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Project Summary

The Current Status of Commercial Utility Flue Gas Desulfurization Systems

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This summarizes a report on the status of commercial flue gas desulfurization (FGD) processes applied to coal-fired utility boilers in the U.S. Major objectives of this work were to examine the impacts of the 1979 New Source Performance Standards on FGD system design and operation and to identify recent improvements in the technology. In the 4 years since the promulgation of the NSPS, the wet limestone process has been selected by utilities for 75 percent of the new plant capacity. In this time period, 77 plants representing over 37,000 MW of capacity have selected FGD systems. Several major trends in the design of limestone systems have become fairly standardized. Nearly all new systems are being built with spare absorber modules to qualify for the NSPS emergency bypass provisions. The predominant absorber design is the open spray tower, due to minimal maintenance requirements. Forced oxidation to produce gypsum solids, which can then be landfilled, is being incorporated in many new units. Selection of the spray drying process for 15 percent of the new sites has also occurred in the last 4 years. The remaining throwaway and regenerable systems have not experienced any significant increases in applications. Finally, organic acid addition has been successfully demonstrated on limestone systems to improve SO_2 removal and system reliability. Organic acid addition is being used at two sites to upgrade the performance of older limestone systems.

This Project Summary was developed by EPA's Industrial Environmental Research Laboratory, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

This report examines the current status of flue gas desulfurization (FGD) systems applied to coal-fired utility boilers to control sulfur dioxide (SO_2) emissions. It documents changes in the design of FGD systems which have occurred over the years, specifically in response to the requirements of the 1979 New Source Performance Standards (NSPS) for utility boilers. This information is useful to EPA Regional Offices in evaluating SO_2 control technology for new utility applications, to the Office of Air Quality Planning and Standards (OAQPS) in their review of the 1979 NSPS, and to the Office of Research and Development in establishing research initiatives. This information is also useful to architects, engineers, vendors, utility companies, and others interested in FGD technology.

Objectives of this study were to examine differences in the designs and applications of FGD systems applied to plants subject to the 1971 and 1979 NSPS. The basic difference between the two standards is inclusion of a minimum percent reduction requirement of SO_2 emissions in the new standard. The 1971 standard limited SO_2 emissions to 1.2 lb* SO_2/million Btu of heat input. The 1979 NSPS requires a minimum of 70 percent removal for all controlled emissions less than 0.6 lb SO_2/million Btu. A sliding-percentage removal scale is used as sulfur levels increase. The maximum emission limit under the new standard is also 1.2 lb SO_2/million Btu. Figure 1 shows the removal requirement of the NSPS for different sulfur levels. The major effect of the new standard has been to require sulfur oxide (SO_x)emission controls for most low sulfur coals which, under the 1971 standard, would not have required any SO_2 removal. The rationale behind the decision to require SO_x emission controls for most coals is discussed in detail in the Federal Register. Two major reasons cited were to promote the use of the best available FGD technology according to provisions of the Clean Air Act, and to maintain a competitive economic balance between high- and low-sulfur coal producing regions in the U.S.

FGD Technology Status

The most dominant trend in FGD technology is the overwhelming selection of the limestone FGD process for new units. Table 1 shows the status of the various FGD technologies as of September 1978, prior to promulgation of the 1979 NSPS, and as of January 1983. The equivalent scrubbed gas capacity (in megawatts) and number of units are presented for each process. The percentage distribution (by megawatts) of the various processes is also shown. The totals presented are for units operating, in construction, contracted, and planned which have selected an FGD technology.

The processes in Table 1 are listed in order of application over the last 3 years. As can be seen, limestone systems have been specified for 75 percent of the capacity of these units. Spray drying systems account for most of the remaining units. The other throwaway and regenerable technologies show only minor increases in application. The two processes showing decreases represent the shutdown of a magnesium oxide test unit and a reduction in size of several units which had planned (in 1978) to use alkaline ash scrubbing. Of particular note is the reduced use of the lime FGD process: in September 1978, 25 percent of the FGD capacity used the wet lime process; however, in the next 3 years, lime processes were specified at only 5 percent of the new units. Sixteen times as many limestone systems were selected as lime units in this interval. In 1978, the ratio was two limestone systems to each lime unit.

The decline in the use of lime systems is due to: (1) the higher reagent cost of lime compared to limestone, (2) the improvement in limestone system performance, and (3) the development of spray drying technology for low sulfur applications.

The early limestone systems had greater operating problems than lime systems. Additionally, the more reactive lime units achieved higher SO_2 removal efficiencies on the higher sulfur coals. Continued research by public and private interests has made the limestone system capable of meeting the current emission regulations for a wide variety of fuels. Consequently, the higher reagent cost of the lime process becomes a detriment in process selection. Most economic studies show the lime process to be more economical than limestone systems only

