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FLUE GAS DESULFURIZATION SYSTEM CAPABILITIES FOR COAL-FIRED STEAM GENERATORS

Volume I. Executive Summary

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Volume I. Executive Summary

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CONTENTS

	Page
Figures	iv
Tables	iv
History of FGD Systems	2
Application of FGD Systems	4
FGD Systems and Their Efficiency	8
Lime and Limestone Scrubbing	8
Wellman-Lord Process	15
Magnesium Oxide Systems	17
Double Alkali Flue Gas Desulfurization Systems	19
FGD System Efficiency Summary	21
FGD System Operation	23
Lime Systems	27
Limestone Systems	29
Operating Problems and Solutions	30
Scaling and Plugging	30
Erosion and Corrosion	32
Equipment Design	33
FGD System Manufacturer Capability	36

FIGURES

Number		Page
1	Actual and design emissions vs potential emissions for existing and planned FGD systems subject to NSPS or more stringent regulations	7
2	Average plant FGD availability/operability versus plant start-up date	24
3	Average availability for selected FGD systems	28

TABLES

Number		Page
1	Number and Capacity of U.S. Utility FGD Systems--August 1977	5
2	Number and Capacity of FGD Systems and Their Regulatory Classifications	6
3	Plants Reporting 90 Percent or Greater SO_2 Removal	22
4	Identification of Plants in Figure 2	25
5	Calculated FGD System Availability Based on Number of Scrubber Modules	26
6	Manufacturers Responding to the Flue Gas Desulfurization System Capability Study and the Process Offered by Each	37

EXECUTIVE SUMMARY

This project was undertaken, at the request of the U.S. Environmental Protection Agency (EPA) to evaluate SO_2 emission control techniques. It is part of EPA's overall program to review New Source Performance Standards for coal-fired steam generators. Specifically, the project examined maximum SO_2 emission control levels attainable with demonstrated techniques which include low-sulfur content coal, coal conversion processes, physical and chemical coal cleaning, and flue gas desulfurization (FGD) systems. Flue gas desulfurization systems were emphasized, since the other control techniques are being studied elsewhere by EPA.

The main emphasis of this study was the objective appraisal of FGD systems with respect to both SO_2 removal potential and system operability. This appraisal was made by reviewing the performance of operating systems and the features of new systems designed to alleviate previous problems.

The study reviewed five major FGD processes in detail. The impact of key design parameters on removal efficiency and process operability was investigated, from a theoretical point of view and by using data from operating systems. In addition to process design and operation, the operating experience of major FGD installations was reviewed. Operating problems and their solutions were analyzed with respect to their impact on process operation. This assessment included major systems in both the United States and Japan. In addition, research studies were selected and their data used

to evaluate the status of process development and the potential for sustained system operation and high removal efficiencies.

It was concluded from this investigation that the major systems, comprising lime and limestone slurry, Wellman-Lord, magnesium oxide scrubbing and double alkali processes, are capable of removing SO_2 with efficiencies in excess of 90 percent when applied to both high- and low-sulfur coal combustion facilities. Such results have been obtained in pilot, prototype and full-scale systems. Though sustained operation at high SO_2 removal efficiencies has not been widely achieved, a basis for design of such systems has been developed. When required, new systems are being designed for 90-percent removal efficiency, and an availability of 90-percent or greater.

This Executive Summary gives a brief history of FGD systems, followed by information on FGD applications and planned installations. This summary then presents information on FGD system problems and solutions, operability, and the design factors affecting efficiency. The capability of equipment manufacturers to supply equipment to meet alternative SO_2 emission standards is also summarized.

HISTORY OF FGD SYSTEMS

The concept of scrubbing flue gases from coal-fired boilers and other industrial processes is not new. In 1926, the 125-MW coal-fired Battersea Power Station in London, England, was equipped with a spray-packed tower and an alkaline wash section. The process was more than 90-percent efficient in the removal of SO_2 and particulate from the combustion gas of coal with a sulfur content of 0.9 percent. Lime-based systems for removal of sulfur dioxide were installed at the Swansea power plant in 1935 and at the Fulham power plant in 1937. The first lime scrubber in Japan started up on a large sulfuric acid plant in 1966.

In the United States, the Tennessee Valley Authority (TVA) conducted small-scale and limited pilot plant studies in the 1950's. The first major pilot plant work appears to have been that of Universal Oil Products (at a Wisconsin utility installation), beginning in 1965. Limestone slurry circulating through a mobile-bed scrubber treating 0.94 m^3/s (2000 acfm) gave good SO_2 removal.

In 1966, Combustion Engineering tested a technique involving injection of limestone, followed by scrubbing, in a pilot unit [1.4 m^3/s (3000 acfm)] at a Detroit Edison power plant. At a stoichiometric limestone-to-SO_2 ratio of 1.1 to 1, SO_2 removal was 98 percent. On the basis of this pilot plant work, the company offered the process to the utility industry and five systems were installed. One installation was at the Union Electric Co. in St. Louis, Missouri (140 MW). Kansas Power and Light Co. installed one on a 125-MW boiler in Lawrence in 1968; another on a 400-MW unit at the same plant started up in 1971. Kansas City Power and Light has used the process on two boilers, one at 100 MW, the other at 140 MW.

Because of major problems associated with dry limestone injection, these systems proved inadequate. The Union Electric installation has been abandoned, and the Kansas Power and Light systems are being replaced by a technique in which a limestone slurry is introduced into the scrubber. The Kansas City Power and Light installations are being converted to lime scrubbing. Problems associated with limestone injection include plugging (especially of the boiler tubes), low SO_2 absorption, and reduced particulate collection in the electrostatic precipitators.

Since then, considerable progress has been made in developing both lime/limestone and other alkali based scrubbing processes. A significant number are already operating on coal-fired boilers, and even more are scheduled for operation in the next few years. Other processes that incorporate major design and operating changes, and thereby differ significantly from conventional direct lime/limestone systems have been evaluated at pilot and prototype development levels, and a few systems have progressed to the installation and operation of demonstration units. A rapid evolution of technology is thus occurring in the FGD technology area.

APPLICATION OF FGD SYSTEMS

Table 1 summarizes the number and capacity of FGD systems on utility boilers in the United States as of August 1977. Of these systems, 29 were operational (8,914 MW); 28 were under construction (11,810); and 68 systems were planned (32,628 MW). This table omits 16 installations (8,592 MW) whose operators are considering FGD as well as other control systems (low sulfur coal, for example). Some 12 to 15 boilers (6000 MW) that are definitely planning to use FGD systems are excluded, because the information is not ready for public release. Also shown in the table are 16 systems (1488 MW) that have been shut down for various reasons. Several of these were demonstration systems; others were based on first-generation technology.

Table 1. NUMBER AND CAPACITY OF U.S.

UTILITY FGD SYSTEMS - AUGUST 1977

Status	Number of units	Capacity, MW
Operational	29	8,914
Under construction	28	11,810
Planned		
Contract awarded	23	11,880
Letter of intent signed	5	1,892
Requesting/evaluating bids	5	2,825
Considering FGD (preliminary design stage)	35	16,031
Shutdown	16	1,488

There have been significant changes in the status of FGD systems between 1974 and 1977:

- The number of operational systems has increased from 19 to 29.
- The average unit size has increased from 173 MW to 307 MW.
- The megawatt capacity associated with operational lime and limestone systems has increased from 80 percent to over 90 percent of the total.
- The capacity of FGD systems associated with full-scale boilers has increased from 2,360 MW to 8,914 MW.

