace	10-15
Coal	Spreader Stoker	30-60
	Water-cooled vibrating-grate stoker	30-60
	Chain-grate and traveling-grate stokers	15-50
	Underfeed stoker	20-50
Fuel oil	Oil burners, register-type	5-10
	Multifuel burners and flat-flame	10-20
Natural gas	Register-type burners	5-10
	Multifuel burners	7-12

2.3 EQUIPMENT IN THE GENERATION PLANT

Three types of coal handling are used in coal-fired generators. First, in the stoker-fired furnace, coal is burned on a moving grate. Because of the limitations in the capacity of the grate, stoker firing is not used on boilers larger than 200,000 kg steam/hr. Most electric utilities use a boiler much larger than 200,000 kg steam/hr. Second, in the pulverized coal-fired furnace, coal is ground in a pulverizing mill so that 70 percent will pass through a screen of 200 mesh. The disadvantages of the pulverized coal-fired furnace are that: the pulverizers require a large amount of power to pulverize the coal, there is a large fly ash discharge into the stack, and a large furnace volume is required for good combustion. However, pulverized coal firing is used rather than stoker firing because of the flexibility in type of coal that can be burned, the larger capacity of furnace which can be constructed, the improvement in response to a change in load, the ease of firing a combination of oil or gas with coal, the increase in thermal efficiency gained from the lower excess air required for combustion, and the lower carbon loss. Third, cyclone firing was adopted as a method to eliminate the requirement for pulverizing coal. In the cyclone furnace crushed coal, 95 percent of which will pass through a screen of 4 mesh, is burned quickly in a high-temperature combustion chamber called the cyclone. Then the hot gases pass into the main furnace for cooling. Most of the ash in the fuel is melted in the combustion chamber and is removed as molten slag.

In the pulverized coal-fired furnace, coal from a storage pile is fed to a hopper which has a storage capacity of about 10 hr. From the hopper the coal is fed to the pulverizers as needed. In the pulverizer the coal is dried, pulverized, and blown into the furnace. Depending on the design, pulverizers store from 100 to 1,000 kg of pulverized coal. A pulverizer storing a large amount of coal may explode if the coal is high in volatile content.

In the cyclone furnace coal either is crushed and stored in a central bin or is crushed and mixed with hot air at each cyclone. Crushing the coal at the cyclone and mixing with hot gases has the advantage of drying the coal which improves the crusher performance and provides better ignition of coals with a high moisture content.

Station auxiliaries either are driven by electric motors or steam turbines. For small power requirements electric motors usually are preferred because of the ease of control, lower maintenance requirements, and lower capital investment. However, turbines frequently are used because of the better overall efficiency gained when the intermediate step of generating electricity is avoided, especially when a large size of motor is required for an induced draft fan.

Mechanical collectors were installed in many older plants for the collection of fly ash. The efficiency of collection for these mechanical collectors was 80-85 percent. Later, electrostatic precipitators were added, either in addition to the mechanical collector or in place of it. The efficiency of collection of these devices was 90-95 percent. Today the new source performance standards require a collector, usually an electrostatic precipitator, with an efficiency of at least 99 percent.

Additional, more specific information on the equipment used in electric generation plants is given in the appendix.

2.4 CONTROL OF THE BOILER

The fuel feed, air supply, and internal pressure are the three independent variables that must be controlled simultaneously in a furnace. Each furnace consists of three control loops that regulate these variables, and these loops are coupled to keep the controlled variables constant at a set value or to maintain a desired ratio between two variables.

In drum boilers the steam pressure in the drum is monitored for the control of the rate of fuel feed, and the steam flow from the boiler can be monitored to determine the desired rate of change of fuel feed. The oxygen content of the flue gas can be used to regulate the air supply. The speeds of the forced draft fans and of the induced draft fans or the dampers on each fan are used to regulate the internal pressure.

In a once-through boiler, which does not have a large amount of water stored in a drum, the furnace must be controlled by the rate of change of steam consumption or turbine control oil pressure to improve the response time of the boiler. The fuel feed can be held at a constant ratio with respect to the water feed.

Differential expansion or contraction of components caused by thermal gradients places a limit on the rate of change of boiler conditions. Frequently, the turbine is the component most sensitive to thermal stress, especially in the larger units, which are 500 - 1,600 Mw in size.

The dry-bottom, pulverized coal-fired furnace has a more rapid transient response than other types of boilers because of the small capacity for the storage of heat. In the stoker-fired furnace, energy is stored in the fuel being burned on the grate, and in the wet-bottom, slag-tap furnace, heat is stored in the slag on the bottom and walls.

The most important factor affecting the response time of the boiler is the rate at which the feed of fuel can be changed. Ball-and-race or rod types of pulverizers store several thousand kilograms of pulverized coal, and this stored coal can be fed to the furnace quickly. High speed, impact pulverizers only store a hundred kilograms of coal. The rate of feeding fuel to the furnace cannot be changed rapidly because of the 20-30 sec response time required to feed additional coal into the pulverizers.

The amount of control of a furnace is measured in terms of steam pressure variation. On large boilers controls usually are designed to maintain the steam pressure within about 2 percent during a steady-state condition. During changes of load a wider tolerance in steam pressure may be allowed. For instance, for a rate of change of load of 10 percent/min a deviation of 10 percent may be allowed in steam pressure.

2.5 UTILIZATION OF STEAM-ELECTRIC GENERATION PLANTS

The diurnal variation in load for an electric utility system may be 40 percent of the peak requirement. To accommodate this variation in load, many electric utilities have constructed fossil-fuel-fired plants, predominantly coal, to maintain the steady "base" load and have used, when available, hydroelectric or internal combustion gas turbine generators to generate the varying part of the power. Both types of generators can respond rapidly to changes in load, whereas the fossil-fuel-fired boiler responds slowly.

Unfortunately, with the rapid growth in demand for electricity, the available hydroelectric power is becoming a smaller part of the total power generated. Because the demand for natural gas far exceeds the supply, gas turbines are expensive to operate and have a limited potential for future application. Therefore, the fossil-fuel-fired plants are being required to absorb a larger part of the variations in load for a utility system, especially now that nuclear plants are being constructed. Nuclear plants operate most efficiently as base-loaded plants.

The variation in load and power generation of two utilities during an entire week is shown in Figures 1 and 2. The distribution for Duke Power Company shown in Figure 1 is typical for the operation of many companies. The nuclear plants are base loaded. The gas turbines and hydroelectric plants make as wide a swing as possible, and the coal-fired plants take the difference. At night, where breakdown by type of generation equipment is shown, the power generated is greater than the system load. During this time, power was being sold to another utility. In August, the amount of hydroelectric power capacity usually is lower than the nominal capacity of the generators because of the limited amount of water that is available in the streams.

Another pattern of generation is shown for the Tennessee Valley Authority (TVA) in Figure 2. During November, TVA had more water in the streams available for use than they had generation capacity, and a shortage of coal was being encountered. Therefore, the hydroelectric plants were operated at full output all day, and the coal-fired plants were cycled to reduce the consumption of coal.

Both of the above cases show that the coal-fired plants must cycle. Usually, the larger, more efficient plants are base loaded, and the older, smaller, and less efficient plants are cycled. Both Duke Power and TVA have relatively favorable conditions for cycling because of the amount of hydroelectric power available in their operating territories. Many operating companies have little or no hydroelectric power available.

Many older plants operate with inefficient pollution control devices because they were constructed at a time when there was little public concern about pollution. Most of the past effort in pollution control has been directed toward the collection of fly

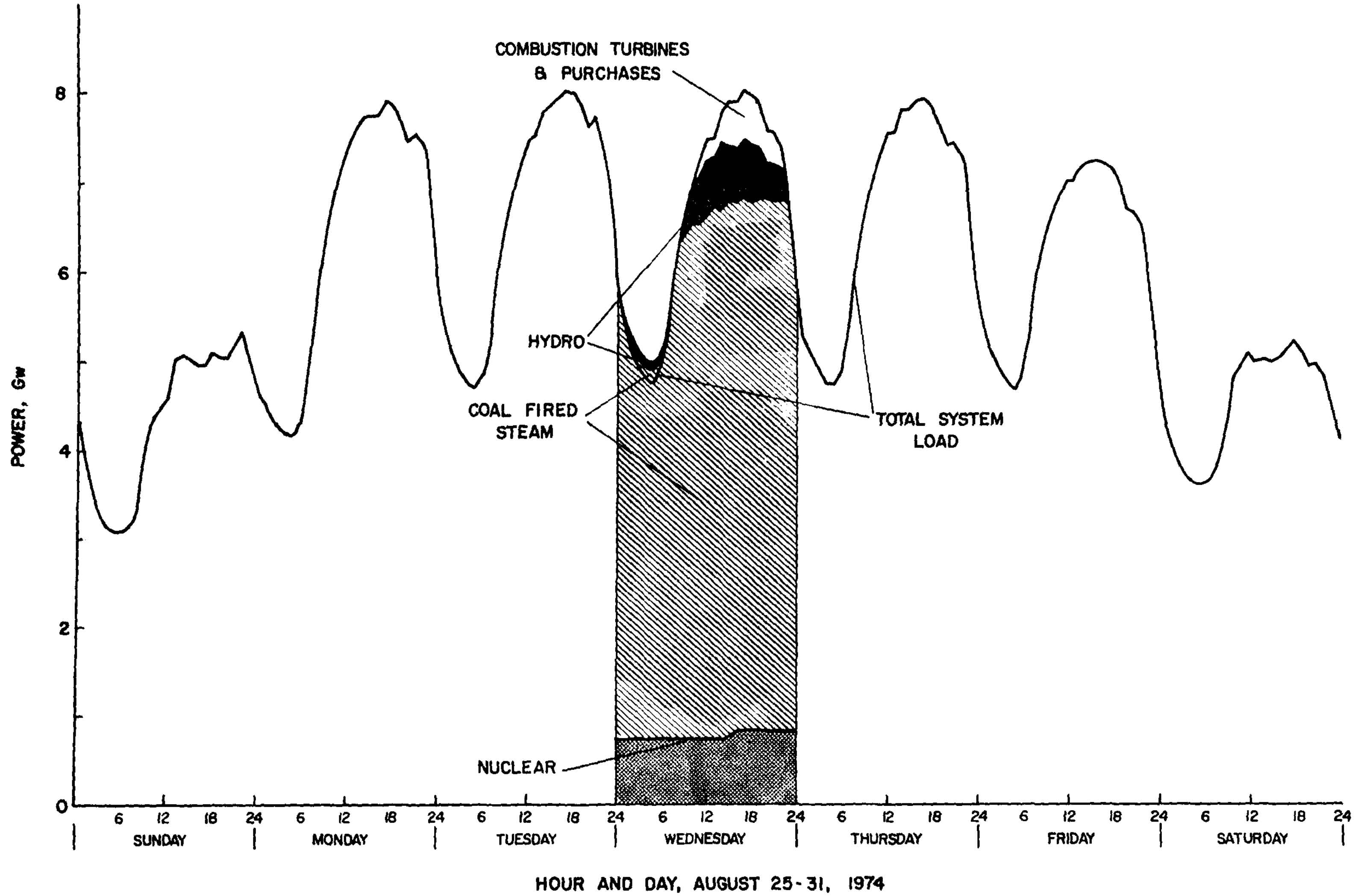


Figure 1. System power generation and load for the Duke Power Company. Power generated in excess of load demand was sold to other operating companies.

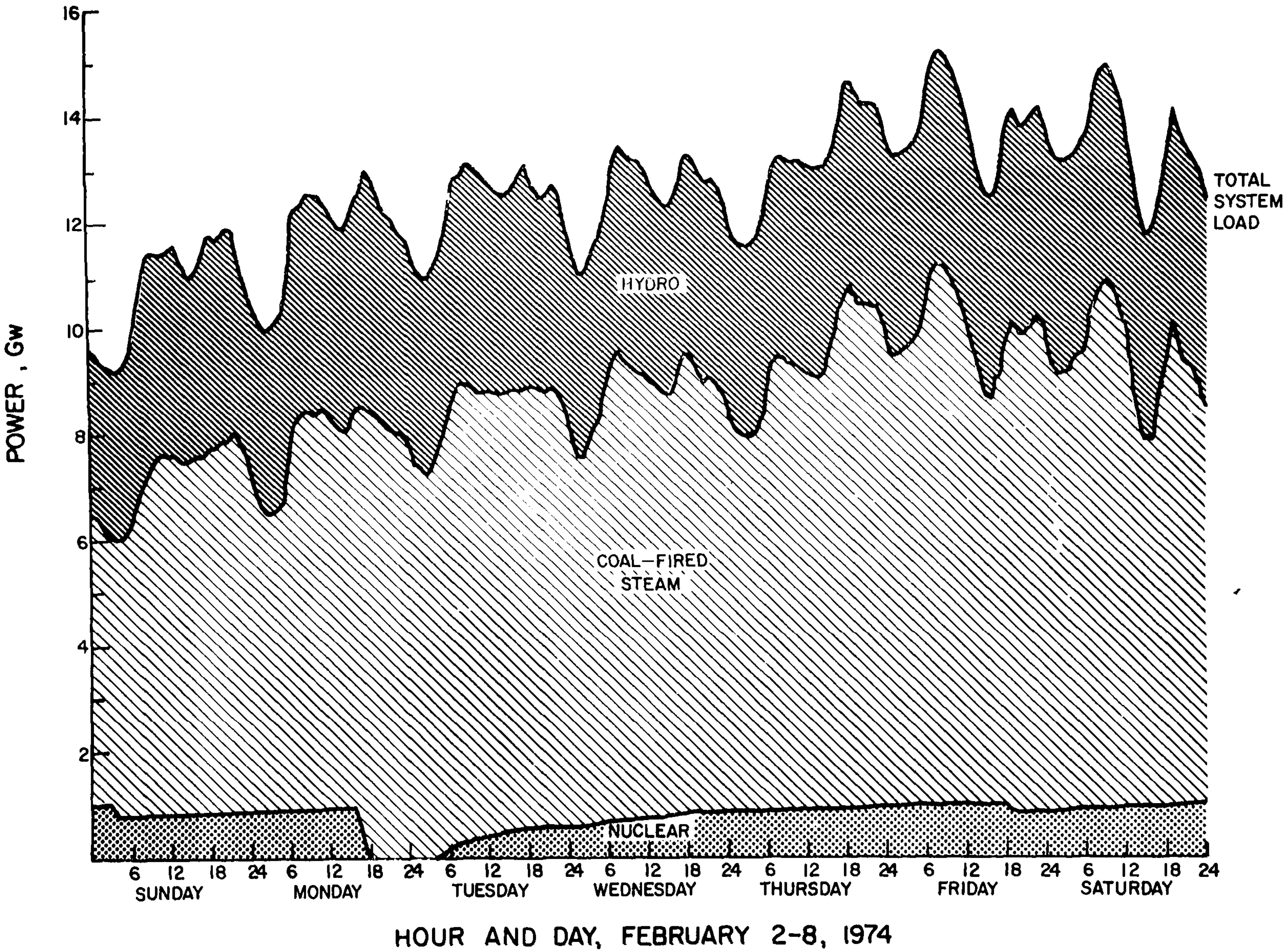


Figure 2. System power generation and load for the Tennessee Valley Authority. No power was purchased or sold during the week. Gas turbines were used to generate less than 400 Mw for brief periods February 3-6.

ash. A plant 15 years old may have a precipitator with an efficiency of 80-95 percent. Occasionally, a high efficiency (that is, better than 99 percent) electrostatic precipitator has been installed recently on an older boiler.

2.6 AVAILABILITY OF DATA ON THE OPERATION OF PLANTS

Because boilers have been operated successfully for many years, utility companies today have little concern about the failure modes of their boilers. Although logs are kept on each boiler, these records tend to be brief, at best making it difficult to obtain information on transient conditions of operation. Frequently, if a failure occurs, all manpower in the plant is directed toward correction of the fault. Then, after the fault is corrected, most personnel will turn their attention to some other problem, often forgetting even to enter the upset condition into the log.

By contrast, utility companies have lacked experience in the operation of equipment such as electrostatic precipitators, and some operating companies have kept detailed records on the performance of various classes of units in their system. For instance, the Tennessee Valley Authority has kept extensive records on the performance of precipitators. Other companies, however, have not kept detailed records of performance, especially when keeping the records has no obvious benefit, such as an improved efficiency of operation or a reduction in costs.

Even when emissions data are available, the conditions of operation are so complex that little can be inferred because of unknown conditions of operation. For instance, in emissions data for a coal-fired plant from Southern California Edison Company presented later in this report the excess air was measured before the air preheater. The leakage of air into the flue gases at the air preheater, however, significantly affects the concentration of pollutants in the stack gases. Even though the fuel characteristics, fuel feed rate, excess air rate, and pollutant concentrations are known, the emission rate per input unit of heat cannot be determined.

3.0 NORMAL, STEADY-STATE EMISSIONS FROM FOSSIL-FUEL-FIRED STEAM GENERATORS

Because of the multitude of variables involved in the operation of steam generators, normal, steady-state operation is difficult to describe. Differences commonly are observed in the operating characteristics of two units of identical design in the same plant and even in the day-to-day operations of the same unit. Meaningful comparison of different units is even more difficult because of design variations. Nevertheless, in order to assess the effects of transient conditions of operation on the emissions from a fossil-fuel-fired steam generator, baseline conditions need to be established.

Contract acceptance tests for equipment and compliance tests for pollution control regulations usually are performed with a rigorously defined set of conditions of operation imposed on the steam generator. Typical specifications may include the following:

1. Constant load on the generator (generally at or near the rated full-load capacity);
2. Constant steam flow, temperature, and pressure,
3. Constant fuel and air flow (that is, the percent excess air is held constant);
4. Constant burner tilt position, if applicable;
5. Constant high voltage supply to the electrostatic precipitator.

With skillful operation and no large perturbations in the plant or load, the parameters of operation can be held nearly steady. Fuel samples are collected frequently during a test, and a composite sample is prepared and analyzed to determine the average characteristics of the fuel.

Using the operating data, acceptance tests, and compliance tests, the emissions from a generation plant can be estimated. Estimated emissions for 15 representative coal-fired generation plants are presented in Table 5. The data, based on the latest published report of the Federal Power Commission, are given for each entire plant which

Table 5. Emissions from selected coal-fired electric generation plants for 1971[a]

Plant capacity[b] Mw	Plant efficiency, percent	No. of boilers	Total generation: Amount, Gw-hr	Total generation: Percent of capacity[c]	Coal consumed[d]: Amount, gigagram[e]	Coal consumed[d]: Heat content,[f] joule/g	Coal consumed[d]: Percent ash content	Coal consumed[d]: Percent sulfur content	Estimated[h] efficiency of particulate collection from stack gases, percent
2,558	36.1	3	12,941.8	58	5,529	23,596	19.3	4.1	95.0
2,000	39.2	4	13,682.7	78	4,632	26,938	14.5	0.9	90.0-95.0
1,510	27.5	2	1,204.7	9	861	28,027	10.8	0.4	97.0
1,315	32.5	6	4,736.7	41	2,008	26,341	12.4	3.4	94.9-99.5
1,155	37.0	5	8,153.4	81	2,964	26,771	15.5	1.1	90.0-95.0
1,125	35.6	2	5,607.8	57	2,106	25,706	17.1	3.2	50.0-95.0
950	37.7	1	5,640.4	68	1,982	26,361	15.2	1.6	81.0
623	35.0	1	3,394.1	62	1,520	22,691	18.6	4.0	98.6
533	30.7	9	2,921.7	63	1,077	27,873	13.0	0.9	88.0
450	32.5	1	1,458.8	37	612	26,436	12.1	3.4	98.7
439	37.1	2	3,226.7	84	1,201	25,631	18.6	0.9	95.0
240	27.1	4	207.3	10	66	25,438	18.7	2.8	95.0
210	29.9	4	1,388.0	75	595	28,094	14.1	1.1	88.0
182	31.7	2	976.9	61	441	25,192	10.9	2.9	86.0-87.0
138	28.2	2	705.5	58	232	27,690	11.5	1.2	75.0-85.0
48	24.0	4	118.4	28	38	25,722	7.8	2.9	80.0

[a]Data obtained from the Federal Power Commission (13).

[b]The plant capacity is the sum of the nameplate ratings for all generators.

[c]Station losses, usually 3-4%, are neglected.

[d]Oil and gas used for starting fire are neglected.

[e]1 kiloton = 0.90718 gigagram.

[f]1 Btu/lb = 2,326 joules/kg.

[g]AlaP – Alabama Power Company, App - Appalachian Power Company, CIL - Central Illinois Light Company, DPCo - Duke Power Company, IPCo - Illinois Power Company, SoCalEd - Southern California Edison Company, TECo - Tampa Electric Company, TVA - Tennessee Valley Authority

[h]The estimation of efficiency is based on measured performance and accounts for time a unit has been out of service.

Table 5. Emissions from selected coal-fired electric generation plants for 1971[a]

Rate of emissions						Plant name	Operator[g]
With respect to heat input,[d] gram/megajoule			With respect to electrical output, kg/Mw-hr				
Particulates	Oxides of nitrogen	Oxides of sulfur	Particulates	Oxides of nitrogen	Oxides of sulfur		
0.04	1.17	3.41	2.0	11.7	34.4	Paradise	TVA
0.46	0.34	0.66	4.2	3.1	6.0	Marshall	DPCo
0.07	0.35	0.27	1.5	7.1	5.3	Mohave	SoCalEd
0.13	0.81	2.53	1.5	9.1	28.3	Gannon	TECo
0.42	0.34	0.80	4.1	3.3	7.8	Allen	DPCo
1.67	0.35	2.45	16.2	3.4	23.6	Widows Creek B	TVA
0.93	0.34	1.22	8.6	3.2	11.3	Bull Run	TVA
0.01	1.21	3.47	0.1	12.3	35.3	Baldwin	IPCo
1.75	0.32	0.66	18.0	3.3	6.8	Buck	DPCo
0.11	0.57	2.51	1.2	6.3	27.8	Big Bend	TECo
0.31	0.35	0.68	2.9	3.4	6.5	Kanawha River	App
0.24	0.29	2.16	1.9	2.4	17.4	Watts Bar	TVA
1.84	0.32	0.77	22.2	3.9	9.3	Cliffside	DPCo
0.49	0.36	2.28	5.6	4.1	25.9	Vermilion	IPCo
0.71	0.39	0.84	6.5	3.6	7.6	Gadsden	AlaP
0.40	0.32	2.18	3.3	2.7	18.2	Keystone	CIL

consists of one to nine boilers as noted. Even though data were not available for making the calculation for each boiler, the emissions data can be considered representative of the emissions from an individual unit. During more recent years, many precipitators have been replaced with more efficient units, and there should be a decrease in the emissions of particulates. Fuel oil and natural gas burned during startups were neglected in the calculation of the rate of emissions.

