Lesson 9

Flue Gas Desulfurization (Acid Gas Removal) Systems

Goal

To familiarize you with the operation of flue gas desulfurization (FGD) systems that use a scrubbing liquid to absorb SO_2 present in the exhaust gas stream.

Objectives

At the end of this lesson, you will be able to do the following:

1. Describe how the following six operating variables affect wet scrubber operation in FGD systems:
   - Liquid-to-gas ratio
   - pH
   - Gas velocity/residence time
   - Gas distribution system
   - Scrubber design
   - Turndown ability
2. Briefly describe four FGD wet scrubbing processes
3. Identify operating problems associated with each FGD process above
4. Identify some of the various scrubber designs and typical operating conditions associated with FGD processes

Introduction

The previous lessons describe various scrubber designs that control emissions of gaseous and particulate pollutants. This lesson discusses a major application for scrubbers in air pollution control: **flue gas desulfurization (FGD)**, which is one of the largest markets for scrubbing systems (in terms of money spent). The term *flue gas desulfurization* has traditionally referred to wet scrubbers that remove sulfur dioxide (SO_2) emissions from large electric utility boilers (mainly coal combustion). However, because of the requirement to control acid emissions from industrial boilers and incinerators and the evolution of different types of acid control systems, the terms *FGD*, *acid gas* or *acid rain control* are used interchangeably to categorize a wide variety of control system designs. FGD systems are also used to reduce SO_2 emissions from process plants such as smelters, acid plants, refineries, and pulp and paper mills.

FGD systems can be categorized as dry or wet. In Lesson 7, you learned about dry scrubbing systems that control SO_2 and other acid gases from utility and industrial boilers and incinerators. This lesson focuses on the traditional, wet FGD systems that have been installed on operating plants. This lesson will also briefly cover some of the emerging technologies (both wet or dry) that are being developed for FGD (acid rain) control.

In wet FGD scrubbing systems, the scrubbing liquid contains an alkali reagent to enhance the absorption of SO_2 and other acid gases. More than a dozen different reagents have been used, with lime and limestone being the most popular. Sodium-based solutions (sometimes referred to as clear solutions) provide better SO_2 solubility and less scaling problems than lime or limestone. However, sodium reagents are much more expensive.

Wet FGD scrubbers can further be classified as nonregenerable or regenerable. **Nonregenerable** processes, also called *throwaway* processes, produce a sludge waste that must be disposed of properly. It should be noted that in throwaway or nonregenerable processes the scrubbing liquid can still be recycled or regenerated; however, no useful product is obtained from the eventual sludge. **Regenerable** processes produce a product from the sludge that may be sold to partially offset the cost of operating the FGD system. Regenerated products include elemental sulfur, sulfuric acid and gypsum. Based on the recent capacities listed in Table 9-1, approximately 91% of FGD processes are nonregenerable, or throwaway. The throwaway processes are simpler and presently more economical than those that recover and sell products. Also, Table 9-1 shows that approximately 78% of the FGD systems represented are wet systems using lime or limestone as a reagent.

Table 9-1. Summary of FGD systems by process (percentage of total Megawatts)

Process	By-product	Percent of total MW (as of 12/89)
Throwaway product		
Wet scrubbing		
Dual alkali		3.4%
Lime		16.3
Lime/alkaline fly ash		7.0
Limestone		48.2
Limestone/alkaline fly ash		2.4
Sodium carbonate		4.0
Spray drying		
Lime		8.8
Sodium carbonate		0
Reagent type not selected		0.7
Dry injection		
Lime		0.2
Sodium carbonate		0
Reagent type not selected		0
Process not selected		0
Saleable product		
Wet scrubbing		
Lime	Metals/fly ash/other	< 0.1
Limestone	Gypsum	4.1
Magnesium oxide	Sulfuric acid	1.4
Wellman Lord	Sulfuric acid	3.1
Spray drying		
Lime	Dry scrubber waste	0
Process undecided		0
Total		100.0

Source: Hance 1991.

Most FGD systems employ two stages: one for **fly ash removal** and the other for **SO_2 removal**. Attempts have been made to remove both the fly ash and SO_2 in one scrubbing vessel. However, these systems experienced severe maintenance problems and low simultaneous removal efficiencies. In wet scrubbing systems the flue gas normally passes first through a fly ash removal device, either an electrostatic precipitator or a wet scrubber, and then into the SO_2 absorber. However, in dry injection or spray drying operations, the SO_2 is first reacted with the sorbent and then the flue gas passes through a particulate control device.

Many different types of absorbers have been used in wet FGD systems, including spray towers, venturis, plate towers, and mobile packed beds. Because of scale buildup, plugging, or erosion, which affect FGD dependability and absorber efficiency, the trend is to use simple scrubbers such as spray towers instead of more complicated ones. The configuration of the tower may be vertical or horizontal, and flue gas can flow cocurrently, countercurrently, or crosscurrently with respect to the liquid. The chief drawback of spray towers is that they require a higher liquid-to-gas ratio requirement for equivalent SO_2 removal than other absorber designs (Makansi 1982).

Numerous operating variables affect the SO_2 removal rate of the absorber. Most of these variables were discussed in previous lessons; however, some are unique to FGD absorbers. The following list contains some of the important parameters affecting the operation of an FGD scrubber (Ponder et al. 1979 and Leivo 1978):

Liquid-to-gas ratio - The ratio of scrubber liquid slurry to gas flow (L/G ratio). For a given set of system variables, a minimum L/G ratio is required to achieve the desired SO_2 absorption, based on the solubility of SO_2 in the liquid. High L/G ratios require more piping and structural design considerations, resulting in higher costs.

pH - Depending on the particular type of FGD system, pH must be kept within a certain range to ensure high solubility of SO_2 and to prevent scale buildup.

Gas velocity - To minimize equipment cost, scrubbers are designed to operate at maximum practicable gas velocities, thereby minimizing vessel size. Maximum velocities are dictated by gas-liquid distribution characteristics and by the maximum allowable liquid entrainment that the mist eliminator can handle. Gas velocities may be 1.5 to 10 m/s (5 to 30 ft/sec) in tower scrubbers and more than 30 m/s (100 ft/sec) in the throat of a venturi scrubber. A common range of the gas velocity for FGD absorbers is 2.0 to 3.0 m/s (7 to 10 ft/sec). The lower the velocity is, the less the entrainment, but the more costly the scrubber will be.

Residence Time - For FGD processes using an alkali slurry for scrubbing, the system should be designed to provide adequate residence time in the absorber vessel for the SO_2 to be absorbed by the alkali slurry. The main objective is to make sure that the maximum amount of alkali is utilized in the scrubber. Residence times in packed towers may be as long as 5 seconds. Residence times in venturi scrubbers are a few hundredths of a second, usually too short for high absorption efficiency of SO_2 in systems using lime or limestone scrubbing slurries, unless additives or two scrubbing stages are used.

Gas distribution - Maintaining a uniform gas flow is a major problem that occurs in commercial FGD scrubbers. If the flow is not uniform, the scrubber will not operate at design efficiencies. In practice, uniform flow has been difficult to achieve. Typically, turning vanes near the scrubber inlet duct and compartmentalization have been used.

Scrubber designs - To promote maximum gas-liquid surface area and contact time, a number of scrubber designs have been used. Common ones are mobile-bed scrubbers, venturi-rod scrubbers, plate towers, packed towers, and spray towers. Countercurrent packed towers are infrequently used because they have a tendency to become plugged by collected particles or to scale when lime or limestone scrubbing slurries are used.

Turndown - The ability to operate at less than full load and to adjust to changes in boiler load. The scrubber must provide good gas-liquid distribution, sufficient residence time, and high gas-liquid interfacial area for varying gas flow rates. Some scrubbers can be turned down to 50% of design, while others must be divided into sections that can be closed off. A variable-throat venturi can be used to accommodate turndown. In a large FGD installation, individual modules can be taken out of service.

It is important to note that the above list does not imply that these are the only parameters affecting SO_2 absorption efficiency. Each FGD process has a unique set of operating criteria.

In addition to the set of factors just given, the coal properties greatly affect FGD system design for boiler operations. The major coal properties affecting FGD system design and operation are (Leivo 1978):

Heating value of coal - Affects flue gas flow rate. Flow rate is generally higher for lower heating value coals, which also contribute a greater water-vapor content to the flue gas.

Moisture content - Affects the heating value (i.e. since the higher the moisture content the lower the heating value) and contributes directly to the moisture content and volume of the flue gas.

Sulfur content - The sulfur content, together with the allowable emission standards, determines the required SO_2 removal efficiency, the FGD system complexity and cost, and also affects sulfite oxidation.

Ash content - May affect FGD system chemistry and increase erosion. In some cases, it may be desirable to remove fly ash upstream from the FGD system.

Chlorine content - May require high-alloy metals or linings to combat corrosion for some process equipment and could affect process chemistry or require prescrubbing.

Another important design consideration associated with wet FGD systems is that the flue gas exiting the absorber is saturated with water and still contains some SO_2. (No system is 100% efficient.) Therefore, these gases are highly corrosive to any downstream equipment - i.e., fans, ducts, and stacks. Two methods that minimize corrosion are: (1) reheating the gases to above their dew point and (2) choosing construction materials and design conditions that allow equipment to withstand the corrosive conditions. The selection of a reheating method or the decision not to reheat (thereby requiring the use of special construction materials) are very controversial topics connected with FGD design (Makansi 1982). Both alternatives are expensive and must be considered on a by-site basis.

Four methods used to reheat stack gases:

1. **Indirect in-line reheating** - The flue gas passes through a heat exchanger that uses steam or hot water.

2. **Indirect-direct reheating** - Steam is used to heat air (outside the duct) and then the hot air is mixed with the scrubbed gases.

3. **Direct combustion reheating** - Oil or gas is burned either in the duct or in an external chamber, and the resulting hot gases are mixed with the scrubbed gases.

4. **Bypass reheating** - A portion of the untreated hot flue gas bypasses the scrubber and is mixed with the scrubbed gases.

None of the above methods has a clear advantage over the others (Makansi 1982). Systems using indirect in-line reheating have experienced severe corrosion and plugging problems. Indirect-direct and direct combustion reheating are expensive because of added fuel costs and bypass reheating is limited in the degree of reheating obtainable (due to SO_2 emissions in the bypass). Because of the expense and problems associated with reheat, newer FGD designs are utilizing more plastics (fiberglass reinforced plastic) and exotic alloys instead of reheat.

This lesson will discuss four of the more popular FGD systems that are nonregenerable, calcium- and/or sodium-based systems. The process chemistry, system description, and operating experience involved in each will be presented.

To test your knowledge of the preceding section, answer the questions in Part 1 of the Review Exercise.

Nonregenerable FGD Processes

Nonregenerable FGD processes generate a sludge or waste product. The sludge must be disposed of properly in a pond or landfill. The three most common nonregenerable processes used on utility boilers in the U. S. are **lime**, **limestone**, and **double-alkali**. Although the double-alkali process regenerates the scrubbing reagent, it is classified as throwaway since it does not produce a saleable product and generates solids that must be disposed of in a landfill. The fourth nonregenerable process discussed here, sodium-based throwaway systems (NaOH and Na_2CO_3), are utilized mostly on industrial boilers.