Table 2 summarizes the FGD systems according to the regulatory standards the facility must meet. Of the 125 operational and pending systems, 57 (23,930 MW) are designed to meet state standards that are more stringent than the current Federal New Source Performance Standard (NSPS). Forty-four systems (22,728 MW) are designed to meet the NSPS and 21 systems (5,819 MW) are designed to meet regulations less stringent than the NSPS. Of 29 operational systems, more than half (approximately two-thirds of the equivalent megawatts) are meeting standards more stringent than the current NSPS requirement. Figure 1 shows the actual and design SO_2 emission rates for FGD systems which meet or exceed current NSPS requirements.

Table 2. NUMBER AND CAPACITY OF FGD SYSTEMS AND THEIR REGULATORY CLASSIFICATIONS

Regulatory classification	Systems	Capacity, MW
Federal NSPS	44	22,728
More stringent than Federal NSPS	57	23,930
Less stringent than Federal NSPS	21	5,819
Undetermined	3	875
Total	125	53,352

Also of interest are the data on the use of high- and low-sulfur coal. Because of the imprecision of the terms, "low-sulfur" coal has been defined for this purpose as any coal that emits up to 520 ng/J (1.2 lbs/10^6 Btu) of SO_2 when burned; "high-sulfur" coal is any coal that produces higher emission values. Using these definitions, the following observations hold:

- Among the operating systems, approximately 85 percent of the equivalent electrical megawatt capacity is on high-sulfur coal.
- Among the systems under construction, approximately 75 percent of the equivalent electrical megawatt capacity is for high-sulfur coal application.
- With regard to planned systems, approximately 90 percent of the equivalent electrical megawatt capacity involves high-sulfur coal application.

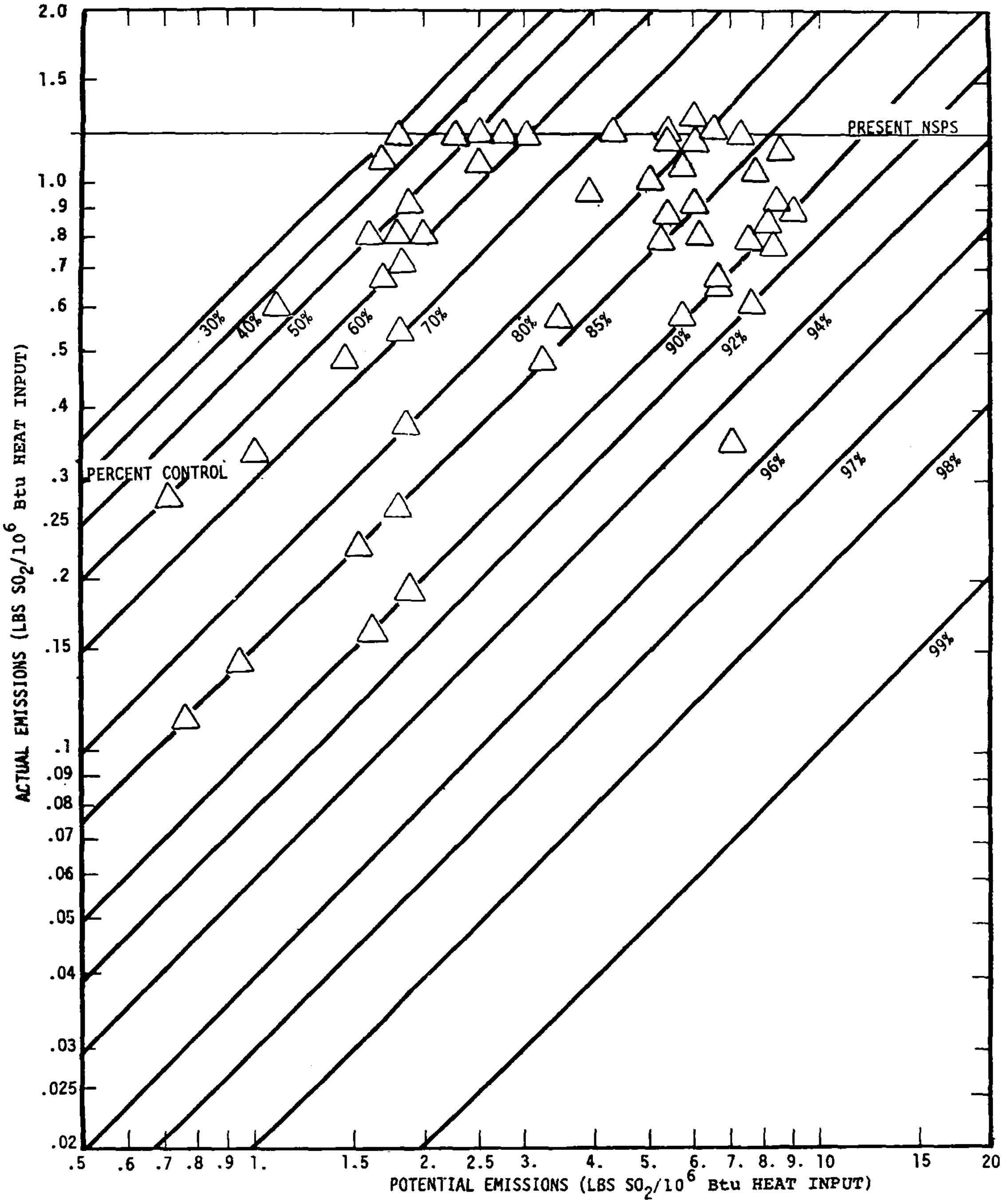

Figure 1. Actual and design emissions vs potential emissions for existing and planned FGD systems subject to NSPS or more stringent regulations.

FGD SYSTEMS AND THEIR EFFICIENCY

Flue gas desulfurization is the process of removing SO_2 from combustion gases. Flue gases are brought in contact with a chemical absorbent in a unit known as an absorber or scrubber which reacts chemically with the SO_2.

Flue gas desulfurization processes are categorized as regenerable or nonregenerable depending on whether sulfur compounds are separated from the absorbent as a by-product or disposed of as a waste. Nonregenerable processes produce a sludge that requires disposal in an environmentally sound manner. Regenerable processes have additional steps to produce by-products such as liquid SO_2, sulfuric acid, and elemental sulfur. The nonregenerable group includes lime and limestone, sodium carbonate and double alkali scrubbing techniques. The regenerable systems currently in operation are typified by the magnesium oxide and the Wellman-Lord systems. The following sections briefly describe these processes, their efficiency and reliability, and present information on their performance at selected installations.

Lime and Limestone Scrubbing

Lime slurry scrubbing is a wet scrubbing process that uses a lime slurry to react with SO_2 in the flue gas. Lime is fed into the system, combined with water to form a slurry, which is then contacted with the flue gas to absorb SO_2. Sulfur dioxide reacts with the slurry to form calcium sulfite and sulfate, which are removed from the system as sludge. The limestone slurry scrubbing process is similar, although it uses limestone rather than lime as the reagent. Facilities using lime and limestone systems have reported both long and short term SO_2 removal efficiencies in excess of 90 percent in the United States. Both have successfully operated on high- and low-sulfur coal-fired applications.

Many operating lime and limestone systems were designed for SO_2 collection efficiencies of less than 90 percent, since this was all that was required to meet an applicable regulation. Often an efficiency in the range of 60 to 70 percent was sufficient, and such values were used to establish system design. Extensive experimental data relating SO_2 removal efficiency to FGD system operating parameters are not available from any of the existing full scale systems; therefore, data from pilot or prototype units must be used for conclusions concerning higher removal capabilities.