The rate of particulate emissions can be affected dramatically by the reliability of the precipitator. For instance, as shown in Table 5, one boiler at the Widows Creek B plant of TVA has a precipitator with an effective collection efficiency of only 50 percent, while the other boiler has a precipitator with an effective collection efficiency of 95 percent.

The trend in the electric utility industry is to construct larger, more efficient boilers that are base loaded and to use the older, less efficient boilers for cycling. To reduce particulate emissions, precipitators with collection efficiencies of 99 percent or greater at full load are used on the large boilers. The older boilers, now used for cycling, originally were equipped with precipitators having a collection efficiency of 80-95 percent. Most of these boilers now have been equipped with new precipitators of high efficiency.

The trend toward the construction of large boilers with high efficiency precipitators results in a population of boilers in the United States in which the rate of particulate emissions tends to decrease as the size of the boiler increases, as shown in Table 5. With the current construction of boilers of 1,000 Mw size, many of the large existing plants are being used for some cycling. For instance, Plant Allen, the second largest plant on the Duke Power system in 1971 and presently the third largest plant, now is being cycled. The five units at Plant Allen are capable of producing about 10 percent of the expected peak system load for 1975.

The magnitude of the diurnal fluctuation in load for a power system determines the amount which the large generation units need in order to be cycled. Sometimes it is more economical to reduce the output of the large units so that the small units can be kept in service and cycled the next day.

Estimates of the baseline emissions sometimes can be made from a knowledge of certain general relationships. The following sections discuss the estimation of the steady-state rates of emissions of pollutants from a steam generator operating in a steady-state condition. The estimations are based on a consideration of the mass balance concept and the primary variables that affect the emissions of pollutants. The estimations are useful for qualitative assessments. To obtain a quantitative prediction of the effect of transient conditions of operation on emissions from a particular boiler, thorough tests must be conducted on that boiler under steady-state conditions.

3.1 THE MASS BALANCE CONCEPT

The fundamental law of the conservation of mass can be applied to the fuel-gas circuit in the following form:

$$\begin{pmatrix}\text{Rate of}\\ \text{mass input}\end{pmatrix} - \begin{pmatrix}\text{Rate of}\\ \text{mass output}\end{pmatrix} = \begin{pmatrix}\text{Rate of mass}\\ \text{accumulation}\end{pmatrix} \qquad (1)$$

In combustion processes, equation (1) commonly is called the mass balance equation. When no significant flow variations with respect to time exist and no mass is accumulated, the system is said to be at steady-state with respect to mass transport, and equation (1) states that what goes into the circuit comes out. This concept of mass balance is valid for the total mass of material entering and leaving the circuit and for the individual chemical elements considered separately. Because of the chemical processes that occur during combustion, the mass of each chemical compound is not conserved, and equation (1) can not be applied to chemical compounds.

Referring to Figure 3, the inputs of the fuel-gas circuit are the fuel and air, and the outputs are the bottom ash, the collected

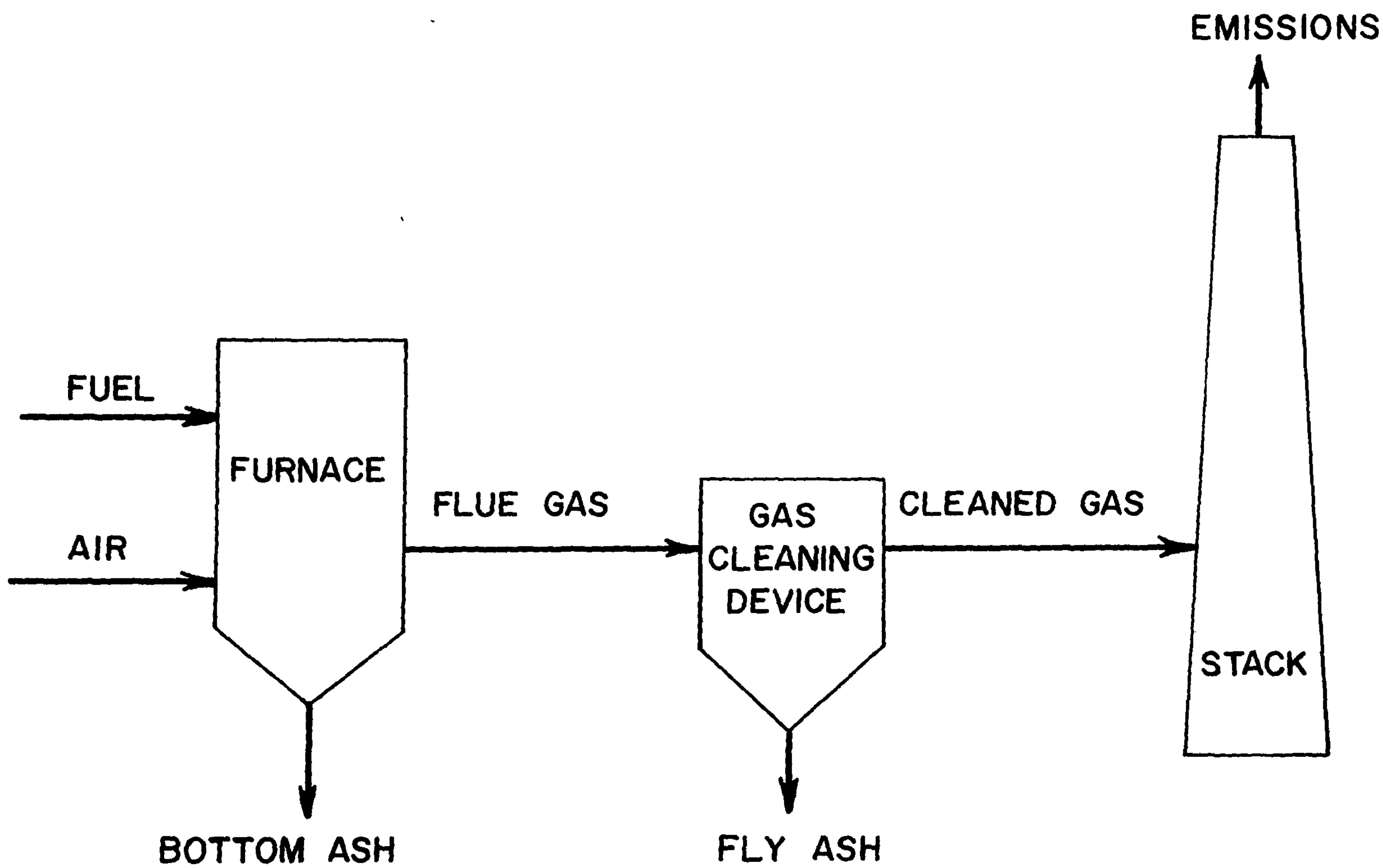


Figure 3. Mass balance schematic of fuel-gas circuit.

fly ash, and the stack gases. In equation (1) the accumulation of ash in the circuit is neglected, all flow rates are assumed constant, operational parameters such as power to the precipitator and burner tilt are held constant, and the fuel quality is assumed constant.

With these assumptions, equation (1) can be used to estimate the particulate and sulfur dioxide emission rates. The nitrogen oxide emission rates can be determined only in a qualitative fashion. These estimations are discussed in the following paragraphs.

3.2 PARTICULATE EMISSIONS

Particulate emissions are derived from the noncombustible elements in the fuel. Of the three fossil fuels, coal in particular contains a significant amount of mineral matter that remains in solid or liquid form even though it may be partially oxidized in the furnace. A laboratory analysis is used to determine the ash content of a particular coal sample. After combustion occurs, part of the ash from the fuel falls or flows to the bottom of the furnace, and the remainder of the ash is carried upward with the flue gases. The percentage of the total ash that is entrained in the gases is a function of the boiler design and combustion parameters. In dry-bottom, pulverized coal boilers, about 75-85 percent of the ash is entrained in the flue gases; in slag tap furnaces burning pulverized coal, about 50 percent is entrained; and in cyclone furnaces, about 20-30 percent is entrained. A relatively small amount of ash falls into hoppers located near the economizer. The percentage of entrained ash leaving a particular boiler can be determined from a coal analysis and the sampling of the flue gas upstream of the gas-cleaning device.

Part of the entrained ash is removed by the gas-cleaning device, the percentage depending on the design and operating characteristics of the device. The percentage of particulate collection can be determined only by testing, although estimates can be made from experience, bench-scale modeling, and theoretical calculations (which are the techniques by which such devices are designed).

The ash not removed in the boiler or by the gas-cleaning device is emitted from the stack with the flue gas. Thus, the steady-state mass balance equation for ash may be written as

$$P = (F)(\alpha)(1 - \beta)(1 - \eta) \tag{2}$$

where

P = particulate emission rate, kg/hr

F = fuel flow rate, kg/hr

α = fraction of ash in fuel, a mass to mass ratio

β = fraction of ash removed as bottom ash

η = fractional efficiency of gas-cleaning device.

To facilitate application of equivalent regulatory limitations to boilers of different size, the mass emission rate frequently is normalized by dividing by the rate of heat input to the boiler, as shown in equation (3).

$$P_N = \frac{P}{(HHV)F} = \frac{\alpha(1 - \beta)(1 - \eta)}{HHV} \tag{3}$$

where

P_N = normalized mass emission rate, kg/joule

HHV = higher heating value of fuel, joule/kg.

Figure 4 illustrates the relationship of the variables in equation (3) for two hypothetical coals burned in each of the three major types of boilers. For the dry-bottom, pulverized-coal boiler $\beta = 0.02$, for the slag tap, pulverized-coal boiler $\beta = 0.50$, and for the cyclone furnace $\beta = 0.75$.

Because the gas-cleaning efficiency can vary significantly during the normal operation of any boiler and precipitator, equation (3) must be used with care. As seen in figure 4, even a 1 percent decrease in η in a high efficiency precipitator can cause a large increase in the mass emission rate.

The efficiency for the collection by an electrostatic precipitator of fly ash from the exhaust gases is given by the Deutsch-Anderson equation (ref. 4)

$$\eta = 1 - \exp(-Aw/v_g) \tag{4}$$

where

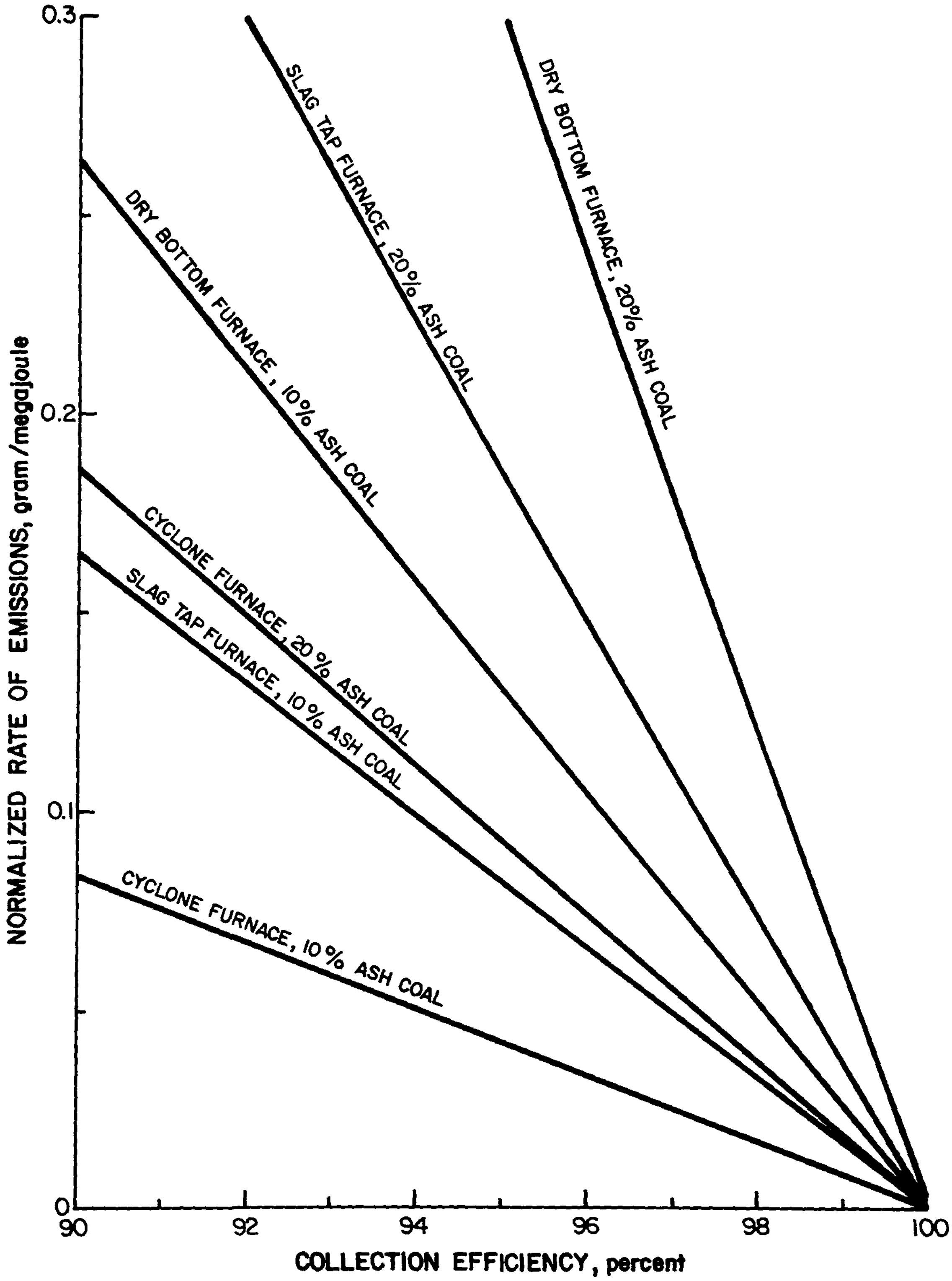


Figure 4. The effect of precipitator collection efficiency on the rate of particulate emissions for several boiler designs and coal characteristics. The coal with 10 percent ash content has a heating value of 30 MJ/kg (13,000 Btu/lb), and the coal with 20 percent ash content had a heating value of 27 MJ/kg (11,500 Btu/lb). One gram/megajoule is 2.33 lb/MBtu.

η = fraction by mass of precipitates collected

A = collector plate area in square meters (square feet)

w = particle migration velocity in meters per minute (feet per minute)

v_g = gas flow rate in cubic meters per minute (cubic feet per minute).

The units given in parentheses often are used by electric utilities. The Deutsch-Anderson equation applies directly to the collection of particles of uniform size and volume distribution, but does not take into account the reentrainment of particles due to rapping. However, an effective migration velocity, sometimes called the precipitation rate parameter, often is determined empirically for a particular unit. This empirical migration velocity does account for reentrainment. However, the Deutsch-Anderson equation still must be used with care because of many effects that are not included, such as the dependence of the effective migration velocity on the rate of gas flow. The overall effective migration velocity depends upon the rate of gas flow because the volumetric distribution of particles is dependent upon the total gas flow rate.

The collector plate area is the basic design parameter of the precipitator, but a gas flow rate must be chosen before a precipitator is designed.

In an electrostatic precipitator this precipitation rate parameter is influenced strongly by the electrical resistivity of the ash. The higher the resistivity of a fly ash particle, the more difficult ash is to collect. Resistivity is influenced most significantly by the flue gas temperature and the fuel sulfur content. Basically, temperature affects resistivity by its influence on the transfer of electrical charges through the particles. The fuel sulfur effect relates to changes in surface electrical characteristics due to adsorption of sulfuric acid on the particle. Figure 5 shows typical trends in resistivity of fly ash with variations in flue gas temperature and sulfur content in coal (ref. 5). Of particular interest in Figure 5

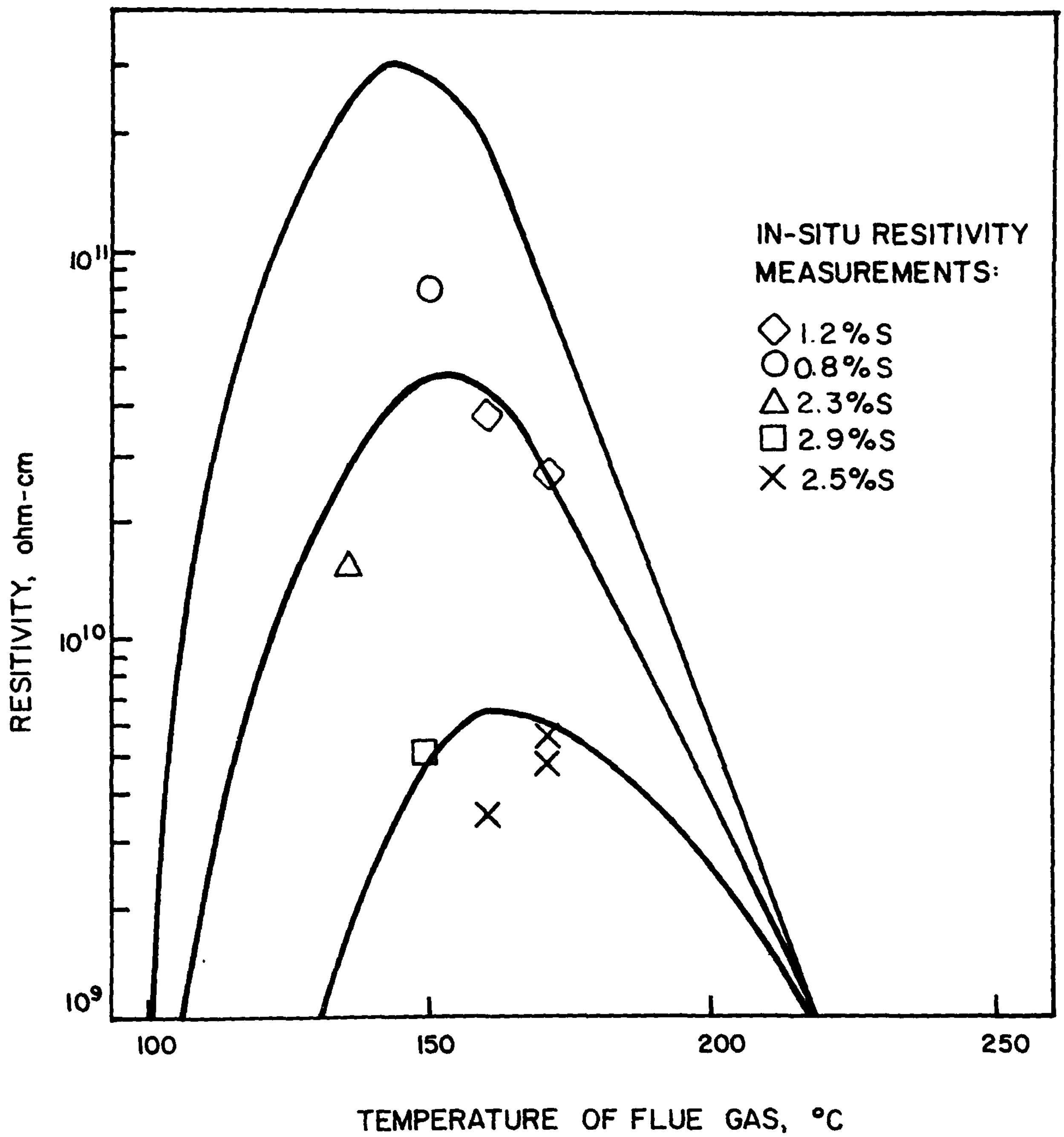


Figure 5. The dependence of fly ash resistivity on flue gas temperature and sulfur content of the coal. These curves represent average values of resistivity. The actual resistivity can vary considerably for any particular temperature and sulfur content. The curve is reprinted in a new format from reference.

is the trend of highest resistivity from about 135 to 165° C. Unfortunately this temperature range is normal for the flue gas temperature downstream from the air preheater in many units. In recent years, to combat this problem many precipitators have been installed upstream of the air preheater where gas temperatures are about 320 to 440° C. This technique of design involves a tradeoff because the gas flow rate, v_g, is larger at higher temperatures, and the precipitator must be larger to achieve a reasonable gas velocity.

Figure 6 illustrates the relative effects of plate area, gas flow rate, and coal sulfur content on the efficiency of an electrostatic precipitator at a constant gas temperature. The Figure 6, adapted from Reference 6, is based on data obtained from a performance study of several precipitators and is consistent with the form of equation (4).

The precipitation rate parameter is strongly affected by the particle size distribution of the ash and weakly affected by the dust loading or concentration of the ash. These variables, which are determined by the fuel burned, must be taken into account during the design of a precipitator. Variations in the characteristics of the fuel which is burned may have a marked effect on the performance of the precipitator.

Multicyclone collectors still are used in the utility industry, although many have been replaced by higher efficiency electrostatic precipitators. Unlike electrostatic precipitators where a low gas velocity is necessary, multicyclone collectors require a high gas velocity through the cyclones for good efficiency. For this reason, tandem installations of an electrostatic precipitator following a series of cyclones do not react the same to changes in gas flow as do precipitators alone. Decreasing the gas flow rate increases the precipitator efficiency but decreases the cyclone efficiency so that the overall efficiency typically increases, but to a lesser extent than would be indicated by the Deutsch-Anderson equation.