Lime Scrubbing

Process Chemistry

Lime scrubbing uses an alkaline slurry made by adding lime (CaO), usually 90% pure, to water. The alkaline slurry is sprayed in the absorber and reacts with the SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber and are removed as sludge.

A number of reactions take place in the absorber. Before the calcium can react with the SO_2, both must be broken down into their respective ions. This is accomplished by slaking (dissolving) the lime in water and then spraying the slurry into the flue gas to dissolve the SO_2. Simplified reactions occur simultaneously and are illustrated below.

SO_2 dissociation:

$$SO_{2\,(gaseous)} \rightarrow SO_{2\,(aqueous)}$$

$$SO_2 + H_2O \rightarrow H_2SO_3$$

$$H_2SO_3 \rightarrow H^+ + HSO_3^- \rightarrow 2H^+ + SO_3^=$$

Lime (CaO) dissolution:

$$CaO_{(solid)} + H_2O \rightarrow Ca(OH)_{2\,(aqueous)}$$

$$Ca(OH_2) \rightarrow Ca^{++} + 2OH^-$$

Now that SO_2 and lime are broken into their ions ($SO_3^=$ and Ca^{++}), the following reaction occurs:

$$Ca^{++} + SO_3^= + 2H^+ + 2OH^- \rightarrow CaSO_{3\,(solid)} + 2H_2O$$

In addition, the following reactions can also occur when there is excess oxygen:

$$SO_3^= + 1/2\ O_2 \rightarrow SO_4^=$$
$$SO_4^= + Ca^{++} \rightarrow CaSO_{4\,(solid)}$$

From the above relationships and assuming that the lime is 90% pure, it will take 1.1 moles of lime to remove 1 mole of SO_2 gas.

System Description

The equipment necessary for SO_2 emission reduction comes under four operations:

1. **Scrubbing or absorption** - Accomplished with scrubbers, holding tanks, liquid-spray nozzles, and circulation pumps.

2. **Lime handling and slurry preparation** - Accomplished with lime unloading and storage equipment, lime processing and slurry preparation equipment.

3. **Sludge processing** - Accomplished with sludge clarifiers for dewatering, sludge pumps and handling equipment, and sludge solidifying equipment.

4. **Flue-gas handling** - Accomplished with inlet and outlet ductwork, dampers, fans, and stack gas reheaters.

Figure 9-1 is a schematic of a typical lime FGD system. Individual FGD systems vary considerably, depending on the FGD vendor and the plant layout. ESPs or scrubbers can be used for particle removal, followed by one of various absorber designs that are effective for SO_2 removal. In general, as shown in Figure 9-1, flue gas from the boiler first passes through a particulate emission removal device then into the absorber where the SO_2 is removed. The gas then passes through the entrainment separator to a reheater and is finally exhausted out of the stack.

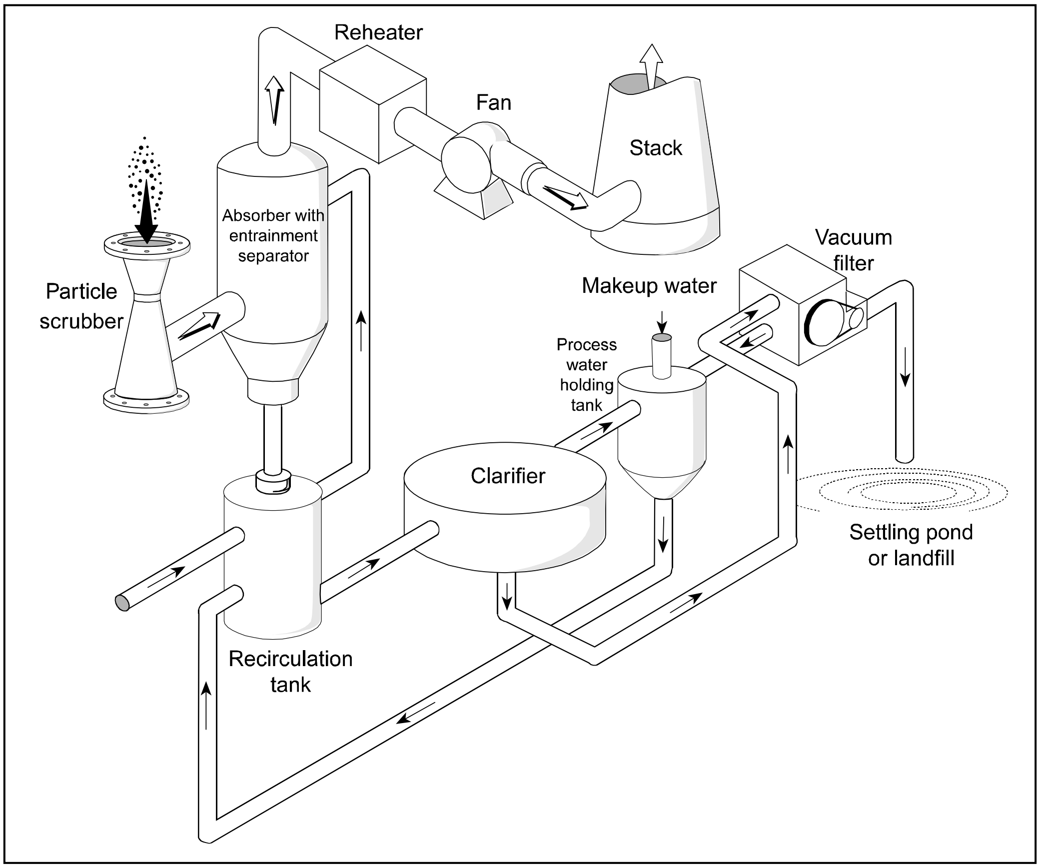

Figure 9-1. Typical process flow for a lime or limestone FGD system

A slurry of spent scrubbing liquid and sludge from the absorber then goes to a recirculation tank. From this tank, a fixed amount of the slurry is bled off to process the sludge, and, at the same time, an equal amount of fresh lime is added to the recirculation tank. Sludge is sent to a clarifier, where a large portion of water is removed from the sludge, and sent to a holding tank. Makeup water is added to the process-water holding tank, and this liquid is returned to the recirculation tank. The partially dewatered sludge from the clarifier is sent to a vacuum filter, where most of the water is removed (and sent to the process-water holding tank) and the sludge is sent to a settling pond. Table 9-2 lists operational data of lime FGD systems, showing the various absorbers used.

Table 9-2. Operational data for lime FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	$gal/1000\ ft^3$	kPa	in. H_2O	Design	Test
Pennsylvania Power												
Bruce Mansfield #1	917	Chemico	1st-stage venturi	3.0	Fixed-throat venturi	6	6.0	45.0	2.0	8.0	92.1	95.0
Bruce Mansfield #2	917	Chemico	1st-stage venturi	3.0	Fixed-throat venturi	6	6.0	45.0	2.0	8.0	92.1	95.0
Bruce Mansfield #3	917	Pullman Kellogg	ESP	3.0	Weir crosscurrent spray	6	-	-	0.7	2.8	92.0	95.0
Columbus & Southern Ohio Electric												
Conesville #5	411	Air Correction Division	ESP	4.7	Mobile bed	1	6.7	50.0	2.0	8.0	89.5	89.7
Conesville #6	411	Air Correction Division	ESP	4.7	Mobile bed	2	6.7	50.0	2.0	8.0	89.5	89.5
Duquesne Light												
Elrama	510	Chemico	ESP	2.2	Variable-throat venturi	5	5.3	40.0	4.0	16.0	83.0	86.0
Phillips	408	Chemico	Cyclone/ESP	1.9	Variable-throat venturi	4	5.3	40.0	4.0	16.0	83.0	90.0
Kentucky Utilities												
Green River	64	American Air Filter	Cyclone/ variable-throat venturi	4.0	Mobile bed	1	4.5	34.0	1.0	4.0	80.0	80.0
Louisville Gas & Electric												
Cane Run #4	188	American Air Filter	ESP	3.7	Mobile bed	2	8.0	60.0	1.0	40.0	85.0	87.5
Cane Run #5	200	Combustion Engineering	ESP	3.7	Countercurrent spray	2	7.4	55.0	0.1	0.5	85.0	91.0
Mill Creek #1	358	Combustion Engineering	-	3.7	-	-	12.7	95.0	-	-	85.0	86.6
Mill Creek #3	442	American Air Filter	ESP	3.7	Mobile bed	4	8.7	65.0	1.6	6.5	85.0	85.7
Paddy's Run #6	72	Combustion Engineering	ESP	2.5	Mobile bed (marbles)	2	2.2	16.5	2.9	11.5	90.0	90.0

Table 9-2. ***(continued)***
Operational data for lime FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pres
							L/m^3	gal/1000 ft^3	kPa
Kansas City Power & Light									
Hawthorn #3	90	Combustion Engineering	-	0.6	Mobile bed (marbles)	2	3.5	26.0	2.7
Hawthorn #4	90	Combustion Engineering	-	0.6	Mobile bed (marbles)	2	3.5	26.0	2.7
Monongahela Power									
Pleasants #1	618	B&W	ESP	3.7	Sieve tray	4	7.4	55.0	1.2
Pleasants #2	618	B&W	ESP	4.5	Sieve tray	4	7.4	55.0	-
Utah Power & Light									
Hunter #1	400	Chemico	ESP	0.6	Countercurrent spray	4	5.7	43.0	0.6
Hunter #2	400	Chemico	ESP	0.6	Countercurrent spray	4	5.7	43.0	0.6
Huntingdon #1	430	Chemico	ESP	0.6	Countercurrent spray	4	5.7	43.0	0.6

Note: A dash (-) indicates that no data are available.

Operating Experience

Early lime FGD systems were plagued with many operational and maintenance problems. Scale buildup and plugging of absorber internals and associated equipment were prominent problems. However, scaling and plugging in lime FGD systems were not as severe as with other calcium-based FGD systems (EPA 1981). Scale buildup ($CaSO_4$) on spray nozzles and entrainment separators was particularly troublesome. New spray nozzle designs and careful control of the recirculating slurry have reduced internal scrubber scaling (EPA 1975). Problems with the entrainment separators have also been reduced by careful separator design, installing adequate wash sprays, and monitoring the pressure drop across them. Additional techniques that reduce scale buildup are (Leivo 1978):

Control of pH - If a lime FGD system is operated above a pH of 8.0 to 9.0, there is a risk of sulfite scaling. Automatic control of the feed by on-line pH sensors has been successful.

Holding tank residence time - By providing retention time in the scrubber recirculation tank, the supersaturation of the liquor can be decreased before recycling to the scrubber. Typical residence times of 5 to 15 minutes have been used in some full-scale systems.

Control of suspended solids concentration - The degree of supersaturation can be minimized by keeping an adequate supply of seed crystals in the scrubber slurry. Typical levels in newer installations range from 5 to 15% suspended solids. Solids are generally controlled by regulating the slurry bleed rate.

Liquid-to-gas ratio - High liquid-to-gas ratios can reduce scaling problems because the absorber outlet slurry is more dilute, containing less calcium sulfates and calcium sulfites that cause scaling.

Another problem that has occurred concerns stack gas reheaters. Stack gas is reheated to avoid condensation on and corrosion of the ductwork and stack, and to enhance plume rise and pollutant dispersion. Reheating is accomplished by using steam coils in the stack, by using hot air supplied by auxiliary oil heaters in the stack, or by other methods previously mentioned. Some reheater failures were caused by acid attack to reheater components. Other reheaters vibrated too much, causing structural deterioration.

