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EFFECTS OF ALTERNATIVE NEW SOURCE PERFORMANCE STANDARDS ON FLUE GAS DESULFURIZATION SYSTEM SUPPLY AND DEMAND

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ABSTRACT

This report assesses the capability of flue gas desulfurization (FGD) system manufacturers to provide the necessary equipment to control sulfur dioxide emissions from new coal-fired steam generators. This assessment was made by estimating the total electrical capacity of new coal-fired boilers and then determining the FGD system manufacturers' capability to design, supply, and install the necessary equipment.

In addition, factors that limit this capability, such as labor supply and availability of key equipment components, were also investigated. Information on system guarantees is also presented.

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SUMMARY

This report presents data on the capability of flue gas desulfurization (FGD) system manufacturers to provide the necessary equipment to control sulfur dioxide emissions from new coal-fired steam generators as required by hypothetical revised New Source Performance Standards (NSPS). The assessment was made by first estimating the total electrical capacity of new coal-fired boilers (largely on the basis of Federal Power Commission data), then surveying the FGD system manufacturers to determine to what extent they are capable of designing, supplying, and installing the necessary equipment.

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 such units, approximately 510,000 MW of coal-fired boiler capacity will be built between 1978 and the year 2000. The hypothetical alternative standards assumed in this study indicate that all of these new units will require FGD systems. The distribution of types of FGD processes for these new boilers was projected on the basis of FGD systems already planned, which

shows that limestone scrubbing systems will account for 52 percent of the installations; lime systems 25 percent; and lime/fly ash systems 13 percent. The balance will be made up of double alkali, sodium-based, and regenerable systems. While this projection of system types is rather crude, it is adequate for the purpose of assessing FGD equipment and personnel requirements.

The responses from the 13 FGD system manufacturers surveyed indicate that 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.

Shortages in specialized construction personnel are a possibility, however, and shortages in large scrubber modules are also predicted by several of the suppliers.

1.0 INTRODUCTION

The U.S. Environmental Protection Agency (EPA) has undertaken a program to review the New Source Performance Standards (NSPS) regulating emission of sulfur dioxide (SO_2) from new utility coal-fired steam generators. To perform this review, EPA needs to know what effects NSPS revisions will have on the ability of manufacturers to meet the demand for flue gas desulfurization (FGD) systems for the utility industry.

For consideration in this evaluation, the EPA specified hypothetical regulations of 215.2 nanograms of SO_2 per joule (0.5 pound per 10^6 Btu) of heat input to the steam generator or an alternative standard of 90 percent overall reduction of potential SO_2 emissions. This report presents the results of an assessment of the capabilities of manufacturers to meet the demand for FGD systems required to achieve the alternative standards.

Section 2 presents forecasts of coal-fired utility capacity additions through the year 2000 and the anticipated demand for FGD systems under present NSPS and the hypothetical alternative standards. Section 3 includes the results of a survey of the manufacturers of FGD systems regarding their capabilities, guarantees, and other factors affecting their ability to design and construct FGD systems for utilities that meet the present or the hypothetical alternative standards up to the year 1992. Section 4 contains an assessment of manpower availability for the installation of FGD systems on utility boilers and time schedules for their construction.

2.0 PROJECTED CAPACITY OF UTILITY COAL-FIRED UNITS AND RESULTANT DEMAND FOR FLUE GAS DESULFURIZATION SYSTEMS

To assess the impact of revising the NSPS, one must determine the number and capacity of planned coal-fired units affected. Several sources of data are available regarding planned coal-fired utility power plants. Because the Federal Power Commission (FPC) has primary responsibility for regulation of the power industry, they are a source of extensive data. Data on planned unit additions from the FPC Electric Utility Information File include ownership, location, size, fuel type, capacity, scheduled start-up dates, and planned pollution control equipment. These data were used to develop a list of planned coal-fired units through the year 2000. Additional data were obtained from a Federal Energy Administration (FEA) listing of projected power plants,[1] a report by Kidder, Peabody and Co., Inc., entitled "Fossil Boilers, A Status Report on Electric Utility Generating Equipment,"[2] and a PEDCo Environmental, Inc., report entitled "Summary Report - Flue Gas Desulfurization Systems, May-June 1977."[3] (The results, tabulated by state and U.S. EPA Region, are presented in Appendix A.) Scheduled year of start-up, ownership, unit name or identification, capacity, coal type, and planned particulate and SO_2 control methods are listed for each unit. These data are summarized in Table 2-1, which presents, by year, the number and capacity of currently planned units. The data in this table reflect only units for which specific data were available. Data on units planned after 1986 are insufficient and do not account for all the capacity projected to meet future electricity needs. It appears that the utilities have not projected their plans for specific units that far in advance because so many factors must be taken into account before definite plans are formulated for a power plant.

Because of the lack of data, it was necessary to assume a growth rate of coal-fired units to project capacities beyond 1986. An FPC News Release on December 8, 1976, presented a staff report on electric utility expansion plans for 1986 to 1995. This report contained a forecast of an annual growth rate of 5.56 percent in electric generation capability through 1995. This represented all types of generating capacity, including nuclear, hydroelectric, turbine, and fossil-fuel-fired. FPC estimates 50.3 percent of the generating capacity will be fossil-fuel-fired by 1995. In 1975 FPC estimated that 69.7 percent of the gen-

Table 2-1. PLANNED NUMBER OF COAL-FIRED BOILERS AND THEIR CAPACITIES THROUGH THE YEAR 2000

Year	No. of Boilers	Capacity, MW
1977	26	12,938
1978	29	11,948
1979	31	13,196
1980	36	19,739
1981	30	15,509
1982	32	15,331
1983	31	17,216
1984	31	16,319
1985	37	19,519
1986	12	6,433
1987	9	6,025
1988	6	3,950
1989	3	1,975
1990	4	2,700
1991	1	800
1992	0	0
1993	2	1,150
1994	1	300
1995	0	0
1996	0	0
1997	0	0
1998	0	0
1999	0	0
2000	0	0

erating capacity at that time was fossil-fuel-fired, but did not indicate what portion was coal-fired. To project coal-fired capacity, it was assumed that the growth rate of coal-fired units would be approximately the same as the growth rate of the overall capacity (5.56%). Although the percentage of fossil-fuel-fired units is expected to decrease, the portion of fossil-fuel-fired capacity comprised of coal-fired units will increase because of the scarcity of oil and natural gas. Figure 2-1 graphically illustrates the capacity of the projected coal-fired units by applying a 5.56 percent growth rate as compared with the cumulative capacity of known coal-fired units and planned additions. Planned additions appear to be sufficient through 1987 for the projected demand, but more capacity will be needed after 1987 than that presently planned. The projected coal-fired capacity additions presented in Table 2-2 are based on differences between the assumed 5.56 percent growth of coal-fired capacity and the coal-fired additions that are known to be planned.

Table 2-3 presents coal-fired capacity additions including both the units known to be planned and the additional ones necessary to meet the demand predicted by FPC through the year 2000. The capacity additions predicted for 1986 and 1987 appear small compared to additions for other

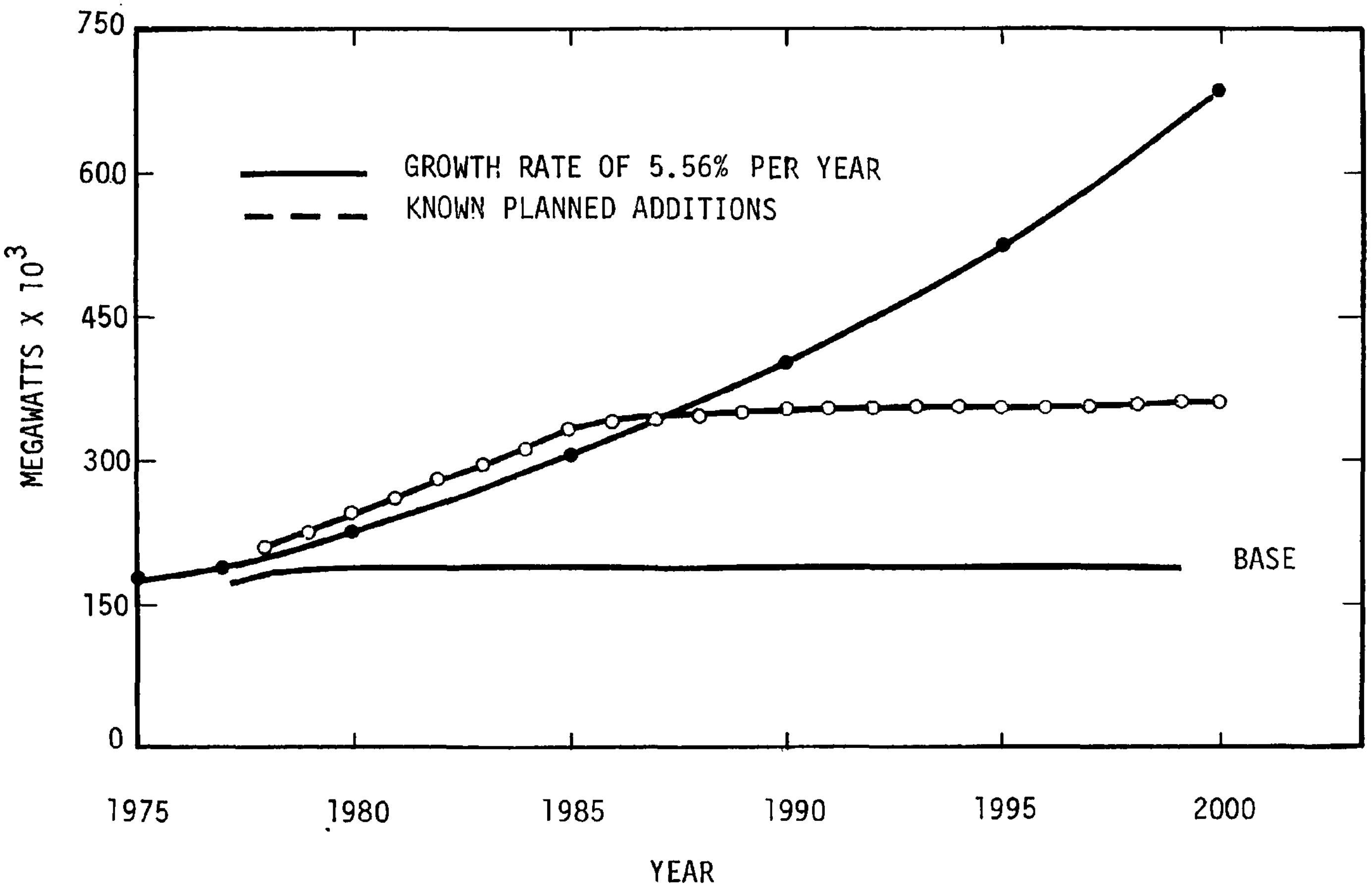


Figure 2-1. Coal-fired capacity growth rate predictions.

Table 2-2. DIFFERENTIAL CAPACITY TO BE ADDED TO COAL-FIRED UNITS KNOWN TO BE PLANNED

Year	Cumulative capacity of planned coal-fired units, MW x 10^3	Cumulative capacity of projected coal-fired units based on 5.56% growth, MW x 10^3	Cumulative difference, MW x 10^3	Additional capacity required MW x 10^3
1987	345	345	0	0
1988	349	364	15	15
1989	351	385	34	19
1990	354	406	52	18
1991	355	429	74	22
1992	355	453	98	24
1993	356	478	126	28
1994	356	505	149	23
1995	356	533	177	28
1996	356	563	207	30
1997	356	595	239	32
1998	356	628	272	33
1999	356	663	307	35
2000	356	700	344	37

Table 2-3. PROJECTED COAL-FIRED CAPACITY ADDITIONS THROUGH THE YEAR 2000

Year[a]	Total projected and planned capacity additions, MW
1978	11,950
1979	13,100
1980	19,700
1981	15,500
1982	15,300
1983	17,200
1984	16,300
1985	19,500
1986	6,400
1987	6,000
1988	19,000
1989	21,000
1990	21,000
1991	24,000
1992	24,000
1993	29,000
1994	23,000
1995	28,000
1996	30,000
1997	32,000
1998	33,000
1999	35,000
2000	37,000

[a] 1978 to 1987 are currently planned (see Table 2-1). 1988 to 2000 are projected capacity requirements.

years. The data for these two years reflect the uncertainty of known planned units this far in the future. Since the growth rate of known units exceeds the assumed 5.56 percent growth rate predicted by FPC, no additional units were assumed for 1986 and 1987, thus the apparent incongruity for these two years.