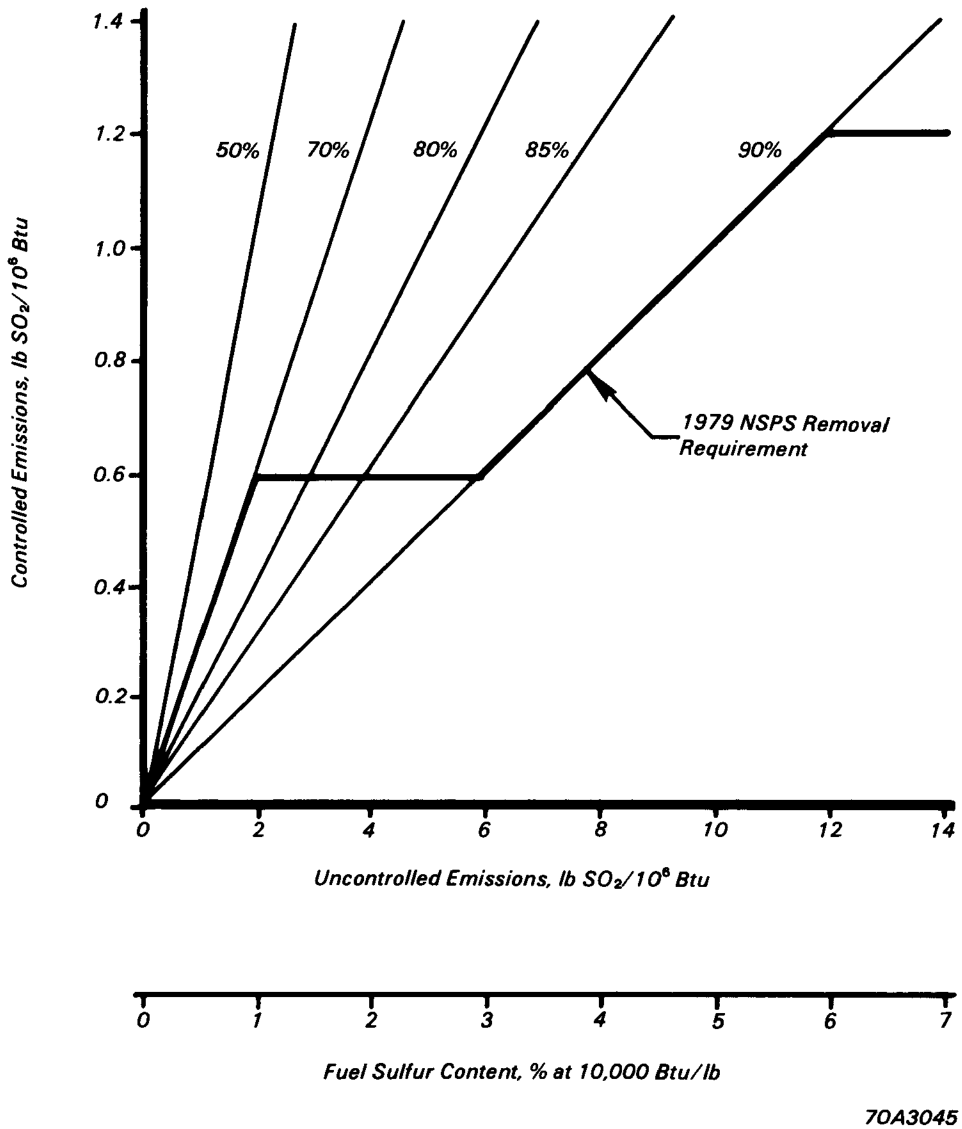

Figure 1. *1979 NSPS removal requirements.*

*Although EPA policy is to use metric units, certain nonmetric units are used here for convenience. Readers mor familiar with the metric system may use the conversion factors at the back.

Table 1. *Comparison of FGD System Status in September 1978 and January 1983*

Process	*September 1978* *MW*	*Number*	*Percent MW*	*January 1983* *MW*	*Number*	*Percent MW*	*Increase from 1978 to 1982* *MW*	*Number*	*Percent MW*
Limestone	*23,849*	*54*	*49.2*	*51,662*	*103*	*60.3*	*27,813*	*49*	*74.8*
Spray Drying	*400*	*1*	*0.8*	*6,353*	*18*	*7.4*	*5,953*	*17*	*16.0*
Lime	*12,065*	*29*	*24.9*	*13,736*	*32*	*16.0*	*1,671*	*3*	*4.5*
Sodium Carbonate	*884*	*4*	*1.8*	*3,155*	*9*	*3.7*	*2,271*	*5*	*6.1*
Dual Alkali	*1,102*	*3*	*2.3*	*2,288*	*6*	*2.7*	*1,186*	*3*	*3.2*
Wellman-Lord	*1,855*	*6*	*3.8*	*2,074*	*8*	*2.4*	*219*	*2*	*0.6*
Aqueous Carbonate	*100*	*1*	*0.2*	*100*	*1*	*0.1*	---	---	---
Citrate	*60*	*1*	*0.1*	*60*	*1*	*0.1*	---	---	---
Magnesium Oxide	*846*	*4*	*1.8*	*724*	*3*	*0.9*	*(122)*	*(1)*	*(-0.3)*
Alkaline Ash-Lime/Limestone	*7,316*	*14*	*15.1*	*5,493*	*13*	*6.4*	*(1,823)*	*(1)*	*(-4.9)*
Total	*48,477*	*117*	*100.0*	*85,645*	*194*	*100.0*	*37,168*	*77*	*100.0*

for small size units or low sulfur fuels: in both applications, the cost of lime is a fairly small portion of the total revenue requirement. However, the spray drying process has recently attained prominence in low sulfur applications, due to anticipated favorable economics and performance characteristics. Therefore, the relative ranking of the wet lime process will probably continue to decline in future applications. Lime is the predominant reagent used in the spray drying systems, which may result in an increase in industry's demand for this reagent.