Design of newer systems which are required to achieve high efficiency must take into account a number of key design variables including:

- inlet SO_2 concentration
- liquid to gas ratio
- scrubber gas velocity
- scrubber liquor inlet pH
- type of absorber
- magnesium content

Higher removal efficiencies can be more easily achieved at lower SO_2 inlet concentrations because the amount of SO_2 that must be absorbed per unit of scrubbing liquor to achieve a specified outlet concentration is smaller. At low SO_2 concentrations the alkali in the liquor can react with a greater percentage of the SO_2 and affect a greater removal efficiency under a given set of operating conditions.

Higher efficiencies are realized at higher liquid to gas (L/G) ratios for lime and limestone systems. For a given absorber, increased L/G ratios will yield higher efficiencies until flooding and poor gas distribution occur. For new designs, absorbers which can accommodate high L/G ratios can be selected and high efficiency maintained. Higher liquid ratios also require larger pumps, pipes, and slurry reaction tanks. Again, these can be designed into the system and should cause no unusual operating problems.

The effects of changes in flue gas absorber velocity on SO_2 removal efficiency, when other variables are kept constant, vary with the type of absorber. For a spray tower, the efficiency decreases at a fixed L/G ratio. This effect is much less noticeable on packed and turbulent contact type absorbers. For a new plant, the scrubber would be designed for the required L/G when considered along with other design parameters.

Increased efficiency is achieved at higher pH since more alkali is available and higher dissolution rates are achieved. Operation at very high pH, however, causes scaling problems. Maintenance of the desired pH by careful measurement and close control of reagent feed and mixing system will prevent the pH variations which reduce efficiency (if too low) or cause scaling (if too high).

A large variety of absorber designs have been utilized to achieve SO_2 removal efficiencies as high as 99 percent. These include cross-flow horizontal spray chambers (Weir), spray towers, packed-grid towers, and turbulent contact (mobile bed) absorbers. The venturi type has also been used, however, it is more useful as a particulate removal scrubber and not as efficient for SO_2 absorption ducts short residence times (unless and additive such as MgO is used). The final selection and design of an absorber are usually based on previous test data and on the required liquid and gas flow rates. Spray towers (either horizontal or vertical) offer a number of advantages including simple internal design which decreases scaling potential, acceptance of high liquid flows and decreased maintenance.

The addition of relatively small amounts of soluble magnesium (less than 1 percent by weight) to the scrubber liquor in the form of magnesium oxide, magnesium sulfate, or dolomitic lime (in lime systems) can greatly increase the SO_2 collection efficiency of the system. Magnesium compounds are much more soluble, compared to calcium, and can react rapidly in the liquid phase with SO_2.

Facilities at which high removal efficiencies have been obtained are briefly described below:

(1) The Mohave Station of the Southern California Edison Company, reported SO_2 removal efficiencies of 95 percent or more with limestone, and of 98 percent with lime. The tests were conducted intermittently over one-year on low-sulfur coal. The unit was a 170-MW equivalent, prototype scrubber.

(2) The packed module on the 115-MW Unit No. 1 at the Cholla Station of Arizona Public Service shows 92-percent removal of SO_2 using limestone slurry scrubbing. This is also a low-sulfur-coal application (0.8%).

(3) Recent tests at the Paddy's Run Station of Louisville Gas and Electric have shown SO_2 removal efficiencies in excess of 99 percent on 3-percent-sulfur coal. This extremely high removal efficiency was due to the addition of magnesium oxide to the lime slurry.

(4) Several tests were conducted at the 10-MW TVA Shawnee Pilot Plant, where SO_2 removal efficiencies of 95 to 99 percent were reported for lime-based systems, and of more than 90 percent for limestone systems. During one test run an efficiency of 96 percent on a turbulent contact absorber (TCA) unit, high-sulfur coal application, was achieved for the limestone system.

A brief summary of three lime-based systems follows, namely: the Green River facility of Kentucky Utilities, the

Bruce Mansfield Station of Pennsylvania Power Company, and the Mohave Station of Southern California Edison. Two limestone slurry systems are also discussed: the LaCygne Station of Kansas City Power and Light, and Sherburne No. 1 and 2 of Northern States Power Company.

° Kentucky Utilities, Green River No. 1, 2, and 3

The FGD system is installed on three boilers which generate an equivalent of 64-MW and burn coal with a sulfur content of 3.8 percent. This system is designed to remove 80 percent of the SO_2 in a turbulent contact scrubber and 99 percent of particulates. The unit started up in September 1975 and commercial operation began in the late fall of 1975. Before commercial service, the system went through an extensive four-phase, pre-startup evaluation.

Sulfur dioxide removal efficiency has been well above the design value, averaging about 90 percent. After commercial start-up, several relatively minor problems were encountered and corrected. Closed-loop, full-capacity operation began in March 1976, with the initiation of a six-month vendor qualification test. To date, performance of the system has been good; mechanical reliability is excellent. Average system operability has been above 90 percent since March of 1976, with the exception of a period between February and April of 1977, when the unit was shut down for stack repair.

° Pennsylvania Power Company, Bruce Mansfield No. 1

This two stage venturi FGD system is installed on Unit No. 1, which is rated at 839 MW and burns coal with a sulfur content between 4.5 and 5.0 percent. The FGD system was designed for 92-percent SO_2 removal and 99.8-percent particulate removal. Unit No. 1 started up in April 1976, and full commercial operation began in May 1976. Availability was reportedly very high during the first seven months after start-up; operating problems were solved without causing boiler downtime. Since then, however, the unit has experienced serious problems with the stack liner, and the load must be reduced by approximately 50 percent for about a year for liner repairs.

Two performance tests were conducted in July 1977. The results were 190 and 540 ng/J (0.44 and 1.26 lbs $SO_2/10^6$ Btu), representing 94-percent and 83-percent removal respectively. The allowable emission rate is 300 ng/J (0.6 lbs $SO_2/10^6$ Btu). The variations in emissions were apparently due to pH fluctuations which have since been corrected.

° Southern California Edison, Mohave Station

Participants in the Navaho/Mohave Power Project funded a full-scale scrubber demonstration at the Mohave Generating Station. The 170-MW demonstration facility was installed on a 790-MW boiler firing coal with an average sulfur content of 0.4 percent. Two types of scrubber were installed for the demonstration tests: a horizontal cross-flow scrubber, and a vertical countercurrent unit. The vertical module was operated both in a TCA and in a packed grid configuration. Sulfur dioxide removal efficiency was excellent for all three absorbers. Although the SO_2 inlet concentration was only 200 ppm, all three configurations were capable of removing 95 percent of the inlet SO_2. Calculated availability percentages for the horizontal and vertical modules were 81.3 and 72.8 percent, respectively. Since this was a test facility, several design changes that contributed to low availability were made during the period.

° Kansas City Power and Light Company, LaCygne No. 1

The unit is rated at 820 MW and burns coal with a sulfur content ranging from 5 to 6 percent. The FGD system installed in 1972 consists of eight identical scrubbing modules, each with a venturi scrubber for particulate emission control and an absorber for SO_2 control. Particulate removal efficiency is from 97 to 99 percent. The system was designed for 76-percent SO_2 removal. Actual SO_2 removal efficiency is 80 percent with seven modules operating on 729-MW. Under maximum load, the removal efficiency averaged 76.2 percent. Efficiencies under both conditions should improve now that eight modules are operating.

