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**ECONOMIC ASSESSMENT OF ADVANCED FLUE GAS
DESULFURIZATION PROCESSES**

Final Report—Volume 1

By

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September 1981

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UNITED STATES DEPARTMENT OF ENERGY

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1. SUMMARY

1.1 INTRODUCTION

This report presents the results of a project sponsored by the Morgantown Energy Technology Center (METC) under Contract No. DE-AT21-MC08333, Task 17. The purpose of the study was to perform an economic and market assessment of advanced flue gas desulfurization (FGD) processes for application to coal-fired electric utility plants. The time period considered in the study is 1981 through 1990, and costs are reported in 1980 dollars.

The task was divided into the following four subtasks:

- 1) Determine the factors affecting FGD cost evaluations
- 2) Select FGD processes to be cost-analyzed
- 3) Define the future electric utility FGD system market
- 4) Perform cost analyses for the selected FGD processes

The study was initiated in September 1979, and separate reports were prepared for the first two subtasks. The results of the latter two subtasks appear only in this final report, since the end-date of those subtasks coincided with the end-date of the overall task. The Subtask 1 report, "Criteria and Methods for Performing FGD Cost Evaluations," was completed in October 1980. A slightly modified and condensed version of that report appears as Appendix B to this report. The Subtask 2 report, "FGD Candidate Process Selection," was completed in January 1981, and the principal outputs of that subtask appear in Appendices C and D to this report.

1.2 REGIONAL BASIS OF THE STUDY

Although national in scope, the study was conducted on a regional basis, employing fourteen regions and subregions defined by the National Electric Reliability Council (NERC). Alternatives considered were the Federal administrative regions and the Census regions. In consultation with the Technical Project Officer it was ultimately decided that the NERC regions were preferred, since only electric utility plant-size scrubbers were to be analyzed and the results would be more readily useful to the industry.

It was necessary to use subregions in some cases because the regions are so large and their geographic features so varied that the regions cannot be characterized. This is especially true of the Western Systems Coordinating Council (WSCC) Region, which covers (very nearly) eleven Western states and about one-third of the U. S. land area. A similar, but less pronounced, situation exists for the Mid-Continent Area Reliability Coordination Agreement (MARCA) Region and the Southwest Power Pool (SPP) Region. This notion led to the use of fourteen geographic regional areas as the basis for the study.

For each region/subregion, the location of the geographic centroid was graphically approximated. The centroid was further identified in terms of the nearest community that has rail service, since the quantities of coal and sorbents used by power plants are such that rail transportation is required. The regions/subregions and their approximate geographic centroids are shown in Figure 1-1.

A variety of regional conditions, such as the availability of different commodities required by FGD systems, were determined. A simplifying assumption in the analysis is that future FGD systems will be uniformly distributed about the geographic centroid of each region/subregion. As a result the centroid (i.e., community with rail service) represents the destination point for all commodities transported to that region.

Figure 1-1. ELECTRIC RELIABILITY COUNCIL REGIONS

Most of the commodity costs were obtained from published data and averaged on a regional basis. However, the availability and transportation cost associated with four FGD commodities (lime, limestone, magnesium oxide, and sodium carbonate) has been determined in accordance with how far the commodity must be moved to reach the centroid of each region. FOB prices were determined and transportation costs were developed using rail transit.

For each of these four commodities, points of origin were established as a function of the number and density of locations from which the commodity could be purchased. For a commodity having only a few production facilities in the United States and where interregional transport will be required, the closest production facility to the destination point was chosen to determine the transportation cost. For a commodity having several production facilities within each region, the closest facility to the destination point gave biased results. In such cases other methods for calculating average travel distances within a region were developed. The methodologies for determining the origin to destination routes are described in Appendix B.

1.3 THE MARKET FOR ELECTRIC UTILITY FGD SYSTEMS

The expected market for FGD systems in the 1981-1990 period is defined in terms of actual power plants that might employ them. These include plants that the electric utilities plan to build over the next 10 years and which will be required to meet the revised New Source Performance Standards (NSPS); existing oil- or gas-fired plants that might switch to coal under Fuel Use Act prohibition orders; and existing coal-fired plants that are not in compliance with air quality requirements under State Implementation Plans. On this basis, it has been possible to define the potential FGD system market fairly well. In addition, this approach indicates the potential for both new plants and retrofit systems in each of the 14 NERC regions and subregions. Details of the market assessment are given in Section 2.

The total expected electric utility market for FGD systems by 1990 is 117,633 MW, in a total of 232 units, broken down between new plants and retrofit systems as follows:

	<u>MW</u>	<u>Units</u>
New	110,284	200
Retrofit	<u>7,349</u>	<u>32</u>
Totals	117,633	232

Approximately 90 percent of this demand (in MW) stems from new plants that will have to meet the NSPS (Revised). Thus, any future changes in these regulations, particularly to reduce their stringency, could have major impact on the market for FGD systems.

The heaviest activity, in terms of FGD system installations, is expected to occur over the 4-year period of 1985-1988, when some 72 percent of the new FGD capacity will be acquired. The peak year is anticipated to be 1987, with a requirement for 23,187 MW of FGD capacity, or about 20 percent of the total.

The market assessment made no attempt to forecast the individual market shares that might go to the advanced FGD processes analyzed in this study. Some insight is available, however, through review of the data for FGD systems already specified by the utilities for installation during 1981-1990. In those cases, 62 percent have been limestone systems, 23 percent have been lime systems, and 7 percent have been lime spray dryers. Thus, all advanced processes together (other than the lime spray dryer) have garnered only 8 percent of the market to date.

1.4 COST ANALYSIS OF FGD SYSTEMS

A total of seven (7) FGD processes were subjected to analysis. Of the large variety of FGD processes available, wet scrubbing with lime or limestone is the most advanced commercially and, indeed, numerous systems

are in use at electric power plants. Therefore, lime and limestone processes were selected to serve as baseline reference systems in establishing the framework for comparison. The advanced (technically) processes selected for comparative analysis are the lime spray dryer; magnesia slurry (MgO); Wellman-Lord; aqueous carbonate; and a dual alkali system.

Performance of a sound comparative cost analysis of these FGD systems has two essential requirements. One is for a cost model that treats all systems equally and fairly. The other is the availability of reliable system cost data in forms useful to the model. Another factor in this case was the desire to utilize an existing cost model if at all possible.