The regenerable systems (Wellman-Lord, magnesium oxide (MgO), Citrate, and Aqueous Carbonate) have not shown any substantial increase in applications. Part of the reason includes the developmental nature of two of these processes, as well as the higher costs associated with regenerable systems in general.

Table 2 shows the distribution of processes according to the emission requirements of each unit. Again, the totals are for systems operating, in construction, contracted, and planned.

Each process in Table 2, except MgO, Aqueous Carbonate, and Citrate, will be or have been used in commercial applications to meet the 1979 NSPS or a more stringent state standard. However, the selection of a process technology is very site specific; not all processes are applicable to every situation. The following discussion outlines the range of applications of each process and comments generally on performance, energy requirements, environmental effects, and reliability.

Table 2. *FGD Systems and Regulatory Classifications - January 1983*

Applicable Emission Standard, MW, (Number of Units)

Process	*1979 NSPS*	*1971 NSPS*	*More Stringent Than 1979 NSPS*	*More Stringent Than 1971 NSPS, But Less Than 1979 NSPS*	*Less Than 1971 NSPS*
Limestone	*27,461 (45)*	*9,309 (25)*	*7,239 (14)*	*3,151 (10)*	*4,502 (9)*
Lime	*715 (2)*	*4,551 (10)*	*2,140 (4)*	*5,486 (12)*	*844 (4)*
Spray Drying	*2,077 (8)*	*1,180 (3)*	*2,099 (4)*	*887 (2)*	*110 (1)*
Alkaline Ash-Lime/Limestone	*475 (1)*	*1,374 (4)*	*1,979 (5)*	*1,665 (3)*	----
Sodium Carbonate	*1,900 (4)*	*375 (3)*	*330 (1)*	*550 (1)*	----
Wellman-Lord	----	----	*1,779 (4)*	*295 (4)*	----
Dual Alkali	*1,107 (3)*	*881 (2)*	----	*300 (1)*	----
Magnesium Oxide	----	----	----	*724 (3)*	----
Aqueous Carbonate	----	----	----	----	*100 (1)*
Citrate	----	*60 (1)*	----	----	----
Total	*33,735 (63)*	*17,730 (48)*	*15,566 (32)*	*13,058 (36)*	*5,556 (15)*

FGD Applications and Characteristics

Although most commercial FGD processes could be used at many types of sites, generally the plants using the same process have some similar characteristics which favor the use of the selected process. These trends are discussed, and general comments are made on energy requirements, environmental considerations, and reliability. Table 3 summarizes these comments.

Applications and Recent Process Improvements

The limestone process is the predominant FGD system in use because of several factors. First, limestone deposits are, in many parts of the country, leading to low transportation and reagent costs. Second, limestone systems have been in use longer than other types of

Table 3. Qualitative Evaluation of Commercial FGD Processes

Process	Performance	Energy Requirements	Environmental Considerations	Reliability
Limestone	*New systems are being designed to meet the 1979 NSPS with high and low sulfur coals. Additives can be used to enhance SO_2 removal.*	*Moderate to high. Depends on absorber pressure drop, amount of grinding required to prepare limestone.*	*Produces large volumes of sludge.*	*Historically the lowest of commercial processes, additives may improve performance.*
Lime	*Traditionally lime systems are somewhat more effective than limestone units at equivalent operating parameters.*	*Moderate, since reagent preparation does not require grinding.*	*Produces large volumes of sludge.*	*Better than limestone; however, still can experience scaling and plugging.*
Spray Drying	*Currently only able to meet NSPS for lower sulfur fuels.*	*Very low because of small pumping requirements and no reheat requirements.*	*Dry waste product often requires wetting for disposal.*	*Insufficient data base; however, process simplicity is an advantage.*
Alkaline Ash	*Limited to certain fuel types, usually only low sulfur coals.*	*Comparable to lime systems.*	*Produces large volume of fly ash/FGD sludge.*	*Comparable to lime systems.*
Sodium Carbonate	*High SO_2 removal achievable.*	*Low due to high alkalinity of reagent.*	*Large volume of soluble waste produced. Requires special disposal.*	*Very reliable due to simplicity.*
Dual Alkali	*High SO_2 removal achievable on high sulfur fuels.*	*Low due to high alkalinity of reagent.*	*Large volume of sludge produced.*	*Based on operating units, most reliable commercial system.*
Wellman-Lord	*High SO_2 removal achievable on high sulfur coal.*	*Fairly high because of steam requirements and gas for regeneration.*	*Produces sulfur, sulfuric acid, and sodium sulfate, saleable by-products.*	*Fairly good, but may suffer somewhat due to process complexity.*
Magnesium Oxide	*High SO_2 removal achievable.*	*Moderate, coal can be used in drying and regeneration.*	*Produces sulfuric acid.*	*No commercial systems. Prototype plants had many mechanical problems.*

processes; consequently, vendors and utilities are familiar with them. Perhaps most importantly, until the advent of spray drying, limestone units were typically the lowest cost process available. Commercial experience has also shown that limestone systems can be used successfully on a wide variety of fuels. Several innovations in process design have become commonplace in limestone process designs. The absorber vessel is almost always an open spray tower, which requires less maintenance than packed towers. Forced oxidation of the sludge produces better handling solids and reduces the scaling potential of the slurry. Additives such as magnesium and organic acids are being used commercially to raise the SO_2 removal closer to levels typically reached by more reactive sodium and lime systems. This flexibility has resulted in the large number of limestone systems in use. However, because of site specific factors and utility preferences, other processes have often been selected.