Availability of control technology to enable compliance with the required emission levels also must be considered in revising NSPS. Coal-fired boilers can attain compliance with current NSPS by several methods--burning low-sulfur coal, washing selected coals, applying flue gas desulfurization, and combinations of these methods. FPC's Electric Utility Information File and PEDCo Environmental's "Summary Report - Flue Gas Desulfurization Systems, May, June 1977"[4] indicate that flue gas desulfurization is a primary control method planned for new coal-fired units. According to these references, a sufficient number of FGD systems will be installed by the end of 1987 to serve approximately 60,000 MW of capacity on new coal-fired utility boilers. Table 2-4 presents planned FGD capacity additions through the year 2000.

As indicated in Table 2-4, the percentage application of planned FGD units drops drastically beyond 1980. This does not necessarily mean that more utilities plan to fire

Table 2-4. PLANNED UTILIZATION OF FLUE GAS DESULFURIZATION SYSTEMS ON FUTURE COAL-FIRED BOILERS

Year	Planned coal-fired capacity additions, MW	Planned utilization of FGD under present NSPS, MW	Percentage using FGD, %
1977	12,938	10,359	80
1978	11,948	10,204	85
1979	13,196	8,271	63
1980	19,739	11,190	57
1981	15,509	4,975	32
1982	15,331	8,010	52
1983	17,216	4,223	25
1984	16,319	2,146	13
1985	19,519	1,115	6
1986	6,433	0	0
1987	6,025	0	0
1988	3,950	500	13
1989	1,975	0	0
1990	2,700	0	0
1991	800	0	0
1992	0	0	0
1993	1,150	350	30
1994	300	0	0
1995	0	0	0
1996	0	0	0
1997	0	0	0
1998	0	0	0
1999	0	0	0
2000	0	0	0

low-sulfur coal to attain compliance; rather it indicates a lack of a commitment by the utilities to a specific control technique. Many factors can change during the construction of a power boiler, such as the cost of low-sulfur coal, the state of development of a particular FGD system, applicable regulations, and other economic and technological factors that have a bearing on the attractiveness of particular control options. These unknowns make utilities reluctant to commit themselves to a particular control technique too far in advance.

Approximately 3 years lead time is required for application of an FGD system on a coal-fired utility boiler (discussed in Section 4.0). It is assumed, therefore, that units coming on line through 1980 are definitely committed to a particular SO_2 control strategy. The application of FGD in 1979 and 1980 is planned for about 60 percent of the units representing coal-fired capacity. This should provide a good approximation of the extent of FGD application under the present NSPS.

For purposes of this study, EPA has proposed the following alternatives as hypothetical NSPS revisions: (1) 90 percent reduction of SO_2 emissions regardless of the sulfur content of the coal, and (2) an emission level of 215.2 nanograms SO_2 per joule (0.5 pounds of SO_2 per 10^6 Btu) of heat input. If alternative (1) is adopted as the standard, the overall effect would be the installation of FGD on all new units subject to this regulation. Alternative (2) would have essentially the same effect because coal reserves are inadequate to meet such a standard. Therefore, for either alternative it can be assumed that FGD will be required for all new coal-fired units. Table 2-5 presents anticipated FGD usage under present NSPS and under hypothetical NSPS revisions.

Several types of FGD systems are available for utility-size boilers (discussed in Section 3). Utilities usually have selected the process for FGD installations planned through 1980, but they have not decided upon a specific type of process for FGD systems installed after 1980. To evaluate the types of FGD systems required in the future, some assumptions must be made regarding distribution. Table 2-6 presents a percentage distribution of different FGD processes based on currently planned FGD systems on new units[5] and on the assumption that all New England (U.S. EPA Region I) utilities will use regenerable systems. This distribution assumption was applied to new units through the year 2000 and used to arrive at the FGD capacity requirements, by process, for present NSPS and hypothetical revised standards (as presented in Table 2-7).

Table 2-5. PROJECTED UTILIZATION OF FLUE GAS DESULFURIZATION ON NEW COAL-FIRED UNITS

Year	Total projected capacity additions, MW	Projected utilization of FGD under present NSPS,[a] MW	Total projected utilization of FGD under a 0.5 lb $SO_2/10^6$ Btu or 90% control regulation,[b] MW
1978	11,950	10,200	11,950
1979	13,100	8,300	13,100
1980	19,700	11,200	19,700
1981	15,500	9,300	15,500
1982	15,300	9,200	15,300
1983	17,200	10,300	17,200
1984	16,300	9,800	16,300
1985	19,500	11,700	19,500
1986	6,400	3,800	6,400
1987	6,000	3,600	6,000
1988	19,000	11,400	19,000
1989	21,000	12,600	21,000
1990	21,000	12,600	21,000
1991	24,000	14,400	24,000
1992	24,000	14,400	24,000
1993	29,000	17,400	29,000
1994	23,000	13,800	23,000
1995	28,000	16,800	28,000
1996	30,000	18,000	30,000
1997	32,000	19,200	32,000
1998	33,000	19,800	33,000
1999	35,000	21,000	35,000
2000	37,000	22,200	37,000

[a] Figures after 1980 reflect an assumed 60% utilization of FGD.
[b] Based on 100% of utilization of FGD on new coal-fired boilers shown in Table 2-3.

Table 2-6. APPROXIMATE PROCESS DISTRIBUTION OF PLANNED FGD SYSTEMS ON NEW COAL-FIRED UTILITY BOILERS

FGD process	Percent application to new units, %
Nonregenerable	
Lime scrubbing	25
Lime/alkaline flyash scrubbing	13
Limestone scrubbing	52
Double alkali	3
Sodium carbonate	2
Regenerable	
Sodium solution	3
Magnesium oxide	2

Table 2-7. FGD CAPACITY REQUIREMENTS BY PROCESS FROM 1978 TO 2000

Regulation: 516.5 ng SO_2/J (1.2 lb $SO_2/10^6$ Btu)

Year	Capacity by FGD process, MW						
	Lime	Lime/flyash	Limestone	Double alkali	Sodium carbonate	Sodium solution	Magnesium oxide
1978	2550	1326	5304	306	204	306	204
1979	2075	1079	4316	249	166	249	166
1980	2800	1456	5824	336	224	336	224
1981	2325	1209	4836	279	186	279	186
1982	2300	1196	4784	276	184	276	184
1983	2575	1339	5356	309	206	309	206
1984	2450	1274	5096	294	196	294	196
1985	2925	1521	6084	351	234	351	234
1986	950	494	1976	114	76	114	76
1987	900	468	1872	108	72	108	72
1988	2850	1482	5928	342	228	342	228
1989	3150	1638	6552	378	252	378	252
1990	3150	1638	6552	378	252	378	252
1991	3600	1872	7488	432	288	432	288
1992	3600	1872	7488	432	288	432	288
1993	4350	2262	9048	522	348	522	348
1994	3450	1794	7176	414	276	414	276
1995	4200	2184	8736	504	336	504	336
1996	4500	2340	9360	540	360	540	360
1997	4800	2496	9984	576	384	576	384
1998	4950	2574	10296	594	396	594	396
1999	5250	2730	10920	630	420	630	420
2000	5550	2886	11544	666	444	666	444

Table 2-7 (continued). FGD CAPACITY REQUIREMENTS BY PROCESS FROM 1978 TO 2000

Regulation: 215.2 ng/J (0.5 lb $SO_2/10^6$ Btu) or 90% SO_2 removal

Year	Capacity by FGD process, MW						
	Lime	Lime/flyash	Limestone	Double alkali	Sodium carbonate	Sodium solution	Magnesium oxide
1978	2988	1554	6214	359	239	359	239
1979	3275	1703	6812	393	262	393	262
1980	4925	2561	10,244	591	394	591	394
1981	3875	2015	8060	465	310	465	310
1982	3825	1989	7956	459	306	459	306
1983	4300	2236	8944	516	344	516	344
1984	4075	2119	8476	489	326	489	326
1985	4875	2535	10,140	585	390	585	390
1986	1600	832	3328	192	128	192	128
1987	1500	780	3120	180	120	180	120
1988	4750	2470	9880	570	380	570	380
1989	5250	2730	10,920	630	420	630	420
1990	5250	2730	10,920	630	420	630	420
1991	6000	3120	12,480	720	480	720	480
1992	6000	3120	12,480	720	480	720	480
1993	7250	3770	15,080	870	580	870	580
1994	5750	2990	11,960	690	460	690	460
1995	7000	3640	14,560	840	560	840	560
1996	7500	3900	15,600	900	600	900	600
1997	8000	4160	16,640	960	640	960	640
1998	8250	4290	17,160	990	660	990	660
1999	8750	4550	18,200	1050	700	1050	700
2000	9250	4810	19,240	1110	740	1110	740

These projections provide a basis for making economic and environmental impacts, and also for estimating the capabilities of equipment manufacturers to meet this demand (discussed in the next section).

REFERENCES FOR SECTION 2

1. Inventory of Power Plants in the United States. June 1977. Federal Energy Administration. Washington, D.C. pp. 311-344.

2. Fossil Boilers, A Status Report on Electric Utility Generating Equipment. Kidder Peabody & Co., Inc.

3. Summary Report - Flue Gas Desulfurization Systems - May-June 1977. PEDCo Environmental, Inc.

4. Ibid. p. 215.

5. Ibid.

3.0 CAPABILITIES OF MANUFACTURERS TO PRODUCE FGD SYSTEMS

This section contains an assessment of the capabilities of manufacturers to supply and install the FGD systems required to meet present and alternative New Source Performance Standards. The assessment includes an evaluation of the availability of individual components required in FGD systems, and conditions of the guarantees manufacturers are willing to offer. To provide information related to the evaluation, two separate surveys were conducted in which projections were requested to the year 1992.

3.1 SURVEY OF FGD MANUFACTURERS

In the first survey, 18 representative manufacturers of FGD systems were contacted. Thirteen of the 18 responded by either completing or partially completing the survey form. Table 3-1 lists these 13 and the FGD systems they market.

Basically, FGD systems fall into two classes: regenerative and nonregenerative. A regenerative flue gas desulfurization system removes the SO_2 from flue gas and converts it to a marketable by-product, usually, elemental sulfur, sulfuric acid, or a concentrated SO_2 gas stream. Examples of regenerative processes include magnesium oxide

Table 3-1. MANUFACTURERS RESPONDING TO THE FLUE GAS DESULFURIZATION SYSTEM SURVEY AND THE PROCESS OFFERED BY EACH

Manufacturer	Type of FGD System Offered										
	Regenerative system					Nonregenerative system					
	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					

(MgO) scrubbing, the Wellman-Lord process, the citrate process, the phosphate process, and the catalytic oxidation system.

A nonregenerative system removes the SO_2 from flue gas by reacting it with a compound that produces a sludge as the product of reaction. The sludge must be disposed of in an environmentally sound manner. The various processes of the nonregenerative type include lime scrubbing, limestone scrubbing, the sodium carbonate process, the double alkali process, and the Chiyoda Thoroughbred 101 process.

Table 3-2 summarizes the cumulative number and capacity of FGD systems that manufacturers can design and install over three 5-year periods. These figures include estimates with their present staff and with an expanded staff under conditions of high market demand.