Corrosion of scrubber internals, fans and ductwork, and stack linings have been reduced by using special materials such as rubber- or plastic-coated steel and by carefully controlling slurry pH with monitors. Additional operation and maintenance problems and solutions are found in *Lime FGD Systems Data Book,* Second Edition (EPRI 1983).

To test your knowledge of the preceding section, answer the questions in Part 2 of the Review Exercise.

Limestone Scrubbing

Process Chemistry

Limestone scrubbers are very similar to lime scrubbers. The use of limestone ($CaCO_3$) instead of lime requires different feed preparation equipment and higher liquid-to-gas ratios (since limestone is less reactive than lime). Even with these differences, the processes are so similar that an FGD system can be set up to use either lime or limestone in the scrubbing liquid (See Figure 9-1).

The basic chemical reactions occurring in the limestone process are very similar to those in the lime-scrubbing process. The only difference is in the dissolution reaction that generates the calcium ion. When limestone is mixed with water, the following reaction occurs:

$$CaCO_{3\ (solid)} + H_2O \rightarrow Ca^{++} + HCO_3^- + OH^-$$

The other reactions are the same as those for lime scrubbing.

System Description

The equipment necessary for SO_2 absorption is the same as that for lime scrubbing, except in the slurry preparation. The limestone feed (rock) is reduced in size by crushing it in a ball mill. Limestone is sent to a size classifier. Pieces larger than 200 mesh are sent back to the ball mill for recrushing. Limestone is mixed with water in a slurry supply tank. Limestone is generally 2 to 4 times cheaper than lime, making it more popular for large FGD systems. Table 9-3 lists operations data for limestone FGD systems. Note the similarities in equipment and operating conditions to those of lime FGD systems.

See Table 9-3. Operational data for limestone FGD systems on utility boilers

Table 9-3. Operational data for limestone FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pres
							L/m^3	$gal/1000\ ft^3$	kPa
Alabama Electric									
Tombigbee #2	255	Peabody	ESP	1.2	Countercurrent spray	2	9.4	70.0	1.0
Tombigbee #3	255	Peabody	ESP	1.2	Countercurrent spray	2	9.4	70.0	1.0
Arizona Electric Power									
Apache #2	195	Research-Cottrell	ESP	0.5	Spray/packed bed	2	2.8	20.6	1.5
Apache #3	195	Research-Cottrell	ESP	0.5	Spray/packed bed	2	2.8	20.6	1.5
Cholla #1	119	Research-Cottrell	Cyclone/venturi	0.5	Spray/packed bed	1	6.5	48.9	0.1
Cholla #2	264	Research-Cottrell	Cyclone/venturi	0.5	Spray/packed bed	4	6.5	48.9	0.1
Basin Electric Power									
Laramie River #1	570	Research-Cottrell	ESP	0.8	Spray/packed bed	5	8.0	60.0	-
Laramie River #2	570	Research-Cottrell	ESP	0.8	Spray/packed bed	5	8.0	60.0	-
Central Illinois Light									
Duck Creek #1	416	Environeering	ESP	3.7	Rod deck packed tower	4	6.7	50.0	2.0
Colorado Ute Electrical									
Craig #1	447	Peabody	ESP	0.4	Countercurrent spray	4	6.7	50.0	1.6
Craig #2	455	Peabody	ESP	0.4	Countercurrent spray	4	6.7	50.0	1.6
Commonwealth Edison									
Powerton	450	Air Correction Division - UOP	ESP	3.5	Mobile bed (TCA)	3	8.0	60.0	3.0
Indianapolis Power & Light									
Petersburg #3	532	Air Correction Division - UOP	ESP	3.2	Mobile bed (TCA)	4	6.7	50.0	1.7

Table 9-3. *(continued)*
Operational data for limestone FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pres
							L/m^3	gal/1000 ft^3	kPa
Kansas City Power & Light									
La Cygne	820	B&W	Variable venturi	5.4	Sieve tray	8	5.0	37.7	1.5
Jeffery #1	720	Combustion Engineering	ESP	0.3	Countercurrent spray	6	4.1	30.4	1.0
Jeffery #2	700	Combustion Engineering	ESP	0.3	Countercurrent spray	-	4.1	30.4	1.0
Lawrence #4	125	Combustion Engineering	Rod venturi	0.6	Countercurrent spray	2	4.0	30.0	0.6
Lawrence #5	420	Combustion Engineering	Rod venturi	0.6	Countercurrent spray	2	2.5	19.0	0.6
Salt River Project									
Coronado #1	350	Pullman Kellogg	ESP	1.0	Weir crosscurrent spray	2	-	-	0.4
Coronado #2	350	Pullman Kellogg	ESP	1.0	Weir crosscurrent spray	2	-	-	0.4
South Carolina Public Service									
Winyah #2	280	B&W	ESP	1.7	Venturi/sieve tray	2	6.3	47.5	1.1
Winyah #3	280	B&W	ESP	1.7	Countercurrent spray	2	-	-	-
South Mississippi Electric									
R. D. Morrow #1	200	Environeering	ESP	1.3	Rod deck packed tower	1	6.6	49.0	2.0
R. D. Morrow #2	200	Environeering	ESP	1.3	Rod deck packed tower	1	6.6	49.0	2.0
Southern Illinois									
Marion #4	173	B&W	ESP	3.8	Countercurrent spray	2	9.9	74.0	1.5

Table 9-3. *(continued)*
Operational data for limestone FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pres
							L/m^3	gal/1000 ft^3	kPa
Springfield City									
Southwest #1	194	Air Correction Division - UOP	ESP	3.5	Mobile bed (TCA)	2	5.5	41.0	1.5
Springfield Water, Light & Power									
Dallman #3	205	Research-Cottrell	Cyclone/ESP	3.3	Spray/packed tower	2	-	-	0.2
TVA									
Widows Creek #8	550	TVA	ESP/venturi	3.7	Mobile packed bed and grid packing	1 3	8.0	60.0	0.5
Texas Power & Light									
Sandow #4	545	Combustion Engineering	ESP	1.6	Countercurrent spray	3	-	-	-
Texas Utilities									
Martin Lake #1	793	Research-Cottrell	ESP	0.9	Spray/packed bed	6	-	-	1.1
Martin Lake #2	793	Research-Cottrell	ESP	0.9	Spray/packed bed	6	-	-	1.1
Martin Lake #3	793	Research-Cottrell	ESP	0.9	Spray/packed bed	6	-	-	1.1
Monticello	800	Chemico	ESP	1.5	Countercurrent spray	3	9.4	70.0	1.2

Note: A dash (-) indicates that no data are available.

Operating Experience

Early limestone FGD systems had scrubber operating problems similar to those of lime scrubbing systems. Plugged and clogged nozzles, scrubber internals, and mist eliminators (entrainment separators) resulted from inefficient SO_2 absorption by limestone in the scrubber.

Increased absorption efficiency is achievable at high pH values since more alkali is available to dissolve the SO_2 gas. However, scale buildup will occur if the scrubber is operated at very high pH values. The pH levels can be maintained by carefully controlling limestone and water feed rates. Low pH reduces removal efficiency; high pH causes scale buildup on scrubber internals.

As you can see from Tables 9-2 and 9-3, the SO_2 removal efficiencies for various lime and limestone FGD installations range from 52% to 97%. These FGD systems were designed to meet existing air pollution regulations. Lime and limestone FGD systems are capable of removing SO_2 with efficiencies in excess of 90%. The addition of small amounts of reagents (such as soluble magnesium) to the scrubber liquor can greatly increase SO_2 removal efficiencies to as high as 99% (Devitt et al. 1978).

Another scrubber operating problem occurring in lime and limestone FGD systems is that calcium sulfite in the sludge settles and filters poorly. It can be removed from the scrubber slurry only in a semi-liquid or paste-like form. A process improvement called forced oxidation was developed by an EPA research laboratory to address this problem. In **forced oxidation**, air is blown into a designated section of the absorber module or into a separate reaction (oxidation) tank. The air oxidizes the calcium sulfite to calcium sulfate in the following reaction:

$$CaSO_3 + H_2O + 1/2\ O_2 \rightarrow CaSO_4 + H_2O$$

Calcium sulfate formed by this reaction grows to a larger crystal size than calcium sulfite. As a result, calcium sulfate is easily filtered, forming a drier and more stable material that can be disposed of in a landfill or has the potential to be sold as a product to make cement, gypsum wallboard, or as a fertilizer additive.

Forced oxidation also helps control scale buildup problems on scrubber internals by removing the calcium sulfite from the slurry in the form of calcium sulfate, which is more easily filtered. This prevents calcium sulfites from oxidizing and precipitating out in the scrubber internal areas. Another method to prevent oxidation of calcium sulfite to calcium sulfate is by use of chemical inhibitors. Sulfur, magnesium and dibasic acid have all been tested and proven effective in inhibiting oxidation and thus reducing scaling in lime and limestone FGD systems.

To test your knowledge of the preceding section, answer the questions in Part 3 of the Review Exercise.

Dual-Alkali Scrubbing

Dual- or double-alkali scrubbing is a third throwaway FGD process that uses a sodium-based alkali solution to remove SO_2 from combustion exhaust gas. The sodium alkali solution absorbs SO_2, and the spent absorbing liquor is regenerated with lime or limestone. Using both sodium- and calcium-based compounds is where the name *dual* or *double-alkali* comes from. Calcium sulfites and sulfates are precipitated and discarded as sludge. The regenerated sodium scrubbing solution is returned to the absorber loop. The dual-alkali process has reduced plugging and scaling problems in the absorber because sodium scrubbing compounds are very soluble. Dual-alkali systems are capable of 95% SO_2 reduction.

Particulate matter is removed prior to SO_2 scrubbing by an electrostatic precipitator or a venturi scrubber. This prevents the following: (1) fly ash erosion of the absorber internals and (2) any appreciable oxidation of the sodium solution in the absorber due to catalytic elements in the fly ash (EPA 1978).

Process Chemistry

The sodium alkali solution is usually a mixture of the following compounds:

1. Sodium hydroxide (NaOH), also called caustic
2. Sodium carbonate (Na_2CO_3), also called soda ash
3. Sodium sulfite (Na_2SO_3)

The SO_2 reacts with the alkaline components to primarily form sodium sulfite and sodium bisulfite ($NaHSO_3$). The following are the main absorption reactions (EPA 1981):

$$2\ NaOH + SO_2 \rightarrow Na_2SO_3 + H_2O$$

$$NaOH + SO_2 \rightarrow NaHSO_3$$

$$Na_2CO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

$$Na_2CO_3 + SO_2 \rightarrow Na_2SO_3 + CO_2$$

$$Na_2SO_3 + SO_2 + H_2O \rightarrow 2NaHSO_3$$

In addition to the above reactions, some of the SO_3 present may react with alkaline components to produce sodium sulfate. For example,

$$2NaOH + SO_3 \rightarrow Na_2SO_4 + H_2O$$

Throughout the system, some sodium sulfite is oxidized to sulfate by:

$$2Na_2SO_3 + O_2 \rightarrow 2Na_2SO_4$$

After reaction in the absorber, spent scrubbing liquor is bled to a reactor tank for regeneration. Sodium bisulfite and sodium sulfate are inactive salts and do not absorb any SO_2. Actually, it is the hydroxide ion (OH^-), sulfite ion ($SO_3^=$), and carbonate ion ($CO_3^=$) that absorb SO_2 gas. Sodium bisulfite and sodium sulfate are reacted with lime or limestone to produce a calcium sludge and a regenerated sodium solution.

$$\underset{}{2NaHSO_3} + \underset{\text{(lime)}}{Ca(OH)_2} \rightarrow Na_2SO_3 + \underset{\text{(sludge)}}{CaSO_3 \bullet 1/2\, H_2O\downarrow} + 3/2\, H_2O$$

$$Na_2SO_3 + \underset{\text{(lime)}}{Ca(OH)_2} + 1/2\, H_2O \rightarrow 2NaOH + \underset{\text{(sludge)}}{CaSO_3 \bullet 1/2\, H_2O\downarrow}$$

$$Na_2SO_4 + \underset{\text{(lime)}}{Ca(OH)_2} \rightarrow 2NaOH + \underset{\text{(sludge)}}{CaSO_4\downarrow}$$

At the present time, lime regeneration is the only process that has been used on commercial dual-alkali installations.