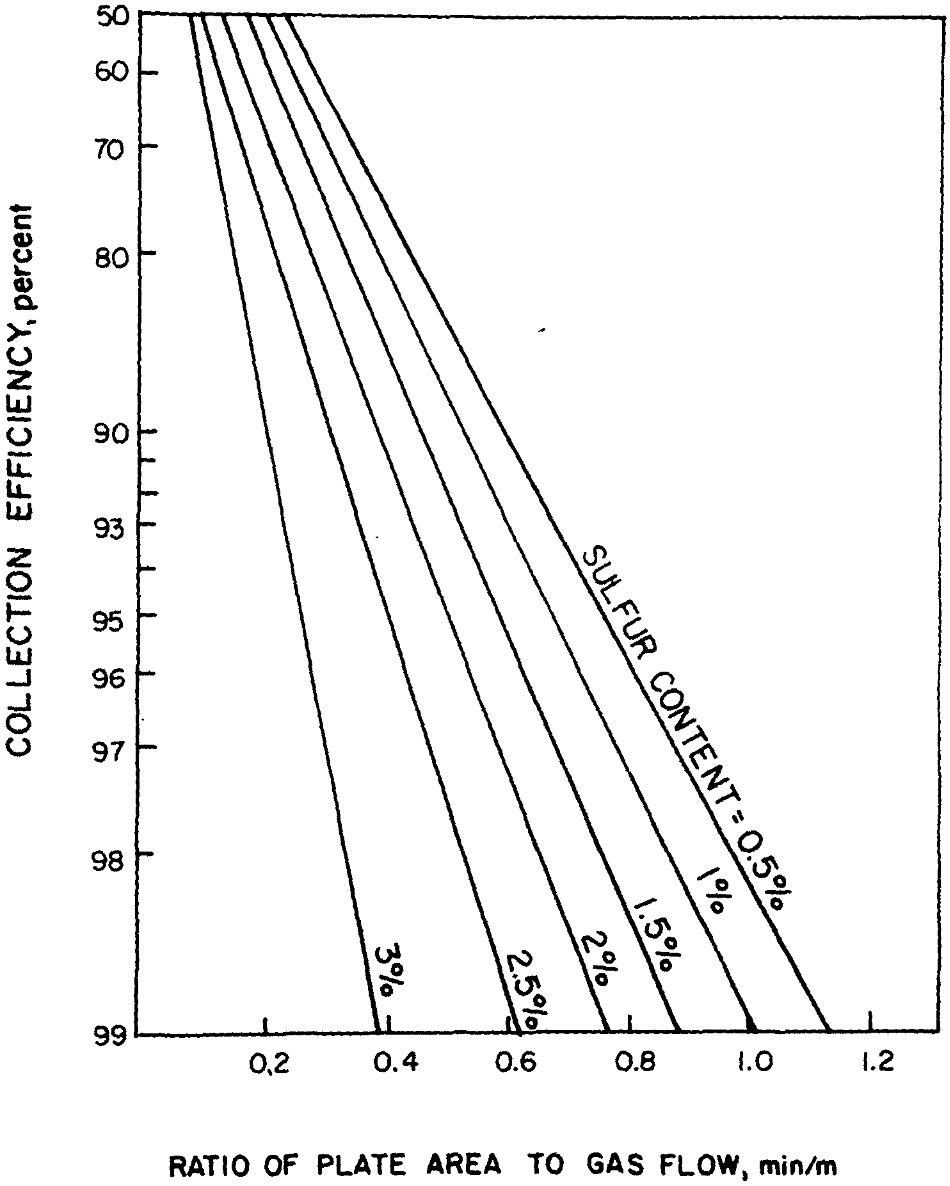


Figure 6. Relationship between collection efficiency and plate area to gas flow ratio with various coal sulfur contents (constant gas temperature).

3.3 VISIBLE EMISSIONS

The visible emissions from the stack of a fossil-fuel-fired electric generation plant consist of soot, which is unburned carbon, and fly ash. The emission of unburned carbon during a startup of a boiler with a distillate oil occurs because of the unfavorable conditions for combustion. The emissions of fly ash arise from the ash content of the coal. The fly ash is the portion of ash which remains suspended in the furnace gases; the remainder of the ash, called bottom ash, is collected on the bottom of the furnace as dry ash or as molten slag.

Fly ash is the most important visible emission from a fossil-fuel-fired steam-electric generation plant. Soot, blown from the walls during each wall-cleaning cycle, is collected by the electrostatic precipitation. Normally, a significant amount of soot is emitted only during the initial firing of the boiler when the precipitator is not energized.

Visible emissions are measured by the determination of the opacity of the stack gases. The traditional method for the measurement of the opacity of stack gases has been the determination of the Ringelmann number. To determine the Ringelmann number, the stack plume is compared to reference shades of gray that are numbered from light to dark.

The current trend in the measurement of opacity is to measure the attenuation of a beam of visible light which is directed across the stack. Usually, filters eliminate portions of the spectral output of the light source which would be affected by moisture and carbon dioxide, and special techniques commonly applied in spectroscopy are used to improve the sensitivity and maintain the calibration of the instrument.

An *in situ* instrument for the measurement of opacity commonly is used by the electric utility industry to monitor stack emissions. Calibration tests are conducted each 6 to 12 months by using the EPA reference method. However, variations in the ash content of the coal being burned and variations in the performance of the electrostatic precipitator, such as the loss of a bus section, can have a significant effect on the accuracy of the determination of particulate emissions by monitoring opacity.

3.4 SULFUR OXIDE EMISSIONS

As indicated in Tables 2 and 3, sulfur is a common component of fuel oils and coals. In the combustion of a fuel, sulfur is converted rapidly to sulfur dioxide (SO_2) and sulfur trioxide (SO_3) (ref. 7), but the theoretical concentration of SO_3 is only about 0.5 percent of the SO_2 concentration (ref. 8). As the gases cool, SO_2 is oxidized slowly to SO_3 by homogeneous gas-phase reactions and by catalytic oxidation near iron oxide surfaces of the fly ash and the boiler tubes (ref. 8). The equilibrium concentration of SO_3 is not obtained, but the final concentration does reach about 1-4 percent of the SO_2 concentration (ref. 9). Within this range the final SO_3 concentration is roughly proportional to the excess air percentage (ref. 9). Sulfur trioxide combines with moisture in the flue gas to form sulfuric acid and is adsorbed on the fly ash and on metal surfaces, particularly in the air preheater where it can become a corrosion problem. The ash may retain a small amount of other sulfur compounds that were not evaporated during combustion. Although the SO_3 concentration is important with respect to corrosion and fly ash resistivity, the total mass of sulfur retained in the ash or boiler is negligible in comparison to the total mass in the fuel. Thus, the rate of sulfur oxide emissions is given by equation (5).

$$SOX_G = 2(F)(S) \tag{5}$$

where

SOX_G = emission rate of sulfur oxides, kg/hr

2 = stoichiometric ratio of SO_2 to S

F = fuel flow rate, kg/hr

S = fraction of sulfur in fuel.

Normalizing the emission rate by dividing the heat input to the boiler yields equation (6).

$$SOX_N = \frac{SOX_G}{(F)(HHV)} + \frac{2S}{HHV} \qquad (6)$$

where,

SOX_N = normalized sulfur oxide emission rate, kg/joule.

As indicated by equations (5) and (6) the only factors that have a significant effect on the gross emission rate of sulfur oxides are the rate of fuel fired and the sulfur content of the fuel. The normalized emission rate is directly proportional to the fuel sulfur content and inversely proportional to the heating value of the fuel.

3.5 NITROGEN OXIDE EMISSIONS

The oxides of nitrogen, which occur in the stack emissions from a fossil-fuel-fired generator, arise from the interaction of oxygen in the air supplied to the furnace for combustion with nitrogen, which is found free in the combustion air and bound in fuel. Molecular nitrogen (N_2) constitutes approximately 79 percent of normal air, and nitrogen is found bound chemically in small but significant concentrations in all fossil fuels.

The nitrogen reactions in the combustion are complex, and the nitrogen oxide emissions are the most difficult to predict. During combustion of the fuel, part of the fuel and atmospheric nitrogen are converted to nitrogen oxides (noted collectively as NO_x). In utility boilers, NO_x is typically about 95 percent nitric oxide (NO) and about 5 percent nitrogen dioxide (NO_2). The mass balance concept is valid, but without extensive measurements it can not be determined whether the nitrogen that enters the boiler leaves as N_2, NO, NO_2, or as some other even less prevalent nitrogen compound.

The approximate range of NO_x emissions from tangentially fired boilers manufactured by Combustion Engineering is illustrated in Figure 7. However, boilers of different design and origin of manufacture may exhibit NO_x emission levels significantly different from those illustrated.

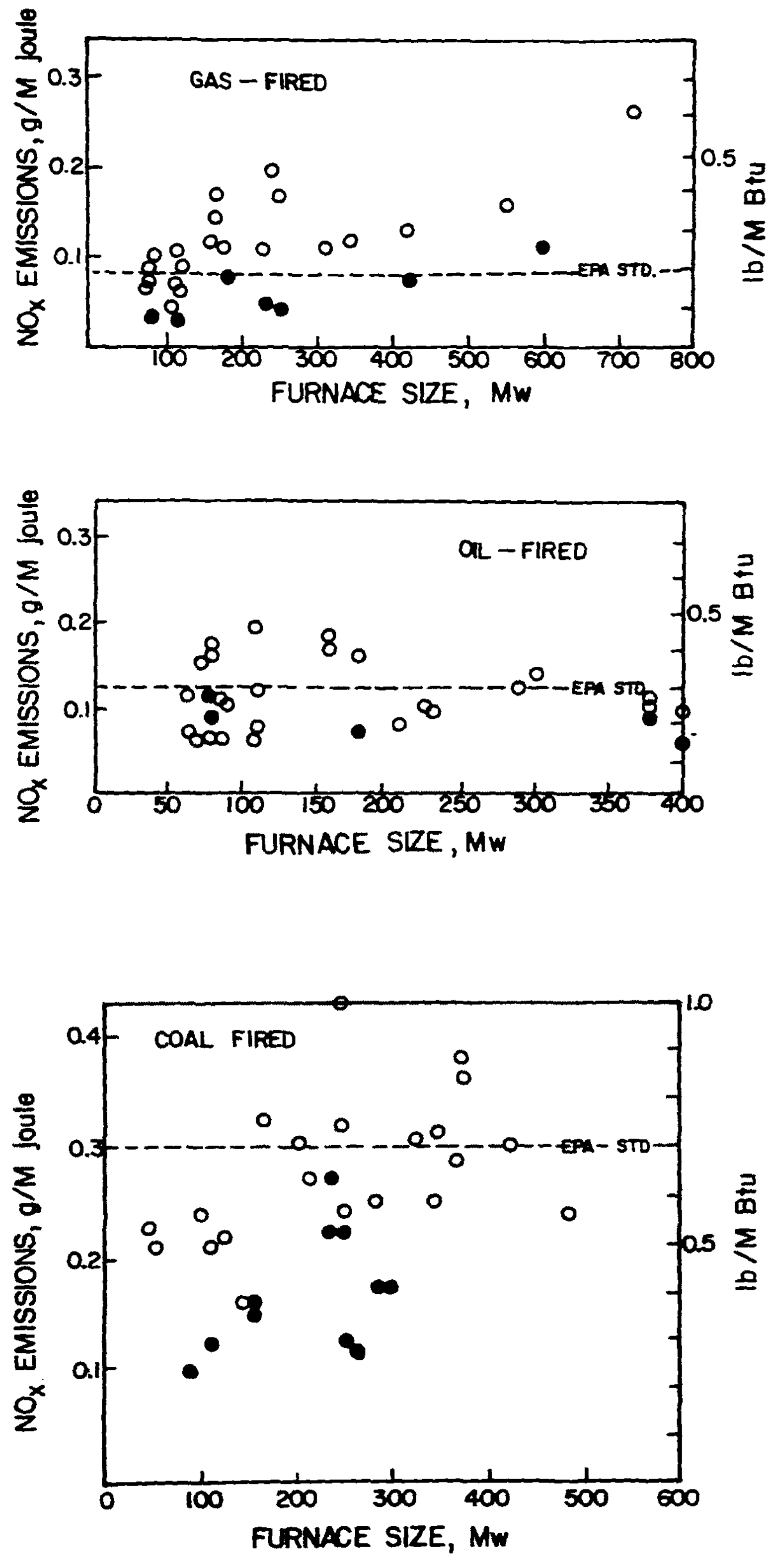


Figure 7. Nitrogen oxide emissions from selected tangentially fired boilers manufactured by Combustion Engineering, Inc. The open circles indicate emissions for normal firing, and the solid circles indicate emissions for furnaces modified for overfire air firing (reprinted from reference 11).

NO_x emissions, while significant as a pollution problem, account for less than 0.1 percent of the total nitrogen entering the boiler. The balance leaves as N_2 or other trace compounds that appear in even smaller concentration than NO_x. The total emissions of nitrogen oxides frequently are reported as "NO_2" although the predominant form is NO.

The amount of atmospheric nitrogen that is oxidized is determined by the rate at which various chemical reactions occur and the time that the reactants stay in the combustion zone. The reaction rates have been shown to be dependent on the amount of excess air, incoming air temperature, the design of burners and heat transfer surfaces, the extent of slag deposition on the walls, and the extent of flue gas recirculation, if applicable. A special technique called two-stage combustion (also called off-stoichiometric combustion or overfire air addition) has been shown to reduce the formation of nitrogen oxides. Basically, two-state combustion is accomplished by admitting a rich mixture of air and fuel in the lower burners while maintaining the overall excess air level by admitting a lean mixture of air and fuel through upper burners. Overfire air refers to the condition occurring when part of the combustion air is admitted at the upper portion of the furnace. Overfire air appears to work better on tangentially fired boilers where fuel burns over a long path after entering the furnace.

The result of two-stage combustion is that a shortage of oxygen occurs in the fuel-rich regions and the oxygen reacts preferentially with hydrogen, carbon, and sulfur rather than with nitrogen (ref. 10). In the area where the remaining oxygen is admitted, combustion temperatures are lower and the oxidation of N_2 occurs more slowly. The overall effect of two-stage combustion with low excess air has been shown to reduce NO_x emissions 55 to 64 percent compared to normal operation (ref. 10).

Complex theoretical models and experimental data correlations have been developed to predict nitrogen oxide emissions for various types of boilers under different operating conditions. A full presentation of these models and correlations is far beyond the scope of this report, but qualified generalizations can be made for several important factors.

1. Excess Air--The excess air is the amount of air supplied to the furnace in excess of what is required stoichiometrically for complete combustion. Generally, increasing the excess air increases the formation of NO_x during combustion and reduces the efficiency of the boiler because of the loss of energy to the oxygen gas leaving the combustion chamber.

Operation with a high level of excess air tends to create a more stable flame. However, the excess air in a well-controlled furnace can be reduced until the carbon monoxide emissions are about 50 ppm, which results in a minimum of NO_x emissions and a maximum efficiency of generation. A further reduction of excess air would increase the carbon monoxide emissions and the danger of a furnace explosion due to unstable conditions of combustion. Investigations have shown that a 10 percent increase of excess air 10 percent above the normal level of operation will increase NO_x emissions about 20 percent with all fuels (refs. 10, 11). Similarly, a reduction in the amount of excess air to half of the normal level decreases NO_x emissions about 20-30 percent (refs. 10, 12), but may cause excessive smoke and CO emissions.

2. Air Flow Distribution--Increasing the percentage of air flow through the fuel compartments of a burner increases "early" mixing of fuel and air and has been observed to increase NO_x emissions in tangentially fired coal and oil units. With gas firing, increases in NO_x emissions have been observed when the distribution of air flow through either fuel or air compartments is changed (ref. 11).

3. Two-Stage Combustion--Two-stage combustion has been achieved in tests on existing boilers by omitting fuel flow to some of the upper parts in the windbox while maintaining air flow. In some cases a load reduction was required because the burners were not sufficiently oversized to maintain full load under these conditions. Figure 7 illustrates the effect of this method of operation. Some new boilers are being designed with overfire air systems.

4. Flue Gas Recirculation--Reductions in NO_x emissions of 35 percent with oil and 60 percent with gas have been achieved by the recirculation of 30 percent of the flue gas to the primary combustion zone (ref. 11).

5. Combustion Air Temperature--A reduction in the temperature of the combustion air reduces the flame temperature and, thus, reduces the formation of NO_x. Full-sized boiler tests have shown about a 20 percent reduction in NO_x emission with a 40° C reduction in combustion air temperature. However, the efficiency of the boiler is reduced with this technique.

6. Burner Design and Configuration--Many different burner designs and configurations are used by the various manufacturers of steam generation equipment. Burner designs range from those that promote high turbulence for the rapid mixing of fuel and air to those that promote comparatively slow mixing with diffusion flames. Generally, NO_x emission levels are higher from boilers equipped with highly turbulent burners, but different conclusions can be drawn from alternative methods of presenting experimental data. For example, plotting NO_x emissions versus gross load per furnace firing wall may lead to a significantly different correlation than plotting emissions versus burning area heat release or steam flow. Because the correlation methods have not been standarized among different research groups, a conclusive, quantitative comparison of particular burner designs has not been established.

7. Burner Tilt--With respect to NO_x emission, adjustment of burner tilt in tangentially fired boilers appears to have offsetting beneficial and detrimental effects related to excess air level and effective high temperature residence time. Minimum NO_x emissions are generally achieved with the burners at a horizontal or slightly upward tilt (refs. 10, 11).

8. Heat Release Rate--The heat release rate is a design parameter that can be qualitatively considered as the "concentration" of heat in the furnace. It is measured in terms of the heat generated per unit

area of water-cooled surface in the furance. This parameter is quite inportant to NO_x emissions because it is related to the time-temperature history of the combustion mixture. Because the rate of oxidation of nitrogen increases rapidly at higher temperatures, high heat release rates generally result in higher NO_x emission levels. Cyclone furnaces and wet-bottom, pulverized-coal furnaces usually have higher heat release rates than dry-bottom, pulverized-coal furnaces.

9. Furnace Slagging--Excessive wall deposits in coal-fired furnaces tend to increase NO_x emissions by reducing heat transfer rates, thus raising the bulk temperature in the flame zone. Operation with higher excess air helps to control heavy slagging but also increases NO_x emissions as previously discussed.

10. Load--A reduction of the load on a boiler tends to reduce the NO_x emission level by decreasing the bulk flame temperature and reducing turbulence in the primary flame zone. In tests performed on tangentially fired boilers, a 25 percent reduction in load resulted in a 50 percent NO_x reduction with gas firing and 25 percent NO_x reduction with gas firing and 25 percent NO_x reduction with oil and coal firing (ref. 11).

11. Fuel Nitrogen--The oxidation of fuel nitrogen is essentially a separate phenomenon from the oxidation of atmospheric nitrogen except in natural gas where nitrogen appears as N_2. The effect of fuel nitrogen on NO_x emissions is known to be an important factor with oil and coal firing, but quantitative trends are still subject to controversy. A conversion rate of 20 percent of fuel nitrogen to NO_x has been reported as a reasonable approximation for fuels with average fuel nitrogen content (ref. 12). This conversion rate produces emissions of 0.3 g NO_2/MJ for coal containing 1 percent nitrogen or 0.05 g NO_2/MJ for number 6 fuel oil containing 0.3 percent nitrogen. Referring to Figure 7, the subtraction of these calculated amounts of fuel NO_x emission from the reported coal and oil-fired data would leave the NO_x emission level attributable to oxidation of atmospheric nitrogen. Although the data shown considerable scatter and the actual fuel nitrogen may have varied from these assumed values, this simple manipulation reduces the data spread for the three fuels to

approximately the same range, indicating that 20 percent oxidation of fuel nitrogen is probably a reasonable estimate. It is thus apparent that fuel nitrogen could account for over 50 percent of the NO_x emitted from boilers burning coal or oil with a high nitrogen content.

3.6 MEASUREMENT OF SULFUR OXIDE AND NITROGEN OXIDE EMISSIONS

Emissions of the sulfur oxides and nitrogen oxides are measured by two methods, *in situ* and extraction. *In situ* monitors use the techniques of absorption spectroscopy to determine the concentration of the pollutant in the stack gas. The extractive monitors extract a representating sample of flue gas from the stack and measure the concentration of the pollutant by spectroscopic techniques or wet chemical techniques.

In situ monitors measure the absorption of radiation which has passed through the flue gases in the stack. Visible, ultraviolet, or infrared radiation is used, depending upon what is being measured. For local calibration a know concentration of the pollutant gas is kept in a reference cell. For the pollutants NO, NO_2, SO_2, and CO the Lambert-Beer law is used. The ratio of a resonant absorption to a nonresonant absorption determines the concentration of the pollutant.

In an extractive monitor the sample must be handled with care. Some extractive monitors keep the flue gas sample hot and analyze the gas while hot, after removing the particulates. Other extractive monitors dry the flue gas sample, remove the particulate, let the gas cool, and then analyze the gas at ambient temperature.

3.7 RELATIONSHIP BETWEEN MEASUREMENTS OF EMISSIONS IN PARTS PER MILLION AND RATE OF EMISSIONS IN MASS PER INPUT HEATING UNIT

Standards for emissions are given in terms of mass of emissions output per input heating unit, usually g/MJ or $lb/10^6$ Btu. However, NO_x and SO_x measurements are made in terms of the ratio of volumes of the pollutant gas to the total stack gas, usually ppm (liter of pollutant gas to million liters of flue gas). The following formula can be used to determine the mass emission rate if the volume emission rate is known:

$$E_m = (2.68 \times 10^{-3})\ V_g\ M\ E_v \qquad (7)$$

where

E_m = mass emissions rate of pollutant, g/m

V_g = volumetric flow rate of stack gas, standard m^3/min

M = molecular weight of pollutant

E_v = volumetric rate of emissions, ppm.

The emissions can be compared to the input heat rate which is a characteristic of the fuel being burned by use of the following formula:

$$E_H = (E_m \times 10^6)(HHV)\ F \qquad (8)$$

where

E_H = emissions per input heating unit, g/megajoule

HHV = higher heating value of the fuel, joule/g

F = rate of fuel feed = g/hr.

The rate of emissions per unit heating unit can be determined by combining the above equations.

$$E_H = 2.68 \times 10^3\ V_g\ M\ E_v/(HHV)\ F. \qquad (9)$$

Sometimes, all the parameters needed to determine E_H from E_v are not known. Suppose, for instance, that V_g is not known. V_g can be estimated using design data (11) in the following equation:

$$V_g = 2.38 \times 10^{-6}\ A_T\ (1 + E_A)(HHV)\ F \qquad (10)$$

where

A_T = theoretical air required for complete combustion, g/joule

E_A = fractional rate of excess air

and there are 10.17 standard cubic meters per mole and 1315 g dry air per mole. For coal, heavy oil, and natural gas, let A_T be 327, 321, and 309 g/J, respectively; and, E_A = 0.20, 0.12, and 0.08. Then

$$E_{H(coal)} = 9.3 \times 10^{-4}\ ME_V. \tag{11}$$

$$E_{H(oil)} = 8.6 \times 10^{-4}\ ME_V. \tag{12}$$

$$E_{H(gas)} = 7.9 \times 10^{-4}\ ME_V. \tag{13}$$

4.0 EMISSIONS DURING TRANSIENT CONDITIONS OF OPERATION AND EQUIPMENT MALFUNCTIONS

The normal, steady-state operation of a fossil-fuel-fired steam generator at the rated full-load capacity with no change in fuel or air flow or fuel quality already has been discussed in this report. Basic relationships among pollutant emissions and operating parameters were developed and discussed, and the difficulty in achieving a characterization of "typical" emissions from a steam generator even under these stringent conditions was emphasized. Under transient conditions of operation, the variability of emissions in a particular boiler or between two or more boilers is even greater than under steady-state operations.