The FGD installation was plagued with start-up problems. However, analysis reveals that nearly all of them were due to mechanical design rather than to process chemistry limitations. The availability of this system has improved steadily as solutions to the various problems have been found. The system is now one of the most reliable FGD systems on a large boiler in the United States. The availability for 1976 averaged 91 percent, and for the first half of 1977 averaged about 93 percent.

° Northern States Power Company, Sherburne Station No. 1 and No. 2

Each unit has a net generating capability of 700 MW and fires a subbituminous western coal with a 28-percent moisture, 9-percent ash and 0.8-percent sulfur content. Each system has 12 scrubber modules, 11 of which are required for full-load operation. Sulfur dioxide removal is between 50 and 55 percent, which is sufficient to meet local requirements and approximates the value for which the system was designed. Availability for Unit No. 1, which started up in March 1976, averaged 85 percent for the first four months of operation. During the past 12 months, availability has been in excess of 90 percent. Unit No. 2 started up in April 1977 and has shown even better start-up performance. Availabilities have averaged about 95 percent for the first four months.

Wellman-Lord Process

The Wellman-Lord Process uses an aqueous sodium sulfite solution to absorb SO_2 and form sodium bisulfite. The solution is regenerated and SO_2 is released in an evaporator-crystallizer. The regenerated sodium sulfite is dissolved for recycle in the absorber. The concentrated SO_2 stream is recovered as liquid SO_2, sulfuric acid, or elemental sulfur. Guidelines to obtain high efficiency for Wellman-Lord Systems include:

Installation of a prescrubber with a separate water recirculation system for final particulate control and reduction of SO_3 and chlorides.

Use of a three to five tray absorber with an L/G of 1.0 to 1.3 l/m^3 (6 to 10 gal/1000 acf).

A superficial gas velocity in the range of 2.7 to 3.1 m/sec (9 to 10 ft/sec).

Maintenance of the required sodium sulfite scrubbing solution at a pH of 6.0 at the absorber inlet.

System make-up of fresh, 20 percent sodium carbonate solution should be approximately 0.07 l/m^3 (0.5 gallon/1000 acf) per tray.

As SO_2 inlet concentration decreases, the number of trays required to obtain high SO_2 removal should be increased.

Seven Wellman-Lord systems are operating in the United States. Six units are installed on SO_2 or Claus sulfur recovery plants. The SO_2 removal efficiency of these six is typically 90 percent or greater, and removal efficiencies in excess of 97 percent have been reported. On-stream time for the absorption area of these plants is more than 97 percent.

The No. 11 unit at the D. H. Mitchell Generating Station at Northern Indiana Public Service Company (NIPSCO) is currently the only operational Wellman-Lord system on a utility boiler in the United States. It is also the only coal-fired application in the world. The process is designed to remove at least 90 percent of the SO_2 when firing coal containing up to 3.5 percent sulfur. The supplier guarantees the mechanical soundness and product quality of the process, as well as water, electricity, and chemical consumption. The initial start-up of the NIPSCO unit began July 19, 1976, and an extended shake-down period began November 28, 1976. During this period, the Unit 11 boiler operated for 121 full days and 10 partial days, whereas the SO_2 removal system operated for 71 full days and 23 partial days, and was down for 38 days. In course of the three sustained operating periods, the absorber demonstrated the capability of greater SO_2 removal than specified. A boiler-related mishap occurred January 15, 1977, causing the unit to be shut down for repairs until May 1977. The absorber resumed operation June 13, 1977. Operation has been erratic since then, again primarily because of boiler problems. Trials began on August 29, 1977 and were successfully completed on September 15, 1977. The equipment met the guarantee covering SO_2 and particulate removal, chemical makeup, and utility usage.

Three Wellman-Lord systems are currently under construction. Two of these will be on coal-fired boilers at the San Juan Station of the Public Service Company of New Mexico. Each unit will be on a coal-fired boiler with approximately a 350-MW rating. Both units are designed for 90-percent removal of SO_2. The third unit is at ARCO/Polymers in Monaca, Pennsylvania, where a single scrubber will receive flue gases from three coal-fired boilers with a total equivalent rating of 100 MW. The unit is designed for approximately 87.5-percent SO_2 removal.

Magnesium Oxide Systems

This process uses a magnesium oxide slurry to react with SO_2. The reaction product, magnesium sulfite, is dried and calcined to regenerate magnesium oxide. Sulfur dioxide, liberated in the regeneration step, is recovered for conversion to sulfuric acid or for reduction to elemental sulfur. Guidelines to achieve high efficiency include:

High efficiency particulate removal should precede the absorber.

A prescrubber should be used to remove any remaining particulate and most of the chlorides and SO_3.

Utilize venturi absorbers, typically operating at a pressure drop of 25 cm (10 inches) of water or greater, or Turbulent Contact Absorbers operating at approximately 20 cm (8 inches) of water pressure drop, at an L/G of 5.3 to 6.6 l/m^3 (40 to 50 gal/1000 acf).

The absorber superficial gas velocity should not exceed approximately 3.0 m/sec (10 ft/sec) range.

The slurry pH measured at the absorber discharge should be maintained in the 6.0 to 7.5 range.

Three full-scale units have been operated in the United States: Mystic Station, Unit No. 6, of Boston Edison (oil fired); Dickerson No. 3, of Potomac Electric and Power; and Eddystone No. 1A, of Philadelphia Electric (both coal fired). All used fuel with 2- to 2.5-percent sulfur content. Sulfur dioxide removal efficiencies at all three locations have been in excess of 90 percent. In general, however, the three units experienced serious problems: mechanical, material-related, product-related, corrosion, and handling. These problems have limited operability to between 27 and 80 percent. When reviewing these operability levels, however, several points must be kept in mind:

- Sulfur dioxide collection efficiencies were frequently over 90 percent during test periods.
- Two units (Mystic and Dickerson) were trial installations, built to obtain operating data. As such, various construction materials were used that would not have been used in a full-scale plant designed for long-term operation.
- The sulfuric acid plant that was to receive SO_2 from the Eddystone MgO regeneration facility was shut down by its owner and another had to be found.
- The single regeneration facility at Rumford, Rhode Island, could not process material from the Mystic and Dickerson stations simultaneously since it was too small.
- Many problems at the Eddystone installation are related to particulate scrubbing and not to the SO_2 absorber section.
- Many design and operating problems at these installations were solved during these early programs and would not be encountered in new designs.

In the past, the MgO systems installed by Chemico (Mystic and Dickerson) and United Engineers (Eddystone) have not had overall performance guarantees. Rather, the manufacturers of certain components guaranteed them against manufacturing defects only. Now, however, Chemico is willing to guarantee the entire MgO system mechanically, as well as specify that the unit will meet applicable SO_2 emission regulations, including a 90-percent removal efficiency.

Double Alkali Flue Gas Desulfurization Systems

Double alkali scrubbing is an indirect lime/limestone process, in which a soluble alkaline medium is used in the scrubbing vessel to react with SO_2. The scrubber effluent is then treated with lime or limestone in a reactor outside the scrubber loop, where calcium sulfites and sulfates are precipitated and the scrubbing liquor regenerated and returned to the scrubber. This system greatly reduces the problems of plugging and scaling. Various double alkali process configurations are available and are described in the full report. Guidelines to achieve high efficiency include:

Utilization of a prescrubber with a separate water recirculating system for control of particulates and chlorides for high chloride coal (>0.04 percent Cl by weight in the coal).