The most significant determinant of process selection is probably fuel composition, specifically sulfur level, although chloride and ash levels are also important. The sodium based processes (dual alkali, Wellman-Lord) are good candidates for high sulfur fuels because of the high sorption capability of the scrubbing liquor. A dual alkali system vendor is now marketing a process using limestone (rather than the more expensive lime) as the regenerant to improve process economics.

For low sulfur applications, spray drying is currently the most popular process, due to the reduced reagent volumes needed and reduced capital costs. Depending on the ash composition, the alkaline ash process can also be used in low sulfur applications, although no new units are being planned for this process. High chloride coals can cause both process chemistry problems and corrosion. A prescrubber before the SO_2 absorber is often used to remove the chloride, although it can cause serious corrosion.

Land availability favors the regenerable over the throwaway processes such as the Wellman-Lord and MgO systems. These processes produce saleable by-products rather than throwaway sludges. The local availability of a reagent also affects process selection. All sodium carbonate systems are near natural deposits of the material. If transportation costs are a major portion of the delivered reagent price, lime can have an advantage over limestone because of its greater reactivity per pound.

Water availability is often cited as a factor in FGD process selection; however, all processes use nearly the same amount of water. Spray drying may use slightly less water because the flue gas is not totally saturated; however, the dry waste product is moistened before disposal. The water requirements of the FGD system are typically less than 10 percent of the plant's total requirement. A more important consideration is the type of water used in the FGD system. Throwaway systems can generally tolerate poorer quality water than regenerable systems.

Energy Requirements

Energy requirements for FGD systems vary significantly, depending on the basis for analysis. For example, electrical and steam requirements for commercial processes have been generally shown to increase as follows (lowest to highest): spray drying, sodium carbonate, dual alkali, alkaline ash, lime, limestone, MgO, and Wellman-Lord. The energy requirement as a percentage of new power plant output is often reported to be less than 1 percent for sodium systems, normally about 3 percent for limestone systems (excluding reheat), and even 10 percent for some regenerable units. The problem with comparing the energy consumption required by the FGD system alone is that it does not reflect the energy required to process the reagents or the sludge, nor does it include any by-product energy credit. These energy requirements are reflected in the reagent cost and by-product credits.

A TVA study examined the ground-to-ground energy requirements of three FGD systems. The design basis was a 500 MW unit burning 3.5 percent sulfur coal meeting the 1971 NSPS. Results for the three systems are shown in Table 4. The lime system had the lowest energy requirement if only the FGD system is considered. However, the energy required to calcine limestone into lime (which is reflected in the price of lime) is significant. When all of these energy requirements are considered, the limestone process has the lowest energy requirement. The credit for sulfuric acid in the MgO process reflects the energy required to mine and convert an equivalent amount of elemental sulfur. This credit makes the regenerable process almost as efficient as the lime system. Since spray drying and dual alkali systems use lime, their overall ground-to-ground energy requirements are much closer to the other systems than would be indicated by just comparing the FGD system energy requirement.

Environmental Considerations

The six commercial throwaway FGD systems produce large volumes of waste material requiring disposal. The calcium based sludge from the limestone, lime, alkaline ash, and dual alkali processes are very similar in composition. Typically, this sludge is disposed of in a clay-lined pond. A thickened slurry is pumped to the pond where the solids settle out. Supernatant water is usually returned to the FGD system. Many of the newer plants are using landfilling for disposal. In this practice, the sludge is vacuum filtered or centrifuged to a higher solids content, and mixed with lime and/or fly ash to form a stable mass. In either installation, a liner material is used to prevent ground water contamination due to leachate from the sludge.

Solid waste from spray drying, if lime is used as the reagent, is also similar to the material described above, except that it is a dry powder. However, to dispose of this waste, it is often wetted to increase its compressive strength and to reduce dusting problems. Several research programs are being sponsored by the EPA and EPRI to determine the best methods of disposing of spray drying wastes.

The sodium carbonate process produces a liquid purge stream high in sodium sulfites and sulfates. The plants which use the process, use evaporation ponds to crystallize the salts. This technique is only applicable in arid regions. Pond liners may also be necessary to prevent ground water contamination.

The regenerable processes have a much smaller secondary environmental impact since they produce by-products which are sold to user industries. However, lime and limestone processes may be designed to produce gypsum wall board or other by-products if desired.

Reliability

The reliability of an FGD system is a major concern to utilities operating plants subject to the 1979 NSPS. Older plants and regulations often allowed bypassing flue gas around malfunctioning absorber modules or the entire system. However, the 1979 NSPS has significantly reduced the possibility of bypassing the FGD system except in emergencies. The final standards allow an owner or operator to bypass uncontrolled flue gas around a malfunctioning FGD system if: (1) the FGD system has a built-in spare FGD module, (2) enough FGD modules are not available to treat the entire quantity of flue gas generated, and (3) all available electric generating capacity is being utilized in a power pool or network consisting of the generating capacity of the affected utility company (except for the capacity of the largest single generating unit in the company), and the amount of power that could be purchased from neighboring interconnected utility companies. From the constraints expressed in the third requirement it is evident that utility companies are expected to install reliable FGD equipment. This requirement also places an economic incentive on the utilities to obtain reliable operation from their FGD systems, since the available electric generating capacity will often include uneconomic gas-fired turbines and oil- or gas-fired boilers.