The manufacturers were also asked to identify the sources of personnel to perform various stages of FGD system design and installation. Table 3-3 summarizes the information they provided.

In addition, the surveyed manufacturers were requested to estimate the time required to design, install, and start up the systems they offer. Table 3-4 presents the average and range of time required to design, install, and start up FGD systems of various sizes.

Table 3-2. NUMBER AND CAPACITY OF FGD SYSTEMS THAT MANUFACTURERS CAN DESIGN AND INSTALL OVER A 15-YEAR PERIOD[a]

	Five-year period (inclusive)					
	1978-1982		1983-1987		1988-1992	
Systems designed[b]	Present staff	Expanded staff	Present staff	Expanded staff	Present staff	Expanded staff
Number	936	1,639	992	1,902	1,106	1,959
Capacity, MW	205,710	371,500	212,885	421,890	218,540	434,990
Systems installed[b]						
Number	699	1,135	797	1,435	828	1,475
Capacity, MW	144,285	238,455	160,510	293,365	166,190	303,940

[a] Represents the responses of 12 manufacturers. The capability shown in this table refers to both regenerative and nonregenerative systems.

[b] The difference between the number of systems designed and the number installed results from the long lead time required for installation of FGD systems.

Table 3-3. SOURCES OF PERSONNEL TO ACCOMPLISH VARIOUS STAGES OF FGD SYSTEM DESIGN AND INSTALLATION[a,b]

Item	No. of manufacturers using in-house personnel	No. of manufacturers using outside labor
Process design	12	1
Detailed engineering design	11	3
Equipment fabrication		
Scrubber vessels/tanks	4	9
Fans/pumps	1	11
Sludge disposal	0	11
System installation		
Supervision	10	3
Crafts	1	11

[a] Some manufacturers indicated that they use both in-house personnel and outside labor to accomplish the different stages of FGD system design and installation.

[b] Represents the responses of 12 manufacturers.

Table 3-4. TIME REQUIRED FOR FGD SYSTEM DESIGN, INSTALLATION, AND START-UP[a]

Size, MW	Time required for design and installation		Time required for start-up[b]	
	Average	Range	Average	Range
<100	22.2 months	6 months to 36 months	1.8 months	0.5 months to 6 months
100-400	24.4 months	8 months to 36 months	2.3 months	0.5 months to 6 months
400-800	30.1 months	18 months to 42 months	2.4 months	0.5 months to 7 months
>800	33.1 months	20 months to 42 months	2.7 months	0.5 months to 7 months

[a] Represents the responses of 12 manufacturers.

[b] "Start-up" is defined as the time between completion of plant construction and when plant is capable of operating at an acceptable level of capacity.

In response to a request that they identify items that could frequently delay installation schedules, the manufacturers furnished lead times and delay frequencies for various items, as shown in Table 3-5. Equipment installation delays apparently effect project completion frequently.

The manufacturers responding to the FGD survey reported ample availability of raw materials used in their FGD systems. Lime and limestone are the most widely used raw materials for FGD systems. The total amount of lime and limestone production in the U.S. in 1976 amounted to 18.3 million Mg (20.2 million tons) and 601.4 million Mg (662.9 million tons), respectively.[+] If all new FGD systems used limestone, approximately 18 million Mg (20 million tons) would be required in addition to current demand by 1985. Table 3-6 shows the raw material specifications for five different FGD systems.

The manufacturers were asked to supply information on by-products generated by each type of FGD systems. Table 3-7 summarizes this information.

3.2 ASSESSMENT OF FGD MANUFACTURERS' CAPABILITIES VERSUS PROJECTED DEMAND

As indicated earlier, FGD manufacturers were queried as to their capacity to supply FGD systems for the time period 1978 through 1992 (Table 3-2). The demand for FGD systems

[+] National Lime Association, Washington, D.C.

Table 3-5. LEAD TIME AND DELAY FREQUENCY OF VARIOUS ITEMS IN THE DESIGN AND INSTALLATION OF AN FGD SYSTEM

Item	Average lead time, months[a]	Number of manufacturers replying[b]				
		Critical path item		Delay frequency		
		Yes	No	High	Average	Low
Process design	2.6	8	2	1	4	5
Detailed engineering design	8.6	9	1	1	6	3
Equipment fabrication						
° Structural steel	6.0	4	6	0	6	4
° Scrubber vessel/tanks	7.6	7	3	2	4	4
° Fans	11.4	10	0	2	6	2
° Pumps	9.4	3	7	2	5	3
° Instrumentation	8.3	2	8	4	3	3
° Motors	8.0	4	6	2	4	4
° Piping	7.2	7	3	0	9	1
Equipment installation	12.5	9	1	5	4	1
Reactant procurement (e.g., limestone)	2.0	1	9	0	5	5

[a] Represents the responses of 9 manufacturers.

[b] Represents the responses of 10 manufacturers.

Table 3-6. RAW MATERIAL SPECIFICATIONS FOR VARIOUS FGD SYSTEMS

FGD system	Raw materials	
	Type	Specifications
1. Lime	Calcium oxide	90% CaO
2. Limestone	Calcium carbonate	90% $CaCO_3$
3. Magnesium oxide	Magnesium oxide	98.5% MgO
4. Double alkali	Sodium carbonate	98% Na_2SO_3
5. Wellman-Lord	Caustic soda	50% NaOH in water

TABLE 3-7. SUMMARY OF BY-PRODUCTS FROM FLUE GAS DESULFURIZATION SYSTEMS

Item	Regenerable system	Nonregenerable system
By-products	S, SO_2 and H_2SO_4	$CaSO_4$ (Sludge)
Quantity	a	2.47 kg dry per kg SO_2 (2.47 lb dry per lb SO_2) removed (Average) 1.8 to 4 kg dry per kg SO_2 (1.8 to 4 lb dry per lb SO_2) removed (Range)
Utilization/ disposal technique	Sold to other industries	Landfilled

[a] The manufacturers were not asked to supply this information.

under present regulations was determined in Section 2 (Table 2-5). In Table 3-8, manufacturing capability is compared with the projected market demand from 1978 to 1992. The manufacturers appear to have more than sufficient capacity to install FGD systems required under present NSPS.

Table 3-8. COMPARISON OF SUPPLY VERSUS DEMAND FOR FGD SYSTEMS ON NEW COAL-FIRED UTILITY BOILERS UNDER PRESENT NSPS

Time period	FGD manufacturers' capability with present staff, MW[a]	Projected demand, MW[b]	Differential capacity, MW
1978-1982	205,710	48,200	+ 157,510
1983-1987	212,885	39,200	+ 173,685
1988-1992	218,540	65,400	+ 153,140
Total	637,135	152,800	484,335

[a] From Table 3-2. These are largely lime and limestone systems.
[b] From Table 2-5.

If the NSPS were revised to more stringent levels such as 215.2 ng SO_2/J (0.5 lb $SO_2/10^6$ Btu) or 90 percent SO_2 emission reduction, the demand for FGD systems would be greatly increased. Manufacturers would, of necessity, expand their staffs to cope with this high market demand. Table 3-9 presents a comparison of the projected demand for FGD under more stringent NSPS regulations versus the capability of FGD manufacturers to supply systems under high market demand conditions. The data indicate that the manufacturers believe they can supply all of the projected demand for systems under conditions that would require every new coal-fired power plant to have an FGD system.

Table 3-9. COMPARISON OF SUPPLY VERSUS DEMAND FOR FGD SYSTEMS ON COAL-FIRED UTILITY BOILERS UNDER MORE STRINGENT NSPS

Time period	FGD manufacturers' capability with expanded staff, MW[a]	Projected demand, MW[b]	Differential capacity, MW
1978-1982	371,500	75,550	+ 295,950
1983-1987	421,890	65,400	+ 356,490
1988-1992	434,990	109,000	+ 325,990
Total	1,228,380	249,950	978,430

[a] From Table 3-2. These are largely lime and limestone systems.
[b] From Table 2-5.

3.3 ASSESSMENT OF GUARANTEES BY FGD MANUFACTURERS

The results of the survey indicate that in most cases the manufacturers are willing to guarantee 90 percent SO_2 removal. Many of the same manufacturers are prepared to guarantee better than 90 percent SO_2 removal on a case-by-case basis. The levels of SO_2 removal guarantees offered by manufacturers are briefly summarized in Table 3-10. Terms of the guarantees were not disclosed by manufacturers.

Table 3-10. GUARANTEES OFFERED BY MANUFACTURERS FOR SO_2 REMOVAL

Company[a]	Level of SO_2 removal guaranteed		
	<90	90%	>90%
A		Minimum guarantee given	Is willing to offer 95% guarantee on case-by-case basis
B		Minimum guarantee given	For >90%, it is based on inlet SO_2 concentration
C			Would guarantee 95% in all cases
D			Would guarantee up to 92% in the past. Currently case-by-case.
E			Have guaranteed >90% in the past
F		This guarantee is normally given	Depending upon the process, they would guarantee >90%
G		This guarantee is given where SO_2 inlet concentration is 500-4,000 ppm	Have guaranteed up to 95% in the past
H	Would normally guarantee 80-85%	This guarantee is given where low-sulfur coal is utilized	
I		Minimum guarantee given	Are prepared to offer better than 90% with low- or high-sulfur coal, but would not guarantee less than 50 ppm SO_2 concentration in exit stream
J		This guarantee is usually given with coal having 3-4% sulfur	
K		This guarantee is normally given with low- or high-sulfur coal	In many cases they guarantee 95% with high-sulfur coal
L		Minimum guarantee given	May guarantee up to 95% on a case by case basis

[a] Company names are deliberately withheld.

More than half the manufacturers responding to the survey indicated willingness to guarantee availability (performance) of their FGD systems. The typical level of performance guarantee was quoted as 90 percent. The levels of performance guarantees are briefly summarized in Table 3-11.

All manufacturers responding to the survey were willing to offer guarantees on the cost of their FGD systems:

- Four manufacturers would base the guarantee subject to an escalation clause.
- One manufacturer would negotiate the terms of the guarantee.

None of the other respondents specified the provisions of their cost guarantees.

The manufacturers were asked to indicate their willingness to contract for operation and maintenance of the FGD system after installation. Two-thirds of them responded affirmatively (Table 3-12).

Table 3-11. SUMMARY OF AVAILABILITY GUARANTEES OFFERED BY MANUFACTURERS

Company[a]	Guarantee offered: Yes (level)	No
A	Normally better than 90%	
B		X
C	Typically 90% during performance testing; sometimes up to 95%	
D	Maximum of 90% based on boiler hours	
E	Yes (level of guarantee not disclosed)	
F	Have guaranteed in excess of 90%	
G	Normally 85 to 90% for 1 or 2 years	
H		X
I		X
J	Maximum of 90% on a case by case basis	
K		X
L		X

[a] Company names are deliberately withheld.

Table 3-12. WILLINGNESS OF MANUFACTURERS TO PROVIDE OPERATION AND MAINTENANCE SERVICE FOR FGD SYSTEMS

Company	Provide operation and maintenance service	
	Yes	No
A	X	
B		X
C		X
D	X	
E		X
F	X	
G	X	
H	X	
I	X	
J		X
K	X	
L	X	

Those indicating a willingness to operate and maintain the system also indicated that this could affect the guarantee, but did not specify the provisions affected.

3.4 ASSESSMENT OF AVAILABILITY OF KEY FGD SYSTEM COMPONENTS

Although FGD system manufacturers contract for the entire design and installation of the system, various components of the FGD system are supplied by other manufacturers under subcontract. An accurate assessment of the ability of FGD manufacturers to supply complete systems requires a determination of the subcontractors' ability to supply the system manufacturers with the necessary components. To determine the capability of subcontractors to meet future demands for individual components and to evaluate the effects of revised NSPS on this capability, a survey was conducted of the manufacturers of the following major FGD components:

- Scrubbers
- Pumps
- Fans
- Ball mills
- Clarifiers
- Vacuum filters

Table 3-13 lists the component manufacturers who were contacted and the type of equipment they manufacture. Of the 18 manufacturers contacted, 9 responded.