Use of a two-stage tray or packed tower absorber with an L/G in the 1.3 to 2.7 l/m^3 (10 to 20 gal/1000 acf). Typically the absorber pressure drop is 15 to 30 cm (6 to 12 inches) of water.

The absorber scrubbing liquor pH being recycled to the absorber should be in the range 6.0 to 7.0 pH range.

If lime regeneration is used, the reaction tank residence time should be approximately 10 minutes.

If limestone regeneration is used, the reactor tank residence time should be approximately 30 minutes.

A number of successful bench-scale, pilot plant, and prototype double alkali systems have been tested on both industrial and utility boiler flue gas applications in the United States. The success of these programs has resulted in commitments by three separate utilities to install full-scale, double alkali systems on coal-fired boilers. As yet, however, no full-scale system is operating on utility boilers, although several are in operation on coal-fired industrial boilers.

At the Cane Run No. 6 unit of Louisville Gas and Electric, a 277-MW coal-fired unit, the double alkali system is scheduled to start up in February 1979. The unit is designed to have 200 ppm of SO_2 or less in the discharge from the scrubber, and 95-percent SO_2 removal when the sulfur content of the coal is 5 percent or greater. Coal sulfur content is expected to be between 3.5 and 4 percent.

At the A. B. Brown No. 1 installation of Southern Indiana Gas and Electric, the double alkali system will be applied to a 250-MW boiler firing coal with an average sulfur content of 3.5 percent. The unit is scheduled for start-up in April 1979, and designed to remove 85 percent of the SO_2 when burning 4.5-percent sulfur coal, the maximum sulfur content expected.

At the Newton No. 1 unit of Central Illinois Public Service, the double alkali system will be installed on a 575-MW boiler firing coal with an average sulfur content of 4 percent. The unit will start up in November 1979. The design SO_2 removal efficiency is 95 percent, or less than 200 ppm in the exit gas.

Four double alkali systems have been installed on industrial coal-fired boilers. These systems have operated with high removal efficiency, ranging from 85 to 99 percent (mostly 90 to 95 percent). While some have had mechanical problems, the systems have shown themselves reliable; generally operability has been over 90 percent. In addition, two prototype double alkali systems were operated on utility coal-fired boilers, one on low-sulfur coal and the other on high-sulfur coal. Both had SO_2 removal efficiencies above 90 percent, and their success has resulted in the design of a full-scale system that is expected to have high levels of operability and efficiency.

FGD System Efficiency Summary

Table 3 identifies facilities at which FGD systems have removed 90 percent or more of SO_2. In addition, systems are operating or are being designed for efficiencies of 90 percent or greater (see Figure 1).

Furthermore, the major suppliers of systems are now offering SO_2 removal guarantees. Levels of SO_2 removal which vendors will guarantee exceed 90 percent, and in some cases 95 percent, but they often have a lower limit on outlet SO_2 concentration (e.g. 50 ppm). For lower sulfur coals, this lower limit, rather than efficiency, would become the basis of the guarantee. Thus existing technology is adequate for meeting a 90-percent SO_2 removal requirement.

Table 3. PLANTS REPORTING 90 PERCENT OR GREATER SO_2 REMOVAL

Utility Company	Station	Unit	MW	Nature	Process	% S in fuel	SO_2 removal, %
Arizona Public Service	Cholla	No. 1	115	Full-scale	Limestone	0.4-1.0	92
	Four Corners	No. 5	160	Demonstration	Lime	0.7	95
Duquesne Light	Phillips	Nos. 1-6	410	Full-scale	Lime	1.0-2.8	90+
Louisville Gas & Electric	Cane Run	No. 4	175	Full-scale	Lime	3.5-4.0	85
	Paddy's Run	No. 6	65	Demonstration	Lime	3.5-4.0	99.5
Northern Indiana Public Service	Mitchell	No. 11	115	Demonstration	Wellman-Lord	3.2-3.5	90
Philadelphia Electric	Eddystone	No. 1	120	Demonstration	Mag-Ox	2.5	95-98
Tennessee Valley Authority	Shawnee	No. 10	10	Prototype	Lime/limestone	0.8-5.0	95-99
Boston Edison	Mystic	No. 6	150	Demonstration+	Mag-Ox	2.5	90
Detroit Edison	St. Clair	No. 6	163	Demonstration	Limestone	0.3	90-91
General Motors	Parma	No. 1-4	32	Full-scale*	Double-alkali	4.0	90+
Gulf Power	Scholz	No. 1	20	Prototype	Double-alkali	3.0	95
	Scholz	No. 1-2	20	Prototype	Chiyoda	3.0	95
	Scholz	No. 2	20	Prototype	Carbon	3.0	90+
Potomac Electric & Power	Dickerson	No. 3	95	Demonstration	Mag-Ox	2.0	90
Southern California Edison	Mohave	No. 1	170	Demonstration	Limestone	0.6	95
	Mohave	No. 2	170	Demonstration	Lime	0.6	95
U.S. Air Force	Rickenbacker	No. 1-9	20	Full-scale**	Lime	3.6	99
Kentucky Utilities	Green River	No. 1-3	64	Full-scale	Lime	3.8	90+

* Industrial
** Military Base
\+ Oil Fired

NOTE: Most reported SO_2 removal data are based on intermittent manual tests.

FGD SYSTEM OPERATION

Two basic features characterize FGD performance: removal efficiency, and process operating ability. This operating ability has been defined in various ways, but the terms most commonly referred to are system availability and operability. These terms are defined as follows:

- Availability: Hours the FGD system is operated or available for operation divided by total hours in the time period.
- Operability: Hours the FGD system is operated divided by hours the boiler is operated.

FGD system availability is dependent on both system design and the manner in which the system is operated. Even so, there is a trend in overall system availability, as a function of the year the system was started up (Figure 2). Continuing improvement in availability is evident as the newer, improved units come on line. Although some recent installations have not shown particularly high availability, a statistically significant correlation does exist between start-up date and average availability. In addition, only one of these newer stations had a redundant (spare) module available for use in the event of malfunction of the operating modules. A redundant scrubbing module has a significant effect on overall system availability since it can replace a module which may be shut down for any reason. This is shown in Table 5 where calculated availabilities with and without a spare module are shown.

When operation at less than full load is required, which is usually the case, opportunities for preventative