Figure 8 shows a chart recording of the gross generator electrical output an SO_2 and NO_x emissions during 2 days for the Mohave Plant of the Southern California Edison Company. The chart recording demonstrates the fluctuations which can be expected in the operation of a coal-fired generation plant. The emissions data have not been adjusted to the equivalent emissions for a constant 3 percent level of excess oxygen. The excess oxygen varied during the period of recording from 5.5 to 8 percent. The coordination of the recorders of boiler parameters and stack emissions was not adequate for an analysis of the data.

Very little has been published in the scientific literature on the effects of transient conditions of operation on boiler emissions. The relationships between emissions and operating parameters already developed in this report are useful in a discussion of the trends of emission levels during transient conditions of operation, but no reliable quantitative relationships have been developed.

A qualitative appraisal of the effects of transient conditions of operation on the emissions of particulates and the oxides of nitrogen is presented in Table 1. The remainder of this chapter consists of a discussion of the trends presented in this table. Table 1 reflects practical experience of operations learned through reviews and discussions which were held with personnel from Duke Power Company, Carolina

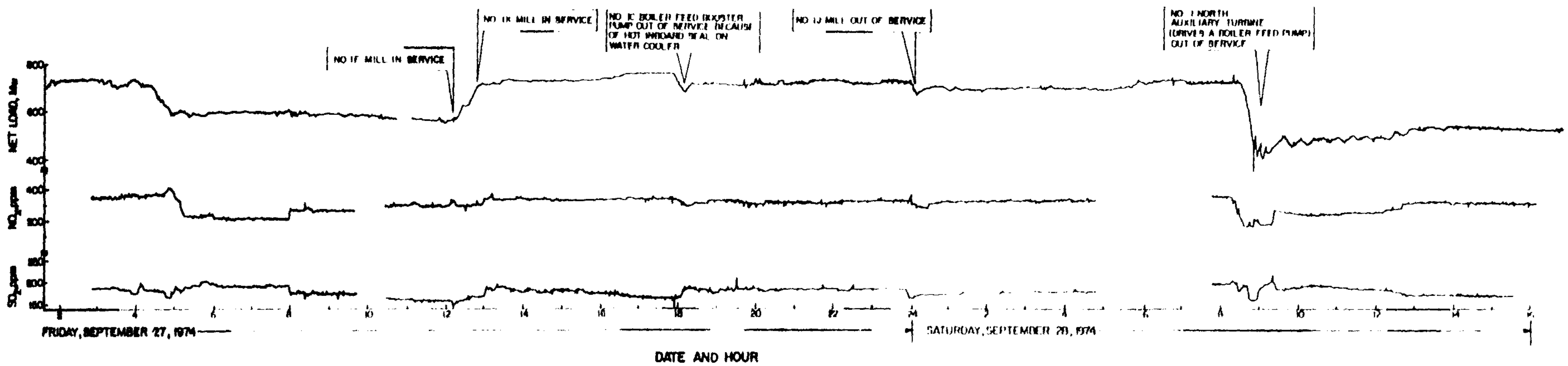


Figure 8. The gross electrical output and emissions of NO_x and SO_2 from Unit No. 1 of the Mohave Plant of the Southern California Edison Company. The emission rates shown are not adjusted to a constant 3 percent level of excess oxygen. Excess oxygen varied during the period of recording from 5.5 to 8 percent. The chart, a reconstruction of several charts provided by Southern California Edison, is presented only to illustrate the normal variations in output and emissions; no careful control was maintained to assure the validity of the data.

Power and Light Company, the Tennessee Valley Authority, Georgia Power and Light Company, the American Electric Power Services Corporation, Southern Services Company, Riley Stoker Corporation, the Southern California Edison Company, Combustion Engineering, Incorporated, and Environmental Data Corporation. While the conclusions do not necessarily reflect the opinions of any one of these organizations, neither is any of them markedly out of agreement.

Transient conditions of operation have no effect on the mass emission rate of the oxides of sulfur. Theoretically, the principle of the conservation of mass requires that all sulfur entering the boiler in the fuel must leave either as a component of the bottom ash or fly ash or as an oxide component in the stack gas. The emissions of the oxides of sulfur then should correspond directly to the sulfur input to the boiler. No datum was found adequate to confirm or refute directly the expected relationship between fuel feed and sulfur oxide effluents. However, in conversations with several persons who had monitored sulfur oxide emissions from steam generation plants for reasons other than to correlate the sulfur oxide emissions with the rate of feeding fuel, it was found that the sulfur oxide emissions had followed the load and, by inference, the rate of feeding fuel. For want of data or contradictory theories, no further consideration was given the emissions of the oxides of sulfur.

4.1 STARTUPS

A cold startup procedure for a coal-fired boiler requires 4 or more hours during which the boiler and related equipment are on manual control. The procedure begins with ignition of No. 2 fuel oil or an alternate light fuel in the boiler. The flow of fuel oil and air are increased gradually as the boiler is warmed. The temperature and pressure of water in the tubes gradually rise. Steam forms and is admitted slowly to the steam chest to warm the turbine. When the temperature of the steam reaches a level sufficient to prevent condensation of water on the blades, the turbine is allowed to roll, being gradually brought to operating speed (normally 1,800 or 3,600 rpm). When the turbine is rotating at the proper operating speed, the electrical output is paralleled with the system.

The low flame temperature during a startup tends to suppress formation of nitrogen oxides, but the low temperature operation may be offset somewhat by a higher level of excess air, which is used to maintain the flame. The net effect is that the nitrogen oxide emissions are lower during startup than at full load operation. The emissions of sulfur oxides usually are less during this startup period because the normal startup fuels, No. 2 fuel oil or natural gas, are low in sulfur.

When the generation is connected to the electrical system, the electrical load is very low, typically less than 5 percent of capacity. The first pulverizer mill is put into service, and coal is delivered to the boiler. (In some installations, the normal operating procedure calls for putting one pulverizer mill into service before paralleling the unit. Sometimes on generation units used for providing power during peak periods of load, all burners are fired and burned at a low output so that an increase in load can be assumed more rapidly.) The coal flow is increased by putting additional pulverizer mills into service, one at a time. The electrical load of the unit gradually is increased. To maintain flame stability, firing of the startup fuel is sometimes continued until two or three pulverizing mills are in operation.

The electrostatic precipitator is energized when the gas temperature at the inlet to the precipitator reaches a specified value, commonly 90 to 135° C. The delay in energization of the precipitator until the gas temperature is above the dew point reduces condensation on the high voltage insulators and avoids the collection of wet ash, which would foul and corrode the wires and plate or plug the ash hoppers.

The recommended gas temperature and corresponding fractional load attained before energization of the precipitator varies among different plant operators, but the practice of waiting until the flue gas temperature is higher than the dew point is considered to be necessary for preventive maintenance. The Tennessee Valley Authority

(TVA) and Pennsylvania Power and Light Company (PP&L), however, have a policy that the electrostatic precipitator should be energized before any coal is fired. Both companies have operated successfully with this policy. To reduce condensation of stack gas on surfaces during startups, the precipitator bushings are heated by TVA and oil is fired longer by PP&L than would be required just to maintain the flame in the furnace.

The magnitude of particulate emissions, which occur during a startup period when coal is fired with no ash collection, is shown in Figure 9. Particulate emissions from the combustion of oil or gas during the startup are neglected. The emissions are expressed in Figure 9 as the time the boiler can operate at full load with the precipitator in service for equal total emissions. The graph is plotted in units of total startup time, which usually is between 4 and 8 hours. A linear rate of firing coal from the beginning of the startup period to full load is assumed. As an illustration, suppose the startup time for a boiler is 6 hours and the efficiency of the precipitator at full load is 99 percent, which is common for a cycling plant. If the precipitator is energized after 2.4 hours, which is 40 percent of the startup period, the amount of emissions during the first 2.4 hours of operation would be the same as the total emissions during 48 hours (8 x 6 hours) of operation at full load. Futhermore, assuming a daily cycle between half load and full load, which would be an average load of three-fourths full load, the total emissions during the first 2.4 hours would equal 64 hours' or 2.7 days' operation of the boiler. The more efficient the precipitator and the longer the startup time, the more desirable it is to energize the precipitator when coal first is fired.

In Figure 9 the fraction of total ash reaching the precipitator is assumed not to vary as a function of the load. The fallout of ash in the economizer hoppers is a function of particle size and gas velocity, and the fraction of bottom ash is influenced by the flame zone temperature and turbulence. However, a more careful analysis taking these effects into consideration would cause no significant change in Figure 9.

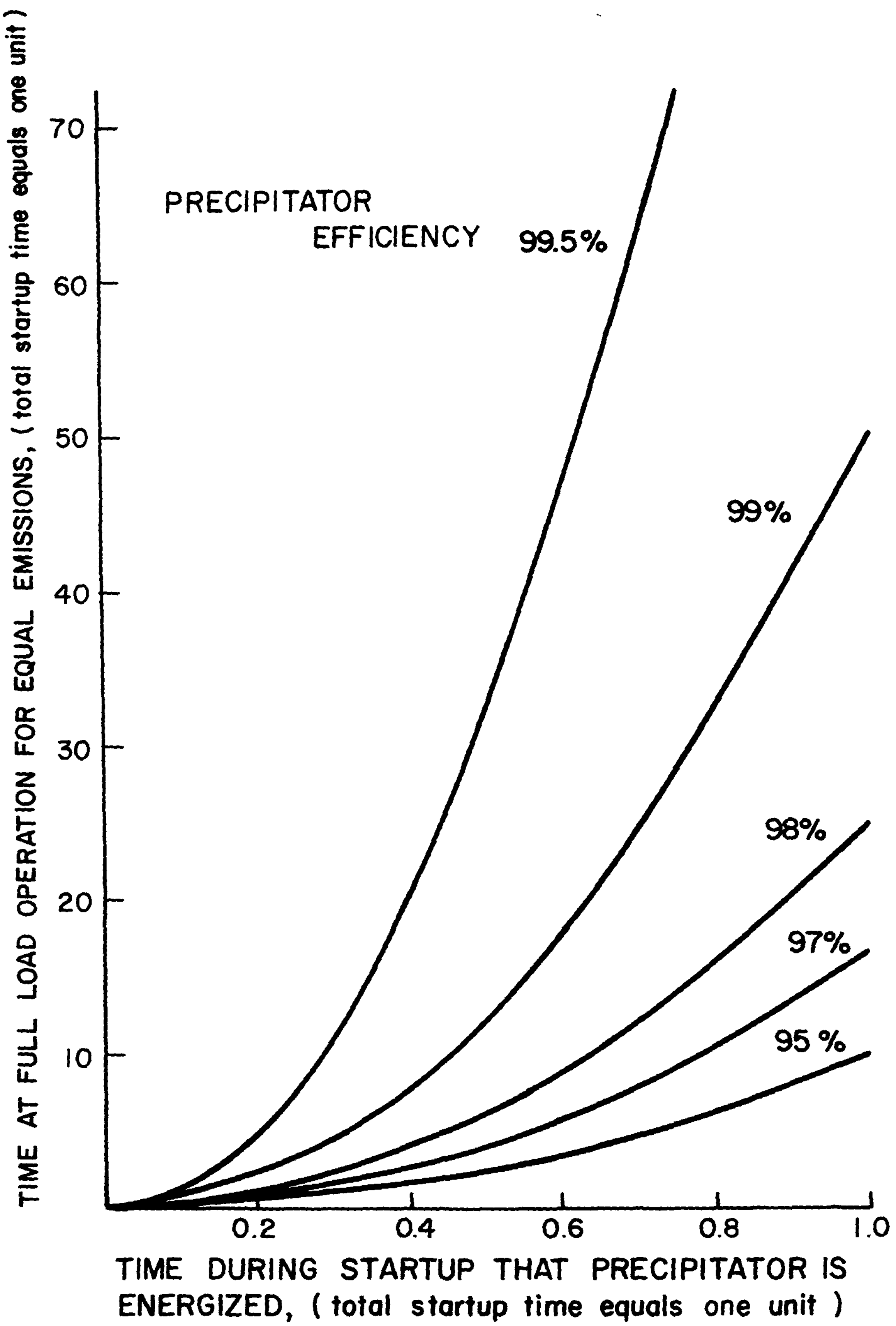


Figure 9. Time a boiler can operate at full load for emissions to be the same as during a boiler startup. Normal startup time is 4 to 8 hours. The load is assumed to increase linearly to full capacity at the end of the startup period.

Estimates of particulate emissions from coal-fired boilers during cold starts are shown in Table 6. The estimates were calculated by Georgia Power Company from the amount of fuel consumption measured during cold starts between January and March of 1975. Complete combustion was assumed to have occurred. The number of cold starts that occurred in 1973 is given for each boiler. The practice of Georgia Power Company is to wait until an air heater gas outlet temperature of 135° C is reached before energizing a precipitator, so that acid condensation on the precipitator surfaces can be avoided.

After the electrostatic precipitator is energized, the load continues to be increased until full load is achieved or the load on the unit is maintained at some load less than full capacity. During this portion of the startup transient, the level of particulate emissions is less than the normal steady-state emission rate because the gas velocity is less than the full load design value and, therefore, the precipitator efficiency is greater than the full-load design value. The emission of nitrogen oxides is less than the full load emission rate during this transient period because of the lower flame temperatures. The emission rate of sulfur oxide is unaffected by the reduced load because it depends only on the amount of sulfur in the fuel.

In some electric power stations, small units on peaking or cycling duty may be taken off line overnight while their generation capacity is not needed and then returned to service the next day. During this period the boiler can be kept warm by stopping the fans and closing the boiler to reduce heat loss. When returned to service, the boiler can undergo a hot startup in which the startup time may be reduced by one half.

4.2 SHUTDOWNS

A normal shutdown of a steam-electric generator from full load requires approximately 1 to 3 hours. The electrical load gradually is dropped, and the fuel and air flows are decreased simultaneously. The fuel-to-air ratio is kept within the normal range for complete combustion. As the load is decreased, the emissions of particulate

Table 6. Particulate emissions for coal-fired boilers of Georgia Power Company during cold starts.

Plant/units(s)	Unit rating, MW	Oil consumed, liters	Coal consumed, kg	Particulate emissions, kg	Number of cold starts in 1973
Arkwright/1-4	45	3,800	8,000	980	52
Bowen/1,2	700	378,500	454,000	54,000	27
Hammond/1-3	112	4,500	77,000	9,300	18
Hammond/4	500	45,400	454,000	54,000	11
Branch/1	250	11,400	73,000	8,690	10
Branch/2	319	15,100	73,000	5,500	13
Branch/3,4	480/490	11,400	445,000	54,000	29
Mitchell/1,2	22.5	950	1,000	160	35
Mitchell/3	165	17,800	118,000	14,200	8
Yates/1-3	105	26,500	16,000	1,900	11
Yates/4, 5	145	34,100	39,000	4,600	19

*The starting period lasts until the air heater gas outlet temperature of 135° C is reached when the precipitator is energized. The estimates were calculated by Georgia Power Company from measured values of fuel consumption under the assumption that complete combustion occurred, the ash content of the oil was 0.06 percent and the ash content of the coal was 0.12 percent.

matter drop with the fuel flow, and the normalized particulate emission rate decreases because of the lower gas flow and the increased collection efficiency of the electrostatic precipitators. The emission of nitrogen oxides is reduced because of lower flame temperatures. The normalized emission of sulfur dioxide is unaffected. When the boiler load has been reduced to approximately one-third to one-half of its full capacity, the fuel flow is stopped, and the emission of nitrogen oxides and sulfur oxides ceases. Then the electrostatic precipitator is deenergized, but rapping continues as long as dust settles into the precipitator's ash hopper. While the draft fans continue to circulate air through the furnace, particulates will be carried out the stack with no heat input to the boiler. This situation, mathematically an infinite rate of emissions per unit of heat input, is unavoidable and negligible.

If maintenance work is to be done inside the boiler or a hot restart is not desired, the forced draft and induced draft fans continue to circulate air through the boiler for cooling. Cooling of the boiler to a temperature at which internal work can be accomlished requires 12 to 14 hours. During this cooling period wisps of fly ash released from the internal surfaces of the boiler are emitted from the stack. The electrostatic precipitator is not energized during boiler cooling because gases would condense on the surfaces of the wires and plates and combine with the fly ash already present to form a hard residue. This residue is difficult to remove, and it would have a detrimental effect on the precipitator efficiency when the unit was restarted.

A turbine trip is an emergency shutdown caused by a malfunction in the turbine, generator, output transformer, or other equipment or controls. The trip requires a sudden removal of the electrical load and an immediate stop in operation. The steam valves are closed immediately, blocking steam from the turbine; the fuel flow is stopped; and the excess steam generated in the boiler is vented to the atmosphere through pressure relief valves. The ventilation of steam depressurizes the boiler in about 1 to 2 minutes. The process of steam ventilation can cause vibrations of the boiler, which could shake loose ash deposits from the internal surfaces of the boiler and cause puffs of fly ash to pass through the precipitator and out the stack. Emissions of nitrogen oxides and sulfur oxides decrease rapidly to zero as the fuel flow is stopped. The electrostatic precipitator is tripped manually or automatically soon after the turbine trip. If boiler maintenance must be accomplished or a hot startup is not planned for another reason, the boiler cooling procedure described above will follow a turbine trip.

Another type of emergency shutdown is a fuel trip caused by a malfunction in the boiler, fuel system, or other related equipment or controls. This type of emergency shutdown is characterized by an immediate loss of fuel flowing to the boiler. The fuel flow stops completely within a few seconds, and the electrostatic precipitator is then tripped. Because operation of the turbine presents no hazards to the equipment or plant personnel, the residual heat in the boiler normally is used to generate steam and drive the turbine as long as possible. As the steam pressure decreases, the electrical load is dropped. With a fuel trip, the emission of particulate matter, nitrogen oxides, and sulfur oxides decreases rapidly as the fuel flow is lost. If the boiler cooling procedure is followed, wisps of fly ash will be emitted from the boiler for 12 to 14 hours.

4.3 LOAD CHANGES

Peaking, cycling, and in some cases, base-loaded steam-electric generators undergo controlled, cyclical load variations. These load changes are accomplished gradually while maintaining near optimum firing conditions. During cycling, transient effects probably are negligible. The duration of the cycling transient can vary considerably. A typical scheduled change of 10 percent reduction or increase in the maximum rated load might take 15 to 30 minutes. During this transient period, the emission rates of particulates, nitrogen oxides, and sulfur oxides should be approximately the same as the steady-state emission rate characteristic of the instantaneous load. If a boiler is cycled too rapidly, there may be inadequate control of the fire, creating nonoptimum conditions of combustion. These poor conditions of combustion may result in excessive emissions or a loss of service if the flame in the furnace cannot be maintained.

For normal cycling the rate of particulate emissions with respect to input heat decreases with a drop in load and increases with an increase in load because an electrostatic precipitator efficiency increases with a reduction in gas flow. Because of the changes in the time-temperature history of the flue gases, nitrogen oxide emissions are reduced at lower loads and increased above the normal, steady-state value at overload. Sulfur oxide emissions are affected only by the fuel sulfur content, and the normalized SO_x emission rate remains constant during load variations.

Forced load reductions can be categorized according to the system which is affected first. A reduction caused by disruption of the fuel supply is associated with a malfunction in a feeder, pulverizer mill, burner, or other fuel-cycle equipment or control. This type of transient is created by a fuel supply that is inadequate for the load and, consequently, by a temporary excess air level which is higher than normal. To compensate for the loss of fuel, the electrical load is reduced, and the furnace draft is reduced to the normal excess air range by manual or automatic controls. Oil or natural gas may be admitted to the boiler to assist in flame stabilization. The time of this type of transient can vary greatly with the design of the boiler and its control systems. Newer electronic controls normally are faster than pneumatic controls in correcting imbalances between fuel and air. The duration of the transient is dependent on the magnitude of the required load reduction. With respect to particulate emissions, a load reduction caused by a fuel supply disruption normally has no transient effect other than to increase precipitator efficiency at lower gas flow rate. The emission of nitrogen oxides would be increased while the excess air is at a higher than normal level. When the load is stabilized at a lower setting, NO_x emissions should be decreased. The normalized emission rate of sulfur oxide is unaffected.

Forced load reductions can be caused by malfunctions in components not directly limiting fuel or air flow, such as a failure in the feed-water, steam, or condensate system. Depending on the cause and severity of the problem, the load might be reduced slowly in a controlled fashion or abruptly with a resultant loss of optimum firing conditions. The transient condition can exist from as little as a few seconds to as long as several hours for severe upsets. The electrical load is reduced, and the fuel flow-to-air flow ratio is adjusted until the normal range is achieved at the new reduced load. Particulate emissions will be increased temporarily by the presence of unburned carbon if the excess air level drops more than a few percent below the normal value. When the unit is stabilized at a lower load, the normalized particulate emission rate will be decreased because of the lower gas velocity. The emission of nitrogen oxides may cycle with a disruption in the balance of fuel and air with higher NO_x emissions resulting from high excess air and lower NO_x emissions resulting from low excess air. When the unit is stabilized at a lower load, the NO_x emissions will be decreased. Sulfur oxide emissions are unaffected.

An abrupt increase in load may be caused by the sudden demand for electricity by a large industrial customer or by the loss of a large generation unit elsewhere in the utility system. The fuel and air flow must be increased suddenly to satisfy the increased load. The fuel-to-air ratio may cycle about the normal range until the control system brings the unit back to optimum operating conditions at the increased load. The time of the transient condition will vary according to the design of the boiler and process control system and the magnitude of the load increase. If the excess air level drops more than a few percent below the normal range, unburned carbon may be emitted. At the higher load, the particulate emission rate will be increased because of the higher gas flow rate and a resultant lower collection efficiency in the precipitator, but the emission rate may not be in excess of the normal full load steady-state level. The emission of nitrogen oxides may exhibit a cyclic variation until the excess air level is returned to the usual range. When the unit is stabilized the NO_x emission rate will be higher than at the lower load, but not necessarily higher than the full load steady-state rate. Normalized sulfur oxide emissions are unaffected by this type of transient.

With respect to load changes in general, a particular boiler manufacturer has observed that transient NO_x emissions are a function of instantaneous load and excess air. This manufacturer reports that in most utility boilers, the oxygen leads the fuel during a load increase and lags the fuel during a load decrease (ref. 13). This situation would result in increased NO_x emission rates during load increases and a decreased NO_x emission rate during load decreases. These observations have not been confirmed for all types of boilers and boiler control systems.