System Description

The dual-alkali process uses two loops - absorption and regeneration. In the **absorption loop**, the sodium solution contacts the flue gas in the absorber to remove SO_2. As shown in Figure 9-2, the scrubbing liquor from the bottom of the absorber is mixed with regenerated solution and sprayed in at the top of the absorber. A bleed stream from the recirculating liquid is sent to the reactor tank in the **regeneration loop**. The bleed stream is mixed with a lime slurry in a reactor tank, where insoluble calcium salts are formed and the absorbent is regenerated. The sludge from the reactor is then sent to a clarifier, or thickener, where the calcium sludge is drawn off the bottom, filtered, and washed with water. From the filter, the sodium solution is recycled to the clarifier, and the sludge is discarded. From the clarifier, the regenerated sodium solution is sent to a mixing tank where the sodium compounds and makeup water are added.

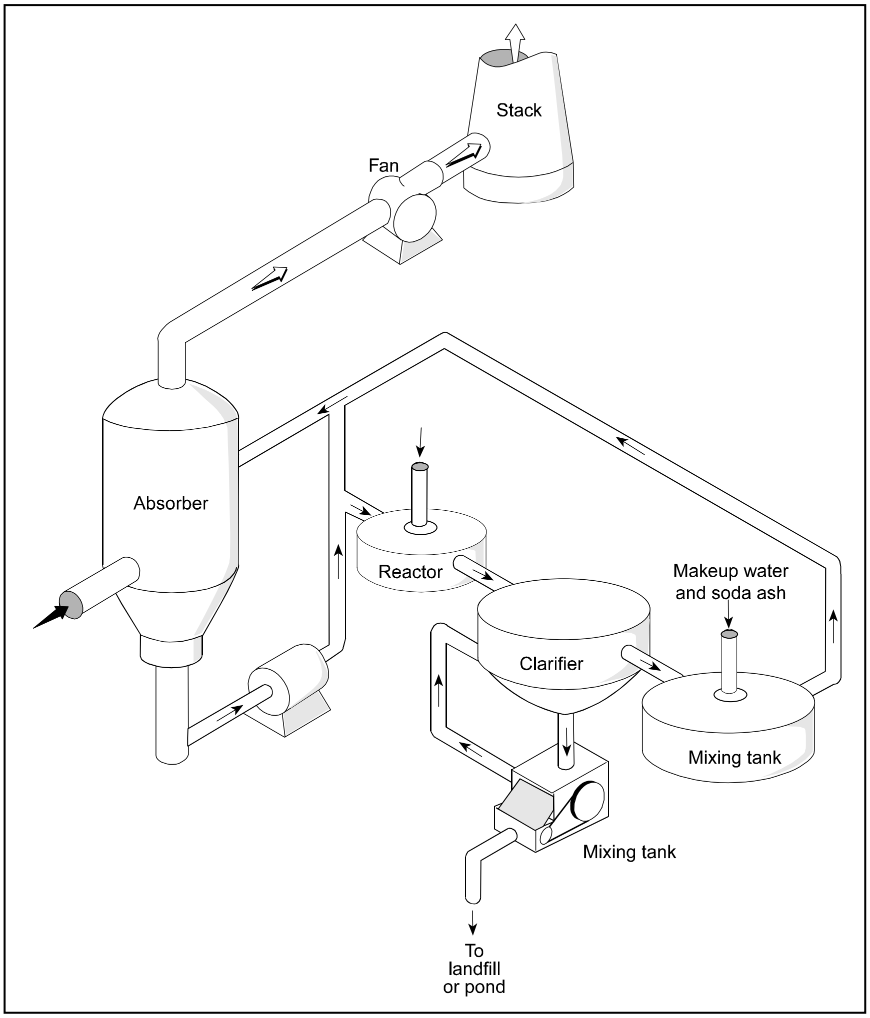

Figure 9-2. Typical process flow for a double-alkali FGD system

Some sodium sulfate solution is unreacted in the regeneration step. Additional sodium to makeup for that lost in the sludge is added to the regenerated solution in the form of soda ash or caustic soda. This regenerated absorbent is now ready to be used again.

Operating Experience

The dual-alkali process has been installed and operating on both utility and industrial boilers for a number of years. Corrosion of, erosion of, and scale buildup on system equipment have not been major operating problems at dual-alkali FGD installations in the U.S. (EPA 1981). Operating data for the dual-alkali systems are presented in Table 9-4. Note the much lower L/G ratios of these systems compared to those of lime and limestone systems. The sodium solution is more efficient than both the lime and limestone slurries in absorbing SO_2.

See Table 9-4. Operational data for double-alkali FGD systems on utility and industrial boilers

Table 9-4. Operational data for double-alkali FGD systems on utility and industrial boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio L/m^3	L/G ratio gal/1000 ft^3	Pres kPa
Central Illinois Public Service									
Newton #1	617	Buell	ESP	2.5	Mobile bed	4	1.3	10.0	1.5
Louisville Gas & Electric									
Cane Run #6	299	Combustion Equipment Association	ESP	4.8	Sieve plates	2	1.3	10.0	2.5
Southern Indiana Gas & Electric									
A. B. Brown #1	265	FMC	ESP	3.6	Variable-throat venturi	2	1.3	10.0	2.5
Caterpillar Tractor									
East Peoria, IL	105	FMC	Cyclone	3.2	Venturi	4	2.2	16.0	-
Joliet, IL	34	Zurn	Cyclone	3.2	Dustraxtor	2	-	-	-
Morton, IL	19	Zurn	Cyclone	3.2	Dustraxtor	2	-	-	-
Mossville, IL	70	FMC	Cyclone	-	Venturi	4	1.2	8.6	-
Firestone Tire									
Pottstown, PA	4	FMC	Cyclone	3.0	Venturi	1	1.3	10.0	-
General Motors									
Parma, OH	64	GM Environmental	Cyclone	-	Bubble-cap plates	4	2.6	20.0	0.9

Note: A dash (-) indicates that no data are available.

Some operating problems include regenerating scrubbing liquor and controlling the solids content of the sludge. Sodium sulfate, one of the compounds in the spent scrubbing liquor, is difficult to regenerate because it does not react efficiently with hydrated lime in the presence of sodium sulfite (Leivo 1978). Process conditions must be carefully controlled to adjust for the amounts of sodium sulfate and sodium sulfite that are formed in the spent scrubbing liquid. Another problem occurring in dual-alkali systems is that the solids content of the sludge can vary greatly, causing problems in handling and stabilizing the sludge for final disposal (Makansi 1982).

To test your knowledge of the preceding section, answer the questions in Part 4 of the Review Exercise.

Sodium-Based Once-Through Scrubbing

Sodium-based once-through (throwaway) scrubbing systems are installed on a number of industrial boilers. These systems use a clear liquid absorbent of either sodium carbonate, sodium hydroxide, or sodium bicarbonate. According to Makansi (1982), sodium-based systems are favored for treating flue gas from industrial boilers for the following reasons:

- Sodium alkali is the most efficient of the commercial reagents in removing SO_2, and the chemistry is relatively simple.
- They are soluble systems—as opposed to slurry systems—making for scale-free operation and fewer components.
- Such systems can handle the wider variations in flue-gas composition resulting from the burning of many different fuels by industry.
- The systems are often smaller, and operating costs are a small percentage of total plant costs.
- In some cases, these plants have a waste caustic stream or soda ash available for use as the absorbent.

These systems have been applied to only a few large utility boilers for these reasons:

- The process consumes a premium chemical ($NaOH$ or Na_2CO_3) that is much more costly per pound than calcium-based reagents.
- The liquid wastes contain highly soluble sodium salt compounds. Therefore, the huge quantities of liquid wastes generated by large utilities would have to be sent to ponds to allow the water to evaporate.

Process Chemistry

The process chemistry is very similar to that of the dual-alkali process, except the absorbent is not regenerated.

System Description

A basic sodium-based throwaway FGD system is illustrated in Figure 9-3. Exhaust gas from the boiler may first pass through an ESP or baghouse to remove particulate matter. Sodium chemicals are mixed with water and sprayed into the absorber. The solution reacts with the SO_2 in the flue gas to form sodium sulfite, sodium bisulfite, and a very small amount of sodium sulfate. A bleed stream is taken from the scrubbing liquor recirculation stream at a rate equal to the amount of SO_2 that is being absorbed. The bleed stream is sent to a neutralization tank and aeration tower before being sent to a lined disposal pond.

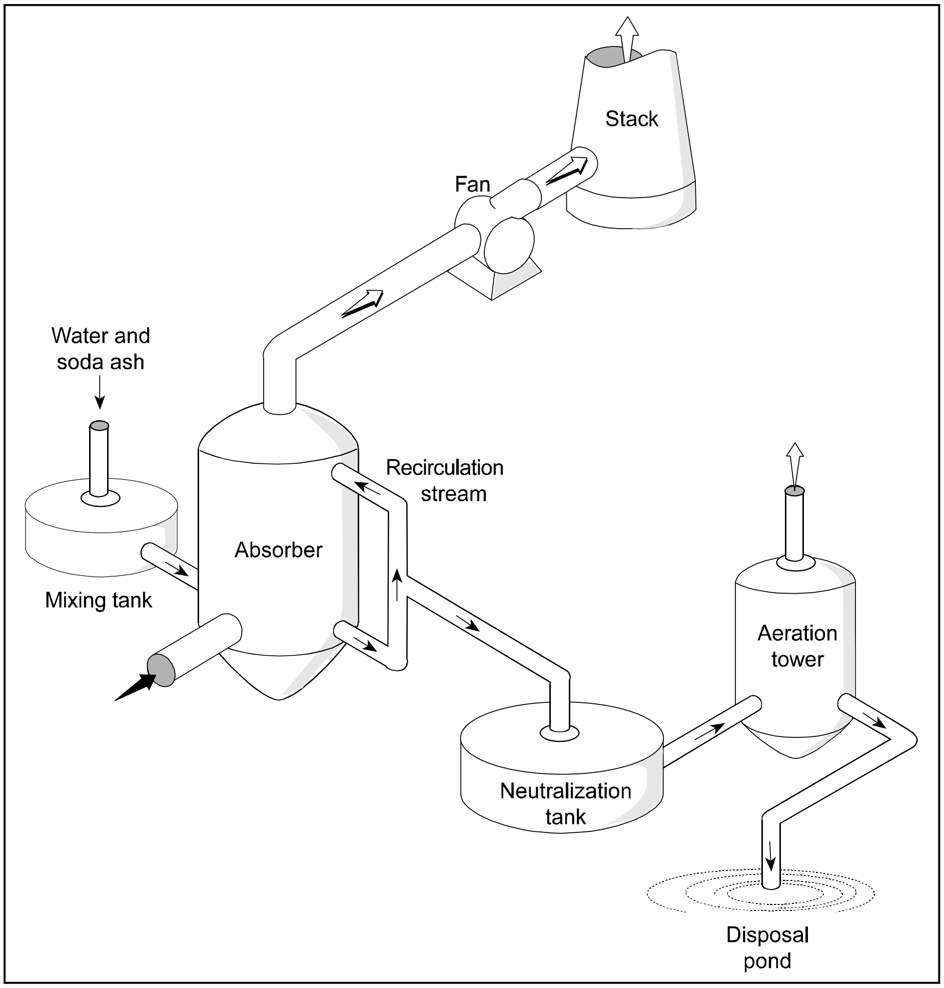

Figure 9-3. Typical process flow for a sodium-based throwaway (single-alkali) FGD system