The demand for additional FGD system components for various sized plants was calculated through the year 1992, using standard engineering calculations and assumptions (see Appendix B). Table 3-14 shows those items that would change if more rigid controls were implemented.

Data contained in the responses from these manufacturers were tabulated and summarized by component size and year. For comparison, the projected demand for each component was also tabulated. Tables 3-15 through 3-20 present the results of this survey.

The responses indicate that shortages of scrubbers and fans may possibly occur in the future. The shortages would not be as great as the data indicate, however, because all

Table 3-13. MAJOR MANUFACTURERS OF FGD SYSTEM COMPONENTS

Manufacturers	FGD System Component					
	Fans	Scrubbers	Ball mills	Pumps	Vacuum filters	Clarifiers
1. Allis-Chalmers			x	x		
2. American Air Filter		x				
3. Bird Manufacturing Co.					x	
4. Buffalo Forge Co.				x		
5. Combustion Engineering	x	x			x	
6. Denver Equipment Co.			x		x	x
7. Dorr-Oliver Inc.				x		x
8. Environeering Inc.	x	x				
9. Envirotech Corp.					x	x
10. FMC Corp.		x			x	x
11. Goulds Pump Inc.				x		
12. Ingersoll-Rand Co.				x		
13. Joy Manufacturing Co.	x	x				
14. Kennedy Van Saun Corp.			x			
15. Koppers Co. Inc.			x			x
16. UOP Engineering Products Corp.	x	x				
17. Worthington Pump Inc.				x		
18. Zurn Industries Inc.	x					

Table 3-14. FGD SYSTEM COMPONENTS THAT WOULD CHANGE IF MORE RIGID CONTROLS WERE APPLIED

System	Component	Changes
Limestone handling	Conveyors	Speed-up conveyors or increase belt width
Limestone crushing	Silos Ball mills with clarifier	Acquire additional equipment or increase size of present equipment
Scrubber	Pumps Tanks Steel	Acquire additional equipment or increase size of present equipment
	I.D. fan	Increase ΔP
	Switchgear Transformer	
Sludge disposal	Pumps Vacuum filter	Acquire additional equipment or increase size of present equipment
Air pollution control	Weigh feeder Vibrating feeder Air compressor Fabric filter Valves	

Table 3-15. CAPABILITY OF MANUFACTURERS TO MEET THE DEMAND FOR SCRUBBERS[a]

Years (inclusive)	Size m^3/s @149°C (acfm @300°F)							
	85 (180,000) (50 MW)		142 (300,000) (90 MW)		170 (360,000) (110 MW)		198 (420,000) (140 MW)	
	Demand	Capacity	Demand	Capacity	Demand	Capacity	Demand	Capacity
1978 to 1982	19	144	66	157	287	234	800	459
1983 to 1987	1[b]	150	9[b]	139	41[b]	174	263	515
1988 to 1992	0[b]	150	3[b]	150	13[b]	200	852	515

[a] Represents the responses from three manufacturers.

[b] The very low demand during certain time periods is based on the assumption that plants coming on line after 1986 will be 500-MW units and will require larger equipment.

Table 3-16. CAPABILITY OF MANUFACTURERS TO MEET THE DEMAND FOR PUMPS[a,b]

Years (inclusive)	Size ℓ/s (gpm)			
	0-305 (0-5,000)		305-610 (5,000-10,000)	
	Demand[c]	Capacity	Demand	Capacity
1978 to 1982	56	112	3,132	6,264
1983 to 1987	3	6	850	1,700
1988 to 1992	0	112	2,342	4,684

[a] Assume specific gravity = 1.06 and ΔH = 45.7 m (150 ft.)

[b] Represents the responses of two manufacturers.

[c] The very low demand during certain time periods is based on the assumption that the plants coming on line after 1986 will be 500-MW units and will require larger equipment.

Table 3-17. CAPABILITY OF MANUFACTURERS TO MEET THE DEMAND FOR FANS[a,b]

Years (inclusive)	Size m^3/s (acfm)							
	85 (180,000) (50 MW)		142 (300,000) (90 MW)		170 (360,000) (110 MW)		198 (420,000) (140 MW)	
	Demand[c]	Capacity	Demand[c]	Capacity	Demand[c]	Capacity	Demand	Capacity
1978 to 1982	19	450	66	410	287	370	800	330
1983 to 1987	1	625	9	575	41	525	263	475
1988 to 1992	0	625	3	575	13	525	852	475

[a] Assume ΔP = 46 cm (18 in.), temperature = 149°C (300°F).

[b] Represents the response from one manufacturer.

[c] The very low demand during certain time periods is based on the assumption that the plants coming on line after 1986 will be 500-MW units and these plants will require larger equipment.

Table 3-18. CAPABILITY OF MANUFACTURERS TO MEET THE DEMAND FOR BALL MILLS[a]

Years (inclusive)	Size kg/hr, (tons/hr)					
	0-7258 (0-8)		7258-14,515 (8-16)		14,515-21,773 (16-24)	
	Demand[b]	Capacity	Demand[b]	Capacity	Demand	Capacity
1978 to 1982	131	662	99	594	186	448
1983 to 1987	20	860	13	710	86	560
1988 to 1992	1	860	0	710	426	560

[a] Represents the responses from two manufacturers.

[b] The very low demand during certain time periods is based on the assumption that the plants coming on line after 1986 will be 500-MW units and these plants will require larger equipment.

Table 3-19. CAPABILITY OF MANUFACTURERS TO MEET THE DEMAND FOR CLARIFIERS[a,b]

Years (inclusive)	Size diameter - m (ft)					
	0-15.2 (0-50)		15.2-30.5 (50-100)		30.5-45.7 (100-150)	
	Demand[c]	Capacity	Demand[c]	Capacity	Demand	Capacity
1978 to 1982	50	200	119	360	130	400
1983 to 1987	2	250	21	450	64	500
1988 to 1992	0	250	2	450	426	500

[a] Assume maximum height of 3.1 m (10 foot).

[b] Represents the response of 1 vendor.

[c] The very low demand during certain time periods is based on the assumption that the plants coming on line after 1986 will be 500-MW units and these plants will require larger equipment.

Table 3-20. CAPABILITY OF MANUFACTURERS TO MEET THE DEMAND FOR VACUUM FILTERS[a]

Years (inclusive)	Size m^2 (ft^2): 0-25.9 (0-279) Demand[b]	Size m^2 (ft^2): 0-25.9 (0-279) Capacity	Size m^2 (ft^2): 25.9-54.6 (279-588) Demand[b]	Size m^2 (ft^2): 25.9-54.6 (279-588) Capacity	Size m^2 (ft^2): 54.6-77.4 (588-833) Demand	Size m^2 (ft^2): 54.6-77.4 (588-833) Capacity
1978 to 1982	141	244	47	260	114	260
1983 to 1987	21	340	8	260	46	260
1988 to 1992	1	352	1	260	212	260

[a] Represents the responses of two manufacturers; one of the two manufacturers did not predict the capacity in the size range 25.9 to 54.6 sq m (279 to 833 sq ft).

[b] The very low demand during certain time periods is based on the assumption that the plants coming on line after 1986 will be 500-MW units and these plants will require larger equipment.

the manufacturers did not respond. The data are further qualified by the assumption used in calculating demand--that all new units after 1986 will be 500 megawatts or greater in capacity. This assumption slants the requirements for equipment to larger capacities, whereas the manufacturers' responses covered a wide size range.

The projected demand for scrubbers from 1978 through 1992 is estimated to be 1915 at a capacity of 198 m^3/s (420,000 acfm) at 149°C (300°F), 341 at 170 m^3/s (360,000 acfm), 78 at 142 m^3/s (300,000 acfm), and 20 at 85 m^3/s (180,000 acfm). The capacity of manufacturers to supply scrubbers during this time period is 1489 at 198 m^3/s (420,000 acfm), 608 at 170 m^3/s (360,000 acfm), 446 at 142 m^3/s (300,000 acfm), and 444 at 85 m^3/s (180,000 acfm). The only shortage is in the 198 m^3/s (420,000 acfm) size category, whereas excess capacity exists in smaller size categories. An examination of the capacities on a total m^3/s (acfm) handled basis shows a demand of 450,200 m^3/s (954,060,000 acfm) from 1978 through 1992 versus a capacity of 499,200 m^3/s (1,057,900,000 acfm). On this basis, it appears the total demand for scrubbers can be met during this period. This belief is further strengthened by the fact that the manufacturers of FGD systems did not anticipate any shortages.

The apparent shortage of fans can be qualified in a like manner. The data are slanted toward the larger capacities. Examined on a total volume treated basis, the demand for fans between 1978 and 1992 is 450,200 m^3/s (954,060,000 acfm), whereas the capacity is 860,200 m^3/s (1,822,800,000 acfm). On this basis, it appears that the demand for fans from 1978 through 1992 can also be met.

The survey did not indicate anticipated shortages of any of the other components.

4.0 INSTALLATION OF FGD SYSTEMS ON POWER PLANT BOILERS

4.1 CONSTRUCTION SCHEDULES

The construction of a power plant involves two major phases: (1) preliminary study and (2) detail design and construction of the facility. Preliminary study includes the following activities:

- Site selection
- Planning and agency approval
- Construction fund appropriation
- Preparation of specifications
- Bid evaluation
- Contract award

The major items of work that go into the design and construction of a power plant include the following:

- Site preparation
- Construction of coal handling facility
- Erection of powerhouse building
- Erection of powerhouse mechanical system
- Erection of powerhouse electrical system
- Construction of transformer and switchyard

- Construction of service bay
- Construction of water supply and discharge facility
- Erection of control building

Industry reports indicate that the size of a typical coal-fired power plant committed for construction between 1977 and 1996 ranges from 450 to 550 MW.[1] The average time required to design and construct a 500-MW power plant is approximately 6 years. This includes the time from the initiation of a preliminary study to commercial operation of the plant, but does not include the installation of an FGD system.

Figure 4-1 shows the construction schedule for a 500-MW unit.[2] The elapsed time needed to erect a complete power plant is a function of man-hours. The number of men that can be used during any one stage of erection is limited, however, for any given size of unit due to space and installation equipment constraints.