In the search for a suitable cost model, attention focused on the TVA/Bechtel model and the PEDCo model (see Section 4), especially since both of these sources include detailed system cost data down to the equipment cost level. The TVA/Bechtel model proved to be limited because it was designed for analysis of lime/limestone systems and was unable to accommodate the advanced systems to be analyzed. The PEDCo model was unable to accommodate the aqueous carbonate system and the lime spray dryer. In addition, the PEDCo model (as reported in the literature) included process technology and design parameters that reflected early 1970s development status, rather than the latest mature technology.

For these principal reasons, SAI developed a cost model that makes partial use of selected features of the TVA/Bechtel and PEDCo models, but which can accommodate all of the FGD systems equally. System cost data developed by TVA/EPA were selected for use in the analysis, both because the data are well-documented for all seven systems of interest, and because the format of the data makes it most directly useful.

The detailed results of the comparative systems cost analysis are presented in Section 5, along with sensitivity analyses of selected cost elements. Two plant sizes -- 500 MW and 100 MW -- were analyzed in each of the 14 NERC regions. Moreover, costs were also developed for power plant

operation on two different types of coal in each region. These were high- and low-sulfur coals, as represented by actual coal consumption data for the regions.

All costs were converted to 1980 dollars, and both plant sizes were analyzed for the new plant and retrofit system cases. Costs were developed in a variety of ways for comparison, including system capital costs, levelized capital costs, levelized operating costs, and total levelized costs. In developing the levelized costs, a 30-year life was assumed for the new plants while a 20-year life was assumed for the retrofit systems. Thus, it is possible to compare and rank the FGD systems in each region on a variety of cost bases.

One of the more useful of these is total levelized costs. For this basis, Figures 1-2 through 1-5 present the ranges of costs for each FGD system and identify the NERC regions where the high- and low-cost values occur. The ranges are presented for both the high and low SO₂ removal cases. High and low SO₂ removal is used here rather than high- and low-sulfur coal because the coals employed in the analysis were those actually consumed in the regions (according to EIA data), and in some regions the "high sulfur coal" had a sufficiently low sulfur content that as little as 70 percent SO₂ removal would be required.

In any event, Figures 1-2 through 1-5 illustrate FGD system rankings as well as costs. In general, the SPP-1 and ERCOT regions experience the highest total levelized costs, while the MAAC and WSCC-4 regions experience the lowest such costs. These consistent results are due to the heating value and sulfur content of the coals used in the regions. These, in turn, affect system capital costs (equipment sizes) and operating costs (sorbents, power, maintenance) because of the quantities of flue gas that must be handled and the quantities of SO₂ that need to be removed.

There is a substantially wider spread between high and low costs for the high SO₂ removal case than for the low SO₂ removal case. The reason is

Figure 1-2. RANGE OF TOTAL LEVELIZED COSTS FOR NEW 500 MW FGD SYSTEMS (RANGE OVER REGIONS)

Figure 1-3. RANGE OF TOTAL LEVELIZED COSTS FOR NEW 100 MW FGD SYSTEMS (RANGE OVER REGIONS)

Figure 1-4. RANGE OF TOTAL LEVELIZED COSTS FOR RETROFIT 500 MW FGD SYSTEMS (RANGE OVER REGIONS)

Figure 1-5. RANGE OF TOTAL LEVELIZED COSTS FOR RETROFIT 100 MW FGD SYSTEMS (RANGE OVER REGIONS)

that the range of sulfur content among the high-sulfur coals is wider than for the low-sulfur coals commonly used in the regions.

Among the FGD systems themselves, the Wellman-Lord is consistently highest in cost. This stems from several factors, but principally from the substantial capital cost of the system's sulfur production subsystem (which is not sufficiently offset by the value of marketable sulfur produced), and relatively high operating costs accruing from the steam and natural gas required by the system.

The lime spray dryer consistently demonstrated the lowest total levelized costs. This is attributable to capital cost factors that include: 1) substantially lower direct investment for waste disposal compared with the other throw-away systems, 2) lower direct investment for stack gas reheat, and 3) an ESP credit resulting from the elimination of the electrostatic precipitator in favor of the somewhat lower cost baghouses for removal of particulates. For the LSD system the SO₂ absorption subsystem cost includes the baghouse (see Table 5-1 for capital cost details.)

It should be noted that all FGD systems considered in this study were assumed to be equally effective in achieving the required SO₂ removal. In other words, it was assumed that all of the systems can, in fact, satisfy the controlling emission standards (Revised NSPS).

It is also noted that the model computations were very extensive, and that a variety of further conclusions can be drawn from the results. A total of 112 combinations of parameters was analyzed for each system. However, a complete summary is not possible because the analysis compared the system on a regional cost basis. Thus, to use these results as an aid in selecting or further analyzing one of the FGD systems covered, the focus should be on individual regions.

2. ASSESSMENT OF THE MARKET FOR FGD PROCESSES

The objective of the market assessment (project subtask 3) is to make a quantitative determination of the future FGD markets on a regional basis. The regions and subregions selected for the assessment are the NERC regions shown in Figure 1-1. The selection of these regions for both the market evaluation and the comparative costing of advanced FGD systems places the overall analysis on a consistent bases. The time span being considered for the market evaluation is 1981 through 1990.

Possible uses of these data include:

- o Ranking of regions where FGD byproducts may be produced
- o Identification of regions where required FGD process commodities may not be available
- o Ranking of areas where coal usage is likely to increase due to electric utilities
- o Ranking of regions where FGD waste disposal is likely to increase
- o First order identification (by region) of potential production of FGD byproducts.

2.1 REGULATIONS AFFECTING FUTURE COAL AND FGD USAGE

The two major Federal laws which will affect coal and FGD usage are the Powerplant and Industrial Fuel Use Act (FUA) and the Clean Air Act (CAA). The FUA prohibits the use of oil and gas in new facilities and in existing utilities which meet certain requirements. The CAA mandates the use of FGD for new coal-fired utility plants and could affect FGD usage in existing plants. Each Act is described below.

2.1.1 Powerplant and Industrial Fuel Use Act

The FUA and its predecessor, the Energy Supply and Environmental Coordination Act (ESECA), mandated that existing powerplants be restricted from burning oil and gas if certain conditions are met.