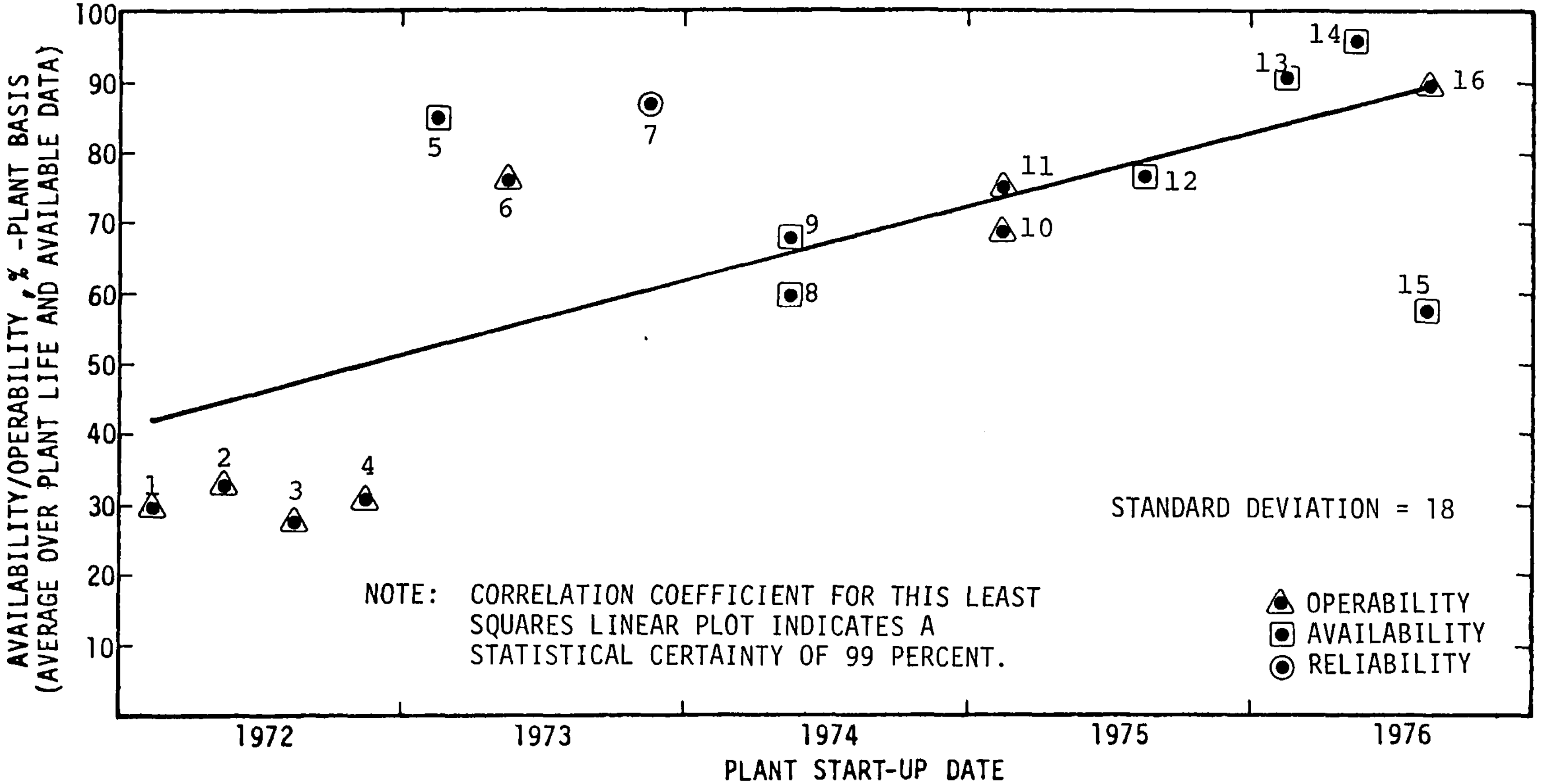

Figure 2. Average plant FGD availability/operability versus plant start-up date.
(See Table 4 for plant identification)

Table 4. IDENTIFICATION OF PLANTS IN FIGURE 2

1. Will County No. 1 Commonwealth Edison	9. Reid Gardner No. 2 Nevada Power
2. Mystic No. 6 Boston Edison	10. Scholz No. 1B and 2B Gulf Power Co.
3. Hawthorn No. 4 Kansas City Power and Light	11. Scholz No. 1A Gulf Power Co.
4. Hawthorn No. 3 Kansas City Power and Light	12. Green River No. 1 and 2 Kentucky Utilities
5. LaCygne No. 1 Kansas City Power and Light	13. Sherburne County Station No. 1 Northern States Power Co.
6. Paddys Run No. 6 Louisville Gas and Electric	14. Bruce Mansfield No. 1 Pennsylvania Power
7. Cholla No. 1 Arizona Electric Power Co-Op	15. Reid Gardner No. 3 Nevada Power
8. Reid Gardner No. 1 Nevada Power	16. Cane Run No. 4 Louisville Gas and Electric

Table 5. CALCULATED FGD SYSTEM AVAILABILITY

BASED ON NUMBER OF SCRUBBER MODULES

Number of modules	FGD System Availability based on Single Module Availability of: No spares			One spare		
	70	80	90	70	80	90
1	70	80	90	91	96	99
2	49	64	81	78	90	97
3	34	51	73	65	82	95
4	24	41	66	53	74	92
5	16	37	59	42	66	89
6	12	30	53	33	58	85
7	8	24	48	26	50	82
8	6	19	43	20	44	77

Assumes continuous full load operation is required.

maintenance and repair occur without effecting system operation and still better availability can be achieved compared to continuous full load operation.

Continued improvement in system availability is also shown in Figure 3 where average availability data for selected FGD systems serving high and low sulfur coal applications are presented. High availabilities are becoming more common as design and operating advances are implemented. This improvement in system availability has also prompted some FGD system supplies to guarantee a 90-percent availability level. In a survey conducted for this study, seven out of twelve FGD system suppliers offered availability guarantees of 90-percent.

Several examples of the improved availability and operability of new FGD systems are described below.

<u>Lime Systems</u>

- Louisville Gas and Electric, Cane Run Unit No. 4, Louisville, Kentucky (178 MW).

  The unit began operation in August 1976. With the exception of a shutdown caused by the lack of lime (frozen rivers prevented barge deliveries), and process modifications, the unit has averaged in excess of 95 percent operability through July 1977.

- Louisville Gas and Electric, Paddy's Run Unit No. 6, Louisville, Kentucky (65 MW).

  The unit began operation in April 1973. Start-up problems, modifications, and an extended boiler shut-down kept operability low until October 1974. Operability from October 1974 to August 1977 has been in the 95 to 100 percent range, although the boiler operates primarily as a peak load station.

- Kentucky Utilities, Green River Units No. 1, 2, and 3, Central City, Kentucky (64 MW).