In most cases, an FGD system can be installed on a new power plant without its having a significant impact on the construction time schedule. It is assumed that adequate space, material and labor will be available, thereby making it possible for a major portion of the construction of the FGD

	No.	Item
Preliminary Engineering	1	Site selection
	2	Economic evaluation
Planning and Agency Approved	3	Environmental impact assessment
	4	Draft and final environmental impact statements
Construction Fund Appropriation	5	Obtain funds for construction
Preparation of Specifications	6	Preliminary design and layout
	7	Specification writing
Bid Evaluation	8	Evaluate bids
	9	Award contract
	10	Sign contract
Construction Plant	11	Grading and roads
	12	Buildings and utilities
	13	Concrete plant
Yards and General	14	Cleaning and grading
	15	General mechanical and electrical
Coal Handling	16	Coal handling facility erection
Power House Building	17	Power house building erection
Power House Mechanical	18	Steam and turbo generators
	19	Ash disposal
	20	Fans
	21	Stacks
	22	Heaters, tanks, pumps
	23	Piping
Power House Electrical	24	Power house electrical connection
Transformer and Switchyard	25	Transformer and switchyard erection
Service Bay	26	Service bay erection
Condenser Water	27	Erection of condenser water supply and discharge structure
Water Treatment	28	Erection of water treatment facility
Control Building	29	Miscellaneous wiring, grounding, and lighting

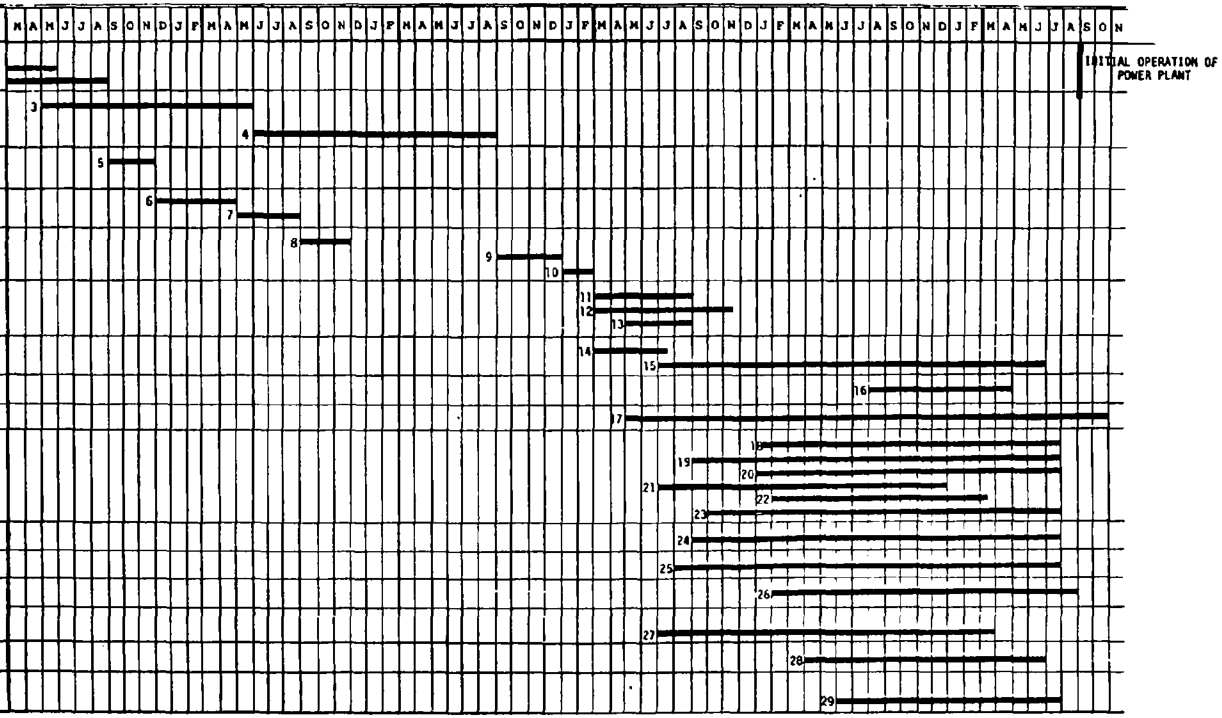


Figure 4-1. Construction schedule for typical 500-MW power plants.

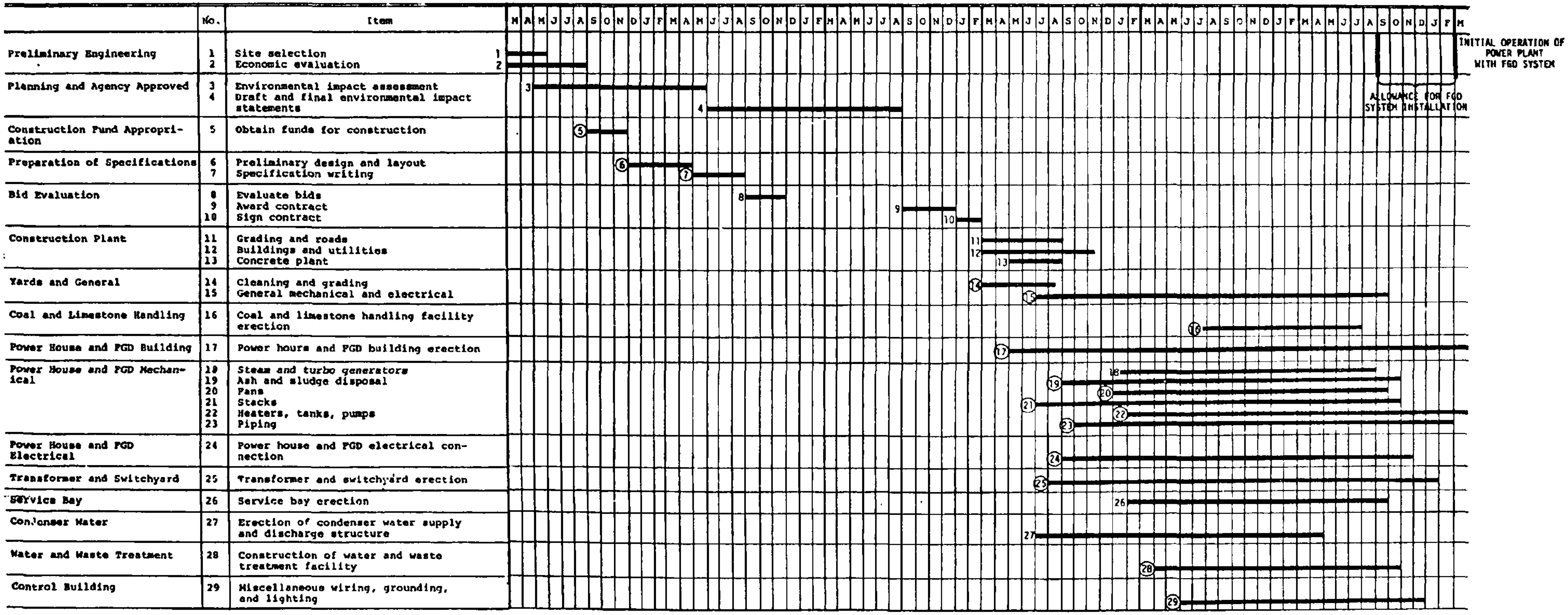
unit to parallel the boiler erection, as illustrated in Figure 4-2.[3] The design and construction of a flue gas desulfurization system usually takes less time than the power plant construction. The estimated extension to the construction schedule due to the installation of an FGD system is about 6 months. This six month extention is comprised of three months for check out and shakedown of the FGD system and three months due to extra construction time typically caused by space and labor constraints. Depending upon site specific conditions and assuming that the erection of the boiler and the FGD system can occur simultaneously, there would be no impact on the overall construction schedule if the application of an FGD system was decided upon six months after signing of a boiler design and construction contract.

4.2 DESIGN AND CONSTRUCTION FORCE AVAILABILITY

Installation of power plants and FGD systems requires the services of the same types of laborers. Because FGD manufacturers subcontract construction labor, they are not always aware of potential shortages.

The following are the key crafts required for power plant and FGD system installation:

- Boilermakers
- Carpenters
- Electricians
- Ironworkers



(x) These activities may delay the schedule by about 6 months for a power plant with an FGD system.

Figure 4-2. Construction schedule for a typical power plant equipped with an FGD system.

- Laborers
- Millwrights
- Pipe fitters

Because the domestic construction industry is in a slump, an increase in construction activity could be manned initially by those building tradesmen currently unemployed.[4] Short-term growth requirements for labor could be met with few problems in most regions, except for highly skilled mechanical craftsmen (including welders). As of mid-summer 1977, the following selected areas reported existing or anticipated shortages of skilled craftsmen:[5]

Location	Craftsmen
Denver, Colorado	Carpenters Ironworkers
Detroit, Michigan	Boilermakers Pipe fitters
Boston, Massachusetts	Electricians
Missouri and Nebraska	Boilermakers Pipe fitters
Raleigh, North Carolina	Carpenters

The South's growing influx of people is expected to increase industrial construction activity and, thus, the demand on the available manpower in that area of the country.

A selected number of large national power plant contractors that were contacted indicated that a shortage of skilled craftsmen in all disciplines is possible, indeed probable.[6] Unskilled laborers will be plentiful, but it takes several years of training to acquire the various skills required for power plant construction. The more remote an area is from high-population centers, the more acute the anticipated shortage.

The increasing demand for craftsmen in power plant construction could possibly be met by the following course of action:[7]

1. Expansion of apprenticeship programs - Over the past 20 years, apprenticeship programs have been the major means of increasing the supply of construction workers. In times of high construction activity, apprenticeship programs have been expanded and other supplemental training programs initiated and accepted by local unions.

2. Training nonconstruction work forces for use in industrial construction - If energy-related construction schedules were to cause the demand for craftsmen to greatly exceed the available supply, high schools, vocational schools, and community colleges would have to be contacted to take the initial step in training nonconstruction personnel.

3. Attracting workers to more remote areas - The establishment of good housing, camp facilities, and trailer parks with hookups for utilities would be essential to attract workers for projects located in more remote areas.

In summary, it is believed that it would be very difficult to realize the 10 percent annual increase in craftsmen necessary for the anticipated construction of energy-related facilities (including power plants) for any extended period. The number and location of the facilities planned and the impact of their schedules over and above the current workload will add greatly to some manpower problems already being experienced.

To estimate labor requirements for installing FGD systems, the manhours required to construct a plant of known size was used as a basis for determining the deviation in manhours required to increase or decrease the time of installation. The known FGD system had four scrubbers, venturis, and hold tanks, ball mills, limestone storage tanks, slurry tank, by-pass duct, fans, pumps, sludge piping, disposal pond, vacuum filter, electrical house, etc. The scrubbers were rated at 177 m^3 per second (375,000 acfm) at 149°C (300°F). The known plant was a 550 MW capacity unit burning coal with the following characteristics: 4 percent sulfur, 20 percent ash, 7 percent moisture, and had a heating value of 24,500 J/g (10,500 Btu per pound). A labor estimate was then made to design and construct a plant with one less scrubber train and also for a plant with one additional scrubber train. The regulation to be met was 516.5 ng SO_2/J (1.2 lb $SO_2/10^6$ Btu). The following equation was then used to determine the labor relationship for increasing or decreasing the amount of scrubber capacity:

$$A = B \left(\frac{a}{b}\right)^x$$

where:

A = Manhours for known plant

B = Manhours estimated for removing or adding one scrubber train

a = Megawatt capacity of plant "A"

b = Megawatt capacity of plant "B"

The equation was solved for the exponent "x" which was 0.72.

In the case of 90 percent SO_2 removal and 215.2 ng SO_2/J (0.5 lb $SO_2/10^6$ Btu), the gas flow was constant but other factors varied. Dwell time, liquid to gas ratio, stochiometry of reactants, etc., were determined and allowances in labor for installing larger equipment or greater number of modules were made.

Table 4-1 shows the computed manhours using the above formula. Figure 4-3 presents a graphical interpretation of the computation. It can be seen from Figure 4-3 that the manpower differential is insignificant for the alternative emission standards.

Thus, although alternative NSPS for SO_2 emissions of 215.2 ng SO_2/J (0.5 lb/10^6 Btu) and 90 percent control would not significantly impact the demand for power plant construction forces above the present NSPS of 516.5 ng SO_2/J (1.2 lb $SO_2/10^6$ Btu), the demand for skilled laborers will probably still exceed the supply in future years.