Under ESECA, the Federal Energy Administration (FEA), later part of the Department of Energy (DOE), was required to prohibit certain existing powerplants from using petroleum and natural gas as fuel. The Act also allowed DOE to order that new powerplants be designed and constructed with the capability of burning coal as their primary energy source. Before DOE could prohibit an existing powerplant from burning petroleum or natural gas, it had to determine whether the unit in question possessed or could acquire the necessary coal-handling facilities and equipment to burn coal, and the associated cost. DOE also had to determine that: the burning of coal at the facility was practicable and consistent with the purposes of ESECA; coal and coal transportation facilities would be available for the period the order would be in effect; and the order would not impair the reliability of service in the area served by the converting powerplant. Under ESECA the burden of making and defending these case-by-case findings was placed solely upon DOE. Also, all provisions of the National Environmental Policy Act of 1969 (NEPA) and the Clean Air Act had to be met, including conducting environmental impact analyses. The U.S. Environmental Protection Agency (EPA) needed to certify the earliest date on which a facility could convert to coal and still meet all applicable air quality regulations. Prior to certification, EPA required the concurrence of the governor of the state in which the facility is located.

The FUA prohibits the use of petroleum and natural gas in new electric powerplants and prohibits the use of natural gas in existing powerplants in 1990 or thereafter. It prohibits the construction of new electric powerplants without the capability to use coal or another alternate fuel. These statutory prohibitions distinguish FUA from ESECA because ESECA required specific orders for every unit.

The Act also grants DOE the authority to issue orders prohibiting the use of petroleum or natural gas in specific existing powerplants. To do this, DOE must make certain findings regarding the technical capability of the unit to burn coal or an alternate fuel and the financial feasibility of the conversion. The Department's FUA prohibition authority and burden of proof requirement are similar to that under ESECA. A principal difference is that FUA permits DOE to base its findings on any one of a wide variety of alternate fuels, such as wood and municipal waste, rather than exclusively on coal. Moreover, when a powerplant cannot use coal or another alternate fuel solely, DOE may prohibit the use of oil or gas in excess of a minimum amount needed in a fuels mixture to maintain reliability and fuel efficiency. Additionally, EPA certification and concurrence by the state governor are no longer required.

The FUA provides for temporary and permanent exemptions from statutory as well as discretionary prohibitions. Exemptions may be granted where the petitioner demonstrates that certain physical, economic, environmental, legal, or other factors preclude the use of an alternate fuel or mixture. The burden of proof that an exemption is warranted rests with the petitioner.

2.1.2 Clean Air Act (CAA)

The Clean Air Act (CAA) mandates FGD systems through several sets of regulations which are implemented through each state's State Implementation Plan (SIP). For the most part, the regulations are developed by EPA and adopted by the states through the passage of enabling legislation. In the case of existing sources, the regulations are developed by the state and reviewed and adopted by EPA. The Prevention of Significant Deterioration (PSD) regulations allow for Federal and state joint determination of the specifics. The regulations which affect the usage of FGD by electric utilities are:

- o New Source Performance Standards
- o EPA Emission Offset Interpretive Ruling
- o Prevention of Significant Deterioration
- o Emission Limitations for Existing Sources

Each of these is summarized below. Further information may be found in the Subtask 1 report for this project.

New Source Performance Standards

New Source Performance Standards (NSPS) for electric utilities first took effect on all utilities commencing construction operation after August 18, 1971. These standards limited the SO₂ emission rate to 1.2 lb SO₂/10⁶ Btu heat input for all utilities with a rated capacity of 73 MW or greater. Most utilities were able to meet this requirement without the use of FGD. Utilities commencing operation after September 18, 1978, are required to install FGD.

Their maximum emission rate is still limited to $1.2 \text{ lb SO}_2/10^6 \text{ Btu}$ of heat input. However, for steam coals burned by utilities with uncontrolled emissions exceeding $12 \text{ lb SO}_2/10^6 \text{ Btu}$, SO_2 reductions exceeding 90 percent would be required to limit emissions to a maximum of $1.2 \text{ lb SO}_2/10^6 \text{ Btu}$. For those coals whose uncontrolled emissions would range from 12 to $6 \text{ lb}/10^6 \text{ Btu}$, a constant 90-percent removal is required, resulting in controlled emissions ranging from $1.2 \text{ lb SO}_2/10^6 \text{ Btu}$ to $0.6 \text{ lb}/10^6 \text{ Btu}$. For coals with sulfur contents that would emit 6 to $2 \text{ lb SO}_2/10^6 \text{ Btu}$, a variable removal rate between 90 and 70 percent is required to achieve a constant $0.6 \text{ lb SO}_2/10^6 \text{ Btu}$.³

These requirements apply not only to new facilities but to some existing facilities which undergo modifications. Modifications are defined to include any change, physically or operationally, to an existing facility resulting in an increase in the emission rate of sulfur dioxide. However, the term "modification" explicitly excludes:

- 1) Any facility converting from oil or gas to coal as a major fuel source, or
- 2) Any existing facility which increases its production rate without the aid of a capital expenditure on that facility.

EPA Emission Offset Interpretation Ruling

EPA's emission offset ruling is applicable to new and modified power plants in areas exceeding the Primary National Ambient Air Quality Standards. It has become known as EPA's Bubble Concept. Under this ruling, a utility cannot commence construction until it has met the following requirements:

- 1) The emission rate must be the lowest achievable for such a source
- 2) All other existing major sources located in the same state and owned by the same company must be in compliance with any applicable emission limitations or standards
- 3) Compensating emission reductions in the affected area are required

- 4) The emission offset should provide a positive air quality benefit in the affected area.

The lowest achievable emission rate (LAER) will be determined on a case-by-case basis. However, at a minimum, it must be as stringent as the NSPS.

The above requirements are waived for the following modifications:

- o Increasing production rates without exceeding the operating design capacity of the source,
- o Changing to an alternative fuel or raw material, if on December 21, 1976, the source was capable of burning such fuel or material, and/or
- o Fuel switching due to a lack of adequate fuel supplies or as a result of EPA regulations.⁴

Prevention of Significant Deterioration

Prevention of Significant Deterioration Regulations were mandated by the Supreme Court to ensure that areas cleaner than the Secondary Ambient Air Quality Standards were not indiscriminately polluted up to these secondary standards. They require major new sources to apply the Best Available Control Technology (BACT). BACT is to be determined on a case-by-case basis and must be at least as stringent as the NSPS. Major modifications and/or changes in operation which increase SO₂ emission by more than 100 tons per year are included in these regulations. A change in operation will not include "use of an alternate fuel or raw material, if prior to January 6, 1975, the source was capable of accommodating such fuel or material," nor fuel switching orders mandated by ESECA and any superseding legislation.⁵

Emission Limitations for Existing Sources

Each state was required to develop a State Implementation Plan (SIP) under the CAA which would demonstrate the ability of the state to meet and maintain ambient air quality standards (AAQS). The basic approach was to limit emissions from existing sources, including absolute reductions where

necessary. For point sources, such as utilities, the states put restrictions on the fuels to be burned and/or developed specific emission rates on a source-by-source basis. Where specific emission rates were developed, a compliance schedule (negotiated with the source) was developed. Hence, each existing electric utility facility has some limitation placed on its emissions. In cases where a utility's limits were based on low sulfur oil or gas, conversion to coal is quite likely to violate the emission limitations unless a variance is applied for and favorably acted on by the state and EPA.