The few operating units regulated by the 1979 NSPS have not experienced enough operating time to determine if they are more reliable than older units.

Table 4. FGD Ground-to-Ground Energy Requirements

	Btu/lb Sulfur Removed		
Function	*Limestone*	*Lime*	*Magnesium Oxide*
Mining	*438*	*356*	*25*
Absorbent Processing	- - -	*6,198*	*161*
Transportation	*176*	*143*	*33*
FGD	*14,042*	*13,165*	*26,387*
Waste Disposal	*22*	*15*	- - -
By-product Credit	- - -	- - -	*(5,491)*
Total	*14,678*	*19,877*	*21,115*
Btu/kWh	*291*	*395*	*420*
% Gross Power Unit Output	*3.2*	*4.4*	*4.7*

Several studies have addressed the reliability of some of the older units. A study by the National Electric Reliability Council (NERC) has categorized causes of outages for 400 MW and larger FGD systems. Results of the study are given in Table 5. As can be seen, two-thirds of the outage time was caused by non-specific FGD technology problems. This indicates that FGD processes often suffer a poor reliability image because of peripheral equipment failures rather than process related problems.

Table 5. *Percent of Plant Outage Time Caused by Specified FGD Component Failure (NERC Data)*

Component	*Percent of Outage Time*
Dampers	28
Duct system, baffles	19
Absorber tower	16
Fans, ID, FD, blades, vibration	17
Mist eliminator	9
Reaction tank	4
Spray pumps	3
External causes	2
Thickener	1
Test programs	1

An FGD data base, maintained for the EPA by PEDCo, contains information on availability and operability of individual plants. The average availability and operability of the commercial FGD processes are presented in Table 6, along with definitions of the two terms. The availability index can be artificially high if the boiler is not in operation although the FGD system could operate. The operability index is a more accurate estimates of the reliability of the various processes since it involves the actual time that the boiler is operated. It can be lowered, however, if a decision is made not to operate the FGD system.

Table 6 indicates that limestone and lime systems are generally the most unreliable processes. However, it is difficult to compare reliability data of various processes because of differences in plant designs and operating requirements. No data are available from plants regulated by the 1979 NSPS. Very few operating systems in the EPA/PEDCo data base have spare modules which increase reliability. Additionally, the design differences make it difficult to compare reliability figures. New units are incorporating design improvements obtained from experience with existing systems. Many of the older limestone and lime systems with poor designs are included in the averages. Their recurring problems reduce the reliability figures for the process. Consequently, the construction of new units should produce a gradual increase in overall process reliability. The effects of a new technology, such as the use of adipic acid with limestone systems, can also significantly improve the reliability of a system. However, it is difficult to quantify in advance the magnitude of reliability increases due to process improvements.

Table 6. *Dependabilities of FGD Systems (March 1981-March 1982)*

Process	*Number of Operating Systems*	*Systems Included in Averages*	*Availability**	*Operability***
Limestone	39	24	73.5	73.8
Lime	24	23	84.1	75.4
Wellman-Lord	7	7	88.5	70.0
Alkaline Ash	9	6	89.3	78.0
Sodium Carbonate	5	4	89.9	87.4
Dual Alkali	3	3	96.2	79.7

** Percentage of hours the FGD system is available for operation (whether used or not) divided by the hours in the period.*

***Percentage of hours the FGD system was operated divided by the boiler operating hours during the period.*

A recent study examined the effect of forced outages of scrubber modules on utility system production costs. Two different utility fuel-mix systems were analyzed. The results indicate that, in many instances, the addition of a second spare module is economically justified. For the system based primarily on coal capacity (49 percent coal, 24 percent oil), module outage time greater than 14 percent favors using a second spare. In the oil-based system,(19 percent coal, 57 percent oil), two spare modules are justified above a 10 percent module forced outage rate. The assumptions used in this study are site specific; however, they do provide an interesting perspective on reliability. However, the most crucial piece of data, the actual module outage rate for a well designed system, is not given.

Economics

The costs of FGD systems are very site specific. Coal composition, degree of control required, and economic bases all have a major influence on the reported or estimated costs. Consequently, the actual cost of a "standard" FGD system can vary considerably, leading to confusion as to what the actual costs are. Several recent reports have estimated the costs of various FGD processes for a standard size plant by examining the various design and economic bases. TVA has published the most recent economic study of limestone and lime systems, using a mid-1982 time basis for capital costs. The standard plant is a 500 MW unit burning 3.5 percent sulfur bituminous coal meeting the 1979 NSPS. A bypass duct capable of handling 50 percent of the flue gas is also included. Although many site specific factors affect the capital cost of an FGD system, four parameters account for most of the cost differences between estimates for a standard size plant and fuel: the estimate date, use of a spare module, bypass ducts, and the SO_2 removal requirement.