Table 4-1. MAN-HOURS REQUIRED TO MEET THE ALTERNATIVE SO_2 EMISSION STANDARDS

Alternative SO_2 emission standards	Capacity, MW										
	140	200	300	400	500	550	600	700	800	900	1000
51.6 g/10^8 J (1.2 lb/10^6 Btu)	485,400	627,522	840,262	1,033,644	1,213,797	1,300,016	1,384,065	1,546,530	1,702,599	1,853,285	1,999,345
90%	492,100	636,184	851,861	1,047,911	1,230,551	1,317,960	1,403,169	1,567,876	1,726,100	1,878,866	2,026,942
21.5 g/10^8 J (0.5 lb/10^6 Btu)	498,900	644,975	863,632	1,062,391	1,247,555	1,336,172	1,422,559	1,589,542	1,749,952	1,904,829	2,054,950

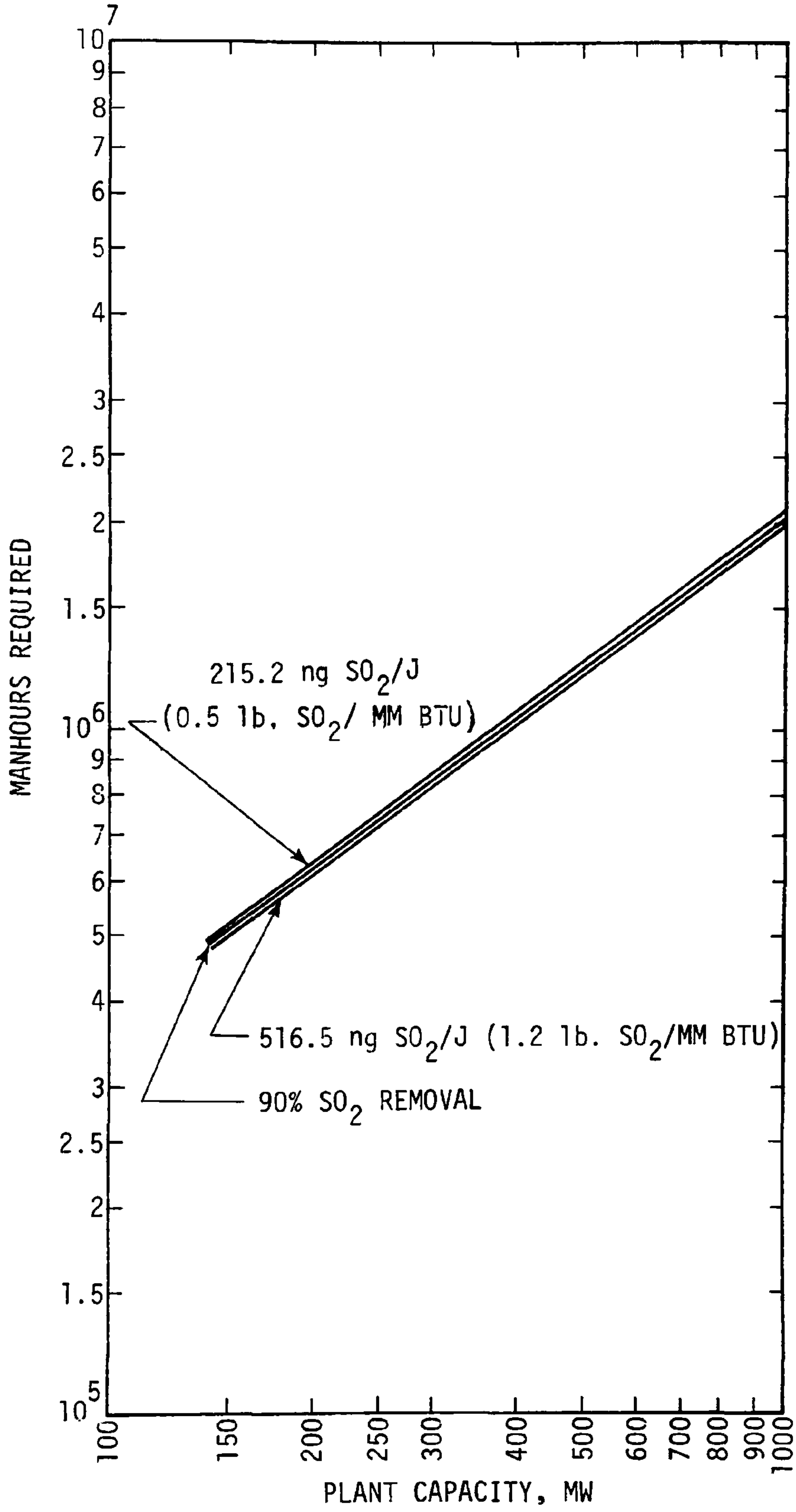


Figure 4-3. Manhours required to meet alternative emission standards.

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APPENDIX A

PLANNED COAL-FIRED UNITS THROUGH 1998

The following tables list the planned coal-fired units through 1998, their capacities, and planned pollution control equipment. The following is a key for the abbreviations used for various types of pollution control devices.

KEY FOR TABLE A-1.

Sulfur Control - Assign appropriate code from following list:

LSS - Limestone Scrubbers
LMS - Lime Scrubbers
LST - Limestone
LIM - Lime
MOS - Magnesium Oxide Scrubbers
CO - Catalytic Oxidation
WL - Wellman-Lord
FUL - Low Sulfur Fuel
CB - Combination
LAFS - Lime/Alkaline Fly Ash Scrubbing
ASB - Aqueous Sodium Base Scrubbers
DA - Double Alkali
PNS - Process Not Selected
OTH - Other
HS - High Stack
NA - Not Applicable
SCR - Unknown Type of Scrubber

Particulate Control - Assign appropriate code from following list:

PNS - Process Not Selected
GRAV - Gravitational or Baffled Chamber
SCTA - Single Cyclone - Conventional Reverse-flow, Tangential Inlet
SCAX - Single Cyclone - Conventional Reverse-flow, Axial Inlet
MCTA - Multiple Cyclones - Conventional Reverse-flow, Tangential Inlet
MCAX - Multiple Cyclones - Conventional Reverse-flow, Axial Inlet
CYCL - Straight-through-flow Cyclones
IMPE - Impellor Connector
VENT - Wet Collector; Venturi
WETC - Wet Collector; Other
BAGH - Baghouse (Fabric Collector)
OTHE - Other
ELEC - Electrostatic Precipitator
HOTP - Hot Precipitator
COMB - Combined Electrostatic and Mechanical precipitators
NA - Not Applicable
PREC - Unknown Type of Precipitator
DUST - Dust Collector

U.S. EPA Region I State: Massachusetts

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1981	Mass. Mun. Wholesale Elec.	Unnamed 1	400				

U.S. EPA Region II State: New Jersey

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1990	GPU: Jersey Cen. Pow. & Light	Gilbert 9	800				

U.S. EPA Region II State : New York

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1982	Power Auth. State of N.Y.	MTA-Arthur Kill 1	760			Elec.	SCR
1983	N.Y. State Elec. & Gas	Cayuga 1	850			Elec.	FUL
1985	Niagra Mohawk Power	Lake Erie 1	850			-	-
1987	Niagra Mohawk Power	Lake Erie 2	850				

U.S. EPA Region III State: Delaware

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1979	Delmarva Power & Light	Indian River 4	400			Elec.	PNS

U.S. EPA Region III State: Maryland

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1982	Potomac Elec. Power	Dickerson 4	800			Elec.	SCR

U.S. EPA Region III State: Pennsylvania

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Ohio Edison	Mansfield 2	835	Bit.	4.7	Prec.	LMS
1977	GPU: Penn. Elec. Co.	Homer City 3	693			Elec.	PNS
1980	Ohio Edison	Mansfield 3	835	Bit.	4.7		LMS
1984	GPU: Penn. Elec. Co.	Seward 7	800			-	-
1987	Penn. Power Co.	Coho 1	800				
1988	Philadelphia Elec.	Unnamed 1	600				
1990	Philadelphia Elec.	Unnamed 2	600				
1991	GPU: Metropolitan Edison	Scottsville 1	800				
1993	Penn. Power Co.	Wehrum 1	800				

U.S. EPA Region III State: West Virginia

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1979	APS/Allegheny Power System	Pleasants 1	626	Bit.	4.5	Elec.	LMS
1980	AEP: Appalachian Power	Project 1301 1	1300			-	-
1980	APS: Allegheny Power Sys.	Pleasants 2	626	Bit.	4.5	Elec.	LMS
1980	AEP: Appalachian Power	1300-4	1300				
1984	Allegheny Power Systems	Unsited 1	630			-	-
1985	Allegheny Power Systems	Unsited 2	630			-	-

U.S. EPA Region IV State: Alabama

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1978	S. Co. Alabama Power	Miller 1	718			PNS	PNS
1978	Alabama Elec. Coop.	Tombigbee 2	235	Bit.	.8-1.5	-	LSS
1979	Alabama Elec. Coop.	Tombigbee 3	235	Bit.	.8-1.5	-	LSS
1981	So. Co. Alabama Power	Miller 2	718			-	-
1982	So. Co. Alabama Power	Miller 3	718			PNS	PNS
1983	So. Co. Alabama Power	Miller 4	718			-	-
1984	Alabama Power Co.	Unlocated 1	801			-	-
1985	Alabama Power Co.	Unlocated 2	801			-	-

U.S. EPA Region IV State: Florida

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1981	Lakeland, City of	Plant #3 (McIntosh)	336			-	FUL
1982	So. Co. Gulf Power Co.	Ellis 1	553			HOTP	PNS
1983	Florida Power Co	Unsited C 1	600			-	-
1984	So. Co. Gulf Power Co.	Ellis 2	553			HOTP	PNS
1985	Tampa Electric Co.	Beacon Key 1	425			-	-
1985	Florida Power Co	Unsited C 2	600			-	-
1985	Florida Power Co	Unsited C 3	600			-	-
1986	Tampa Electric Co.	Big Bend 4	425				

U.S. EPA Region IV State: Georgia

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1978	So. Co. Georgia Power Co.	Wansley 2	952			Elec.	HS
1981	So. Co. Georgia Power Co.	Scherer 1	952			-	-
1982	So. Co. Georgia Power Co.	Scherer 2	952			-	-
1984	So. Co. Georgia Power Co.	Scherer 3	952			-	-
1985	So. Co. Georgia Power Co.	Scherer 4	952			-	-

U.S. EPA Region IV State: Kentucky

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	E. Ky. Power Coop	H.L. Spurlock 1	300			HOTP	FUL
1977	Louisville Gas & Elec.	Mill Creek 3	425	Bit.	3.5-4.0	-	LMS
1979	Big Rivers Elec. Corp.	Reid 2	200	Bit.	3.5-4.0	-	LMS
1980	E. Ky. Power Coop	H.L. Spurlock 2	500			HOTP	PNS
1980	Louisville Gas & Elec.	Mill Creek 4	495			Prec.	LMS
1981	Ky. Utilities Co.	Ghent 2	500			HOTP	FUL
1981	Cincinnati Gas & Elec.	East bend 2	600			HOTP	PNS
1981	Ky. Utilities Co.	Unsited 1	500			-	-
1983	Ky. Utilities Co.	Unsited P 2	500			-	-
1983	Louisville Gas & Elec.	Trimble County 1	495				
1984	Cincinnati Gas & Elec.	East Bend 1	600			-	-
1984	Cincinnati Gas & Elec.	East Bend 3	600			-	-
1984	Big Rivers Elec. Corp.	Reid 3	200			-	-
1984	E. Ky. Power Coop	Unsited 2	500			-	-
1984	Ky. Utilities Co.	Ghent 3	500			-	-
1984	E. Ky. Power Coop	Unsited 1	500			-	-
1985	Ky. Utilities Co.	Unsited 4	650			-	-
1985	Louisville Gas & Elec.	Trimble County 2	495				
1987	Louisville Gas & Elec.	Trimble County 3	675				
1989	Louisville Gas & Elec.	Trimble County 4	675				

U.S. EPA Region IV State: Mississippi

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	So. Co. Mississippi Power Co.	Jackson County 1	548			Elec.	HS
1978	So. Miss. Elec. Power Assn.	Morrow 1	203		1.0	-	LSS
1978	So. Miss. Elec. Power Assn.	Morrow 2	203		1.0	-	LSS
1980	So. Co. Miss. Power Co.	Jackson County 2	548			Elec.	HS
1985	Mid. So.: Miss. Power & Light	Unsited P 1	700				
1986	Mid. So.: Miss. Power & Light	Unsited P 2	700				
1986	Mid. So.: Miss. Power & Light	Middle South Coal 7	700				
1987	Mid. So.: Miss. Power & Light	Middle South Coal 8	700				
1987	Mid. So.: Miss. Power & Light	Middle South Coal 9	700				
1988	Mid. So.: Miss. Power & Light	Middle South Coal 10	700				
1988	Mid. So.: Miss. Power & Light	Middle South Coal 11	700				
1988	Mid. So.: Miss. Power & Light	Middle South Coal 12	700				
1989	Mid. So.: Miss. Power & Light	Middle South Coal 13	700				
1990	Mid. So.: Miss. Power & Light	Middle South Coal 14	700				