2.2 METHODOLOGY

2.2.1 New FGD Applications

New FGD applications are defined as those FGD systems which will be placed on new power plants. That is, the FGD systems will come on-line at approximately the same time as the plant. In order to determine the number, size, and location of new power plants coming on-line between 1980 and 1990, several references were used, including DOE's Inventory of Power Plants in the United States^{6,7} and EPA's Utility FGD Survey.⁸

The 1978 NSPS were used to determine which new power plants would require FGD. Consequently, if a construction period of approximately 4 years⁹ is assumed for coal-fired power plants, all plants coming on-line on or after January 1, 1983, will be required to comply with the 1978 NSPS. As a result, the following conditions define which new plants should require FGD:

- 1) Power plants coming on-line prior to January 1, 1983, might require FGD and EPA's Utility FGD Survey identifies these plants.
- 2) Power plants coming on-line on January 1, 1983, or later will require FGD and DOE's Inventory of Power plants and EPA's Utility FGD Survey combined identifies these plants.

With this as the guideline, the following data were collected:

- o Utility and station name
- o State and ERC region
- o Boiler size and on-line date.
- o FGD type, size, and on-line date
- o Controlling regulation

Controlling regulation was either identified as NSPS ORIGINAL or NSPS REVISED. NSPS ORIGINAL refers to plants initiating construction prior to or on September 18, 1978, and NSPS REVISED refers to plants initiating construction after September 18, 1978. Data verifications and entries were made as follows:

- o For power plants coming on-line prior to January 1, 1983
 - Utility and station name; location; size, type and on-line date of FGD systems were obtained from EPA's utility FGD Survey
 - FGD size and on-line date were checked with boiler size and startup date identified in DOE's Inventory
 - = If EPA's FGD size was less than or equal to DOE's boiler size, it was entered into the data base.* If EPA's FGD size was greater than DOE's boiler size, the FGD size was reduced to the boiler size and entered into the data base.
 - = If EPA's FGD on-line date was the same or later than DOE's, boiler on-line date was entered into the data base.* If EPA's FGD on-line date was earlier than DOE's boiler on-line date, the boiler on-line date was also used as the FGD on-line date.
- o For power plants coming on-line on or after January 1, 1983
 - All plants listed in DOE's Inventory for this period were entered into the data base. FGD size and startup date entries were matched to that of the boiler. If EPA's Survey identified a type of FGD system for the particular plant, it was also entered into the data base.

* Plants coming on-line in this period could have an FGD unit smaller than the boiler or coming on-line later than the boiler since FGD was not required.

- EPA's Survey was then checked for future FGD systems on plants which were not listed in DOE's Inventory. All such plants identified were entered into the data base.

2.2.2 Retrofit FGD Applications

Retrofit FGD applications are defined as those FGD systems which will be placed on existing power plants. These systems will have an on-line date sometime after that of the power plant. Retrofit FGD applications have been subdivided into two categories: COMMITTED RETROFIT and POTENTIALLY REQUIRED RETROFIT. Committed retrofit applications are those in which the utility has committed to the use of FGD. Identification of these committed systems was accomplished by use of EPA's Utility FGD Survey and by contacting EPA regional offices where the status of commitment and/or requirement was not clear. Potentially required cases are those where commitment and/or requirements are still not clear. The majority of these cases are power plants with outstanding orders (under ESECA and FUA) to convert to coal. An in-house analysis conducted by DOE¹⁰ identified power plants in the northeast section of the country as either requiring FGD or not if conversion took place. These data were used to eliminate those plants indicated as not requiring FGD from the possible cases and, therefore, from the data base.

Data entries for the retrofit cases are similar to those for new FGD applications. Data gathering and verification were conducted for each retrofit case as follows:

o Committed Retrofit

- EPA's utility FGD Survey was utilized to collect all data for those plants listed in the survey. All of these applications were determined to be due to existing SIP schedules.
- FGD size was verified via comparison with its boiler size as noted in Electrical World. If EPA's Survey indicated a FGD size equal to or less than the boiler size, it was reduced to the size of the boiler and entered.
- A list of all power plants not in SIP compliance was obtained from EPA.¹² EPA regional offices were contacted

to determine if FGD was included as part of the compliance schedule. In no case was FGD required.

- A list of all power plants upgrading their facilities so as to increase their net MW capacity was produced from the DOE power plant inventory. State and EPA regional offices were contacted to determine if FGD would be required as a result of the modifications. In no case was FGD required.

- o Potentially Required Retrofit

- As noted earlier, these cases include mostly those potentially required FGD applications due to fuel conversion orders. The data on each FGD application were taken from the DOE in-house analysis¹⁰ and compared to that in Electrical World in exactly the same manner EPA's Survey data were compared for the Committed Retrofit cases.

2.3 CONCLUSIONS

The data base resulting from the above described methodology appears as Appendix A of this report.

The following tables summarize the information contained in that data base.

Table 2-1 summarizes the committed and potentially required FGD capacity for the years 1981 through 1990. Approximately 24 percent of the planned capacity shown in Table 2-1 has already had a type of FGD system specified. Such capacity is not included in the FGD market. The FGD market contains only the FGD-unspecified portion of the electric utility capacity that is either committed or potentially required to reduce SO₂ emissions in the 1981 to 1990 period.