Examining the various site-specific cost factors used to estimate the costs of several FGD systems, and adjusting the factors to a common basis, can produce a fairly consistent set of cost estimates. The results of this exercise are shown in Table 7, and in Figures 2 and 3. As shown in Table 7 and Figure 2, the raw (unadjusted) cost estimates reported for six commercial FGD processes vary considerably. However, when these estimates are adjusted to a common basis (Figure 3) the variance in the estimate significantly decreases.

Costs were adjusted, using the Chemical Engineering plant cost index to adjust for inflation. A spare module and associated equipment for a 500 MW unit was assumed to increase capital costs 25 percent. Bypass ducts increased the costs 5 and 10 percent, respectively, for 50 and 100 percent bypass. Increasing the SO_2 removal from the 1971 to the 1979 NSPS was estimated as a 5 percent increase.

As shown in Table 7, the 1982 cost of most of the FGD systems is about $200/kW. The average costs show the same relative rankings as in individual reports which estimate several processes. Lime systems have the lowest capital cost, followed by limestone and dual alkali

Table 7. *Estimates of FGD System Costs*

Process	*Number of Cost Estimates*	*Range of Unadjusted Costs, $/kW*	*Average of Unadjusted Costs, $/kW*	*Range of Adjusted Costs, $/kW*	*Average of Adjusted Costs, $/kW*
Limestone	*5*	*98-206*	*162*	*169-240*	*203*
Lime	*3*	*90-192*	*144*	*155-193*	*180*
Dual Alkali	*2*	*101-166*	*134*	*174-214*	*194*
*Spray Drying**	*3*	*102-200*	*165*	*176-248*	*208*
Wellman-Lord	*4*	*126-267*	*176*	*181-345*	*246*
Magnesium Oxide	*4*	*132-193*	*159*	*195-227*	*220*

**Costs include a baghouse for particulate control. An ESP would be used for the other FGD systems ($38/kW) but was not included in the process cost estimates.*

processes. The regenerable systems are 20-30 percent higher. The spray drying systems include integral particulate control, and have an average cost of $208/kW. ESPs for the other processes will add about 20 percent to the total air pollution control equipment cost. Note that the designs of the spray drying units have not been successfully demonstrated for high-sulfur coal.

The annual costs of the different FGD processes depend as much on capital charges as fixed and variable operating costs. There are too many variables (reagent costs, interest rates, labor rates, operating profile return on investment (ROI), etc.) to use a simplistic approach to present standardized annual costs as was done for the capital costs. In individual reports using the same bases, limestone and spray drying are usually the least expensive, followed by lime and dual alkali, and then, the regenerable systems.

The EPA/PEDCo utility FGD survey compiles reported cost data on operating systems and adjusts the costs to a common basis. Averages of the different processes are shown in Table 8. The low sulfur systems have the lowest capital and operating costs. The high sulfur limestone, lime, and dual alkali units all cost between $140 and $150/kW. Since these are operating systems, they are predominantly units designed for the 1971 NSPS, with no spare modules or bypass ducts and a lower SO_2 removal requirement. Using the previous cost multipliers results in a 1982 cost of $200-220/kW, which is very close to the estimated costs previously presented. As can be seen, when the costs are placed on a common basis, they agree very well.

SO_2 Removal Test Results

Before promulgation of the 1979 NSPS, the EPA performed emission tests on various types of FGD systems. These units were built to meet the 1971 NSPS