4.4 FUEL QUALITY VARIATIONS

Short-term variations (those that last only a few minutes) in the quality of fuel fed to the boiler are not detected by normal fuel analysis techniques. With respect to coal, the "as burned" analysis usually is conducted on a composite sample collected during the filling of the bunker. These composite samples tell only what the average quality is during the filling interval. Composite samples may be collected between the bunker and the boiler. In this case, the samples reflect the average quality during the sample interval but still do not detect short-term variations. Short-term variations in fuel quality are noticeable when they are severe enough to upset the balanced combustion parameters in the boiler. Variations may be detected by continuous monitoring of emissions, provided the monitoring system has sufficient precision and response characteristics and the residence time and mixing of the gases in the boiler do mask the variations. No reports of studies pertaining to the monitoring of short-term fuel quality variations have been found the the literature surveyed for this project.

Operators of steam-electric generating plants normally like to maintain a supply of fuel on site which is sufficient for several weeks operation. The quantity of fuel stored may be limited by the available area. With respect to coal, placing the incoming coal on the storage pile reduces the daily variations in fuel quality. The bunkers of a particular boiler normally are filled batchwise; e.g., the bunker is loaded in a few hours with a fuel supply sufficient to run 1 or more days. Before the next bunker filling, the quality of coal on the storage pile could be changed by unloading of incoming coal, rainy weather, or a storage pile fire. (Fires are uncommon when bulldozers are used to pack piles. If they occur, they have the effect of increasing the ash content and decreasing the heating value of the coal.) If coal is unloaded directly from the incoming supply to the bunkers, a rapid change in quality can occur. If the coal quality changes significantly between filling, the firing condition of the boiler may be upset, and flame instability may be experienced when the bunker turnover point is reached. The fuel flow and air flow will undergo transient adjustments in an effort to return the firing conditions to optimum. As discussed previously, the emissions of particulate matter and oxides of nitrogen generally will be decreased when air flow is reduced and increased when air flow is increased. Sulfur oxide emissions will be affected only to the extent that the percentage of sulfur in the coal is changed.

Excessive moisture in coal can create a transient condition of extended duration. The primary effect of excessive moisture is the clogging of the bunkers, feeders, and pulverizer mills. Coal can leave the pulverizers on the way to the boiler only in a dry form. When the coal is very wet, the pulverizer output is reduced and, consequently, the boiler load must be reduced. Fuel oil or natural gas may be admitted to the boiler as a supplementary fuel to assist in flame stabilization. Excessive moisture in coal, therefore, has essentially the same effect on emissions as any other load reduction caused by a disruption of the fuel supply.

A transient emission effect may be created by the burning of coal or oil with increased ash slagging tendencies. Slag will tend to build up on the furnace walls and reduce the transfer of heat to the tubes. This has the effect of increasing the gas temperature. Excess slagging can be controlled partially by increasing the amount of excess air. The level of particulate emissions may be increased or decreased by this condition depending on the starting point and the magnitude of variations in gas flow and gas temperature. Increasing gas flow tends to decrease electrostatic precipitator efficiency, but the efficiency can be increased or decreased by a rise in the flue gas temperature (see Figure 5). Excessive slagging tends to increase the formation and emission of nitrogen oxides.

Although short-term fuel quality variations are not often noticed by operators as a transient problem, the emission of particulate matter, nitrogen oxides, and sulfur oxides is theoretically a function of the instantaneous ash content, fuel nitrogen content, and fuel sulfur content. The normalized rate of sulfur oxide emissions is directly proportional to the percentage of sulfur in the fuel and inversely proportional to the heating value. Equation 3 given above in the section entitled "Particulate Emissions" indicates that the normalized particulate emission rate is directly proportional to the percentage of ash in the fuel. The influence of ash concentration in the gas stream on the precipitation rate parameter probably alters this direct proportionality, but no quantitative experimental correlation has been reported. The normalized particulate emission rate is inversely proportional to the heating value of the fuel. The effect of the instantaneous fuel nitrogen content on the emissions of nitrogen oxide varies with the three types of fuel. Nitrogen concentration in natural gas is relatively unimportant, but the fuel nitrogen in coal and oil can account for up to 50 percent of the total NO_x emissions.

4.5 MISCELLANEOUS OPERATING TRANSIENT AND EQUIPMENT MALFUNCTIONS

4.5.1 Soot Blowing

Soot blowing is a routine procedure of operation, which removes ash deposits from the heat transfer surfaces. The boiler efficiency is improved by soot blowing, and the emission of nitrogen oxides is reduced because of improved flame cooling and lowered gas temperatures. The transient effects on nitrogen oxide during the soot-blowing operation are unknown. Soot blowing creates an increase in particulate load on the electrostatic precipitator during the 15 minutes to 1 hour that normally is required to complete a total boiler-blowing cycle. Because many electrostatic precipitators are not designed to handle the increased loading soot blowing, an increase in the level of particulate and visible emissions is observed.

The failure of a soot-blowing system normally would not be thought of as a transient emission phenomenon, but it has a theoretical transient effect on the emission of nitrogen oxides and particulate matter. If the deposition of ash on heat transfer surfaces is considered to be a gradual, continuous process, failure of the soot-blowing system will allow this process to continue until the system is repaired. During this time, heat transfer efficiency will continually decrease causing a corresponding increase in the gas temperature. To maintain full load on the boiler, an increased fuel and air flow is required. Thus, nitrogen oxide emissions are increased because of the higher gas temperature and particulate emissions may be increased or decreased depending on the additive or offsetting effects of a higher gas flow rate and a higher gas temperature.

4.5.2 Bottom Ash

In some boiler designs, the accumulation of clinkers in the bottom arch of the boiler can reduce heat transfer to the water wall tubes. Until the clinkers are removed, this condition will create a decrease in heat transfer efficiency similar to the deposition of ash on the walls and will have a similar effect on emissions of particulate matter and nitrogen oxides. If the clinker accumulation problem becomes severe, shutdown of the boiler may be required. The normal shutdown procedure would be followed because the problem would be foreseen ahead of time.

4.5.3 Burner Mechanism

A malfunction of the burner tilt mechanism on boilers equipped with variable-tilt burners may create problems in maintaining proper steam temperature from the boiler. This equipment malfunction has a transient emission effect to the extent that burner tilt position influences the nitrogen oxide emission rate. A quantitative correlation of the effect of burner tilt position on NO_x emissions is not now available.

4.5.4 Ljungstrom Air Preheater

The failure of a rotary (Ljungstrom) air preheater motor can create serious problems with respect to boiler operation. Many units are equipped with a spare motor that can be put into operation quickly to maintain boiler service. However, most Ljungstrom preheaters will be damaged if rotation is stopped even for as short a period of time as several minutes. If a spare motor is not available, or both motors fail, heat transfer between the incoming air and the flue gas is reduced drastically. The pulverizer mills in a coal-fired plant cannot operate normally without preheated primary air, and clogging of the mills may occur, causing a forced load reduction (disruption of fuel supply). If the boiler has only one preheater, shutdown may be necessary to prevent warping of the preheater due to the thermal stress created by the two gas streams of different temperature. In a unit with more than one preheater, the affected heater can be isolated by closing fan dampers, and only a load reduction is required. With respect to emissions, the important effects of an air preheater motor failure are changes in the gas temperature and gas flow rate. Cooler incoming air will result in a lower temperature in the flame zone, and nitrogen oxide emissions will be decreased. Hotter flue gas temperatures may increase or decrease the electrostatic precipitator efficiency, depending on the ash resistivity-temperature relationship. An increase or decrease in the gas volumetric flow will cause a corresponding decrease or increase in precipitator efficiency, as previously discussed.

4.5.5 Electrostatic Precipitator

There are several types of malfunctions which can occur in the operation of an electrostatic precipitator, all of which generally have the effect of increasing the emission of particulate matter. Nitrogen oxide and sulfur oxide emissions are not affected by electrostatic precipitators.

Electrostatic precipitators are subdivided into independent bus sections so that an electrical failure in one part of the precipitator will not result in a complete loss of efficiency. The effect of the loss of service of a particular bus section depends on the location of the section and the total number of sections in the precipitator. A theoretical model can be constructed by considering that the total precipitator consists of several independent units in a combined series-parallel configuration. The Deutsch-Anderson equation can be applied to each independent bus section, and a model for the total precipitator can be formulated. With the model, the change in particulate emissions resulting from the loss of service of any particular bus section can be predicted. This modeling technique has been used in studies by the Tennessee Valley Authority. Figure 10 shows performance curves for a unit of the Shawnee Plant when various bus sections are not in service. Field tests have confirmed these predictions. However, at another plant, TVA has not been able to confirm predictions calculated in similar manner.

Loss of service of one or more precipitator bus sections will result from the following malfunctions.

1. Failure in the power supply transformer or rectifier. Either the unit is repaired on site or replaced by a spare while being repaired at the factory. Shipment to the factory usually is required for repairs. Delays of 4-5 days may occur if equipment is not available on site for lifting and handling the power supply units.
2. Electrode short to ground at a bushing or at the ash hopper. If the short is at a bushing, the boiler must be shut down to repair the bushing. Shorts to the ash hopper sometimes can be eliminated by correcting the ash flow difficulties that created the problem.
3. Broken Electrode. A broken electrode normally will short an entire bus section to ground. To repair the electrodes, the boiler must be shut down.

Clogging of an ash line or ash hopper can prevent ash removal and cause an accumulation of ash above the normal hopper level. This malfunction initially will cause reentrainment of ash in the gas stream and eventually can cause an electrode short at the ash hopper. Ash flow sometimes can be restored without bringing the unit off line, but shutdown may be necessary.

A failure of a rapper or vibrator in the electrostatic precipitator will result in an accumulation of ash or the wire or plate. Particulate emissions generally will be reduced for a few hours because reentrainment of ash is reduced. Eventually, however, the caked ash on the wire or

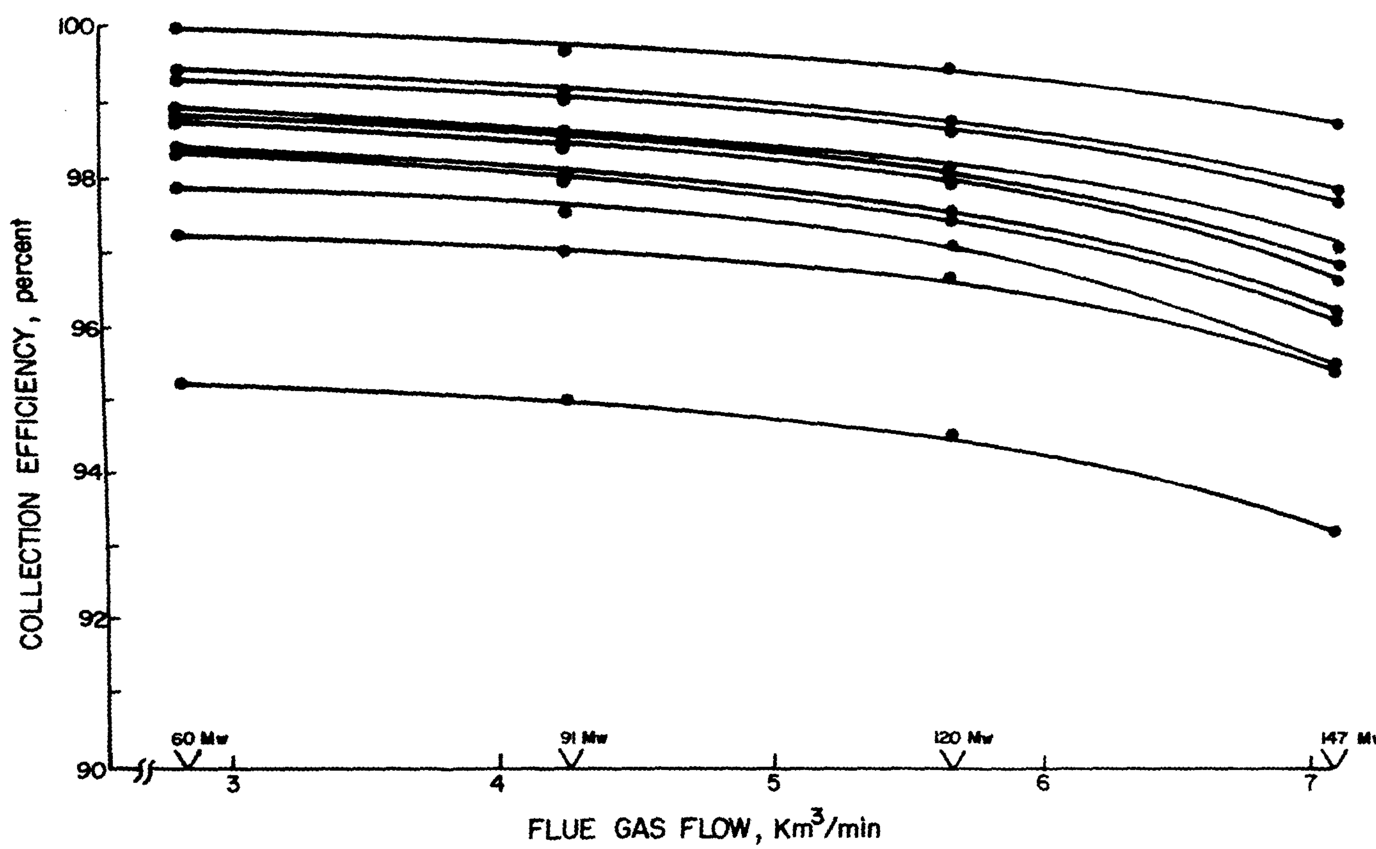


Figure 10. Efficiency of a tandem mechanical collector and electrostatic precipitator at the Shawnee Steam Plant of the Tennessee Valley Authority. The precipitator consists of two parallel sections with three fields each. The conditions are (1) all bus sections in service, (2) one bus out in third field, (3) one bus out in first or second field, (4) two buses out in third field, (5) .....

plate will affect the collection process adversely, and the emission level will increase. Rapper and vibrator failures sometimes can be repaired during operation if the problem is external to the precipitator. Otherwise, the boiler must be shut down to accomplish repair.

The service history for electrostatic precipitators on the TVA system is shown in Figure 11. This data is given in terms of bus unavailability, that is, the percent of time that the average bus section of a given type of precipitator has been available for service. TVA has been able to isolate some of the problems that caused these failures and make corrections, which improve the reliability of the precipitators. The major problems TVA has encountered with electrostatic precipitators are discussed below (ref. 14).

Ash removal problems were caused by insufficient capacity of the ash hopper and a lack of flexibility of the removal and disposal systems. All electrostatic precipitators except one on the Tennessee Valley Authority System have sequentially operated, dry ash-removal systems. With good design and adequate maintenance, these systems have given good performance.

The failure of discharge wires has been a problem for TVA. A severe incidence of wire failures occurred on precipitators serving cyclone furnaces burning coal with 4 percent sulfur content. The failures, occurring immediately below the corona shield, were believed to be the result of acid corrosion and localized arcing between the wire and the corona shield. To reduce the wire deterioration, heated purge air was supplied to the high voltage support insulators from an intermediate section of the tubular air preheater.

The rate of failure of the transformer-rectifier sets has been low for TVA. However, some difficulty has been experienced in replacing a unit with a spare because of handling problems. Specifications for new units now require a means for lifting and handling the transformer-rectifier sets.

The high voltage insulators that support the electrode system in the precipitators of TVA are of two types: the cylindrical-tube type and the post or stacked type. Excessive failures due to surface cracks have

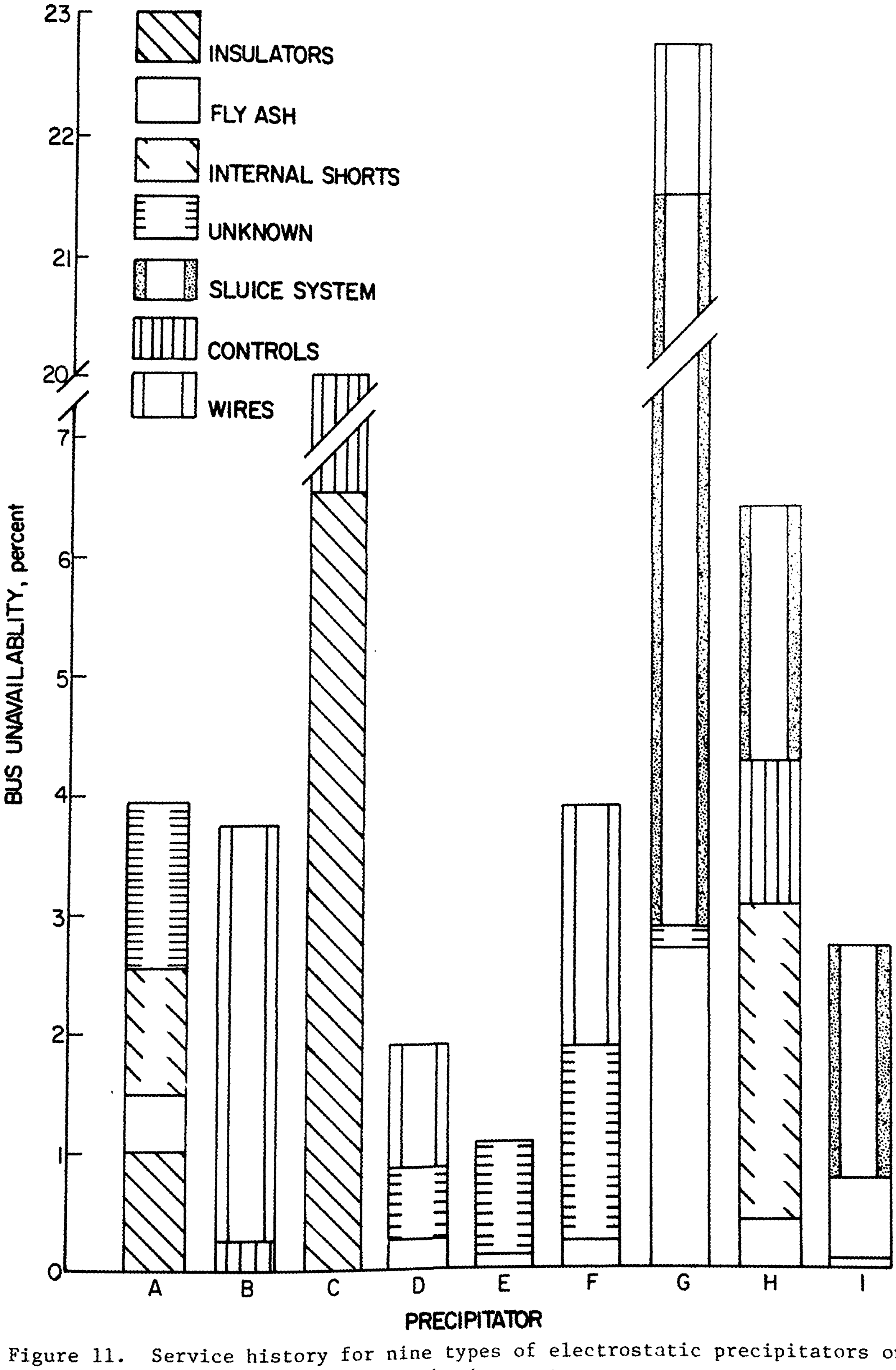


Figure 11. Service history for nine types of electrostatic precipitators on the Tennessee Valley Authority system.

been experienced with the cylindrical-tube type, but no failures have been experienced with the port type of insulator.

TVA has had trouble with the binding or rapper rods. Each rod passes through a sleeve as it penetrates the exterior wall of the precipitator. Ash tend to work into the sleeve and prevent a free motion of the rod.

The current practice of TVA is to write specifications for new precipitators so that the equipment will operate with improved efficiency, reliability, and maintenance cost. The performance tests and maintenance records for the existing units are used as the basis for new modifications in the equipment.

APPENDIX A

THE FOSSIL-FUEL-FIRED STEAM-ELECTRIC GENERATION PLANT

Three predominant energy conversion systems are used for the generation of electricity. First, in the conventional steam-electric generation plant, chemical energy stored in a fossil fuel is released as thermal energy through combustion. The thermal energy, which is stored in steam, is converted into the mechanical energy of a rotating shaft by a turbine, and the mechanical energy is converted into electricity by an alternator. Second, in the hydroelectric generation plant, potential energy stored in elevated water is converted into mechanical energy by a turbine and thence to electrical energy by an alternator. Third, in the nuclear-electric generation plant, molecular energy is released as thermal energy during fission. The thermal energy is stored as steam and converted into electricity as in the conventional steam-electric generation plant. The internal combustion turbine is a variation of the first system described above where the intermediate generation of steam is omitted; instead, the combustion of natural gas occurs in the turbine.

Of the three methods of energy conversion, which are used for the generation of electricity, only the conventional steam-electric generation plant is discussed in this report. Unless otherwise noted, any reference to a steam-electric generation plant refers to the conventional plant, which is fired with a fossil fuel: that is, with coal, oil or natural gas.

With respect to gaseous emissions that are the result of the combustion of fuel, the coal-fired generation plant is of principal interest for several reasons. First, coal is the fuel most frequently used in the generation of electricity; second, the emission products created from combustion of coal generally contain higher pollution concentrations than the products resulting from the combustion of oil or natural gas; and third, the combustion of coal cannot be controlled as well as that of oil or natural gas. Most of this report concerns the coal-fired steam-electric generation plant because any problem that is found in a gas- or oil-fired steam-electric generation plant usually is encountered to a greater degree in a coal-fired plant.

A steam-electric generation plant usually consists of several parallel unitary plants fed from a common supply of fuel and connected to a common electrical load. In each unit, chemical energy stored in the fuel is released by combustion in a furnace and is converted to thermal energy in the boiler by boiling water to produce steam. The thermal energy contained in the steam is then converted to mechanical energy as the steam passes through a turbine, causing it to rotate. The rotating turbine drives the alternator that generates electricity for distribution to customers. The products of combustion, including some of the heat, are released to the atmosphere through a stack after passing through gas-cleaning equipment, such as a mechanical collector, electrostatic precipitator, or gas scrubber.

Many variations occur in the design of generation plants. Sometimes two boilers supply steam to a single turbine, and both boilers are served by a single stack. In older plants, all furnaces may be served by a single stack, with ducts, called breeching, carrying the gases from each furnace to the stack.

Each of the energy conversion steps is accompanied by a characteristic loss of energy. Although the overall energy conversion of a steam-electric generation plant is less than 40 percent and some loss occurs in transmission lines, the electrical energy produced in central generation plants and distributed through an electrical network is more versatile and useful to consumers than the original fuel. Minimizing the loss of energy is a major concern in the design and operation of a fossil-fuel-fired steam-electric generation unit.