Table 2-2 shows the regional FGD markets by year for the period. The market size is expressed in terms of electric utility capacity (MW) coming on-line that will require FGD. Also indicated are the total number of units required to generate the capacity. The first column in Table 2-2 contains the data for retrofit systems only. No year of installation has been determined for the retrofit systems. The retrofits make up

TABLE 2-1. SUMMARY OF COMMITTED AND POTENTIALLY REQUIRED
FGD CAPACITY FOR YEARS 1981-1990, IN GROSS MW

REGION	FGD-COMMITTED		POTENTIALLY REQUIRED			TOTAL	
	NEW		RETROFIT	RETROFIT		SPECIFIED	UNSPECIFIED
	SPECIFIED	UNSPECIFIED	SPECIFIED	SPECIFIED	UNSPECIFIED		
ECAR	6735	19689	1708	0	0	8443	19689
ERCOT	5225	8730	0	0	0	5225	8730
MAAC	0	6870	724	201	249	925	7119
MAIN	1265	4622	0	0	1110	1265	5732
MARCA-1	2720	1720	0	0	220	2720	1940
MARCA-2	1550	4750	0	0	147	1550	4897
NPCC	850	2878	0	0	2948	850	5826
SERC	4294	18447	575	0	1968	4869	20415
SPP-1	280	6603	0	0	707	280	7310
SPP-2	0	19320	0	0	0	0	19320
WSCC-1	4230	1500	0	0	0	4230	1500
WSCC-2	1630	7630	0	0	0	1630	7630
WSCC-3	1850	6365	0	0	0	1850	6365
WSCC-4	1348	1160	0	1510	0	2858	1160
TOTAL	31977	110284	3007	1711	7349	36695	117633

TABLE 2-2. SUMMARY OF FGD MARKET BY YEAR

NEW & RETROFIT SYSTEMS

(GROSS MW/UNIT COUNT)

REGION	19XX A	1981- 1982 B	1983	1984	1985	1986	1987	1988	1989	1990	TOTAL
ECAR	0/ 0	0/ 0	2785/ 5	3516/ 5	3611/ 7	4100/ 6	2103/ 4	3130/ 4	0/ 0	444/ 1	19689/ 32
ERCOT	0/ 0	0/ 0	0/ 0	1150/ 2	1500/ 2	1150/ 2	2440/ 4	2490/ 6	0/ 0	0/ 0	8730/ 16
MAAC	249/ 2	0/ 0	0/ 0	630/ 1	630/ 1	630/ 1	2300/ 4	1880/ 3	0/ 0	800/ 1	7119/ 13
MAIN	1110/ 3	0/ 0	400/ 1	90/ 1	840/ 3	1342/ 5	1400/ 4	0/ 0	550/ 1	0/ 0	5732/ 18
MARCA-1	220/ 2	0/ 0	0/ 0	0/ 0	0/ 0	1220/ 3	0/ 0	500/ 1	0/ 0	0/ 0	1940/ 6
MARCA-2	147/ 1	0/ 0	650/ 1	0/ 0	1100/ 2	900/ 2	800/ 1	500/ 1	800/ 1	0/ 0	4897/ 9
NPCC	2548/ 8	0/ 0	0/ 0	760/ 1	0/ 0	0/ 0	2118/ 3	0/ 0	0/ 0	0/ 0	5826/ 12
SERC	1968/12	0/ 0	1254/ 2	2185/ 3	5464/ 9	787/ 2	5691/ 9	1623/ 2	660/ 1	783/ 1	20415/ 41
SPP-1	707/ 4	0/ 0	1215/ 2	680/ 1	2158/ 5	800/ 2	500/ 1	1250/ 3	0/ 0	0/ 0	7310/ 18
SPP-2	0/ 0	0/ 0	1240/ 2	1180/ 2	3430/ 5	4860/ 7	2890/ 5	5720/ 9	0/ 0	0/ 0	19320/ 30
WSCC-1	0/ 0	0/ 0	0/ 0	0/ 0	0/ 0	500/ 1	0/ 0	1000/ 2	0/ 0	0/ 0	1500/ 3
WSCC-2	0/ 0	0/ 0	830/ 2	1770/ 3	2670/ 5	200/ 1	940/ 2	1220/ 3	0/ 0	0/ 0	7630/ 16
WSCC-3	0/ 0	0/ 0	250/ 1	500/ 2	795/ 2	1595/ 3	1675/ 4	1550/ 3	0/ 0	0/ 0	6365/ 15
WSCC-4	0/ 0	0/ 0	0/ 0	330/ 1	0/ 0	0/ 0	330/ 1	0/ 0	0/ 0	500/ 1	1160/ 3
TOTAL	7349/32	0/ 0	8624/16	12791/22	22198/41	18084/35	23187/42	20863/37	2010/ 3	2527/ 4	117633/232

A. YEAR OF FGD INSTALLATION HAS NOT BEEN DETERMINED FOR RETROFIT SYSTEMS.

B. SYSTEM TYPE ASSUMED ALREADY SPECIFIED FOR FGD START-UP BEFORE 1983.

approximately 6 percent of the total market. The regional distribution of FGD demand indicates that there will be a concentration of future capacity in the mid-west and southeast states. Approximately half of the FGD market is contained in three regions (ECAR, SERC, and SPP-2). Utilities in these regions that select FGD systems producing byproduct sulfur should find a well-developed industry for the storage, consumption and distribution of sulfur. (A further discussion of the commodity and byproduct markets appears in Appendix B.) The unit count data associated with the FGD capacity indicate a demand for smaller sized systems in the market for retrofit FGD systems. The data show an average of only 230 MW per unit for the retrofit systems, while data on non-retrofit future FGD indicate an average of 550 MW per planned unit.

Table 2-3 summarizes the type of FGD systems selected for future capacity where FGD systems have been specified. These systems are not part of the market (since they are already selected) but are of interest since they indicate the trends in the selection process. Limestone and lime rank first and second as the favored systems. Among the "Advanced" systems, lime spray dryer is the preferred system, having captured as much future capacity as the remaining four system-types combined.

Table 2-4 gives some insight into how regulations have influenced the demand for FGD and how the market might be influenced by changes in the existing regulations. For the years 1981 to 1990 the decisions to employ FGD systems have been dominated by the NSPS. Approximately 90 percent of the market demand is due to the Revised NSPS and the next greatest demand (4 percent) is due to the FUA. Within the framework of the technology considered and existing regulations, only a change in the revised NSPS would significantly impact the FGD market.