Some coal-fired units use ESPs or baghouses to remove fly ash before the gas enters the scrubber. In these cases, the absorber can be a plate tower or spray tower that provides good scrubbing efficiency at low pressure drops. For simultaneous SO_2 and fly ash removal, venturi scrubbers can be used. In fact, many of the industrial sodium-based throwaway systems are venturi scrubbers originally designed to remove particulate matter. These units were slightly modified to inject a sodium-based scrubbing liquor. Although removal of both particles and SO_2 in one vessel can be economically attractive, the problems of high pressure drops and finding a scrubbing medium to remove heavy loadings of fly ash must be considered. However, in cases where the particle concentration is low, such as from oil-fired units, simultaneous particulate and SO_2 emission reduction can be effective.

Operating Experience

Presently a number of sodium-based throwaway FGD systems are in operation in the U.S., mainly on industrial boilers. Table 9-5 lists operating data for some of these systems. These systems are generally simpler to operate and maintain than lime or limestone systems. Therefore, reported operating problems have not been as severe or as frequent with the sodium-based system as with calcium-based systems. Control of pH, as with other FGD systems, is of prime concern to maximize absorption efficiency. Troubles with controlling pH can cause scale buildup and plugging of the sample lines. At high pH levels, the liquor absorbs CO_2 and forms carbonate scale in systems where a high amount of calcium or magnesium is present (Makansi 1982). Other problems include ineffective entrainment separation, nozzle plugging, and failure of dampers, duct liners, and stack liners.

See Table 9-5. Operational data for sodium-based once-through FGD systems on utility and industrial boilers

Table 9-5. Operational data for sodium-based once-through FGD systems on utility and industrial bo

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pres
							L/m^3	gal/1000 ft^3	kPa
Nevada Power									
Reid Gardner #1	125	Combustion Equipment Association	Cyclone/venturi	1.0	Sieve plate	1	0.2	1.6	0.7
Reid Gardner #2	125	Combustion Equipment Association	Cyclone/venturi	1.0	Sieve plate	1	0.2	1.6	0.7
Reid Gardner #3	125	Combustion Equipment Association	Cyclone/venturi	1.0	Sieve plate	1	0.2	1.6	0.7
Pacific Power & Light									
Jim Bridger #4	550	Air Correction Division - UOP	ESP	0.6	Sieve plate	3	2.7	20.0	-
Alyeska Pipeline									
Valdez, AK	25	FMC	-	0.1	Disc-and-donut trays	1	1.6	12.0	-
Belridge Oil									
McKittrick, CA	6	C-E NATCO	-	1.1	Eductor venturi with variable disk	1	-	-	-
McKittrick, CA	6	Heater Technology	-	1.1	Eductor venturi with variable disk	1	5.4	40.0	-
McKittrick, CA	6	Thermotics	-	1.1	Eductor venturi with variable disk	1	4.0	30.0	-
Chevron, USA									
Bakersfield, CA	124	Koch Engineering	-	1.1	Flexitrays	3	1.1	8.0	-
Double Barrel									
Bakersfield, CA	6	C-E NATCO	-	1.1	Spray tower/tray tower	1	3.3	25.0	-
FMC									
Green River, WY	223	FMC	ESP	1.0	Disc-and-donut trays	2	2.7	20.0	-

Table 9-5. (*continued*)
Operational data for sodium-based once-through FGD systems on utility and industrial bo

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pres
							L/m^3	gal/1000 ft^3	kPa
General Motors									
St. Louis, MO	32	A. D. Little	None	3.2	Impingement plate	1	-	-	-
Dayton, OH	18	Entoleter	None	2.0	Vane cage	2	0.8	6.0	1.8
Tonowanda, NY	46	FMC	Cyclone	1.2	Variable-throat venturi	4	2.7	20.0	-
Getty Oil									
Bakersfield, CA	36	FMC	None	1.1	Disc-and-donut tray/flexitray	1	1.1	8.4	-
Bakersfield, CA	445	In-house	None	1.1	Flexitray	9	1.2	9.0	-
Orcutt, CA	2.5	In-house	None	4.0	Packed tower	1	-	-	-
ITT Raynier									
Fernandina Beach, FL	88	Neptune Airpol	Cyclone	2.5	Variable-throat venturi	2	-	-	5.5
Kerr-McGee									
Trona, CA	245	Combustion Equipment Association	-	0.5-5	Plate tower	2	-	-	1.5
Mead Paperboard									
Stevenson, AL	50	Neptune Airpol	Venturi	3.0	Bubble-cap plates	1	-	-	-
Northern Ohio Sugar									
Freemont, OH	20	Great Western Sugar	None	1.0	Variable-throat venturi	2	-	-	-
Reichhold Chemicals									
Pensacola, FL	40	Neptune Airpol	None	2.0	Venturi	2	-	-	6.0
Texasgulf									
Granger, WY	70	Swemco	Cyclone/ESP	0.8	Sieve plate	2	-	-	-

Note: A dash (-) indicates that no data are available.

To test your knowledge of the preceding section, answer the questions in Part 5 of the Review Exercise.

Regenerable FGD Processes

Regenerable FGD processes remove SO_2 from the flue gas and generate a saleable product. Regenerable products include elemental sulfur, sulfuric acid, or, in the case of lime or limestone scrubbing, gypsum (used for wallboard). Regenerable processes do not produce a sludge, thereby eliminating the sludge disposal problem. Most regenerable processes also achieve the following:

- Have the potential for consistently obtaining a high SO_2 removal efficiency, usually exceeding 90%
- Utilize the scrubbing reagent more efficiently than nonregenerable processes
- Use scrubbing liquors that do not cause scaling and plugging problems in the scrubber

The major drawback of these processes is that systems using them are usually more complicated in design and are more expensive to install and operate.

Two regenerable processes presently operating in the U.S. are the Wellman-Lord and the magnesium oxide. The Wellman-Lord process has been widely used in both sulfuric acid and petroleum refining industries but has only been installed on a limited number of industrial and utility boilers. The magnesium oxide process has been tested at a number of utility boilers, but the Philadelphia Electric Company's Eddystone and Cromby Stations are the only utility boilers presently operating this process. Because of the limited use of regenerable processes in the utility industry, these processes are not covered in this course. Information on these processes can be obtained from numerous EPA and EPRI publications specific to the demonstration projects.

Emerging Technologies

As shown in Table 9-1 the overwhelming choice for SO_2 control by utilities has been the use of lime or limestone wet scrubbers. The Clean Air Act Amendments of 1990 require reductions in acid rain precursors—both SO_2 and nitrogen oxides (NO_x). Utilities have options as to specifically how they will comply; however, a number of new and/or retrofit FGD technologies will have to be installed. Because of the regulatory requirements and efforts to provide more efficient and cost-effective FGD systems, a number of new technologies are being investigated and developed by vendors, utilities and governmental agencies (EPA and DOE).

Table 9-6 provides summary information on certain new technologies that EPA has evaluated as likely candidates for retrofit to meet acid rain control requirements (Princiotta and Sedman 1993). Table 9-6 provides a description of specific SO_2 and combined SO_2/NO_x control technologies as well as estimates of the level of control and commercial availability. Table 9-1 is not intended to be an all inclusive listing of every emerging FGD technology, as there are a number of others that may be viable options pending pilot demonstration.

Table 9-6. SO_2 and SO_2/NO_x control technologies for coal-fired boilers

Technology	Description	Control %[1]		Estimated commercial availability
		SO_2	NO_x	
Wet flue gas desulfurization (FGD)	Limestone or lime in water removes SO_2 in a scrubber vessel. Additives may be used to enhance SO_2 removal. A wet waste or gypsum is produced.	70-97	0	Current for new boilers and retrofit.
Dry FGD	Lime in water removes SO_2 in a spray dryer, which evaporates the water prior to the vessel exit. Produces a dry waste.	70-95	0	Current for low to moderate S coal for new boilers. High S coal retrofit, 5 yrs.
E-SO_x/in-duct injection	Lime and water are injected in a boiler duct and/or ESP (E-SO_x) similar to a spray dryer.	50-70	0	Pilot scale only. Demonstrations required, 3-7 yrs.
Advanced silicate (ADVACATE)	Several variations. Most attractive: adding limestone to boiler, generating lime. Lime/fly ash collected in cyclone and reacted to generate highly reactive silicate sorbent. Moist sorbent added to downstream duct.	Up to 90	0	Pilot scale only. Demonstrations required, 3-7 yrs.
Limestone injection multistage burners (LIMB)	Low NO_x burners and upper furnace sorbent injection. May use humidification to improve SO_2 capture and ESP performance.	50-70	40-60	Wall-fired, current; T-fired[3], 2 yrs
Natural gas reburning	Boiler fired with 80-90% coal. Remaining fuel (natural gas) is injected higher in boiler to reduce NO_x. Air added to complete burnout. Sorbent may be injected to capture SO_2.	Without sorbent, 10-20; with sorbent 50-60	50-60	Demonstrations in progress
SNRB	Ammonia (NH_3) and lime/sodium injection upstream of catalyst-coated baghouse.	90	90	5 MW_e pilot plant in operation.
NO_xSO	SO_2/NO_x absorption on alumina in fluid bed reactor.	90	90	5 MW_e pilot plant in Clean Coal Technology (CCT) program.
WSA-SNO_x	Catalytic reduction of nitric oxide (NO) and oxidation of SO_2 in two stages. Sulfuric acid recovery.	95	90	35 MW_e pilot in CCT program; 1 unit in Denmark.
$NONO_x$	Ozone/NH_3 promoted absorption of SO_2/NO_x in wet scrubber.	95	75-95	Commercial construction in Europe.