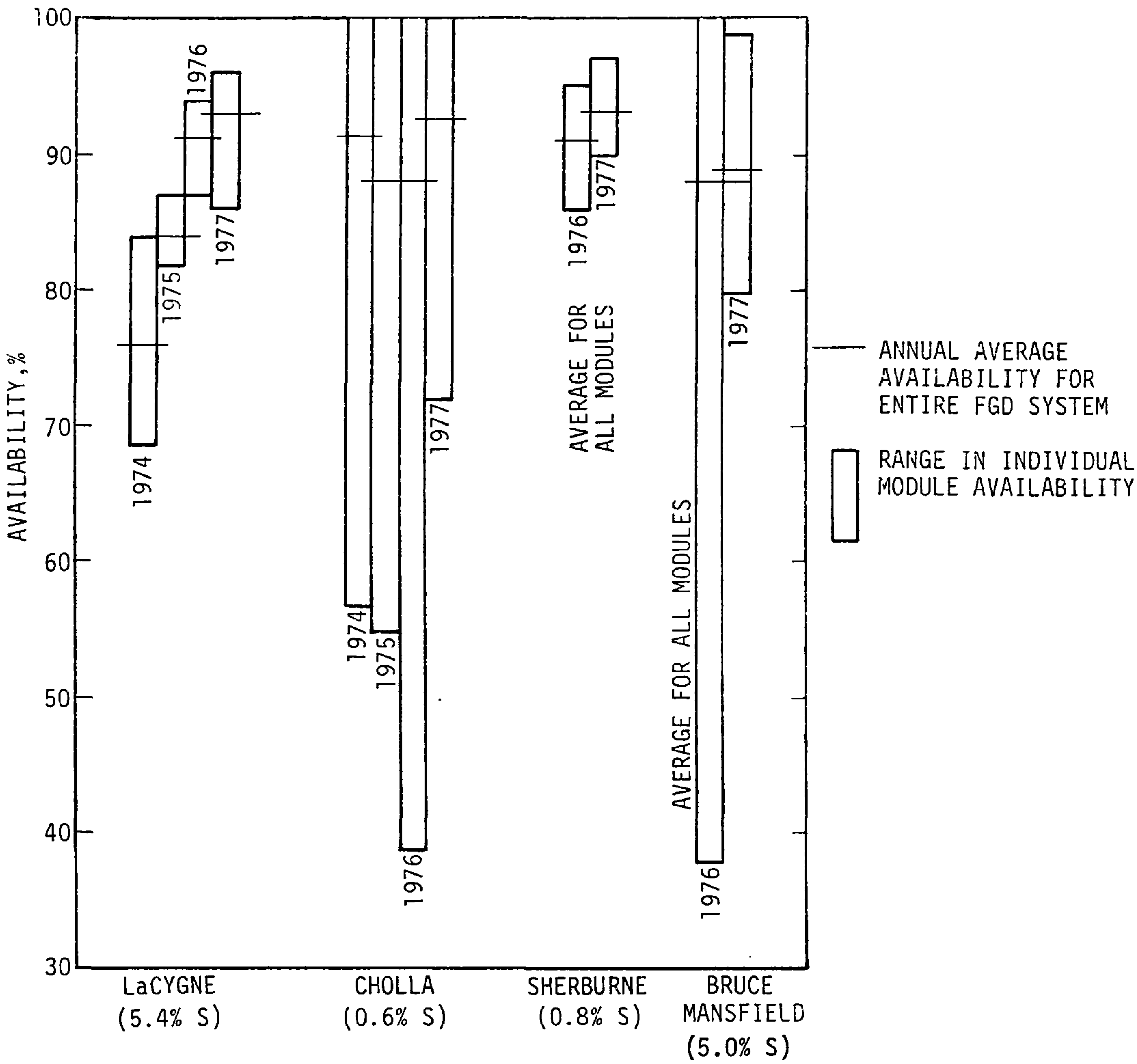

Figure 3. Average availability for selected FGD systems.

This FGD unit began operation in December 1975. After the initial operating period (Dec. 1975-Feb. 1976), the operability of the unit has been 97 percent through June 1977.

Limestone Systems

- Kansas City Power and Light, La Cygne Unit No. 1, La Cygne, Kansas (820 MW).

  Operation of this FGD system began in January, 1974. Since all the flue gas must be treated by the FGD system, availability is a more meaningful parameter. From February 1976 through July 1977, unit availability has averaged 93 percent.

- Northern States Power, Sherburne No. 1 and 2, Sherburne, Minnesota (700 MW each).

  After start-up, No. 1 unit averaged 92-percent availability. No. 2 unit has averaged 95 percent since start-up.

In summary, the availability of full-scale scrubbing facilities has increased steadily to where current systems are demonstrating long-term availabilities in excess of 90 percent.

OPERATING PROBLEMS AND SOLUTIONS

There have been and still are problems associated with FGD systems; however, many of these problems have been solved and the methods of reducing the severity of the remaining items are much better understood.

To date, the problems encountered with FGD systems and the severity of these problems varied both with system type and within units of the same system. The more common problems encountered are listed below.

- Formation of scale in the absorber and associated equipment in lime and limestone systems leading to plugging and reduced capacity.
- Plugging of mist eliminators, lines, and some types of absorbers.
- Failure of ancillary equipment such as pumps, piping, pH sensing equipment, reheaters, centrifuges, fans and duct and stack linings.
- Inadequate absorbent make-up preparation.*
- Handling and disposal of sludge in nonregenerable systems.

Scaling and Plugging

In lime and limestone systems, scaling has been a particular problem and has reduced operability. Both a soft sulfite scale and a hard sulfate scale may form in the absorber, mist eliminator, and ancillary tanks, pumps, and pipes. Specific process control techniques which have produced significant improvements include:

- Use of Magnesium

Full-scale and test facilities in this country have effectively reduced saturation and scaling by addition of magnesium to the circulating slurry. The TVA Shawnee facility, the Phillips facility, and the Paddy's Run facility

*Discussed in full report only.

demonstrated that the addition of magnesium to the lime and limestone slurry eliminated scrubber scale formation. The Bruce Mansfield and Conesville stations use lime containing magnesium oxide to prevent scaling.

° Operation at subsaturation levels for calcium sulfate and sulfite

By maintaining high liquid to gas (L/G) ratios, the proportion of unreacted lime or limestone remains high relative to the absorbed SO_2. There is thus less chance of creating a supersaturated solution of sulfites or sulfates. The higher L/G ratio also improves overall SO_2 collection efficiencies, as described in Section 3.1. The actual L/G will vary with the type of absorber, and values in excess of 10.8 l/m^3 (80 gal/acf) have been used in spray towers.

Increased reaction tank holding time will also decrease saturation by allowing further reaction between the absorbed SO_2 and the lime or limestone slurry. Slurry residence time at the Green River facility is greater than twenty minutes, and scale formation is not a major problem.

° pH Control

Work at the EPA-Shawnee test facility has shown that an important parameter in controlling scale formation is solution pH. The measurement of pH has also received considerable attention. More rugged and dependable sensors are being used; they are located in the slurry stream where they are subject to less breakage, are more accessible, and where they yield data which is more reliable and responsive for pH control. The Bruce Mansfield facility has just completed a renovation program to incorporate these design features into their pH system.

° Co-precipitation of sulfate

Minimizing the oxygen content in the flue gas by reducing any air in-leakage, favors co-precipitation of sulfate crystal. Therefore, air exposure is reduced by covering open reaction tanks, clarifiers, etc.

Plugging caused by deposition of solids on equipment surfaces has sometimes restricted the passage of liquids or gas in FGD systems. It is usually easily removed by flushing with water or steam. Plugging in pipes can be prevented through designs which avoid low flow velocities. Careful control of raw material particle size and screening of the slurry also decrease plugging problems, especially in spray nozzles, pipes and pumps. Since this problem is caused by the deposition of solids from the recirculating slurry, reduction of the overall amount of solids will reduce the plugging. The minimum stoichiometry that will effect the required SO_2 removal efficiency should be used. This has been demonstrated in this country at Shawnee and LaCygne.

Erosion and Corrosion

Many problems with ancillary equipment were due to corrosion and erosion.

Erosion in venturi prescrubbers has resulted from high fly ash loadings. Likewise, prescrubbers remove the bulk of any chlorides and sulfur trioxide in the gas stream; both of these components are highly corrosive. Corrosion occurs more frequently in areas after the absorber subject to wet saturated flue gas as opposed to areas subject to alkaline slurry streams.

There are so many factors involved in FGD operation which affect corrosion rates, that generalizations regarding corrosion resistant materials are difficult. A sufficient amount of data has been accumulated, however, to provide general guidelines for the construction of critical elements in FGD systems as summarized below:

(a) Some systems are incorporating such alloys as Hastelloy C-276, Hastelloy G, Inconel 625, Incoloy 825, 317L stainless steel, 904L stainless steel and Jessop JS700 in wet/day high temperature, high chloride environments, such as in presaturators. The LaCygne Station has found that these materials give excellent reheat service. The Bruce Mansfield station has had good results with Hastelloy wetted parts of the fan.