Figures 2-1 and 2-2 graphically present data from Tables 2-2 and 2-3, showing the future FGD demand and the relative market shares for FGD systems already specified. Figure 2-1 indicates a substantial drop in planned new capacity after 1988. Figure 2-2 shows the current (1981-1990) preferences of electric utilities among the seven types of FGD systems analyzed. The percentage distributions are based on the capacity of

TABLE 2-3. SUMMARY OF FGD CAPACITY BY SPECIFIED SYSTEM TYPE FOR YEARS 1981-1990

NEW SYSTEMS (GROSS MW)							
REGION	LIME	LIMESTONE	AQUE CARB	DUAL ALK	WELMN LORD	MAGNESIA	L SPRY DRY
ECAR	2050	3997	0	688	0	0	0
ERCOT	0	5225	0	0	0	0	0
MAIN	0	1265	0	0	0	0	0
MARCA-1	1478	0	410	0	0	0	832
MARCA-2	0	1550	0	0	0	0	0
NPCC	0	850	0	0	0	0	0
SERC	0	4294	0	0	0	0	0
SPP-1	0	0	0	0	0	0	280
WSCC-1	3070	1160	0	0	0	0	0
WSCC-2	0	500	0	0	0	0	1130
WSCC-3	0	1600	250	0	0	0	0
WSCC-4	0	336	0	0	682	0	330
TOTAL	6598	20777	660	688	682	0	2572

RETROFIT SYSTEMS (GROSS MW)							
REGION	LIME	LIMESTONE	AQUE CARB	DUAL ALK	WELMN LORD	MAGNESIA	L SPRY DRY
ECAR	300	1408	0	0	0	0	0
MAAC	0	0	0	0	0	925	0
SERC	0	575	0	0	0	0	0
WSCC-4	1510	0	0	0	0	0	0
TOTAL	1810	1983	0	0	0	925	0

TABLE 2-4. SUMMARY OF FUTURE FGD CAPACITY BY UNDERLYING
REGULATORY BASIS FOR THE YEARS 1981-1990, IN GROSS MW

9/18/1981

REGIONS	REGULATION> STATUS OF FGD SYSTEMS>	NSPS	NSPS REVISED		SIP		ESECA		FUA
		SPECIFIED	SPECIFIED	UNSPECFD	SPECIFIED	UNSPECFD	SPECIFIED	UNSPECFD	UNSPECFD
ECAR		2027	4703	19689	1708	0	0	0	0
ERCOT		1432	3793	8730	0	0	0	0	0
MAAC		0	0	6870	574	0	351	0	249
MAIN		865	400	4622	0	0	0	75	1035
MARCA-1		1526	1194	1720	0	0	0	220	0
MARCA-2		150	1400	4750	0	0	0	147	0
NPCC		0	850	2878	0	0	0	0	2948
SERC		614	3680	18447	575	0	0	1067	901
SPP-1		0	280	6603	0	0	0	707	0
SPP-2		0	0	19320	0	0	0	0	0
WSCC-1		0	4230	1500	0	0	0	0	0
WSCC-2		1000	630	7630	0	0	0	0	0
WSCC-3		0	1850	6365	0	0	0	0	0
WSCC-4		598	750	1160	1510	0	0	0	0
<hr/>									
TOTAL		8212	23765	110284	4367	0	351	2216	5133

Figure 2-1. Future FGD Demand By Year

Note: Market share data for specified FGD systems is taken from Table 2-3 and Appendix A.

Figure 2-2. Market Shares For FGD Systems Already Specified For Years 1981-1990

specified system-types for combined new and retrofit applications. Among the "Advanced" systems only the magnesium oxide process had a specified retrofit application. Interestingly, it had no new system applications specified.

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3. ADVANCED FGD SYSTEM SELECTION

The purpose of this section is to provide the background and criteria upon which the selection of candidate FGD processes has been made. Five advanced FGD processes were eventually chosen for detailed cost comparison with two baseline, conventional processes - lime and limestone wet scrubbing.

3.1 BACKGROUND

Since the establishment of DOE's activity in fossil-fuel cleanup technology in 1979, the Morgantown Energy Technology Center (METC) has maintained an active and ongoing program of research and development in several FGD process technology areas. The major thrust of METC's efforts has been directed toward improving the operation and performance of conventional lime/limestone processes. Recognizing the rapid development of several new and advanced FGD technologies, DOE has set goals to pursue additional efforts in advanced FGD technology with current emphasis on the following items:

- o Retrofittable FGD systems for eastern coal applications which produce an easily disposable waste product
- o Regenerable FGD systems which produce a salable byproduct and utilize coal for regeneration
- o Dry FGD systems for western coal application with low sorbent consumption and manageable waste products

3.2 SELECTION OF CANDIDATE FGD SYSTEMS

Nearly two dozen FGD processes and systems have emerged as potential candidates for utility application. Figure 3-1 categorizes the major emerging FGD processes into two types; these are 1) recovery processes, and

Figure 3-1. ALTERNATE EMERGING FGD PROCESSES

2) throwaway processes. These processes represent a wide spectrum of technological achievement ranging from commercial technology, through demonstrated, to less-developed processes. Table 3-1 summarizes the total FGD capacity of the major FGD processes used for utility application in the U. S. The total FGD system capacity is comprised of operational, under construction, or planned systems.

Table 3-1. DISTRIBUTION OF UTILITY FGD SYSTEMS BY PROCESS

(As of 1980)

Process	FGD Capacity, MW			
	Operational	Under Construction	Planned	Total
Limestone	11,172	8,816	16,164	36,152
Lime	9,869	4,940	6,035	20,844
Lime/spray drying	0	1,120	1,907	3,027
Lime/limestone	20	0	475	495
Sodium carbonate	925	330	250	1,505
Magnesium oxide	0	574	750	1,324
Wellman Lord	1,540	534	0	2,074
Aqueous carbonate/ spray drying	0	540	0	540
Citrate	60	0	0	60
Total	24,767	16,854	26,423	68,044

Source: Ref. 1

Important trends in FGD process development for the past decade can be generalized as follows:

- o Wet lime/limestone processes provide the greatest process experience and reliability in the U. S. (> 90% total capacity), but these processes face increased waste disposal problems.
- o Advanced FGD processes generally are wet-phase sodium, lime, and magnesium-based processes which produce a recovery by-product (elemental sulfur, sulfuric acid) or high quality gypsum.
- o New promising FGD processes involve the dry injection of nahcolite, lime, and sodium carbonate followed by fabric filters or an electrostatic precipitator. The spray dryer systems are receiving increasing attention, especially for low sulfur western coal applications.