Many factors affect the design and operation of a steam-electric generation unit. Important factors include the magnitude and time variation of the electrical load to be handled, the size of existing units that will be operated in parallel, the costs and chemical composition of available fuels, the type and amount of cooling water available, and the location of the plant. A typical steam-electric generation plant has many complex components and a comprehensive control system. Because generation units in existence today represent various eras of engineering development, only the most common major components will be discussed, and their performance will be related to the gaseous emissions from the stack.

Each steam-electric generation plant consists of two major processes, commonly known as the fuel-gas circuit and the water-steam circuit. Details of these processes are given below. The fuel-gas circuit is especially important because all of the significant air pollutants emitted from a steam-electric generation plant emanate from the fuel-gas circuit. The fuel, the input to the fuel-gas process, is discussed in a separate section.

A.1 The Fuel-Gas Circuit

The fuel, when received at a plant, first enters the preparation and storage facilities. In a coal-fired plant, these facilities normally consist of a system of components to receive, transfer, store, crush, clean, and pulverize the coal. With oil or gas-fired units, less preparation is required and the system normally includes only tanks and other storage vessels with the associated equipment for heating, pumping and regulating the pressure of the fluid fuel.

Fuel taken from the preparation and storage system is forced into the furnace, where combustion occurs. A modern furnace is a large structure as tall as 200 feet (see Figure 12). The fuel enters the furnace through a set of burners located in windboxes in the sides or corners of the furnace. Forced draft fans blow air through the windboxes, and combustion occurs, producing hot gases. The inside walls of the boiler are covered by water-filled tubes that are part of the water-steam circuit. The water circulating through the tubes absorbs part of the heat released by combustion.

After combustion of the coal, the ash residue (called "bottom ash") is collected as a solid or liquid, depending upon the physical properties of the coal. When coal with a high ash-fusion temperature is burned, the lower section of the furnace is funnel-shaped and leads to an ash pit where the solid ash is collected. In furnaces designed to burn coals with a low ash-fusion temperature, the residue is a liquid; hence, the bottom of the boiler is a flat surface on which a pool of liquid slag is maintained and tapped periodically into a slag tank containing water.

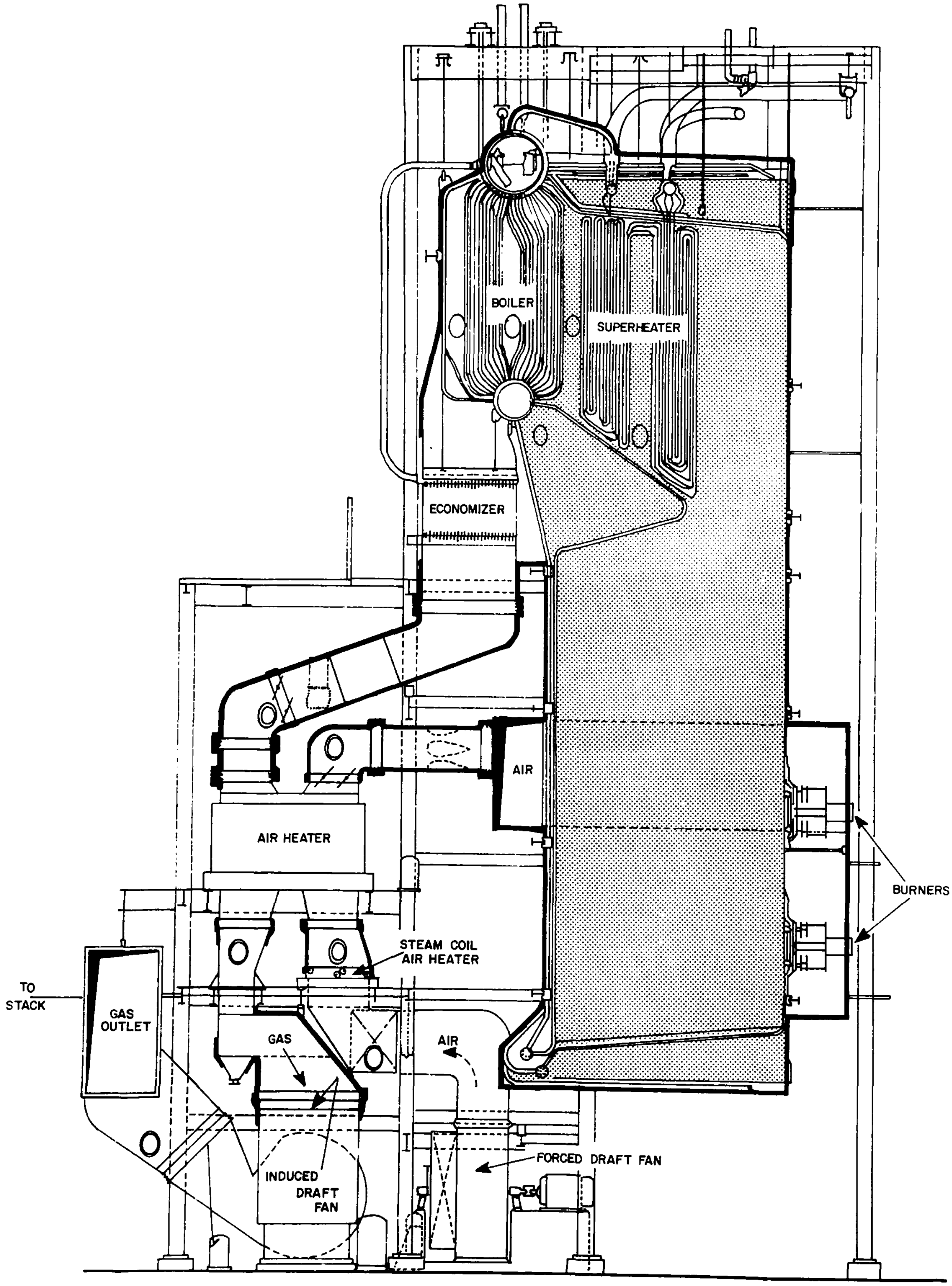


Figure 12. Modern boiler.

Hot furnace gases containing small particles of ash (called "fly ash") travel upward from the region of the furnace flame and pass over several heat recovery devices that are part of the water-steam circuit. In order, these usually are the secondary superheater, the reheater, the primary superheater, and the economizer. In some installations part of the exhaust leaving the economizer is fed back into the bottom of the boiler in a process that is called gas recirculation. This feedback of furnace gases can control the superheat or reheat temperature and the heat absorption pattern under varying conditions of operation.

The last heat recovery device usually encountered by the hot gases is the air preheater through which heat is tranferred from the hot exhaust gases to the air coming into the furnace. The use of an air preheater permits a higher furnace flame temperature and a consequent reduction in heat transfer surface and enables the fuel to be burned more completely.

An exhaust gas cleaner normally is placed after the air preheater to remove the entrained fly ash. Four different types of exhaust gas cleaners are available: electrostatic precipitators, mechanical collectors, fabric filters, and wet scrubbers. Each has a characteristic efficiency, advantage, and limitation, which determine the appropriate choice in a given situation. In some installations that utilize electrostatic precipitators, the exhaust gases pass through the air preheater so that the precipitator can operate at a higher temperature. A precipitator operates better at a high temperature when coal with a low sulfur content is burned because the fly ash has a lower resistivity at the higher temperature.

The cleaned gases are vented to the atmosphere through the stack. The exhaust gases are typically in the range of 250 to 350° F. The stack provides a certain amount of natural draft to help move the gases through the furnace. Supplementary fans, called induced draft fans, often are placed between the exhaust gas cleaner and the stack to increase the draft. Individual components of the fuel-gas circuit are discussed further in Section A.4.

A.2 The Water-Steam Circuit

The water-steam circuit is the medium through which thermal energy released by combustion of the fuel is converted into rotational mechanical energy in the turbine. Industrial boilers usually are rated by the amount of steam that is produced per hour and the temperature and pressure of the steam. However, electric utility boilers are designed as part of a generation unit, and the entire unit is rated in megawatts of capacity. Utility generation units now in service range in capacity from less than 100 MW to over 1,200 MW output power. Maximum steam pressures range from about 1,000 psi in small boilers to over 4,000 psi in large modern boilers.

A working knowledge of the relationship of steam and water is important to the discussion of the water-steam circuit. At a given temperature and pressure, water boils or vaporizes to steam. The latent heat of vaporization is the energy released when steam is condensed to water. As the pressure is increased, the boiling temperature of water increases, and the increment of stored energy per pound of steam decreases. Above the "critical pressure" (about 3,200 psi) there is no demarcation between water and steam. Boilers that operate above the critical pressure are called supercritical boilers, and those that operate below the critical pressure are called subcritical boilers.

A schematic diagram of the water-steam circuit is shown in Figure 13. The inside of the furnace walls are lined with tubes containing water (see Figure 12). The pressurized water circulating through the wall tubes is heated by the furnace gases. The tubes are interconnected in some subcritical boilers with large drums located at the top of the boiler. Steam forms in these drums and is separated from the circulating water. After separation in the drum, the steam is piped through the superheater sections to acquire more energy before entering the turbine. In supercritical boilers and once-through subcritical boilers, boiling and superheating are accomplished during one continuous passage through the tubes, and there is no steam drum.

In a unit with a multiple-stage turbine, the steam may pass back to the boiler between the stages of the turbine to flow through a reheater and gain additional energy. After leaving the last turbine, the low pressure steam is converted back to water in a condenser. The energy released by condensation is absorbed by a constant flow of cool water, which normally is drawn from and returned to a lake or river. Where a suitable

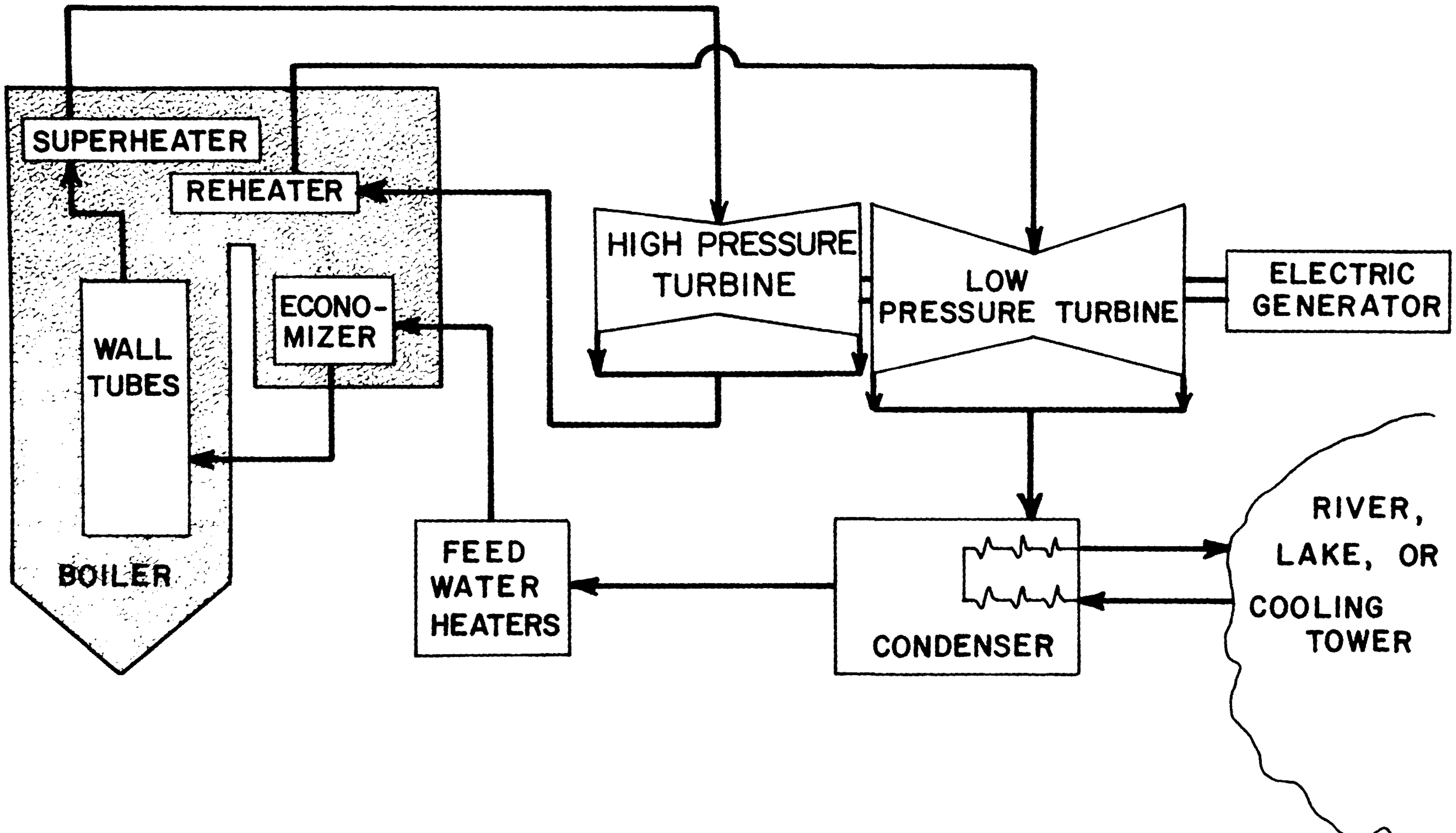


Figure 13. Schematic diagram of the water-steam circuit.

lake or river is not available, cooling towers or manmade ponds may be used to dissipate the unused heat.

The high purity condensate is returned to the boiler as feedwater. On its way back to the wall tubes, it is preheated by feedwater heaters in the economizer section of the boiler. A small amount of makeup water is added to the feedwater to compensate for losses through leakage and ventilation. With the return of the feedwater to the boiler, the water-steam circuit is completed.

A.3 Major Components of the Fuel-Gas Circuit

Since all of the significant air pollutants emitted from a fossil-fuel-fired steam generator are associated with fuel combustion, the design and operation of the fuel-gas circuit is of primary importance in air pollution control. The following discussion of the major components associated with the fuel-gas circuit is directed toward an understanding of the variables of operation and the constraints of the system. The material will provide a background for consideration of the paramenters which affect the emissions of air pollutants.

A.3.1 Fuel Preparation Equipment.

With oil- or gas-fired units, fuel preparation normally involves only the storage and transportation of the fuel to the boiler with no significant effect on air pollutant emissions. Coal, however, requires considerable preparation before it is fired, especially in the more modern boilers.

Ordinarily, coal is partially cleaned, dustproofed, and dried before it arrives at the steam-electric generation plant. These processes reduce the ash and moisture content of the coal and enable the coal to be handled more easily. At the generation plant the coal is unloaded and stored in a large pile. Large bulldozers often are used to pack the piles and reduce the potential for spontaneous combustion or partial oxidation (with a loss of heating value) during storage. The coal is later crushed and transferred to large storage vessels, called bunkers, near the boilers. When coal is burned in a boiler, it is usually pulverized first, and clinkers (chunks of noncombustible materials) are removed. Hot air is forced into the pulverizers to dry the coal and carry it into the boiler. Figure 14 shows a typical coal preparation system for a system utilizing pulverized coal.

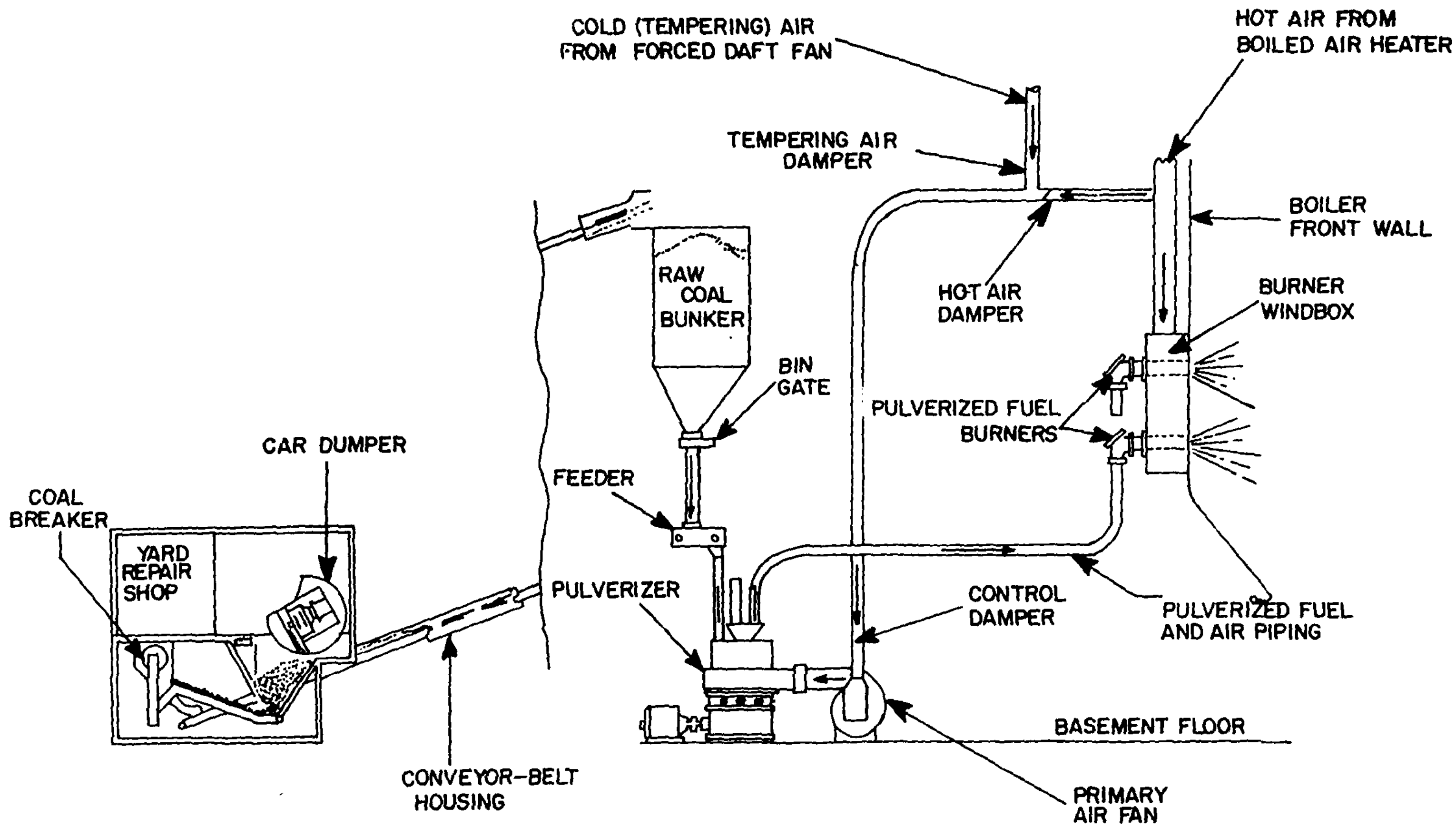


Figure 14. Pulverized coal preparation system.

A.3.2 Fuel-Firing Equipment

Whether the unit fires pulverized coal, oil, or natural gas, the design objectives are to mix intimately the fuel and air, to provide sufficient air to burn the fuel completely, to maintain a temperature high enough to ignite the fuel-air mixture, and to allow the residence time needed for complete combustion.

Fuel-firing equipment can be divided into five general categories: a) stoker furnaces, B) cyclone furnaces, c) pulverized coal furnaces, d) oil-fired furnaces, and e) gas-fired furnaces.

Stoker-fired furnaces now are found only in small and, usually, old boilers. The typical stoker shown in Figure 15 consists of a flat, moving grate carrying a bed of crushed, burning coal several inches thick. A motor-driven feeder moves coal from the bunker or hopper to the moving grate, which is the width of the furnace. Air is admitted from below the bed, and the ash not entrained by the air is dumped into a hopper as the grate passes out of the furnace.

In the cyclone furnace, illustrated in Figure 16, finely crushed coal and primary air are admitted tangentially at one end of a water-cooled, horizontal, cylindrical chamber. Secondary air enters tangentially along the length of the cyclone and imparts a whirling motion to the air-fuel mass. Finer particles burn in suspension, and the coarser particles are thrown to the circumference of the furnace by centrifugal force. Molten slag on the furnace walls retains the coal particles while combustion continues. The slag drains continuously down the walls into a quenching tank. Hot combustion gases leave the furnace through the throat to the additional tube-lined heat transfer area of the boiler.

The remaining three types of fuel-firing equipment differ primarily in the burner design, which is dependent on the type of fuel fired. Figure 17 illustrates some configurations of fuel-firing equipment.

In pulverized coal furnaces, the air used to transport the coal from the pulverizers to the burners is called "primary air." The remaining air, called "secondary air," is supplied through apertures in the windbox and mixes with the coal and primary air. The burners normally are equipped with small oil nozzles, and ignition is achieved with the aid of a light fuel oil. Once combustion is initiated, coal gradually is

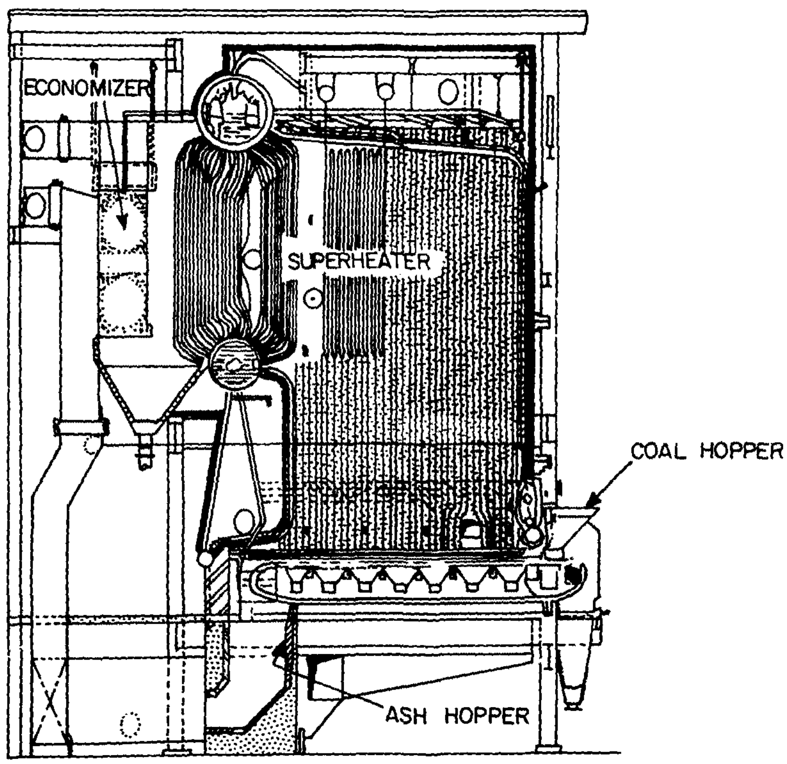


Figure 15. Stoker furnace and boiler.