(b) Synthetic and natural rubber coatings predominate in recycle tanks, pumps, and lines. These materials have been reported to give superior erosion resistance once application problems have been overcome. For instance rubber lined pumps have been used successfully at the following facilities: Green River, LaCygne, Bruce Mansfield, and Conesville.

(c) For liners in the absorbers, exhaust ducts and stacks, a number of materials such as resins, ceramics, polyesters, polyvinyls, polyurethanes, Carboline, and Gunite, have been used with varying degrees of success. Although successful applications have been reported, widespread failures of the liners have been attributed to the undependability and inexperience of lining applicators, instability of the materials at high temperatures, inconvenience of repair, and cost-related factors. These problems are especially evident on higher sulfur coals. Extensive effort is continuing by FGD suppliers to fully solve this problem.

Equipment Design

Approaches utilized to reduce problems with ancillary equipment include:

° Recirculation Pumps - Slurry recirculation pumps provide the driving force for the liquid circuit in FGD systems. In their design, special attention must be given to an accurate service description (solution pH, specific gravity, solids content, gas entrainment, flow rates, and head). A number of general trends are evident and summarized below:

(a) New systems must incorporate spare pumps. Spare capacity from 50 percent (one spare for every two operational) to 100 percent (one spare for every one operational) is useful to avoid downtime.

This type of spare equipment is found at new large stations including Bruce Mansfield and Conesville.

(b) Natural and synthetic molded rubber lining should be specified for wetted parts in the pumps.

(c) Flush-water wash systems are needed to purge the pumps of solids, which tend to settle out during periods of inactivity.

° <u>Mist Elimination</u> - Chevron and baffle-type mist eliminators have been and are currently being used in virtually every FGD system in the United States. The popularity of these collectors is due primarily to design simplicity, high collection efficiency (for moderate to large size drops), low pressure drop, wide-open construction, and low cost. Within these two preferred types of mist eliminators, a number of specific design and construction innovations have been implemented:

(a) Chevron designs (continuous vane construction) are predominate over baffle designs (discontinuous slat construction).

(b) Fiberglass-reinforced plastic is now used at nearly all facilities.

(c) The horizontal configuration (vertical gas flow) is also used in almost all installations for cost reasons.

(d) Two-stage designs predominate over single-stage designs, because they yielded higher elimination efficiencies.

(e) Operation at high alkali utilization.

(f) Bulk entrainment separators, perforated plates, impingement plates and other precollection devices are becoming integral parts of mist elimination systems. These reduce plugging and improve separation. The Conesville facility employs this as well as LaCygne and Coal Creek.

(g) Mist eliminator wash systems that employ intermittent, high-velocity sprays predominate over continuous wash systems. These produce a hydraulic washing effect.

Application of these approaches greatly diminishes mist eliminator problems.

° Reheat - Virtually all the FGD systems coming on-line and planned for future operation incorporate some type of stack gas reheat system. These systems heat the flue gas to avoid condensation with subsequent corrosion to downstream equipment, ductwork, and stack and to suppress plume visibility as well as enhance plume rise and pollutant dispersion. To date, a number of "wet stack" FGD systems (no reheat) have been installed and have encountered corrosion problems. The trend in reheat systems is toward heating of ambient air and mixing with the flue gas and mixing of hot untreated flue gas with scrubbed gas. In-line reheat systems have been subject to corrosion and solids deposition, the latter often occurring because of inefficient upstream mist elimination. Application of heated ambient air reheat systems essentially eliminates reheater problems.

° Fans - Fans installed immediately after an FGD system (wet fans) have experienced corrosion, chloride attack, and solids deposition problems. Deposition problems have caused fan imbalance resulting in excessive bearing wear and damage to the fan. Only two systems have this trouble: Phillips and Bruce Mansfield. The problems associated with fans installed upstream of the FGD system (dry fans) include operation at higher temperatures (over 150°C) resulting in higher gas velocities and abrasion by fly ash. Dry fan problems are more easily solved, and the tendency is toward fans upstream of the FGD system. Where necessary, however, the use of various steel alloys have made wet fans a viable alternative.

FGD SYSTEM MANUFACTURER CAPABILITY

Based on the new coal-fired boilers now planned for construction and a projected growth rate of 5.56 percent per year for the construction of new boilers, approximately 510,000 MW of coal-fired boiler capacity will be built between 1978 and the year 2000. The alternative NSPS standards assumed for this study indicate that all of these new units will require FGD systems.

To determine the capability of FGD system manufacturers to provide these systems, eighteen manufacturers were contacted. Table 6 shows those manufacturers that provided information for this study. The responses from these 13 FGD system manufacturers indicate they will be capable of supplying the design personnel and equipment for the FGD systems required by the alternative standards. The capability of manufacturers to meet FGD system requirements is flexible and increases in proportion to demand. However, even with present staffs, adequate capability apparently exists to supply FGD systems for all new coal fired plants as shown on the last page of this report.

Table 6. MANUFACTURERS RESPONDING TO THE FLUE GAS DESULFURIZATION SYSTEM CAPABILITY STUDY AND THE PROCESS OFFERED BY EACH

	Type of FGD System Offered										
	Regenerative system					Nonregenerative system					
Manufacturer	Magnesium oxide	Phosphate	Wellman-Lord	Catalytic oxidation	Citrate	Double alkali	Lime	Limestone	Chiyoda thoroughbred 101	Sodium carbonate	Hydro
1. Babcock & Wilcox Company							X	X			
2. Chemico Air Pollution Control Company	X	X				X	X	X			
3. Chiyoda International Corp.				X					X		
4. Combustion Engineering, Inc.							X	X			
5. Davy Powergas, Inc.			X								
6. Environeering, Inc.							X	X			
7. Flakt, Inc.							X	X			X
8. FMC Corp.						X				X	
9. Peabody Process Systems, Inc.					X		X	X			
10. Pullman, Inc.							X	X			
11. Research-Cottrell, Inc.								X			
12. UOP, Inc.						X	X	X		X	
13. Zurn Air Systems						X					

Time period	FGD manufacturers' capability, MW	Projected demand with alternative NSPS, MW
1978-1982	205,700	75,500
1983-1987	212,890	65,400
1988-1992	218,540	109,000

These same manufacturers would usually guarantee 90-percent or greater SO_2 removal efficiency. In addition approximatley two-thirds would provide an operation and maintenance service and guarantee a specified level of availability.

Ample limestone, and to a lesser extent, lime, supplies exist in this country to supply all FGD systems. Shortages in specialized construction personnel are a possibility, however the added personnel needs for new FGD systems are a very small portion of the total labor requirement. By about 1990, shortages in large scrubber modules and fans are also predicted by several of the suppliers depending on the sizes required at that time.

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16. ABSTRACT The report discusses the availability of technology for reducing SO2 emissions from coal-fired steam generators using flue gas desulfurization (FGD) systems. Foreign and domestic lime, limestone, double alkali, magnesium slurry, and Wellman-Lord FGD systems are described, and the design parameters and operating experiences are discussed. Steps that have been taken to achieve high system operability are discussed. Also, disposal of FGD system wastes is discussed briefly.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Air Pollution	Alkalies	Air Pollution Control	13B	
Flue Gases	Scrubbers	Stationary Sources	21B	
Desulfurization	Calcium Oxides	Alkali Scrubbing	07A, 07D	07B
Coal	Limestone	Particulate	21D	08G
Boilers	Sulfur Dioxide	Venturi/Spray Towers	13A	
Wastes	Dust	Mist Eliminators		11G

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