Table 9-6. SO_2 and SO_2/NO_x control technologies for coal-fired boilers

Technology	Description	Control %1		Estimated commercial availability
		SO2	NOx	
Activated char	NH_3 injection and absorption of SO_2/SO_3 on char; NO reduction.	90	70	Operational on 3 plants in Europe, 1 in Japan.
DESONO$_x$	One step variant of WSA-SNO$_x$ above.	85	80	20 MW$_e$ demo operating in Germany.
Amine absorption	Amine absorption of SO_2 and NO_x followed by regeneration; acid production.	90+	90+	Several vendors/processes; pilot-scale systems in operation.
Ferrous chelate additive	Ferrous chelate added to magnesium/calcium FGD solubilizes NO.	90	30-70	3 MW$_e$ pilot plant in operation.

1. Control efficiency is % reduction from emission levels for uncontrolled coal-fired power plants.
2. Estimated commercialization for some technologies is strongly dependent on successful demonstrations.
3. T-fired = tangentially fired.

Source: Princiotta and Sedman 1993.

Summary

FGD systems have been installed and operated on many industrial and utility boilers and on some industrial processes for a number of years. These systems are capable of removing approximately 70 to 90% of the SO_2 in the flue gas, depending on the operating conditions of the system. Some systems have achieved an SO_2-removal efficiency of greater than 95%. The most popular FGD systems used on utility boilers are lime or limestone scrubbing. Approximately 75% of the FGD systems installed on utility boilers are either lime or limestone scrubbing. The use of dual-alkali systems on utility boilers is attractive because of their ability to remove SO_2 very efficiently and to reduce scaling problems. The throwaway-sodium FGD systems have been used mostly on industrial boilers. These systems use a sodium scrubbing liquor that is very efficient in absorbing SO_2 emissions, but they produce liquid wastes that can cause waste disposal problems. FGD systems used on utility boilers generate large quantities of liquid wastes. Therefore, throwaway-sodium systems have mainly been used on industrial boilers. Wellman-Lord FGD systems have been used to reduce SO_2 emissions from utility and industrial boilers and from a number of industrial processes. These systems have the advantage of regenerating the scrubbing liquor and producing a saleable product instead of a sludge that can be a disposal problem. However, these systems are more expensive to install and operate than lime, limestone, or dual-alkali systems.

Over the past 25 years, a wealth of material has been written and documented concerning FGD control technology. The authors of this manual suggest that the readers utilize the many publications from EPA and the Electric Power Research Institute (EPRI) concerning this subject, particularly the proceedings from the FGD symposiums sponsored by the EPA.

To test your knowledge of the preceding section, answer the questions in Part 6 of the Review Exercise.

Review Exercise

Part 1

1. True or False? Only *wet* FGD systems have been used on utility boilers.

2. ____________________-based slurries absorb SO_2 better than ____________________; however, the former are much more expensive.

   a. Sodium, lime or limestone
   b. Lime or limestone, sodium
   c. Gypsum, lime or limestone
   d. Limestone, lime

3. Solutions of sodium compounds are referred to as clear liquor solutions because the compounds are:

   a. Blue
   b. Soluble
   c. Insoluble
   d. Transparent

4. True or False? Almost all FGD systems use a single wet scrubber for both SO_2 and fly ash removal.

5. Which problem/problems must be considered when trying to remove both SO_2 and fly ash in the same scrubber?

   a. Pressure drops are higher
   b. The scrubbing liquid, if recirculated, can contain a high level of fly ash
   c. SO_2 absorption efficiency is normally lower
   d. All of the above

6. Spray towers on most FGD systems require higher ____________________ (for equivalent SO_2 removal) than other absorber designs.

   a. Pressure drops
   b. Gas velocities
   c. Liquid-to-gas ratios
   d. All of the above

7. When the gas velocity is lowered, entrainment becomes ____________________; however, the scrubber system will be ____________________ costly.

   a. More, more
   b. More, less
   c. Less, more
   d. Less, less

8. List five properties of the coal (or fuel) that will affect FGD operation.

   ____

   ____

   ____

   ____

   ____

9. Because flue gas contains some SO_2 as it exits the absorber, FGD systems generally use ____________________ to prevent corrosion.

   a. Additional absorbers
   b. Reheaters
   c. Special construction materials for downstream fans and ductwork
   d. Both b and c

Part 2

10. List three nonregenerable FGD processes.

    ____

    ____

    ____

11. Dissolving lime in water is referred to as:

    a. Clarifying
    b. Slaking
    c. Raking
    d. Thickening

12. What is $CaSO_3$ in the following reaction?

$$Ca^{++} + SO_3^{=} + 2H^{+} + 2OH^{-} \rightarrow CaSO_3 + 2H_2O$$

    a. Sludge
    b. Liquid
    c. Gas

13. Lime FGD systems use a(an) ____________________ to remove fly ash from the flue gas before it enters the absorber.

    a. Venturi scrubber
    b. Electrostatic precipitator
    c. Mechanical collector with precipitator or scrubber
    d. Any of the above

14. In early lime FGD systems, scale buildup and plugging of the ____________________ were particularly troublesome.
    a. Spray nozzles
    b. Entrainment separator
    c. Scrubber internals
    d. All of the above

15. Operating a lime FGD system at a pH above 8.0 to 9.0:
    a. Reduces scale buildup
    b. Increases the risk of scale buildup
    c. Is recommended
    d. Eliminates nozzle plugging

16. Most lime FGD systems on utility boilers operate at L/G ratios of:
    a. 0.4 to 1.3 L/m^3 (3 to 10 gal/1000 ft^3)
    b. 3.0 to 8.0 L/m^3 (25 to 60 gal/1000 ft^3)
    c. 13 to 26 L/m^3 (100 to 200 gal/1000 ft^3)
    d. None of the above

17. ____________________ liquid-to-gas ratios reduce the potential for scale buildup.
    a. High
    b. Low

18. Stack gas is reheated to:
    a. Avoid condensation
    b. Enhance plume rise
    c. Give better pollutant dispersion
    d. All of the above

Part 3

19. Limestone FGD systems generally operate at ____________________ liquid-to-gas ratios than lime FGD systems because SO_2 is ____________________ reactive with a limestone slurry.
    a. Higher, more
    b. Higher, less
    c. Lower, more
    d. Lower, less

20. True or False? The chemistry for SO_2 removal in a limestone slurry is very different from that for SO_2 removal in a lime slurry.

21. The major difference in equipment for a limestone FGD system (compared to a lime FGD system) is in the:
    a. Fly ash collection equipment
    b. Type of absorber
    c. Slurry feed preparation
    d. All of the above

22. True or False? Limestone is generally less expensive to purchase than lime.

23. In lime/limestone FGD systems, calcium sulfite formed as part of the sludge is difficult to remove from the slurry. One method used to eliminate this problem is to convert the calcium sulfite to calcium sulfate by the process called:

    a. Forced oxidation
    b. Wellman-Lord
    c. Double-alkali
    d. Direct reduction

Part 4

24. Double-alkali processes generally use a ____________________ solution to absorb the SO_2 from the flue gas and then react it with a ____________________ slurry to regenerate the absorbing solution.

    a. Sodium, citrate
    b. Citrate, lime or limestone
    c. Sodium, lime or limestone
    d. Lime or limestone, sodium

25. In the double-alkali process, the sodium reagent is regenerated by reacting the sludge with lime. As part of this reaction, insoluble ____________________ are formed in the regeneration vessel.

    a. Sodium salts
    b. Calcium salts
    c. Magnesium salts
    d. Citrate salts

26. Compared to lime and limestone scrubbing systems, double-alkali absorbers have a much lower:

    a. Pressure drop
    b. Gas velocity
    c. Liquid-to-gas ratio
    d. All of the above

27. True or False? Using sodium-based scrubbing solutions (as compared to calcium-based) helps eliminate scale buildup.

Part 5

28. True or False? The two sodium compounds used most often in throwaway systems are sodium hydroxide (NaOH) and sodium carbonate (Na_2CO_3).

29. Sodium-based once-through FGD systems have been used on industrial boilers because:

    a. Sodium is the most efficient of the commercial reagents
    b. They operate without scale buildup occurring
    c. They are often smaller and cheaper than other systems
    d. All of the above

30. Large utilities have not used sodium-based once-through systems because of the expense of the sodium reagent and the:

    a. Limited efficiency
    b. Low fly ash removal
    c. Presence of soluble salts in the wastes (wastes cannot be discharged into rivers or lakes)
    d. All of the above

31. True or False? In a sodium-based once-through FGD system, the flue gas may first pass through a baghouse or ESP.

32. True or False? Sodium-based once-through systems are generally simpler to operate and maintain than lime or limestone FGD systems.

33. At high pH values, the scrubbing liquid in the sodium systems absorbs ____________________ and can form carbonate scale.

    a. SO_2
    b. CO_2
    c. O_2
    d. $CaCO_3$

Part 6

34. Regenerable FGD processes generate a saleable product such as:

    a. Sulfur
    b. Sulfuric acid
    c. Gypsum
    d. All of the above

35. List at least three advantages that the regenerable process has over the nonregenerable FGD process.

    ____

    ____

    ____

Review Exercise Answers

Part 1

1. **False**
   Dry FGD systems have been installed on some utility sized boilers (see Lesson 7).
2. **a. Sodium, lime or limestone**
   Sodium-based slurries absorb SO_2 better than lime or limestone; however, the former are much more expensive.
3. **b. Soluble**
   Solutions of sodium compounds are referred to as clear liquor solutions because the compounds are soluble.
4. **False**
   Most FGD systems use two scrubbing stages: one for SO_2 removal and another for fly ash removal.
5. **d. All of the above**
   Problems that must be considered when trying to remove both SO_2 and fly ash in the same scrubber are:
   - Pressure drops are higher
   - The scrubbing liquid, if recirculated, can contain a high level of fly ash
   - SO_2 absorption efficiency is normally lower
6. **c. Liquid-to-gas ratios**
   Spray towers on most FGD systems require higher liquid-to-gas ratios (for equivalent SO_2 removal) than other absorber designs. More liquid is used in spray towers because they have limited contact area available for absorption.
7. **c. Less, more**
   When the gas velocity is lowered, entrainment becomes less; however, the scrubber system will be more costly.
8. Five properties of coal (or fuel) that will affect FGD operation are:
   - Heating value
   - Sulfur content
   - Chlorine content
   - Ash content
   - Moisture content
9. **d. Both b and c**
   Because flue gas contains some SO_2 as it exits the absorber, FGD systems generally use reheaters and special construction materials for downstream fans and ductwork to prevent corrosion.

Part 2

10. **Lime, Limestone, Double-alkali**
    Three nonregenerable FGD processes are:
    - Lime
    - Limestone
    - Double-alkali

11. **b. Slaking**
    Dissolving lime in water is referred to as slaking.

12. **a. Sludge**
    In the following reaction, $CaSO_3$ is sludge.

$$Ca^{++} + SO_3^{=} + 2H^{+} + 2OH^{-} \rightarrow CaSO_3 + 2H_2O$$

13. **d. Any of the above**
    To remove fly ash from the flue gas before it enters the absorber, lime FGD systems can use any of the following:
    - A venturi scrubber
    - An electrostatic precipitator
    - A mechanical collector with precipitator or scrubber

14. **d. All of the above**
    In early lime FGD systems, scale buildup and plugging of the spray nozzles, entrainment separator, and scrubber internals were particularly troublesome.

15. **b. Increases the risk of scale buildup**
    Operating a lime FGD system at a pH above 8.0 to 9.0 increases the risk of scale buildup.