In order to select the candidate FGD system for comparative cost evaluation, thereby providing an objective and consistent means of comparing various processes, screening criteria were established. The screening criteria were then applied to each process, and the results were compared and used to select the processes that appeared to be best suited for near-term commercial applications. The criteria used for this screening were:

- o Development Status in the United States
 - Current development level
 - Use of commercial technology
 - Projected process capacity
- o Process Performance and Technical Consideration
 - SO₂ Removal Efficiency
 - Multiple emission control potential
 - Secondary pollution problem
 - Raw material requirement
 - Land requirement
 - Water and energy consumption

- o Process Applicability and Process Controllability
 - Utility application
 - Industrial application
 - Process controllability
- o Process Economics and Potential Improvements
 - Capital requirement
 - Annual revenue requirement
 - Economic improvement potential

Detailed summaries of technical and economic comparison of various advanced FGD processes using these criteria are contained in Tables C-1 through C-4 of Appendix C. These results were subsequently used to rank each FGD process according to assigned weight points for each sub-criteria area as shown in Table 3-2. After review of ranked systems, DOE/METC selected the following seven systems for FGD cost evaluation:

- o Lime
- o Limestone
- o Double alkali
- o Magnesium oxide
- o Wellman-Lord
- o Aqueous carbonate
- o Lime spray dryer

The first two processes represent a reference baseline for the cost evaluation since over 90 percent of the operating FGD experience is from these process types.

As is evident in Table 3-3 and Table 3-4, each of the five advanced FGD systems and the two base case systems selected for the cost analysis requires different combinations and quantities of raw materials and utilities, and vary in ability to produce a marketable byproduct. As the availability

Table 3-2. PRELIMINARY SCREENING OF ALTERNATIVE FGD PROCESSES

	Maximum Weight Point	Aqueous Carbonate	Absorption/Steam Stripping RESOX	Activated Char and RESOX	Aluminum Sulfate	Chiyoda 121	Double Alkali	Magnesium Oxide	Wellman-Lord	Spray Dryer
o Development Status in the United States										
- Current Development Level	5	3	1	1	3	1	4	5	5	4
- Use of Commercial Technology	5	1	1	2	3	4	5	5	5	5
- Projected Process Capacity	5	3	1	1	1	2	4	5	5	5
Subtotal		7	3	4	7	7	13	15	15	14
o Process Performance and Technical Consideration										
- SO ₂ Removal Efficiency	5	3	4	4	4	3	4	4	4	3
- Multiple Emission Control Potential	5	3	1	5	1	1	3	3	3	4
- Secondary Pollution Problem	5	3	1	3	1	1	1	3	4	4
- Raw Material Requirement	5	3	1	1	3	5	4	4	4	3
- Land Requirement	15	12	12	15	5	5	5	12	12	12
- Water and Energy Consumption	5	3	2	5	1	1	1	4	4	5
Subtotal		27	21	33	15	16	18	30	31	31
o Process Applicability and Process Controllability										
- Utility Application	5	3	2	1	3	4	5	4	5	4
- Industrial Application	5	2	1	1	3	2	5	2	5	5
- Process Controllability	5	2	2	1	4	4	1	4	4	4
Subtotal		7	5	3	10	10	11	10	14	13
o Process Economics and Potential Improvements										
- Capital Requirement	10	6	6	7	8	10	8	8	7	10
- Annual Revenue Requirement	10	4	10	4	6	8	6	8	8	8
- Economic Improvement Potential	10	6	6	6	3	6	3	3	3	6
Subtotal		16	22	17	17	24	17	19	18	24
TOTAL		57	51	57	49	57	59	74	78	82

Table 3-3. IDENTIFICATION OF RAW MATERIAL, UTILITY, AND PRODUCT YIELD ITEMS CHARACTERISTIC OF SEVEN FGD SYSTEMS*

		Lime	Limestone	Dual Alkali	Magnesium Oxide	Wellman Lord	Aqueous Carbonate	Lime Spray Dryer
				Regen	Regen	Regen	Regen	
<u>Raw Material</u>								
Lime	(95% CaO)	x	-	x	-	-	-	x
Limestone	(90% CaCO ₃)	-	x	-	x	-	-	-
Soda Ash	(99.8% Na ₂ CO ₃)	-	-	x	-	x	x	-
Magnesium oxide	(98% MgO)	-	-	-	x	-	-	-
Coal		-	-	-	-	-	x	-
Catalyst		-	-	-	x	-	x	-
<u>Utilities</u>								
Electricity		x	x	x	x	x	x	x
Water		x	x	x	x	x	x	x
Steam		x	x	x	x	x	-	-
Fuel Oil		-	-	-	x	-	x	-
Natural Gas		-	-	-	-	x	-	-
Heat Credit		-	-	-	x	x	x	-
<u>Waste Production</u>								
Pond Disposal		x	x	x	-	-	-	-
Landfill Disposal		-	-	-	-	-	-	x
<u>By-Product Production</u>								
Sulfuric Acid		-	-	-	x	-	-	-
Sulfur		-	-	-	-	x	x	-

* These systems have been selected for the economic analysis.

**Table 3-4. COMPARISON OF TYPICAL RAW MATERIAL AND UTILITY USAGE RATES
AND PRODUCT YIELD FOR SEVEN FGD SYSTEMS***

FGD SYSTEM	BASE CASE SYSTEMS			ADVANCED SYSTEMS				
Units	Lime	Limestone	Dual Alkali	Magnesium Oxide	Wellman Lord	Aqueous Carbonate	Lime Spray Dryer	
<u>Raw Material</u>								
Lime (tons/hr)	12.84	-	12.23	-	-	-	14.14	
Limestone (tons/hr)	-	29.96	-	-	-	-	-	
Soda Ash (tons/hr)	-	-	0.48	-	1.36	1.98	-	
Magnesium oxide (tons/hr)	-	-	-	0.31	-	-	-	
Coal (tons/hr)	-	-	-	-	-	9.37	-	
Catalyst (liters/hr)	-	-	-	0.34	-	N/A	-	
<u>Utilities</u>								
Electricity (kW)	4.4x10 ³	5.20x10 ³	3.10x10 ³	7.21x10 ³	4.46x10 ³	5.99x10 ³	3.95x10 ³	
Water (1000 gal/hr)	26.51	28.90	24.11	368.99	659.63	238.82	7.32	
Steam (10 ⁶ Btu/hr)	42.98	47.87	43.01	44.20	138.67	-	-	
Fuel Oil (gal/hr)	-	-	-	1.19x10 ³	-	475.84	-	
Natural Gas (1000 ft ³ /hr)	-	-	-	-	80.11	-	-	
Heat Credit (10 ⁶ Btu/hr)	-	-	-	25.87	4.19	60.77	-	
<u>Waste Production</u>								
Pond Disposal (tons/hr)	70.64	90.34	70.32	-	-	-	-	
Landfill Disposal (tons/hr)	-	-	-	-	-	-	26.55	
<u>By-Product Production</u>								
Sulfuric Acid (tons/hr)	-	-	-	20.74	-	-	-	
Sulfur (tons/hr)	-	-	-	-	6.32	6.64	-	
<u>Operating Characteristics:</u>								
Plant Size	500 MW			Coal Heating Value		11,000 Btu/lb		
Plant	New			Gas Flow Rate (300°F)		949,000 acfm		
Plant Efficiency Rating	9760 Btu/kWh			SO ₂ Removal Rate		13.275 ton/hr		
Plant Operating Capacity	70%			Ash		15%		
Excess Oxygen	39%			Pond Depth		20 ft		
Coal Sulfur Content	3.5%			Landfill Height		40 ft		

* These systems have been selected for the economic analysis. For cost comparisons, the FGD systems have been assumed equally effective in removing sulfur. It should be noted that greater than 70 percent SO₂ removal has not been demonstrated for the LSD system.