U.S. EPA Region IV State: North Carolina

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Control Part.	Planned Control SO_2
1980	Carolina Power & Light	Roxboro 4	745			Elec.	FUL
1983	Carolina Power & Light	Mayo 1	720			-	-
1985	Carolina Power & Light	Mayo 2	720			-	-

U.S. EPA Region IV State: South Carolina

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	So. Carolina Public Service	Winyah 2	315		1.0	-	LSS
1982	So. Carolina Public Service	Unnamed 1	280			-	-
1984	So. Carolina Elec. & Gas	Unsited P 2	500			-	-
1984	So. Caroline Public Service	Unnamed 2	280			-	-

U.S. EPA Region V State: Illinois

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Central Ill. Public Service	Newton 1	600	Bit.	2.8-3.2	Elec.	D.A.
1978	Springfield, City of	Dallman 3	192				
1978	Illinois Power Co.	Havana 6	450			HOTP	
1978	So. Ill. Power Coop.	Marion 4	173	Bit.	4.5-5.0	-	LSS
1978	Cen. Ill. Light Co.	Duck Creek #1 B	300	Bit.	2.5-3.0		LSS
1981	Central Ill. Public Service	Newton 2	550				
1981	Western Ill. Power Coop	Unsited 1	20				
1982	Central Ill. Light	Duck Creek 2	400	Bit.	2.5-3.0	Elec.	LSS
1984	Central Ill. Public Service	Newton 3	550				
1984	Commonwealth Edison	Unsited P 1	550				
1984	Commonwealth Edison	Unsited P 2	550				
1984	Western Ill. Power Coop	Unsited 2	20				
1985	Commonwealth Edison	Unsited P 3	550				
1985	Commonwealth Edison	Unsited P 4	550				
1986	Central Ill. Light	Duck Creek 3	600				
1986	Springfield, City of	Unnamed 1	203				
1990	Central Ill. Light	Duck Creek 4	600				

U.S. EPA Region V State: Indiana

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Indianapolis Power & Light	Petersburg 3	532	Bit.	3.0-3.5	Elec.	LSS
1978	Public Service Co. Of Ind.	Gibson 3	668	Bit.	3.3	Prec.	PNS
1979	Public Service Co. of Ind.	Gibson 4	668	Bit.	3.3	-	PNS
1979	So. Indiana Gas & Elec.	A.B. Brown 1	265	Bit.	3.75	-	DA
1979	No. Indiana Public Service	R.M. Schahfer 15	556			-	-
1981	Hoosier Energy	Merom 2	490			-	-
1981	Hoosier Energy	Merom 1	490			-	-
1982	Indianapolis Power & Light	Petersburg	532	Bit.	3.5	Elec.	LSS
1984	So. Indiana Gas & Elec.	A.B. Brown 2	350			-	-
1985	Indianapolis Power & Light	Unsited 1	650			-	-
1985	Richmond Power & Light	Whitewater Valley 3	100			-	-
1987	Indianapolis Power & Light	Unsited 2	650			-	-

U.S. EPA Region V State: Michigan

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1978	Upper Peninsula Gen.	Presque Isle 7	80			-	-
1978	Upper Peninsula Gen.	Presque Isle 8	80			-	-
1978	Upper Peninsula Power	Unsited 1	80			-	-
1979	Upper Peninsula Gen.	Presque Isle 9	80			-	-
1979	Upper Peninsula Power	Unsited 2	80			-	-
1980	Consumers Power Co.	J.H. Campbell 3	800			Elec.	FUL
1980	Maquette, City of	Shiras 3	43			-	-
1980	Upper Peninsula Power	Unsited 3	80			-	-
1981	Grand Haven Board of Light and Power	Island 3	20			-	-
1982	Upper Peninsula Power Co.	Undesignated	90			-	-
1982	Detroit Edison	Belle River 1	697			Elec.	FUL
1982	Coldwater, City of	Coldwater 7	20			-	-
1983	Consumers Power Co.	J.H. Campbell 4	800			-	-
1983	Detroit Edison	Belle River 2	697			Elec.	FUL
1984	Upper Peninsula Power	Unsited 4	80			-	-
1984	Consumers Power Co.	Unsited	800				
1986	Lansing, City of	Erickson 2	160				

U.S. EPA Region V State: Minnesota

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Northern States Power Co.	Sherburne 2	720	Bit.	0.8	WETC	LSS
1980	Austin Utilities	North East Sta. 2	44			-	-
1980	Minnesota Power and Light	Clay Boswell 4	555	Bit.	0.8	-	PNS
1981	Northern States Power	Sherburne Co. 3	860	Bit.	0.8	-	PNS
1983	New. Ulm. Pub. Util. Comm.	New. Ulm. 6	40			-	-
1983	Northern States Power	Sherburne Co. 4	680	Bit.	.8	-	PNS
1984	Minn. Power and Light	Floodwood	800				

U.S. EPA Region V State: Ohio

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Cardinal Operating Co.	Cardinal 3	615			-	-
1978	Cincinnat Gas and Elec.	Miami Fort 8	500			Elec.	PNS
1978	Columbus and S. Ohio Elec.	Conesville 6	403	Bit.	4.5-4.9	-	LMS
1981	Columbus and S. Ohio Elec.	Poston 5	403	Bit.	2.5	Elec.	CB
1982	Dayton Power and Light	Killen Sta. 2	661			Elec.	FUL
1983	Columbus and S. Ohio Elec.	Poston 6	403			Elec.	CB
1985	Dayton Power and Light	Killen Sta. 1	661			Elec.	FUL
1985	Columbus and S. Ohio Elec.	Unsited P 1	375			-	-
1985	Dayton Power and Light	Site C 2	375				
1987	Columbus and S. Ohio Elec.	Newbury 1	400				
1989	Columbus and S. Ohio Elec.	Newbury 2	600				

U.S. EPA Region V State: Wisconsin

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1978	Wisconsin Power and Light	Columbia 2	512			-	-
1979	Dairyland Power Coop	Alma 6	350			Elec.	FUL
1980	Wis. Elec. Power	Pleasant Prarie 1	617			-	-
1981	Wisconsin Public Service	Weston 3	350			-	-
1982	Wisconsin Power and Light	Edgewater 5	400				
1982	Wisconsin Power and Light	Pleasant Prarie 2	617			HOTP	PNS

U.S. EPA Region VI State: Arkansas

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Control Part.	Planned Control SO_2
1978	Cen. and S.W. Southwestern Electric Power	Flint Creek	511			Elec.	FUL
1980	Mid. So. Ark. Power and Light	White Bluff 1	700			Elec.	FUL
1981	Mid. So. Ark. Power and Light	White Bluff 2	700			Elec.	FUL
1983	Mid. So. Ark. Power and Light	White Bluff 3	700			-	-
1983	Mid. So. Ark. Power and Light	Arkansas Coal 1	700			-	-
1985	Mid. So. Ark. Power and Light	White Bluff 4	700			-	-
1985	Mid. So. Ark. Power and Light	Arkansas Coal 2	700				

U.S. EPA Region VI State: Louisiana

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Houma Light and Water	Houma 16	48				
1979	Monroe Util. Comm.	Monroe 14	100				
1979	Cajun Elec. Power Coop.	Big Cajun 2 1	540			-	-
1980	Cajun Elec. Power Coop.	Big Cajun 2 2	540			-	-
1980	Cen. La. Elec. Co.	Rhodemacher 2	530			Elec.	FUL
1983	Mid. So. La. Power and Light	Unsited P 1	700			-	-
1984	Mid. So. La. Power and Light	P 2	700			-	-
1985	Mid. So. La. Power and Light	P 3	700			-	-
1985	Cajun Elec. Power Coop.	Big Cajun 2 3	540			-	-
1985	Gulf State Utilities	R.S. Nelson 5	615			OTH	CB
1986	Mid. So. La. Power and Light	Unsited P 4	700				
1986	Central La. Elec. Co.	Rhodemacher 3	530				
1986	Gulf State Utilities	R.S. Nelson 6	615				

U.S. EPA Region VI State: Oklahoma

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Control Part.	Planned Control SO_2
1977	Oklahoma Gas and Elec.	Muskogee 4	572			Elec.	FUL
1977	Ponca City	Ponca Steam 2	43				
1978	Oklahoma Gas and Elec.	Muskogee 5	572			Elec.	FUL
1979	Oklahoma Gas and Elec.	Sooner 1	567			Elec.	FUL
1979	Cen. S.W. Pub. Serv of Okl.	Northeastern 3	450				
1980	Oklahoma Gas and Elec.	Sooner 2	567				
1980	Cen. S.W. Pub. Serv. of Okl.	Northeastern 4	450			-	-
1982	Oklahoma Gas and Elec.	Unsited P 1	700				
1983	Oklahoma Gas and Elec.	Sooner 3	515			-	-
1983	Oklahoma Gas and Elec.	Unsited P 2	700			-	-
1984	Oklahoma Gas and Elec.	Sooner 4	515			-	-
1984	Oklahoma Gas and Elec.	Unsited P 3	700			-	-
1984	Cen. S.W. Pub. Serv. of Okl.	CSR Joint 1	240			-	-

U.S. EPA Region VI State: New Mexico

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Pub. Serv. Co. of N. Mexico	San Juan 1	375	Bit.	0.8		WL
1979	Pub. Serv. Co. of N. Mexico	San Juan 3	461	Bit.	0.8	Elec.	SCR
1981	Pub. Serv. Co. of N. Mexico	San Juan 4	461	Bit.	0.8	Elec.	SCR

U.S. EPA Region VI State: Texas

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	San Antonio Pub. Serv.	J.T. Deely 1	418			HOTP	FUL
1977	Cen. S.W. Elec. Power	Welsh 1	528			Elec.	FUL
1977	Tex. Util. Tex. Power & Light	Martin Lake 1	793	Lig.	1.0	-	LSS
1977	Cen. & S.W. West Tex. Util Co.	Fort Phantom 2	200				
1977	San Antonio Pub. Serv.	J.T. Deely 2	418			HOTP	FUL
1978	Tex. Util. Tex. Power & Light	Martin Lake 2	793	Lig.	1.0	-	LSS
1978	Tex. Util. Tex. Power & Light	Monticello 3	793	Lig.	1.0	Prec.	LSS
1979	Houston Lighting and Power	W.A. Parish 5	734			-	-
1979	S. Tex. Elec. Coop.	Texas Coop 1	400			-	-
1979	S.W. Public Service	Harrington 2	360			-	-
1979	Tex. Util. Tex. Power & Light	Martin Lake 3	793	Lig.	1.0	-	LSS
1979	Lower Colorado River Auth.	Fayette 1	550			-	FUL
1980	Cen. S.W. Cen. Power & Light	Coleto Creek 1	550				FUL

U.S. EPA Region VI State: Texas

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1980	Cen. S.W. Cen. Power Co.	Welsh 2	528				
1980	Lower Colorado River Auth.	Fayette 2	550			-	-
1980	S.W. Public Serv. Co.	Harrington 3	360			-	-
1980	Texas Mun. Power Pool	San Miguel 1	435	Lig.		-	-
1980	Texas Mun. Power Pool	San Miguel 2	435	Lig.		-	-
1981	Houston Lighting and Power	W.A. Parish 6	734			-	-
1981	Tex. Util. Tex. Power & Light	Forest Grove 1	793	Lig.		-	-
1981	Houston Lighting and Power	W.A. Parish 7	750			-	-
1981	S. Tex. Elec. Coop.	Texas Coop 2	400			-	-
1982	Tex. Util. Tex. Power & Light	Martin Lake 4	797	Lig.	1.0	-	LSS
1982	Tex. Power and Light	Sandow 4	575	Lig.		-	LSS
1982	Tex. Mun. Power Pool	TPPI 1 (Bryan)	400	Lig.		-	-
1982	Cen. & S.W.: S.W. Elec. Power Co.	Welsh 3	528			-	-
1982	Houston Lighting and Power	W.A. Parish 8	750			-	-
1982	S.W. Public Service	South Plains	475			-	-
1982	Cen. & S.W.: W. Tex. Util Co.	Unsited P 1	250				
1983	Tex. Util.: Tex. Pwr. & Light	Twin Oak 1	793	Lig.		-	FUL