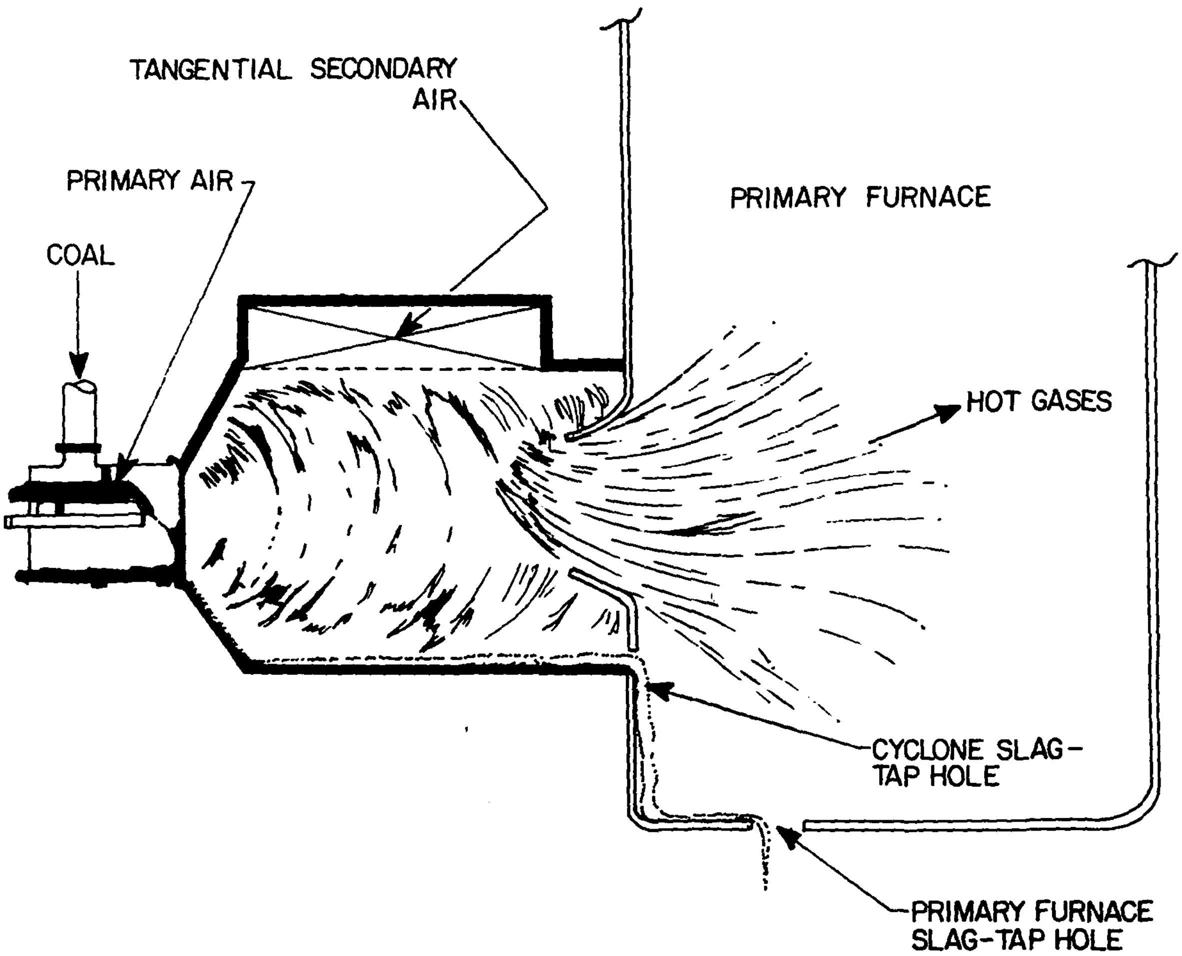


Figure 16. Schematic drawing of cyclone furnace. Usually several cyclones are used on a single primary furnace.

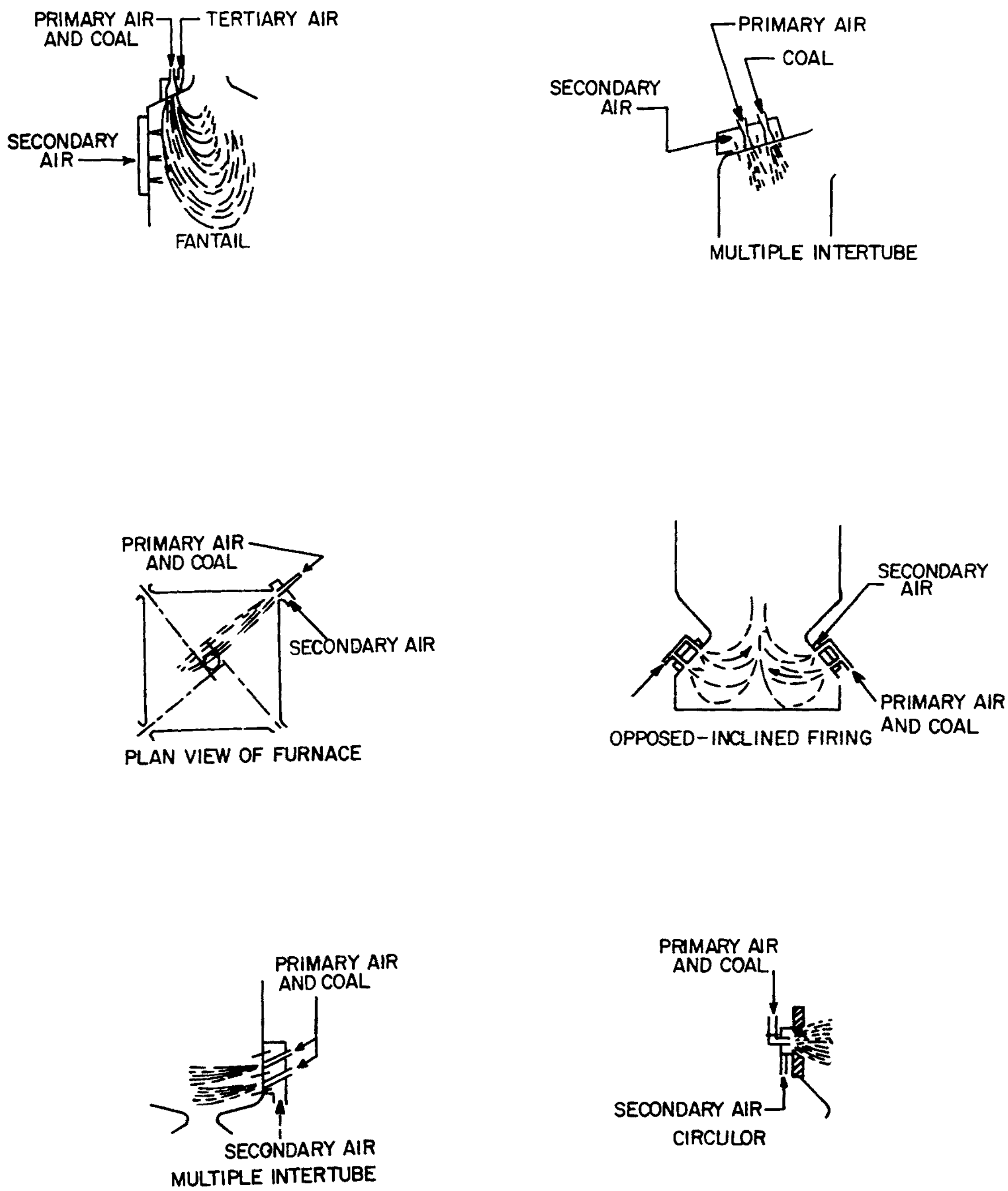


Figure 17. Configurations of fuel-firing equipment in furnaces.

admitted and the pulverized coal allows burning of the coal in a suspended state, a more efficient process than the bed firing that is predominant in stokers. Depending on the type of coal to be fired, pulverized coal furnaces can be designed to remove bottom ash as solid clinkers (dry-bottom boiler) or as a molten slag (wet-bottom boiler).

Fuel oil must be atomized, that is, dispersed into a thin film or mist, to achieve proper combustion with low excess air. Atomization can be accomplished by mechanical devices and pressurized flow or with the aid of auxiliary fluids, either steam or air. Heavier oils must also be preheated to enhance flow and atomization. Combustion air enters the furnace through and around the fuel spray nozzles.

Natural gas combustion can be accomplished with premixing of air and gas as in a carburetor, but this practice is normally not used in steam-electric generators. Common gas burners propagate a diffusion flame, that is, the air and gas remain separated until they are brought into intimate contact at the burners. Various burner designs are available to enhance mixing of the air and gas and to control the release of heat to the transfer surfaces.

By the incorporation of burner design modifications and of the necessary ash-handling facilities, most cyclone furnaces, as well as those illustrated in Figure 17, can be equipped to burn combinations of the three fossil fuels.

A.4 Boilers

The term "boiler" has two general connotations, depending on the context in which it is used. In general discussions regarding major subsystems in a large plant, the term "boiler" ususally refers to the entire structure where steam is generated and includes the furnace, superheater, preheater, economizer, and auxiliary equipment. In more precise discussions of components within the steam-generating units, the boiler is the package of tubes and drums in which water is vaporized into steam. Sometimes the term "boiler proper" is used to eliminate ambiguity. The following discussion is concerned with the boiler proper.

There are many names used to classify modern boilers. The general class of interest here is the water-tube boilers of the bent-tube type. Other names are given to various subclasses within this category, such as the Radiant, two-drum Sterling, and universal pressure. These boilers are distinguished from one another by one or more special design features. It is not necessary here to give detailed descriptions by type. In most modern steam generation units, the entire passage for the hot gases from the burners to the economizer normally has water tubes on the walls. The water-cooled tubes line the furnace, the enclosure around the superheater, and sometimes even the economizer. A bank of tubes, known as the convection boiler surface or convection bank, may be suspended higher in the path of the hot gases beyond the superheater. Steam is generated by the heating of the water in the tubes that line the furnace walls. This section of the water-steam circuit is the boiler proper. The steam generated in the boiler proper is saturated, and any reduction of temperature or increase in pressure will initiate condensation of the steam back into water.

A.4.1 Superheaters and Reheaters

When steam leaves the boiler proper, it passes through the superheater before going to the first stage of the turbine. In the superheater the temperature of the steam is raised above the temperature of boiling water, and the steam can pass through the first stage of the turbine and release energy with no condensation of moisture which would cause excessive wear in the turbine.

The reheater, sometimes called the reheat superheater, is an additional superheater located in the path of steam flow between sections of the turbine or turbines. The reheater superheats the steam after its passage through the high-pressure turbine. Then the steam entering the intermediate or low-pressure turbines can be utilized further, improving the efficiency of the cycle. In recent years a steam temperature of 540 to 600° C has been regarded as a good compromise between increased efficiency and the technical and economic problems associated with material requirements to accommodate the higher steam temperatures.

Physically, superheaters and reheaters are banks of tubes suspended in the path of the hot gases (see Figure 12). Two major categories of each device are the convection type and the radiant type. The convection type is located around a bend in the path of the gases, and the energy to superheat the steam is transferred by convection. The radiant type is transferred for superheating the steam by radiation as well as convection.

A.4.2. Economizers

The economizer is a device designed to recover some of the energy present as heat in the exhaust gases (which would otherwise be partially lost out the stack) by preheating the boiler feedwater. The economizer usually is located after the superheater in the gas flow, and it consists of a bank of tubes set counter-cross-current to the flow of the hot exhaust gases (see Figure 12). Feedwater enters the economizer at the bottom, rises as it passes back and forth across the gas duct through the tubes, and exits through a header at the top.

A.4.3 Air Preheaters

Additional heat is recovered from the flue gases in the air preheater. The air supplied to the combustion zone of the boiler usually is heated to a temperature of 150 to 320° C by the flue gas leaving the boiler. There is a considerable diversity of designs for preheaters. Several tubular types are shown in Figure 18. Another popular preheater is the rotary regenerative (Ljungstrom) type illustrated in Figure 19. Corrugated metal "baskets" are supported in a circular frame and rotated to pass progressively through the gas stream where they are heated and then through the air stream where they give up their heat.

A few installations use other sources of heat for preheating the air. Some units operating with steam heat, and other utilize a separate refractory furnace.

A.4.4 Ash-Removal and Gas-Cleaning Equipment for Particulates.

Ash removal and flue gas cleaning are important functions when coal is burned. The amount of ash in fuel oils and in natural gas is negligible by comparison. Gas-cleaning devices sometimes are employed to remove sulfur dioxide, but the following discussion is limited to the removal of particulate matter.

Coal ash is a complex mixture of mineral compounds, chiefly those of silicon, aluminum, and iron, with smaller amounts of the oxides of titanium, calcium, magnesium, sodium, potassium, and other elements. Oil ashes frequently contain large proportions of sulfur trioxide, vanadium pentoxide, and various alkalies. Besides inhibiting heat transfer and reducing boiler efficiency, ash depositions can be severely corrosive to heat transfer surfaces.

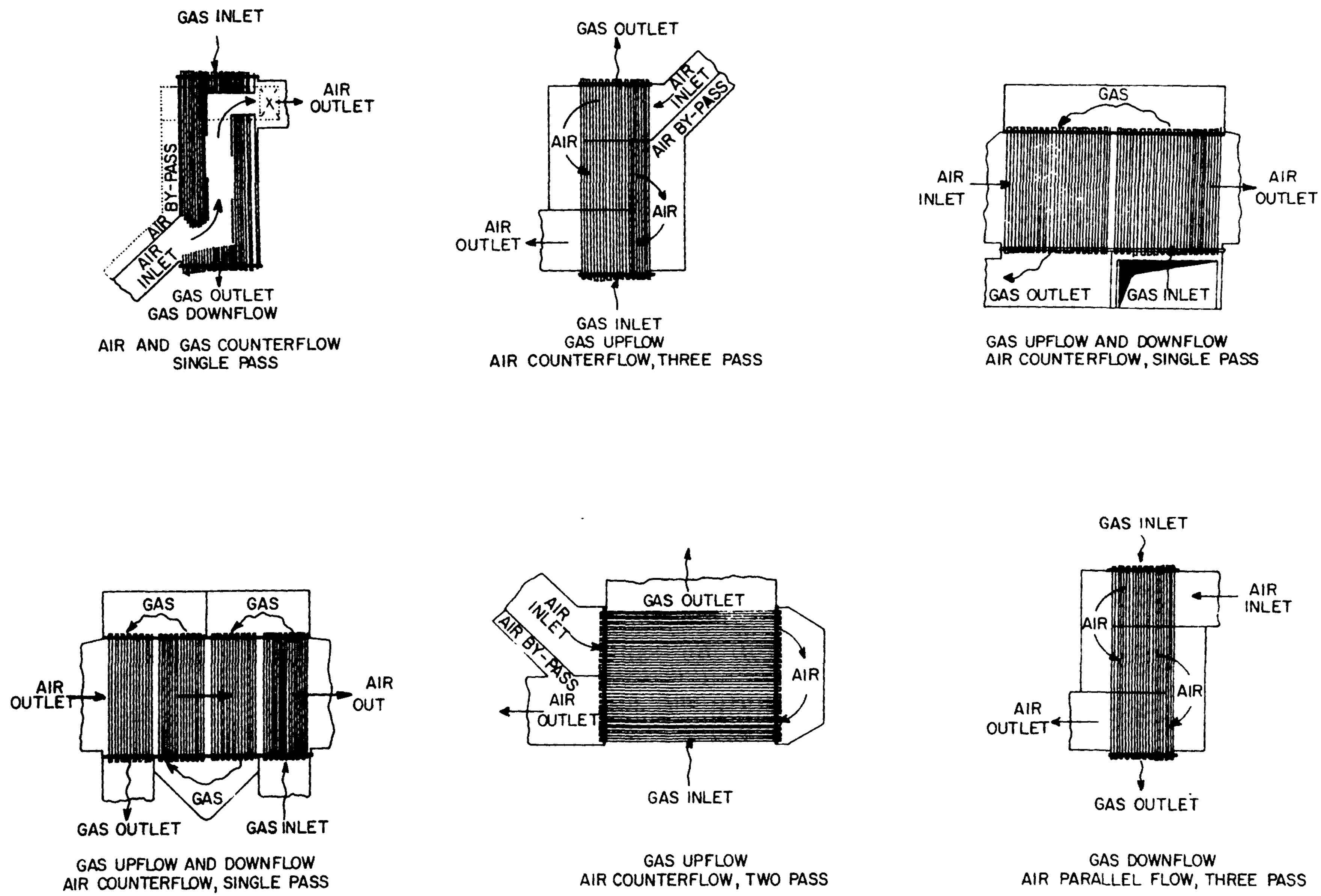


Figure 18. Several designs for tubular air heaters.

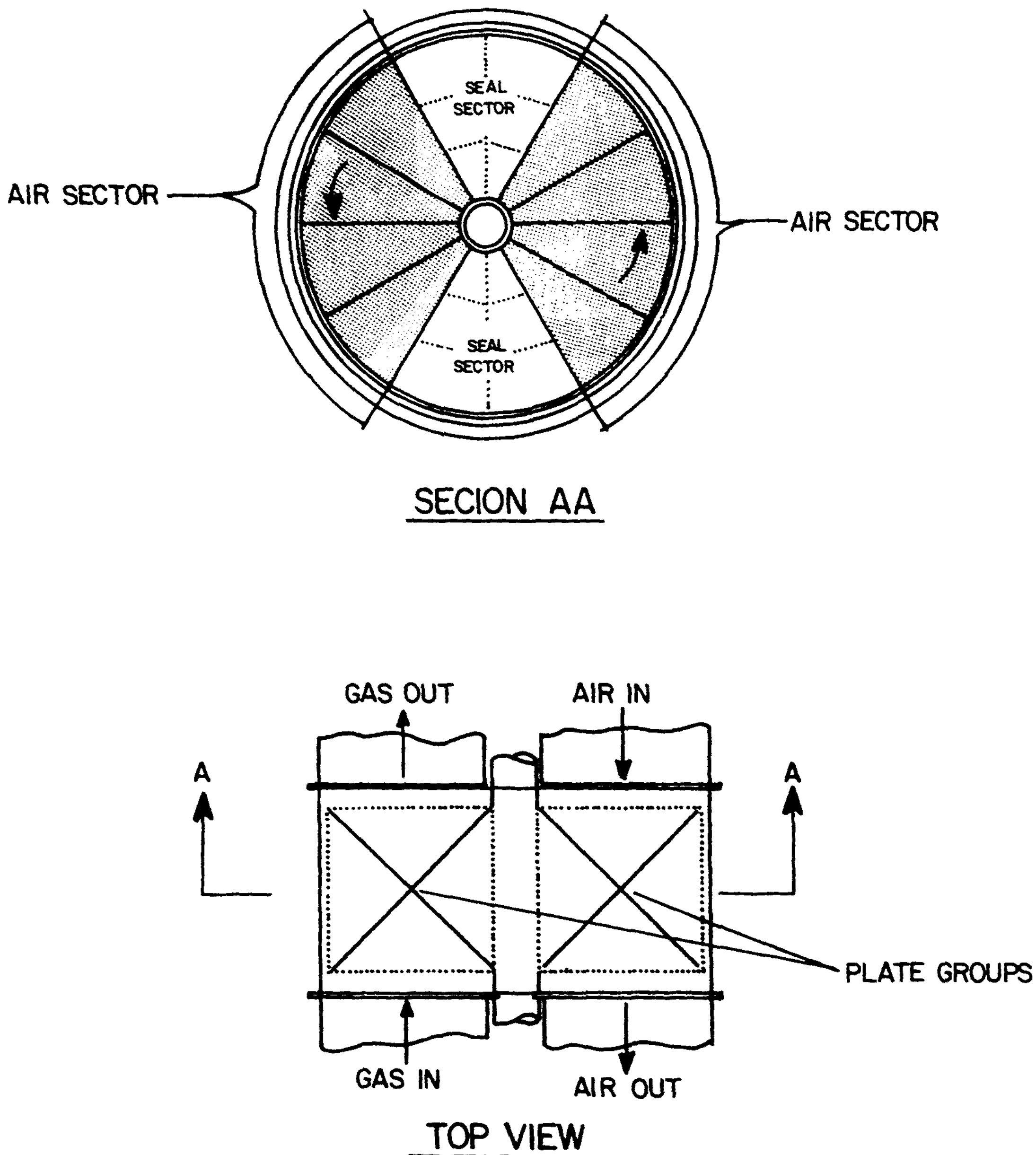
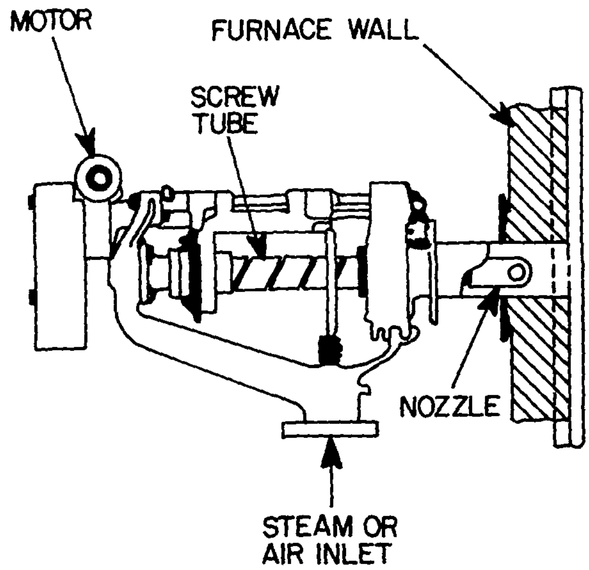


Figure 19. Rotary-type air preheater (Ljungstrom).