16. **b. 3.0 to 8.0 L/m^3 (25 to 60 gal/1000 ft^3)**
    Most lime FGD systems on utility boilers operate at L/G ratios of 3.0 to 8.0 L/m^3 (25 to 60 gal/1000 ft^3).

17. **a. High**
    High liquid-to-gas ratios reduce the potential for scale buildup.

18. **d. All of the above**
    Stack gas is reheated to:
    - Avoid condensation
    - Enhance plume rise
    - Give better pollutant dispersion

Part 3

19. **b. Higher, less**
Limestone FGD systems generally operate at higher liquid-to-gas ratios than lime FGD systems because SO_2 is less reactive with a limestone slurry.

20. **False**
The chemistry for SO_2 removal in a limestone slurry is very similar to that for SO_2 removal in a lime slurry.

21. **c. Slurry feed preparation**
The major difference in equipment for a limestone FGD system (compared to a lime FGD system) is in the slurry feed preparation.

22. **True**
Limestone is generally less expensive to purchase than lime.

23. **a. Forced oxidation**
In lime/limestone FGD systems, calcium sulfite formed as part of the sludge is difficult to remove from the slurry. One method used to eliminate this problem is to convert the calcium sulfite to calcium sulfate by the process called forced oxidation.

Part 4

24. **c. Sodium, lime or limestone**
Double-alkali processes generally use a sodium solution to absorb the SO_2 from the flue gas and then react it with a lime or limestone slurry to regenerate the absorbing solution.

25. **b. Calcium salts**
In the double-alkali process, the sodium reagent is regenerated by reacting the sludge with lime. As part of this reaction, insoluble calcium salts are formed in the regeneration vessel.

26. **c. Liquid-to-gas ratio**
Compared to lime and limestone scrubbing systems, double-alkali absorbers have a much lower liquid-to-gas ratio. Double-alkali systems use sodium which is more effective at acid gas absorption than lime and limestone per mole of compound used. Therefore less sodium and less scrubbing liquid are required.

27. **True**
Using sodium-based scrubbing solutions (as compared to calcium-based) helps eliminate scale buildup. Sodium compounds do not form slake as readily as calcium compounds do.

Part 5

28. **True**
The two sodium compounds used most often in throwaway systems are sodium hydroxide (NaOH) and sodium carbonate (Na_2CO_3).

29. **d. All of the above**
Sodium-based once-through FGD systems have been used on industrial boilers because:

- Sodium is the most efficient of the commercial reagents
- They operate without scale buildup occurring
- They are often smaller and cheaper than other systems

30. **c. Presence of soluble salts in the wastes (wastes cannot be discharged into rivers or lakes)**
Large utilities have not used sodium-based once-through systems because of the expense of the sodium reagent and the presence of soluble salts in the wastes which means wastes cannot be discharged into rivers or lakes.

31. **True**
In a sodium-based once-through FGD system, the flue gas may first pass through a baghouse or ESP.

32. **True**
Sodium-based once-through systems are generally simpler to operate and maintain than lime or limestone FGD systems.

33. **b. CO_2**
At high pH values, the scrubbing liquid in the sodium systems absorbs CO_2 and can form carbonate scale.

Part 6

34. **d. All of the above**
Regenerable FGD processes generate a saleable product such as:

- Sulfur
- Sulfuric acid
- Gypsum

35. **Avoidance of sludge disposal problems**
Consistently higher SO_2 removal
Better utilization of reagent
Use of clear liquid solutions (reduces scaling)

Four advantages that the regenerable process has over the nonregenerable FGD process include:

- Avoidance of sludge disposal problems
- Consistently higher SO_2 removal
- Better utilization of reagent
- Use of clear liquid solutions (reduces scaling)

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Table 9-2. *(continued)* Operational data for lime FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	gal/1000 ft^3	kPa	in. H_2O	Design	Test
Kansas City Power & Light												
Hawthorn #3	90	Combustion Engineering	-	0.6	Mobile bed (marbles)	2	3.5	26.0	2.7	11.0	70.0	70.0
Hawthorn #4	90	Combustion Engineering	-	0.6	Mobile bed (marbles)	2	3.5	26.0	2.7	11.0	70.0	70.0
Monongahela Power												
Pleasants #1	618	B&W	ESP	3.7	Sieve tray	4	7.4	55.0	1.2	5.0	90.0	90.0
Pleasants #2	618	B&W	ESP	4.5	Sieve tray	4	7.4	55.0	-	-	90.0	90.0
Utah Power & Light												
Hunter #1	400	Chemico	ESP	0.6	Countercurrent spray	4	5.7	43.0	0.6	2.5	80.0	80.0
Hunter #2	400	Chemico	ESP	0.6	Countercurrent spray	4	5.7	43.0	0.6	2.5	80.0	80.0
Huntingdon #1	430	Chemico	ESP	0.6	Countercurrent spray	4	5.7	43.0	0.6	2.5	80.0	80.0

Note: A dash (-) indicates that no data are available.

Table 9-2. Operational data for lime FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	gal/1000 ft^3	kPa	in. H_2O	Design	Test
Pennsylvania Power												
Bruce Mansfield #1	917	Chemico	1st-stage venturi	3.0	Fixed-throat venturi	6	6.0	45.0	2.0	8.0	92.1	95.0
Bruce Mansfield #2	917	Chemico	1st-stage venturi	3.0	Fixed-throat venturi	6	6.0	45.0	2.0	8.0	92.1	95.0
Bruce Mansfield #3	917	Pullman Kellogg	ESP	3.0	Weir crosscurrent spray	6	-	-	0.7	2.8	92.0	95.0
Columbus & Southern Ohio Electric												
Conesville #5	411	Air Correction Division	ESP	4.7	Mobile bed	1	6.7	50.0	2.0	8.0	89.5	89.7
Conesville #6	411	Air Correction Division	ESP	4.7	Mobile bed	2	6.7	50.0	2.0	8.0	89.5	89.5
Duquesne Light												
Elrama	510	Chemico	ESP	2.2	Variable-throat venturi	5	5.3	40.0	4.0	16.0	83.0	86.0
Phillips	408	Chemico	Cyclone/ESP	1.9	Variable-throat venturi	4	5.3	40.0	4.0	16.0	83.0	90.0
Kentucky Utilities												
Green River	64	American Air Filter	Cyclone/ variable-throat venturi	4.0	Mobile bed	1	4.5	34.0	1.0	4.0	80.0	80.0
Louisville Gas & Electric												
Cane Run #4	188	American Air Filter	ESP	3.7	Mobile bed	2	8.0	60.0	1.0	40.0	85.0	87.5
Cane Run #5	200	Combustion Engineering	ESP	3.7	Countercurrent spray	2	7.4	55.0	0.1	0.5	85.0	91.0
Mill Creek #1	358	Combustion Engineering	-	3.7	-	-	12.7	95.0	-	-	85.0	86.6
Mill Creek #3	442	American Air Filter	ESP	3.7	Mobile bed	4	8.7	65.0	1.6	6.5	85.0	85.7
Paddy's Run #6	72	Combustion Engineering	ESP	2.5	Mobile bed (marbles)	2	2.2	16.5	2.9	11.5	90.0	90.0

Continued on next page

Table 9-3. *(continued)*
Operational data for limestone FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	gal/1000 ft^3	kPa	in. H_2O	Design	Test
Kansas City Power & Light												
La Cygne	820	B&W	Variable venturi	5.4	Sieve tray	8	5.0	37.7	1.5	6.0	80.0	80.0
Jeffery #1	720	Combustion Engineering	ESP	0.3	Countercurrent spray	6	4.1	30.4	1.0	6.0	80.0	60.0
Jeffery #2	700	Combustion Engineering	ESP	0.3	Countercurrent spray	-	4.1	30.4	1.0	6.0	80.0	60.0
Lawrence #4	125	Combustion Engineering	Rod venturi	0.6	Countercurrent spray	2	4.0	30.0	0.6	2.5	73.0	73.0
Lawrence #5	420	Combustion Engineering	Rod venturi	0.6	Countercurrent spray	2	2.5	19.0	0.6	2.5	52.0	52.0
Salt River Project												
Coronado #1	350	Pullman Kellogg	ESP	1.0	Weir crosscurrent spray	2	-	-	0.4	1.5	66.0	82.0
Coronado #2	350	Pullman Kellogg	ESP	1.0	Weir crosscurrent spray	2	-	-	0.4	1.5	66.0	82.0
South Carolina Public Service												
Winyah #2	280	B&W	ESP	1.7	Venturi/sieve tray	2	6.3	47.5	1.1	4.5	45.0	90.0
Winyah #3	280	B&W	ESP	1.7	Countercurrent spray	2	-	-	-	-	90.0	90.0
South Mississippi Electric												
R. D. Morrow #1	200	Environeering	ESP	1.3	Rod deck packed tower	1	6.6	49.0	2.0	8.0	52.7	85.0
R. D. Morrow #2	200	Environeering	ESP	1.3	Rod deck packed tower	1	6.6	49.0	2.0	8.0	52.7	85.0
Southern Illinois												
Marion #4	173	B&W	ESP	3.8	Countercurrent spray	2	9.9	74.0	1.5	6.0	89.4	89.4

Continued on next page

Table 9-3. *(continued)* Operational data for limestone FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	gal/1000 ft^3	kPa	in. H_2O	Design	Test
Springfield City												
Southwest #1	194	Air Correction Division - UOP	ESP	3.5	Mobile bed (TCA)	2	5.5	41.0	1.5	6.0	80.0	87.0
Springfield Water, Light & Power												
Dallman #3	205	Research-Cottrell	Cyclone/ESP	3.3	Spray/packed tower	2	-	-	0.2	0.7	95.0	95.0
TVA												
Widows Creek #8	550	TVA	ESP/venturi	3.7	Mobile packed bed and grid packing	1 3		60.0	0.5	2.0	70.0	-
Texas Power & Light												
Sandow #4	545	Combustion Engineering	ESP	1.6	Countercurrent spray	3	-	-	-	-	75.0	-
Texas Utilities												
Martin Lake #1	793	Research-Cottrell	ESP	0.9	Spray/packed bed	6	-	-	1.1	4.5	71.0	95.0
Martin Lake #2	793	Research-Cottrell	ESP	0.9	Spray/packed bed	6	-	-	1.1	4.5	71.0	95.0
Martin Lake #3	793	Research-Cottrell	ESP	0.9	Spray/packed bed	6	-	-	1.1	4.5	71.0	95.0
Monticello	800	Chemico	ESP	1.5	Countercurrent spray	3	9.4	70.0	1.2	5.0	74.0	74.0

Note: A dash (-) indicates that no data are available.