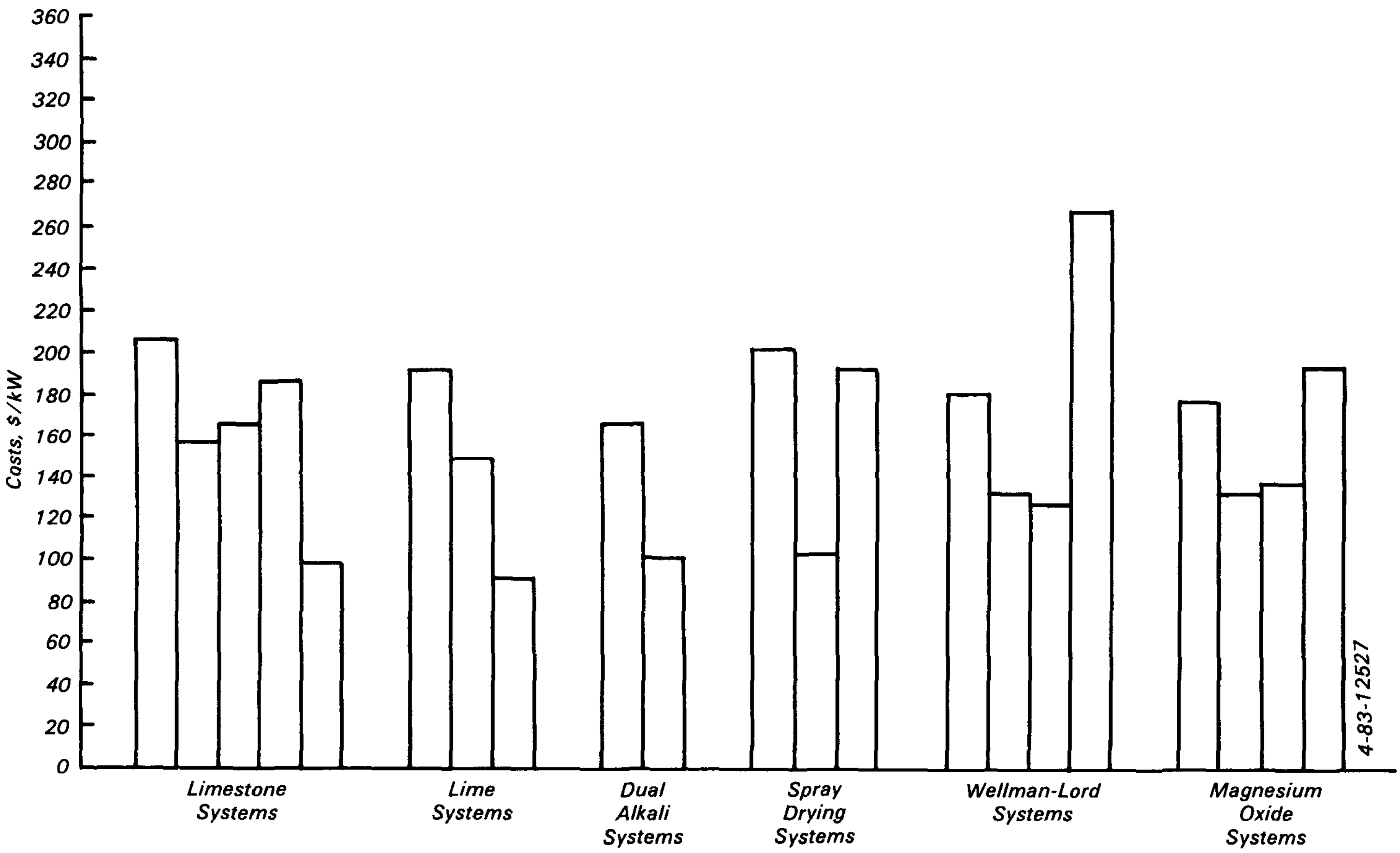

Figure 2. *Raw estimates of FGD system costs.*

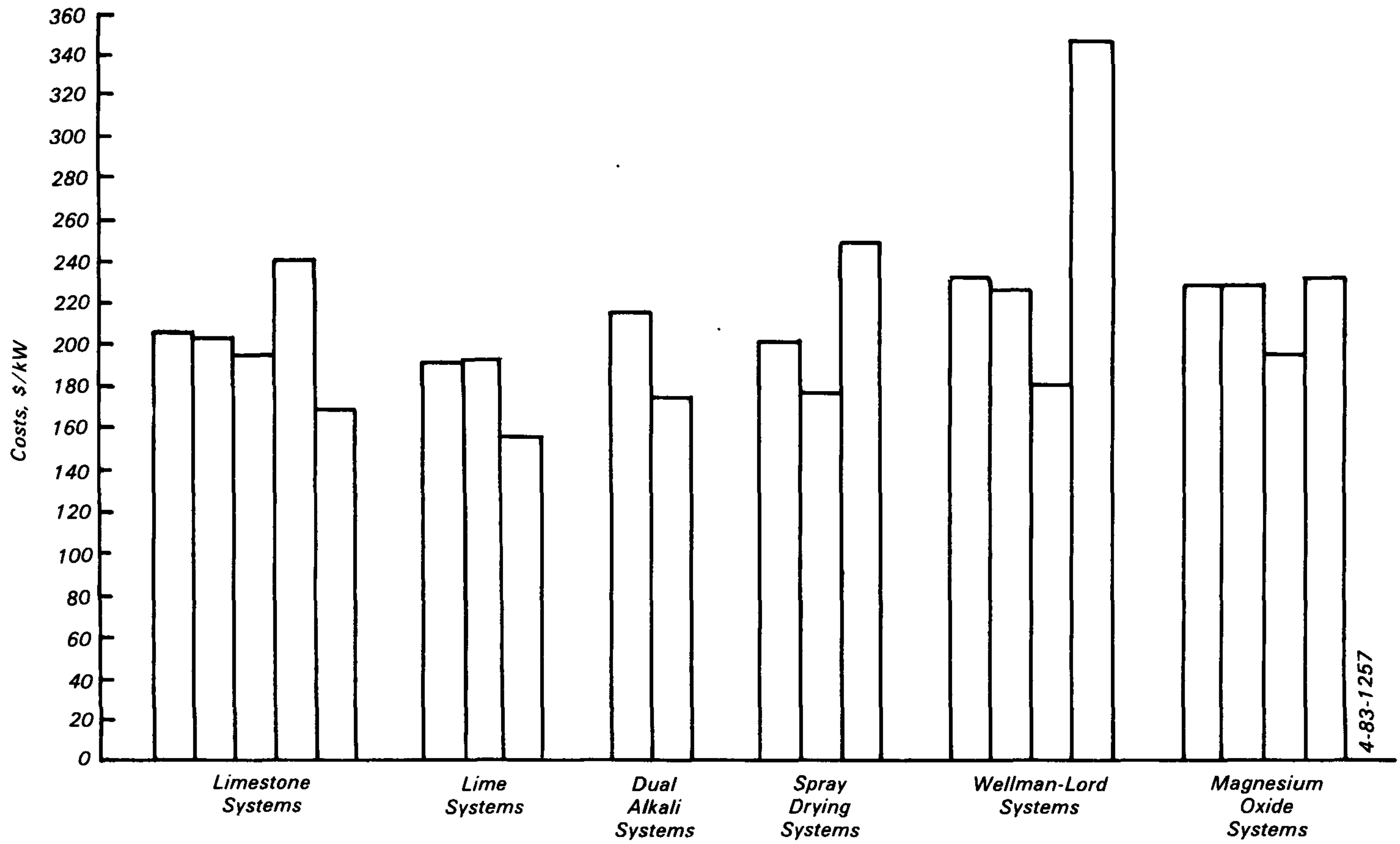

Figure 3. *FGD system cost estimates adjusted to consistent basis.*

Table 8. *Average Costs of Operating FGD Systems (1981 Dollars)*

Process	*Number of Units*	*Capital Cost $/kW*	*Annual Cost mills/kWh*
*Limestone-Low Sulfur**	*16*	*79*	*4.8*
Lime-Low Sulfur	*5*	*72*	*5.1*
Sodium Carbonate	*4*	*111*	*6.4*
Alkaline Ash	*7*	*118*	*6.7*
Dual Alkali	*3*	*147*	*8.7*
*Limestone-High Sulfur***	*7*	*149*	*9.2*
Lime-High Sulfur	*15*	*141*	*10.5*
Wellman-Lord	*3*	*272*	*18.1*

** Low sulfur - < 1.5 percent.*
***High sulfur - > 1.5 percent.*

or state standards, which were not as stringent as the current NSPS. However, many of the units tested meet the 1979 NSPS, or are very close to satisfying its requirements. Based on these test results, EPA set the new standard at a level attainable by current technology. The sites tested and test results are shown in Table 9. In addition, a comment column indicates the SO_2 removal level that would be required for each site to achieve compliance with the 1979 NSPS. As can be seen, 7 of the 13 units built under more lenient standards meet the current NSPS. Several of the other units were within a few percentage points of meeting the standard. Consequently, designing and operating an FGD system to meet the 1979 NSPS required only a moderate advance in the status of FGD technology.

Two readily apparent deficiencies in the continuous emission monitoring results data base need to be recognized: (1) the limestone systems tested were not typical of those being designed and built, predominantly using spray towers; and (2) the growing acceptance of spray drying by the utility industry indicates that a number of these units should also be tested.

Conclusions

The 1979 NSPS for utility boilers requires FGD systems on all new coal-fired boilers. Since initial promulgation on September 18, 1978, 73 FGD systems representing over 35,000 MW of capacity have been constructed, contracted, or planned by the utility industry. In the previous seven years, 48,000 MW (117 units) had been built with FGD systems.

Table 9. FGD System Continuous Emission Monitoring Results

Process	Unit	SO_2 Removal Efficiency percent	Emission Rate lb $SO_2/10^6$ Btu	Comments