U.S. EPA Region VI State: Texas

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1983	Tex. Mun. Pwr. Pool	TPPI 2 (Bryan)	400	Lig.		-	-
1983	Houston Lighting and Power	Unsited P 1	750			-	-
1983	San Antonio Pub. Service	Unsited P 1	375			-	-
1984	Tex. Util.: Tex. Power & Light	Twin Oak 2	793	Lig.		-	FUL
1984	Tex. Mun. Power Pool	TPPI 3 (Bryan)	400	Lig.		-	-
1984	S.W. Public Service Co.	South Plains 2	475			-	-
1985	Tex. Util.: Tex. Power & Light	Unsited P 1	400			-	-
1985	Tex. Util.: Tex. Power & Light	Unsited P 2	750			-	-
1985	Houston Lighting and Power	Unsited P 1	750			-	-
1985	Houston Lighting and Power	Unsited P 2	750				
1986	Cen. & S.W.: Cen. Power & Light	Coleto Creek 2	550				

U.S. EPA Region VII State: Missouri

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Union Electric Co.	Rush Island 1	575			Elec.	PNS
1977	Union Electric Co.	Rush Island 2	575			Elec.	PNS
1977	Assoc. Electric Coop.	New Madrid 2	600			Elec.	-
1980	K.C. Power & Light	Iatan 1	726			PNS	PNS
1981	Assoc. Electric Coop.	Thomas Hill 3	600			-	-
1982	Springfield Utilities	Southwest 2	200			-	-
1984	Empire District Electric Co.	Asbury 2	300			-	-
1985	Missouri Public Service	Unsited P 1	100			-	-
1985	Empire District Electric Co.	Energy Center X-3	300				
1994	Empire district Electric Co.	Energy Center X-5	300				

U.S. EPA Region VII State: Iowa

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Interstate Power Co.	Lansing 4	260			-	-
1979	Iowa Public Service	George Neal 4	576			Elec.	FUL
1979	Iowa Power and Light	Council Bluffs 3	650			Elec.	FUL
1981	Iowa Southern Utilities	Ottumwa 1	675			PNS	PNS

U.S. EPA Region VII State: Kansas

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	K.C. Power & Light	La Cygne 2	686			Elec.	FUL
1978	Kansas Power & Light	Jeffrey 1	720	Bit.	0.3	Elec.	LSS
1979	K.C. Board of Public Utilities	Nearman Creek 1	250			-	-
1980	Kansas Power & Light	Jeffrey 2	680	Bit.	0.3	Elec.	LSS
1982	Sunflower Electric Coop	Sunflower S-3	256				
1982	K.C. Board of Public Utilities	Nearman Creek 2	300			-	-
1983	Kansas Power & Light	Jeffrey 3	680			-	-
1984	Kansas Power & Light	Jeffrey 4	680			-	-

U.S. EPA Region VII State: Nebraska

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Control Part.	Planned Control SO_2
1978	Nebraska Public Power District	Gentleman 1	600			Elec.	FUL
1979	Omaha Public Power District	Nebraska City 1	575			Elec.	PNS
1981	Nebraska Public Power District	Gentleman 2	600			-	-
1981	Grand Island Water & Light	Unsited 1	147			-	-

U.S. EPA Region VIII State: Colorado

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1978	Colorado - Ute Electric Assn.	Craig 1	380	Bit.	0.45	HOTP	LMS
1979	Colorado - Ute Electric Assn.	Craig 2	380	Bit.	0.45	HOTP	LMS
1979	Public Service of Colorado	Pawnee 1	500			-	-
1980	City of Colorado Springs	Ray D. Nixon 1	200			-	-
1981	Public Service of Colorado	Pawnee 2	500			-	-
1981	Colorado - Ute Electric Assn.	Craig 3	380			-	-
1982	Colorado - Ute Electric Assn.	Craig 4	380			-	-
1982	Public Service of Colorado	Major Joint Cap. 1	380				
1983	Public Service of Colorado	Southeastern 1	500			-	-
1983	Public Service of Colorado	Major Joint Cap. 2	380				
1985	Public Service of Colorado	Southeastern 2	500			-	-
1985	Colorado Springs, City of	Ray D. Nixon 2	200			-	-

U.S. EPA Region VIII State: Montana

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1980	Montana Power Co.	Colstrip 3	700	Bit.	0.56	VENT	LAFS
1981	Montana Power Co.	Colstrip 4	700	Bit.	0.7	VENT	LAFS

U.S. EPA Region VIII State: North Dakota

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Minnkota Power Coop.	Milton R. Young 2	454	Lig.	0.7	Elec.	LAFS
1977	Minnkota Power Coop.	Square Butte 2	430				
1978	Cooperative Power Assn.	Coal Creek 1	500	Lig.	0.63	Elec.	LMS
1979	Cooperative Power Assn.	Coal Creek 2	500	Lig.	0.63	Elec.	LMS
1980	Basin Electric Power Coop.	Missouri Basin 1	550	Lig.	0.8		LSS
1980	Basin Electric Power Coop.	Missouri Basin 2	550	Lig.	0.8		LSS
1981	Otter Tail Power Co.	Coyote P 1	440	Lig.	0.9	-	-
1981	Basin Electric Power Coop.	Antelope Valley 1	440	Lig.	1.0	-	LAFS
1982	Montana - Dakota Utility	Coyote 2	410				
1983	Basin Electric Power Coop.	Antelope Valley 2	440	Lig.	1.0	-	-
1983	Basin Electric Power Coop.	Missouri Basin 3	550	Lig.	0.8		PNS

U.S. EPA Region VIII State: Utah

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1977	Utah Power & Light	Huntington Canyon 1	415	Bit.	0.5	-	LMS
1978	Utah Power & Light	Emery 1	400	Bit.	0.5	Elec.	LSS
1980	Utah Power & Light	Emery 2	400			Elec.	PNS
1982	Nevada Power Co.	Warner Valley 1	250			-	PNS
1983	Nevada Power Co.	Warner Valley 2	250			-	PNS

U.S. EPA Region VIII State: Wyoming

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1978	Pacific Power & Light	Wyodak 1	330			Elec.	PNS
1979	Pacific Power & Light	Jim Bridger 4	500	Bit.	0.56	Elec.	WL
1980	Tri State Generating & Trans.	Laramie River 1	550			-	-
1982	Tri State Generating & Trans.	Laramie River 2	550			-	-
1982	Utah Power & Light	Naughton 4	400			Elec.	PNS
1983	Pacific Power & Light	Wyodak 2	330			-	-
1983	Tri State Generating & Trans.	Laramie River 3	550			-	-
1984	Utah Power & Light	Naughton 5	400			-	-

U.S. EPA Region IX State: Arizona

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1978	Arizona Public Service	Cholla 2	250	Bit.	0.44-1.0	-	LSS
1978	Arizona Electric Power Coop.	Apache Station 4	175				
1978	Arizona Electric Power Coop.	Apache Station 2	175	Bit.	0.5-0.8		LSS
1979	Arizona Electric Power Coop.	Apache Station 3	175	Bit.	0.5-0.8		LSS
1979	Salt River Project	Coronado 1	350	Bit.	1.0	PNS	PNS
1979	Arizona Electric Power Coop.	Apache Station 5	175			-	-
1979	Arizona Public Service	Cholla 3	250			-	-
1980	Salt River Project	Coronado 2	350	Bit.	1.0	PNS	LSS
1980	Arizona Public Service	Cholla 4	350			PNS	PNS
1983	Arizona Public Service	Cholla 5	350			-	-
1985	Tucson Gas & Electric	Springerville 1	330			-	-
1985	Salt River Project	Unsited 1	250			-	-
1993	Salt River Project	Coronado 3	350	Bit.	1.0		LSS

U.S. EPA Region IX State: California

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1983	Pacific Gas & Elec.	Unsited C 1	800				

U.S. EPA Region IX State: Nevada

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1982	Sierra Pacific Power	Valmy P 1	250			-	-
1983	Sierra Pacific Power	Valmy P 2	250			-	-
1985	L.A. Dept. of Water & Power	Intermountain 1	750			-	-
1985	Nevada Power	Allen 1	500			OTH	SCR
1986	L.A. Dept. of Water & Power	Intermountain 2	750			-	-
1986	Nevada Power	Allen 2	500			OTH	SCR
1987	L.A. Dept. of Water & Power	Intermountain 3	750			-	-
1987	Nevada Power	Allen 3	500			-	-
1988	Nevada Power	Allen 4	500				PNS
1988	L.A. Dept. of Water & Power	Intermountain 4	750				

U.S. EPA Region X State : Oregon

Year	Utility Name	Unit Name	Capacity MW	Coal Type	Percent Sulfur	Planned Part.	Control SO_2
1980	Portland General Elec.	Boardman Coal 1	550				

APPENDIX B

ASSUMPTIONS USED IN CALCULATING FGD SYSTEM COMPONENT DEMAND

Assumptions Used In Calculating the Demand for FGD System Components

1. The following characteristics of coal were used in the calculations;

Characteristics	Low-sulfur coal	High-sulfur coal
Sulfur content, %	0.8	3.5
Heat value, Btu/lb	8500	12,000

2. Low-sulfur coal is expected to be used at the following locations:

EPA Region	State
VI	New Mexico
	Texas
VIII	Colorado
	Montana
	North Dakota
	Utah
	Wyoming
	Arizona
IX	Nevada

3. A wet limestone nonregenerative system will be used for the FGD effort to be constructed on a new plant; retrofit systems are not considered.

4. Power plants due to come on line in 1977 and 1978 have, of necessity, already made commitments to manufacturers and are not included in this report.

5. The additional capacity of the power plants through year 2000 was projected by

   a. Estimating the additional capacity per year.

   b. Using the capacity of known coal-fired additions for the years 1979 to 1987; by using the difference between the coal-fired additions predicted by the FPC and that of the known additions for the years 1988 to 2000.

6. The additional demand for FGD system components was calculated in the following manner:

   a. Standard engineering calculations were used for the period 1979 to 1987.

   b. For the period 1988 to 2000, calculations were based on the assumptions that a typical power plant (500-MW) burning 3.5 percent sulfur coal requires

      - Two 22,681 kg/hr (25 ton/yr) ball mills
      - Four 198 m^3/s (420,000 acfm) scrubbers
      - Eleven 610 ℓ/s (10,000 gpm) pumps
      - One 54.6 m^2 (588 ft^2) vacuum filter
      - Two clarifiers with diameters of 31.3 M (103 ft) each
      - Four 198 m^3/s (420,000 acfm) fans

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

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7. AUTHOR(S) Vijay P. Patel and L. Gibbs		8. PERFORMING ORGANIZATION REPORT NO.
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16. ABSTRACT The report discusses the capabilities of equipment vendors to supply and install the quantity of flue gas desulfurization systems required to meet alternative standards for coal-fired steam generators. It analyzes limiting factors affecting supply capabilities (such as the availability of components, equipment, and skilled labor). It discusses guarantees that equipment vendors have made and are willing to make, and the penalties that they are willing to be assessed.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Air Pollution Control	13B
Flue Gases	Stationary Sources	21B
Desulfurization	New Source Performance Standards	07A,07D
Performance Standards		
Coal		21D
Boilers		13A

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