Table 9-3. Operational data for limestone FGD systems on utility boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	gal/1000 ft^3	kPa	in. H_2O	Design	Test
Alabama Electric												
Tombigbee #2	255	Peabody	ESP	1.2	Countercurrent spray	2	9.4	70.0	1.0	4.0	59.5	85.0
Tombigbee #3	255	Peabody	ESP	1.2	Countercurrent spray	2	9.4	70.0	1.0	4.0	59.5	85.0
Arizona Electric Power												
Apache #2	195	Research-Cottrell	ESP	0.5	Spray/packed bed	2	2.8	20.6	1.5	6.0	42.5	97.0
Apache #3	195	Research-Cottrell	ESP	0.5	Spray/packed bed	2	2.8	20.6	1.5	6.0	42.5	97.0
Cholla #1	119	Research-Cottrell	Cyclone/venturi	0.5	Spray/packed bed	1	6.5	48.9	0.1	0.5	58.5	92.0
Cholla #2	264	Research-Cottrell	Cyclone/venturi	0.5	Spray/packed bed	4	6.5	48.9	0.1	0.5	75.0	85.0
Basin Electric Power												
Laramie River #1	570	Research-Cottrell	ESP	0.8	Spray/packed bed	5	8.0	60.0	-	-	90.0	90.0
Laramie River #2	570	Research-Cottrell	ESP	0.8	Spray/packed bed	5	8.0	60.0	-	-	90.0	90.0
Central Illinois Light												
Duck Creek #1	416	Environeering	ESP	3.7	Rod deck packed tower	4	6.7	50.0	2.0	8.0	85.0	85.0
Colorado Ute Electrical												
Craig #1	447	Peabody	ESP	0.4	Countercurrent spray	4	6.7	50.0	1.6	6.5	85.0	85.0
Craig #2	455	Peabody	ESP	0.4	Countercurrent spray	4	6.7	50.0	1.6	6.5	85.0	85.0
Commonwealth Edison												
Powerton	450	Air Correction Division - UOP	ESP	3.5	Mobile bed (TCA)	3	8.0	60.0	3.0	12.0	74.0	75.5
Indianapolis Power & Light												
Petersburg #3	532	Air Correction Division - UOP	ESP	3.2	Mobile bed (TCA)	4	6.7	50.0	1.7	7.0	85.0	85.0

Continued on next page

Table 9-4. Operational data for double-alkali FGD systems on utility and industrial boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	gal/1000 ft^3	kPa	in. H_2O	Design	Test
Central Illinois Public Service												
Newton #1	617	Buell	ESP	2.5	Mobile bed	4	1.3	10.0	1.5	6.0	90.0	90.0
Louisville Gas & Electric												
Cane Run #6	299	Combustion Equipment Association	ESP	4.8	Sieve plates	2	1.3	10.0	2.5	9.9	95.0	94.2
Southern Indiana Gas & Electric												
A. B. Brown #1	265	FMC	ESP	3.6	Variable-throat venturi	2	1.3	10.0	2.5	10.0	85.0	85.0
Caterpillar Tractor												
East Peoria, IL	105	FMC	Cyclone	3.2	Venturi	4	2.2	16.0	-	-	-	90.0
Joliet, IL	34	Zurn	Cyclone	3.2	Dustraxtor	2	-	-	-	-	-	90.0
Morton, IL	19	Zurn	Cyclone	3.2	Dustraxtor	2	-	-	-	-	-	90.0
Mossville, IL	70	FMC	Cyclone	-	Venturi	4	1.2	8.6	-	-	-	90.0+
Firestone Tire												
Pottstown, PA	4	FMC	Cyclone	3.0	Venturi	1	1.3	10.0	-	-	-	90.5
General Motors												
Parma, OH	64	GM Environmental	Cyclone	-	Bubble-cap plates	4	2.6	20.0	0.9	8.0	-	90.0

Note: A dash (-) indicates that no data are available.

Table 9-5. Operational data for sodium-based once-through FGD systems on utility and industrial boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	gal/1000 ft^3	kPa	in. H_2O	Design	Test
Nevada Power												
Reid Gardner #1	125	Combustion Equipment Association	Cyclone/venturi	1.0	Sieve plate	1	0.2	1.6	0.7	3.0	90.0	-
Reid Gardner #2	125	Combustion Equipment Association	Cyclone/venturi	1.0	Sieve plate	1	0.2	1.6	0.7	3.0	90.0	91.2
Reid Gardner #3	125	Combustion Equipment Association	Cyclone/venturi	1.0	Sieve plate	1	0.2	1.6	0.7	3.0	85.0	91.2
Pacific Power & Light												
Jim Bridger #4	550	Air Correction Division - UOP	ESP	0.6	Sieve plate	3	2.7	20.0	-	-	91.0	91.0
Alyeska Pipeline												
Valdez, AK	25	FMC	-	0.1	Disc-and-donut trays	1	1.6	12.0	-	-	-	96.0
Belridge Oil												
McKittrick, CA	6	C-E NATCO	-	1.1	Eductor venturi with variable disk	1	-	-	-	-	-	90.0
McKittrick, CA	6	Heater Technology	-	1.1	Eductor venturi with variable disk	1	5.4	40.0	-	-	-	90.0
McKittrick, CA	6	Thermotics	-	1.1	Eductor venturi with variable disk	1	4.0	30.0	-	-	-	90.0
Chevron, USA												
Bakersfield, CA	124	Koch Engineering	-	1.1	Flexitrays	3	1.1	8.0	-	-	-	90.0
Double Barrel												
Bakersfield, CA	6	C-E NATCO	-	1.1	Spray tower/tray tower	1	3.3	25.0	-	-	-	95.0
FMC												
Green River, WY	223	FMC	ESP	1.0	Disc-and-donut trays	2	2.7	20.0	-	-	-	95.0

Continued on next page

Table 9-6. (continued)
SO_2 and SO_2/NO_x control technologies for coal-fired boilers

Technology	Description	Control %1		Estimated commercial availability	Comments
		SO2	NOx		
Activated char	NH_3 injection and absorption of SO_2/SO_3 on char; NO reduction.	90	70	Operational on 3 plants in Europe, 1 in Japan.	
DESONO$_x$	One step variant of WSA-SNO$_x$ above.	85	80	20 MW$_e$ demo operating in Germany.	
Amine absorption	Amine absorption of SO_2 and NO_x followed by regeneration; acid production.	90+	90+	Several vendors/processes; pilot-scale systems in operation.	
Ferrous chelate additive	Ferrous chelate added to magnesium/calcium FGD solubilizes NO.	90	30-70	3 MW$_e$ pilot plant in operation.	

1. Control efficiency is % reduction from emission levels for uncontrolled coal-fired power plants.
2. Estimated commercialization for some technologies is strongly dependent on successful demonstrations.
3. T-fired = tangentially fired.

Source: Princiotta and Sedman 1993.

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Table 9-5. (*continued*)
Operational data for sodium-based once-through FGD systems on utility and industrial boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	gal/1000 ft^3	kPa	in. H_2O	Design	Test
General Motors												
St. Louis, MO	32	A. D. Little	None	3.2	Impingement plate	1	-	-	-	-	-	90.0
Dayton, OH	18	Entoleter	None	2.0	Vane cage	2	0.8	6.0	1.8	7.0	-	86.0
Tonowanda, NY	46	FMC	Cyclone	1.2	Variable-throat venturi	4	2.7	20.0	-	-	-	95.0
Getty Oil												
Bakersfield, CA	36	FMC	None	1.1	Disc-and-donut tray/flexitray	1	1.1	8.4	-	-	-	90.0
Bakersfield, CA	445	In-house	None	1.1	Flexitray	9	1.2	9.0	-	-	-	96.0
Orcutt, CA	2.5	In-house	None	4.0	Packed tower	1	-	-	-	-	-	94.0
ITT Raynier												
Fernandina Beach, FL	88	Neptune Airpol	Cyclone	2.5	Variable-throat venturi	2	-	-	5.5	22.0	-	85.0
Kerr-McGee												
Trona, CA	245	Combustion Equipment Association	-	0.5-5	Plate tower	2	-	-	1.5	6.0		98.0
Mead Paperboard												
Stevenson, AL	50	Neptune Airpol	Venturi	3.0	Bubble-cap plates	1	-	-	-	-	-	95.0
Northern Ohio Sugar												
Freemont, OH	20	Great Western Sugar	None	1.0	Variable-throat venturi	2	-	-	-	-	-	-
Reichhold Chemicals												
Pensacola, FL	40	Neptune Airpol	None	2.0	Venturi	2	-	-	6.0	24.0	-	-

Table 9-5. (*continued*)
Operational data for sodium-based once-through FGD systems on utility and industrial boilers

Company and plant name	MW (gross)	FGD vendor	Fly ash control	%S in coal	SO_2 absorber	No. of modules per boiler	L/G ratio		Pressure drop (Δp)		Efficiency (%)	
							L/m^3	gal/1000 ft^3	kPa	in. H_2O	Design	Test
Texasgulf Granger, WY	70	Swemco	Cyclone/ESP	0.8	Sieve plate	2	-	-	-	-	-	90.0

Note: A dash (-) indicates that no data are available.

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Table 9-6. SO_2 and SO_2/NO_x control technologies for coal-fired boilers

Technology	Description	Control %[1]		Estimated commercial availability	Comments
		SO_2	NO_x		
Wet flue gas desulfurization (FGD)	Limestone or lime in water removes SO_2 in a scrubber vessel. Additives may be used to enhance SO_2 removal. A wet waste or gypsum is produced.	70-97	0	Current for new boilers and retrofit.	State-of-the-art for higher S (sulfur) coal and FGD. Certain retrofits difficult.
Dry FGD	Lime in water removes SO_2 in a spray dryer, which evaporates the water prior to the vessel exit. Produces a dry waste.	70-95	0	Current for low to moderate S coal for new boilers. High S coal retrofit, 5 yrs.	Demonstration for high S coal retrofit is necessary, but may be limited to 90% SO_2 removal.
E-SO_x/in-duct injection	Lime and water are injected in a boiler duct and/or ESP (E-SO_x) similar to a spray dryer.	50-70	0	Pilot scale only. Demonstrations required, 3-7 yrs.	Potentially low cost retrofits. May be site-specific limits.
Advanced silicate (ADVACATE)	Several variations. Most attractive: adding limestone to boiler, generating lime. Lime/fly ash collected in cyclone and reacted to generate highly reactive silicate sorbent. Moist sorbent added to downstream duct.	Up to 90	0	Pilot scale only. Demonstrations required, 3-7 yrs.	Most promising emerging retrofit technology. Capable of 90% removal with costs 50% of wet scrubber.
Limestone injection multistage burners (LIMB)	Low NO_x burners and upper furnace sorbent injection. May use humidification to improve SO_2 capture and ESP performance.	50-70	40-60	Wall-fired, current; T-fired[3], 2 yrs	T-fired wall-fired demonstration complete. Applicable to $\leq$ 3% S coal retrofits.
Natural gas reburning	Boiler fired with 80-90% coal. Remaining fuel (natural gas) is injected higher in boiler to reduce NO_x. Air added to complete burnout. Sorbent may be injected to capture SO_2.	Without sorbent, 10-20; with sorbent 50-60	50-60	Demonstrations in progress	May be only combustion NO_x control for cyclones. Sensitive to natural gas price. New or retrofit.
SNRB	Ammonia (NH_3) and lime/sodium injection upstream of catalyst-coated baghouse.	90	90	5 MW_e pilot plant in operation.	
NO_xSO	SO_2/NO_x absorption on alumina in fluid bed reactor.	90	90	5 MW_e pilot plant in Clean Coal Technology (CCT) program.	
WSA-SNO_x	Catalytic reduction of nitric oxide (NO) and oxidation of SO_2 in two stages. Sulfuric acid recovery.	95	90	35 MW_e pilot in CCT program; 1 unit in Denmark.	
$NONO_x$	Ozone/NH_3 promoted absorption of SO_2/NO_x in wet scrubber.	95	75-95	Commercial construction in Europe.	

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