Limestone	Shawnee V/ST*	96.1	0.22	meets 1979 NSPS
	Lawrence 4	96.6	0.03	meets 1979 NSPS
	Southwest 1	>90	<0.64	meets 1979 NSPS
Lime	Cane Run 4	83.8	0.88	88.8% removal needed for 1979 NSPS
	Conesville 5	89.2	0.80	90.0% removal needed for 1979 NSPS
	Bruce Mansfield 1	85.3	0.78	88.5% removal needed for 1979 NSPS
	Shawnee TCA	88.6	0.64	89.3% removal needed for 1979 NSPS
	Pleasants 1	>90	<0.50	meets 1979 NSPS
Dual Alkali	A.B. Brown 1	87.7	0.85	90.0% removal needed for 1979 NSPS
	Cane Run 6	91.6	0.70	meets 1979 NSPS
Wellman-Lord	D.H. Mitchell 11	89.6	0.60	meets 1979 NSPS
Magnesium Oxide	Eddystone 1A	96.8	0.16	meets 1979 NSPS
Spray Drying	Celanese Amcelle†	70.0	0.92	80.4% removal needed for 1979 NSPS

**Units tested with adipic acid additive.*
†Industrial boiler, utility SO_2 NSPS not directly comparable.

Since the promulgation of the 1979 NSPS, the wet limestone FGD process has been selected for nearly two-thirds of the future plants. The predominance of this process is due to its technical flexibility and favorable economics. Improvements in reliability and efficiency (due to the use of spray towers, forced oxidation, and SO_2 removal enhancement additives) enable the limestone process to be used in many applications.

The use of spray drying to control SO_2 and particulates from lower sulfur coal is the only other technology to be widely favored in the industry. Many commercial spray drying systems will soon be on-line demonstrating this technology. The other throwaway systems (lime, dual alkali, alkaline ash, sodium carbonate) will probably be used infrequently at new plants. Higher reagent costs are the primary reason for the lack of new orders for these systems. The regenerable systems, due to their higher costs, will probably be used only in specialized applications; e.g., land-restricted sites and those with favorable SO_2 regeneration opportunities.

Conversion Factors

Nonmetric	Times	Equals Metric
Btu	1055	J
Btu/lb	2326	J/kg
lb/10^6 Btu	430	ng/J

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The complete report, entitled "The Current Status of Commercial Utility Flue Gas Desulfurization Systems," (Order No. PB 84-133 016; Cost: $20.50, subject to change) will be available only from:
National Technical Information Service
5285 Port Royal Road
Springfield, VA 22161
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