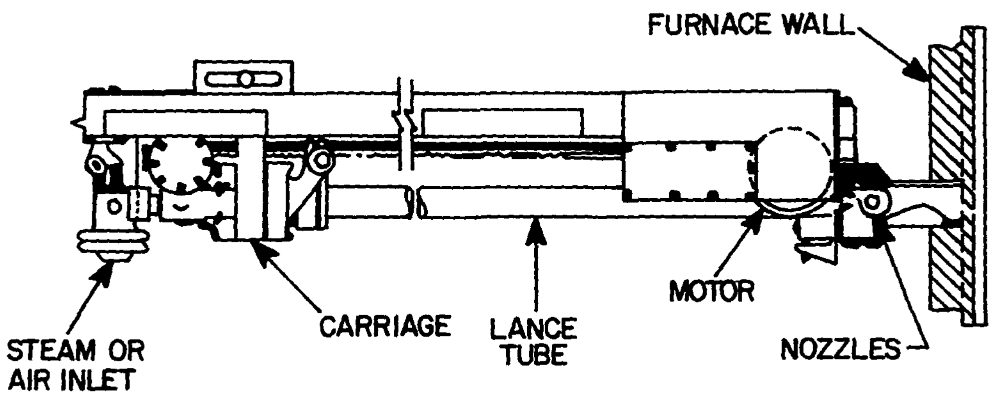
Ash deposition in the boiler is an ever-present problem in coal-fired units, regardless of the design of firing equipment and quality of operation. Equipment and procedures therefore are provided for periodic removal of ash deposits. Typically, soot blowers of the type illustrated in Figure 20 are located at strategic points in the boiler, and jets of air or steam are directed on the heat transfer surfaces while the combustion equipment is in operation. During soot blowing, the flow of air through the boiler should be adequate to remove dust, soot, and fly ash without allowing the formation of an explosive mixture. Burners are adjusted for good stability, and furnace draft and air flow are increased slightly to avoid smothering or loosing fires. Soot-blowing operations may be carried out on a regular schedule varying from almost continuously to about once per day. Sometimes, soot blowing occurs "as needed" at the discretion of the operator. When ash is removed from the heat transfer surfaces by soot blowing, the particulate load of the flue gas is increased.

The ash not deposited on the interior surfaces of the boiler is carried immediately up with the flue gases or falls down to the bottom of the furnace as a solid or as a molten slag. The form of the bottom ash is determined by the combustion temperature and the ash-fusion characteristics. The percentage of the total ash that remains as bottom ash varies with the type of fuel-firing equipment. In stoker furnaces only a small percentage of the ash is normally entrained in the combustion gases. In boilers using pulverized coal, roughly 70 to 80 percent of the ash in coal is entrained in flue gases, if the furnace is the dry-bottom type, and about 50 percent is entrained with a slag-tap furnace. A slag-tap furnace with cyclone burners may emit only 20 percent to 30 percent of the ash in the flue gases. However, a slag-tap furnace with its hot, sticky, liquid slag is difficult to operate, particularly during periods of low-load operation when furnace temperatures may not be high enough to maintain the fluidity necessary for tapping. Once it is removed from the furnace, bottom ash is either conveyed dry or by sluiced water to a disposal site.

Most of the ash that is carried out of the boiler by the flue gases can be recovered by gas-cleaning devices. Four types of air cleaners



(a) Wall Blower



(b) Upper furnace blower

Figure 20. Two types of soot blowers. Both types shown are retractable.

commonly are used for particulate removal: electrostatic precipitators, mechanical collectors, fabric filters, and wet scrubbers. Of these types, the electrostatic precipitator is used predominantly in large steam generators, either by itself or in conjunction with one of the other types of devices. In an electrostatic precipitator, dust suspended in the gas stream is electrically charged and passed through an electric field where electrical forces cause the particles to migrate toward a collection electrode. The dust, separated from the gas by being retained on the collection electrode, is subsequently removed from the device. Usually, the dust is removed mechanically. In some designs, the dust is removed by a continuous washing of the collection electrode.

The construction of an electrostatic precipitator is illustrated in Figure 21. A large steel enclosure containes a bank of parallel, ribbed steel plates. These plates form gas passages about 15 to 35 cm wide and constitute the positive electrodes on which the precipitate is collected. In the middle of these gas passages, a series of vertical wires is fastened to form the negative electrodes. The particles are collected on the steel plates and, to a lesser extent, on the wires. They are removed periodically by a mechanical rap or vibration. Some of the precipitate is reentrained, but most falls into hoppers underneath the electrodes. The cleaned gas passes from the precipitator into the stack. The collected ash is removed from the hoppers and conveyed to a disposal site usually by water sluicing.

Electrostatic precipitators find frequent use in coal-fired power plants because of their ability to handle large rates of gas flow at high temperatures with very little pressure drop. In this application, they are capable of particulate mass removal efficiencies better then 99.5 percent. Most units now being installed are designed to have a removal efficiency greater than 99 percent.

Mechanical collectors have a great variety in design. The most common type for power plants is the dry centrifugal type, sometimes called a cyclone collector. The basic principle behind cyclone collectors is that, with a rapid rotary motion of the dust-laden gases, the particles

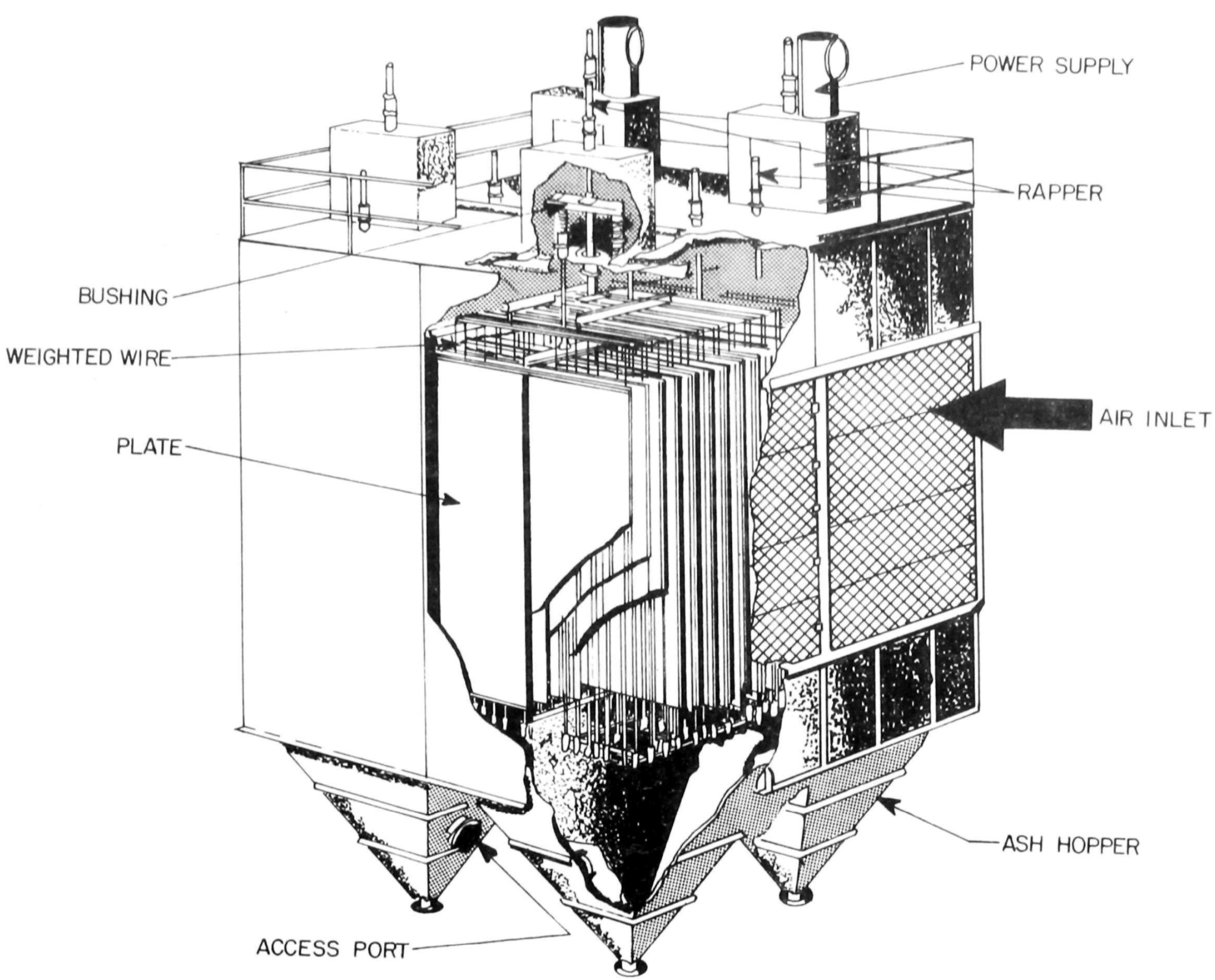


Figure 21. The electrostatic precipitator.

are forced by centrifugal force to the periphery of the device where they slide downward into a collection hopper at the bottom.

The construction of a cyclone collector is illustrated in Figure 22. The gases are introduced tangentially at the upper periphery at a high velocity. Vortices are established, and the particles are separated to the side of the hopper by centrifugal force as the gases circle to the outlet tube. Removal efficiencies of cyclone collectors are usually less than 85 percent. Most of the smaller particles of fly ash are not collected. A series of cyclones sometimes has been used as a precleaner before the use of an electrostatic precipitator. However, electrostatic precipitators remove large particles easily, and the combination of a cyclone collector and electrostatic precipitator usually cannot be justified in a new installation.

Fabric filters usually are placed in a parallel set of tubes, a few inches in diameter and several feet long. The entire structure housing a bank of these fabric tubes is called a baghouse and is illustrated in Figure 23. The particle-laden gases are directed inside the tubes, and the cleaned gases pass through the fabric and out of the baghouse. The tubes are suspended from the roof over a dust-collection hopper. The bags are emptied periodically by mechanical shaking or by a reverse flow of clean air, which drops the dust into the collection hopper for subsequent disposal. Moisture and high gas temperatures have particularly deleterious effects on fabric filters.

Wet scrubbers are devices which remove particles by trapping them in water. A great diversity of designs exists, some of them combining the whirling action of cyclones with the wetting principle. A schematic diagram of a venturi wet scrubber is shown in Figure 24. The dust-laden gas passes through a venturi throat when it is wet by the scrubbing liquid. the wet, dust-laden gas then enters a centrifugal mist separator which separates the wet dust from the gas. The scrubbing liquid with the entrapped dust falls to the bottom of the separator tank. The cleaned gas is vented through the top.

Fabric filters and wet scrubbers are not discussed further because of their limited present use as a particulate control device by the electric

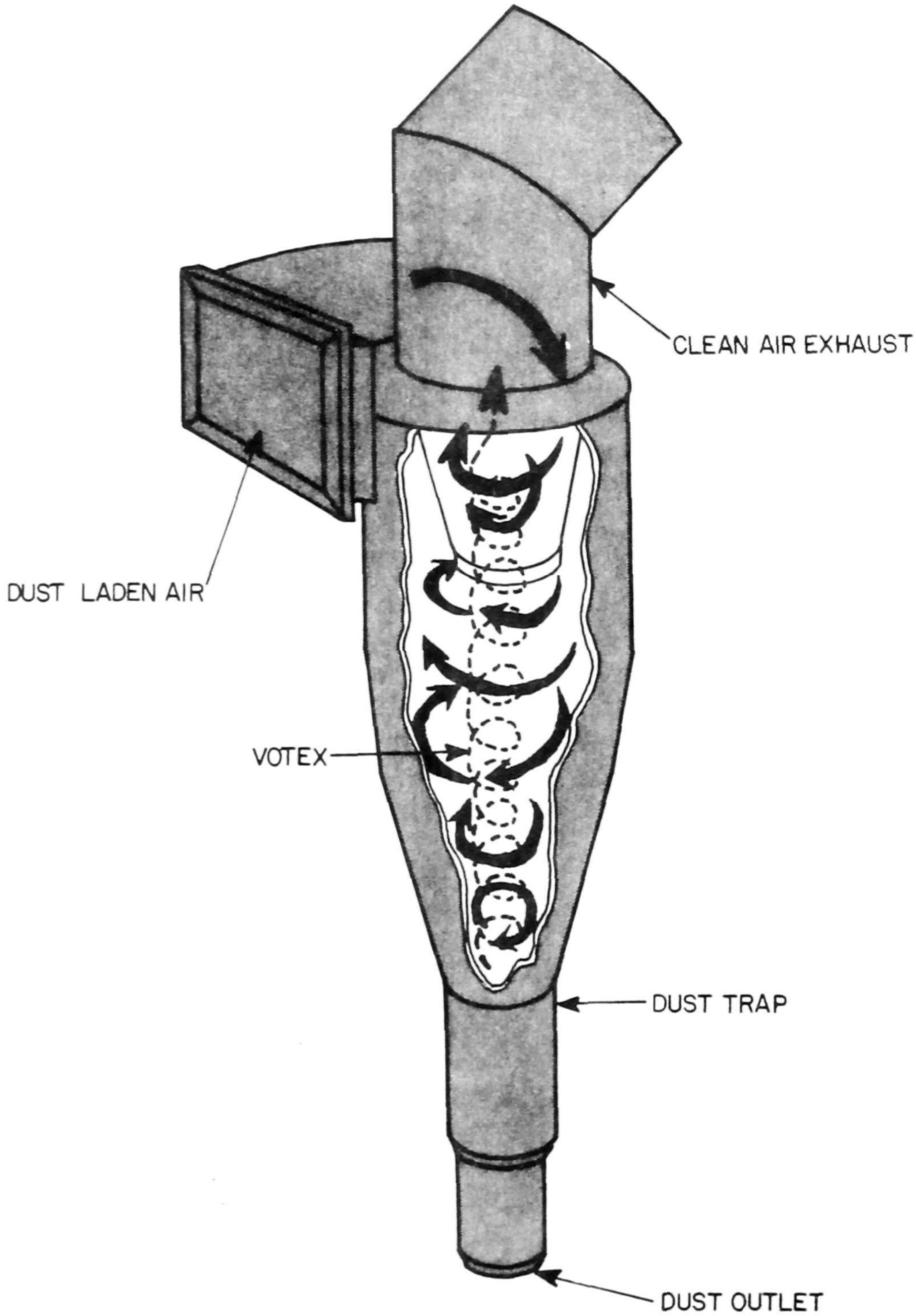


Figure 22. Diagram of cyclone dust collector.

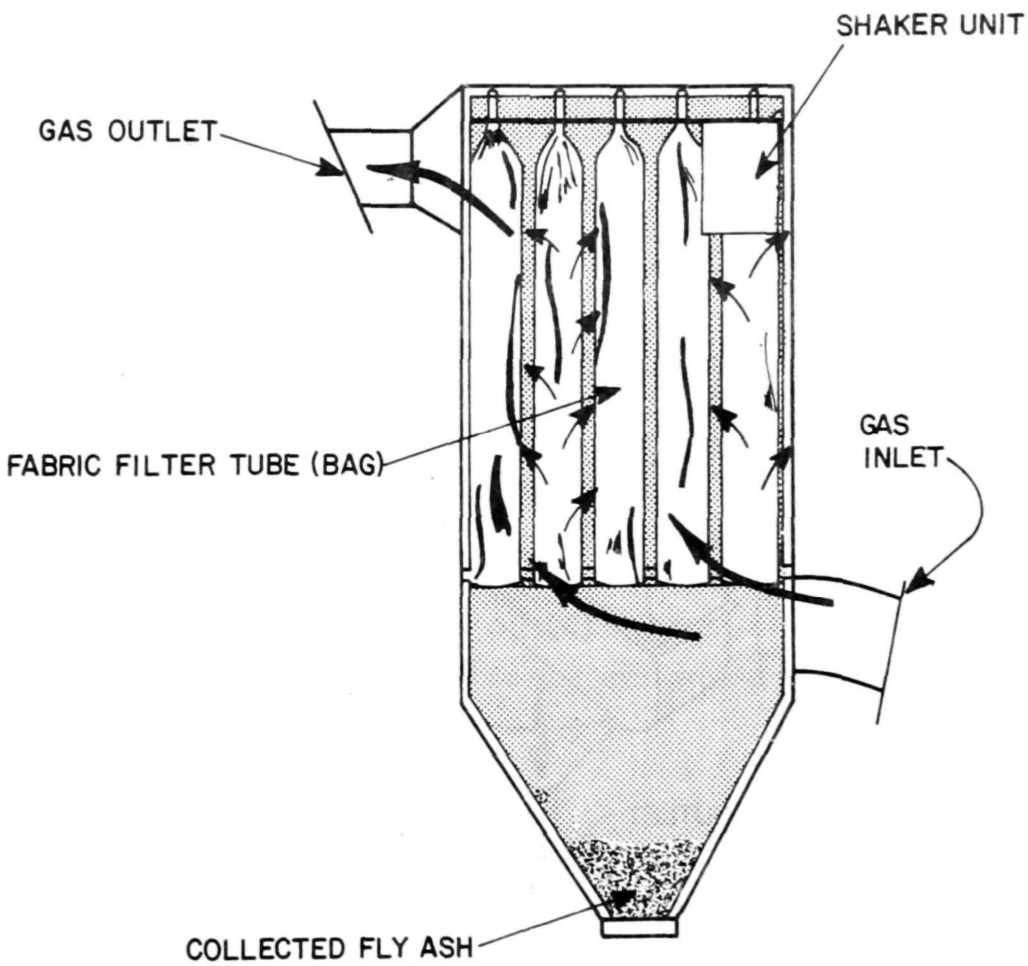


Figure 23. Baghouse dust collector.

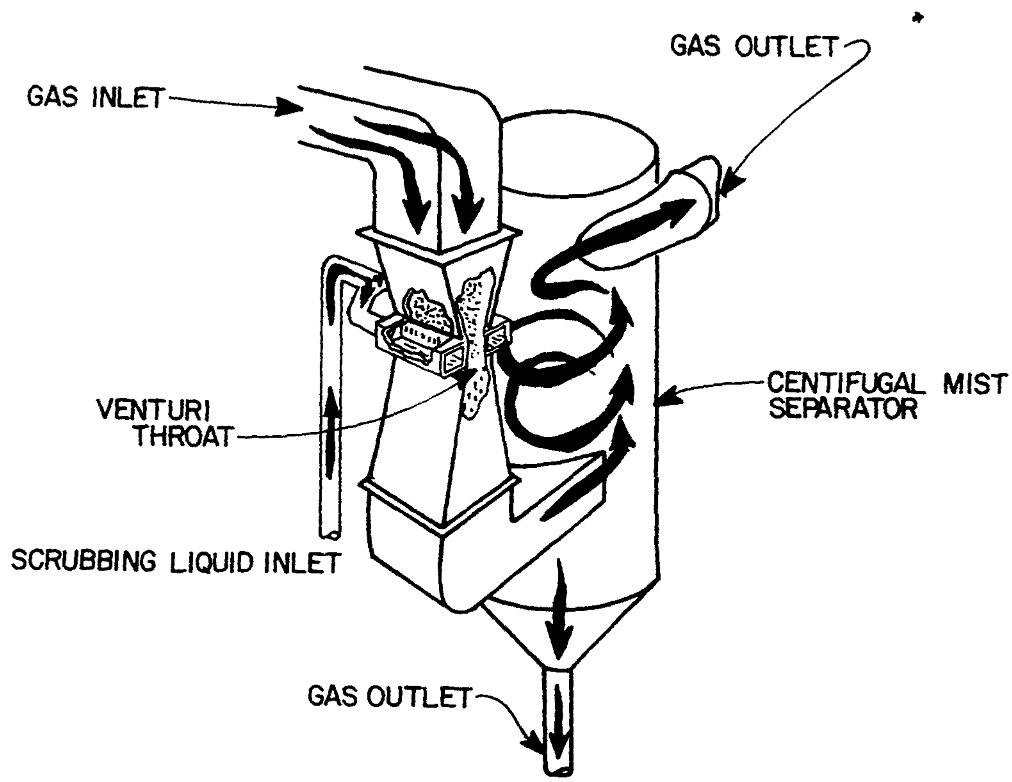


Figure 24. Venturi wet scrubber. The scrubbing liquid is atomized when it is introduced at the Venturi throat. The fly ash particles are trapped in the mist and then separated from the gas in the centrifugal mist separator.

utility industry. However, filters and scrubbers are being used more often now than they were in the past because a combination of filter and scrubber can be used to meet the current new source performance standards.

A.4.5 Stacks

The effect of the stack is to create a natural draft, which forces the flue gases upward because the weight of the column of hot flue gases is less than an equal column of ambient air. This difference increases with increasing height; hence, the greater the height of the stack, the greater the draft.

In a power plant, many considerations act to reduce the theoretical draft available from a stack. These include resistance to flow due to heat recovery devices and other frictional losses. Fans are used to supplement the stack-induced draft. A fan is called a forced-draft fan if it takes in air at atmospheric pressure and forces it into the windbox of the boiler; it is called an induced-draft fan if it takes in flue gases and pushes them through the stack. Most large boilers have both forced-draft and induced-draft fans.

Besides serving to create draft, the stack has an important part in the dispersal of pollutants. Increasing the stack height decreases the average ground level concentration of pollutants. Electric utility stack heights range from about 100 feet above ground to over 1,000 feet.

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TECHNICAL REPORT DATA
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1. REPORT NO. EPA-600/2-75-022	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Effects of Transient Operating Conditions on Steam-Electric Generator Emissions		5. REPORT DATE August 1975
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) J.S. McKnight		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Research Triangle Institute P.O. Box 12194 Research Triangle Park, NC 27709		10. PROGRAM ELEMENT NO. 1AB013; ROAP 21BAV-002
		11. CONTRACT/GRANT NO. 68-02-1325, Task 10
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final; 1/74 - 1/75
		14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES

16. ABSTRACT The report gives results of a review of information currently available on the effects of transient operating conditions on gaseous emissions from fossil-fuel-fired steam-electric generating plants. Information was obtained from scientific literature, personal visits to utility companies, and correspondence with utility companies and manufacturers of generating plant equipment. Emissions of concern are nitrogen oxides, sulfur oxides, particulates, and visible emissions. Particular attention was given to older coal-fired generators, used to provide the cycling portion of the diurnal variation in electricity generated by electric utilities. No consideration is given to flue gas desulfurization processes used to remove sulfur oxides. Transient conditions included in this study are starts, stops, cycling, and upset conditions caused by equipment malfunctions or changes in fuel characteristics or load.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Air Pollution	Flue Dust	Air Pollution Control	13B	21B
Steam Electric Power Generation		Stationary Sources		
Fossil Fuels		Transient Operating Conditions	10A	
Nitrogen Oxides			21D	
Sulfur Oxides		Particulates	07B	
		Visible Emissions		

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS *(This Report)* Unclassified	21. NO. OF PAGES 114
	20. SECURITY CLASS *(This page)* Unclassified	22. PRICE

EPA Form 2220-1 (9-73)