N/A = Not available

of any item decreases within a region,* those FGD systems dependent on that item may become less desirable in that region. Economically, this is reflected in the unit cost of an item which may, in turn, contribute negatively toward a system's economic desirability. This is the basis for performing regional economic analysis on the seven FGD systems. Regional costs are presented in Section 4.2.

* See Appendix B for commodity distribution within the contiguous United States.

SECTION 3 REFERENCES

1. Smith, N. T., N. T. Melia, B. A. LaSake, Jr., "Recent Trends in Utility Flue Gas Desulfurization Systems," presented by PEDCo at 6th Symposium on FGD, Houston, Texas, October 18-30, 1980.

4. COST ANALYSIS OF FGD PROCESSES

4.1 FGD COST MODEL

4.1.1 Cost Model Selection Methodology

Several comprehensive evaluations of FGD system costs and models for estimating such costs have been published during the 1975-1980 period. The most notable ones have been identified in Table 4-1. A review of this published FGD cost data has indicated that a wide disparity exists between different sources. The major differences in projected FGD costs can be attributed to:

- o Different dates of cost estimation
- o Effect of geographic location
- o Varying degree of process technology and equipment design status
- o Different fuel type and emission control requirements
- o Inconsistent cost estimation breakdown and accounting method.

Although the basic assumptions differ, the methodology used to develop the various FGD costs are essentially the same. This methodology basically consists of the following six steps:

- 1) Develop a conceptual process design and obtain material and energy utilization data
- 2) Divide each FGD process into a number of process modules which represent separate process areas
- 3) Size equipment for each process module based on material and energy utilization data
- 4) Prepare direct capital costs for equipment for each process module area based on equipment size and cost data
- 5) Develop relationships for determining indirect capital costs and operating and maintenance costs

Table 4-1. SOURCES PROVIDING COMPREHENSIVE INFORMATION ON
FGD SYSTEM COSTS

o TVA/EPA Interagency

- U. S. Environmental Protection Agency, Definitive SO₂ Control Process Evaluations: Limestone, Double Alkali, and Citrate FGD Processes, by TVA for EPA, EPA-600/7-79-177, August 1979.
- U. S. Environmental Protection Agency, Definitive SO₂ Control Process Evaluations: Limestone, Lime, and Magnesia, by TVA for EPA, EPA-600/ 7-80-001, January 1980.
- Tomlinson, S. V., T. A. Burnett, J. W. Barrier, "Comparative Economic Evaluation Techniques and Results for FGD Systems," TVA paper presented at AIChE 86th Annual Meeting, Houston, Texas, April 1979.
- U. S. Environmental Protection Agency, Preliminary Economic Analysis of a Lime Spray Dryer FGD System, by TVA for EPA, EPA-600/7-80-050, March 1980.

o EPRI

- Electric Power Research Institute, Comparative Economics of Advanced Regenerable Flue Gas Desulfurization Processes, by M. R. Beychok, Consulting Engineer for EPRI, EPRI CS-1381, March 1980.
- Electric Power Research Institute, Economic and Design Factors for Flue Gas Desulfurization Technology, by Bechtel National, Inc., for EPRI, EPRI CS-1428, RP1180-9, April 1980.
- Economics of High SO₂ Removal Designs, by Radian Corporation and SRI International, 1980.

o Battelle Memorial Institute, Analysis of Variations in Costs of FGD Systems, May 1978.

o Stevenson, C. D., and R. I. Torstrick, "The Shawnee Lime/Limestone Computer Program," a TVA paper presented at the Fifth Industry Briefing Conference, December 1979.

o U. S. Environmental Protection Agency, Simplified Procedures for Estimating Flue Gas Desulfurization System Costs, by PEDCo Environmental, Inc., for EPA, EPA-600/2-767-150, June 1975.

- 6) Estimate levelized annual revenue requirements based on capital costs, O&M costs, the discount rate and other economic assumptions.

A comparison of major published FGD cost models based on available information in each cost estimating step is summarized in Table 4-2.

Since the TVA/Bechtel, PEDCo, and TVA/EPA sources provide detailed cost data down to the equipment cost level (while the remaining sources present summary cost data only down to the process area level), these three sources were chosen as candidates capable of providing FGD cost information. Of these three, the TVA/Bechtel and PEDCo sources include a computerized cost model. Using such a model has been determined to be a more efficient approach to performing the regional economic analysis of the various FGD systems. The feasibility of adopting either of these two models as a basis for formulating a simplified computerized cost model is discussed below.

TVA/Bechtel Model¹

The TVA/Bechtel model has been developed to project a complete conceptual design package for a lime or limestone FGD system. The model is based on developmental work at the TVA-Shawnee power plant with costs derived from detailed process conditions (see Appendix D for further details).

This model appears to be the most comprehensive FGD cost model developed to date for the estimation of lime and limestone FGD system costs. The apparent advantages of this model are associated with its ability to accommodate variations in process design alternatives (i.e., alternative scrubber type or sludge disposal designs) or variations in the values of independent design parameters (i.e., L/G ratio, alkali stoichiometry, slurry residence time, reheat temperature, gas velocity, etc.). However, since this model is applicable only to lime and limestone FGD systems, comparable cost models for the remaining five advanced FGD systems, which are to be included in the regional economic assessment, will

Table 4-2. CHARACTERISTICS OF PUBLISHED FGD COST MODELS

	TVA/ Bechtel ¹	PEDCo ²	TVA/ EPA ^{3,4,5,6}	Bechtel/ EPRI ⁷	Battelle ⁸	Stong & Webster/ EPRI ⁹
1. Complete process material and energy balance data	x	-	x	x	-	-
2. Sizing of major equipment	x	-	x	-	-	-
3. Costing of major equipment	x	x	x	-	-	-
4. Sub-module capital estimates	x	x	x	x	x	x
5. Annual O&M cost estimate	x	x	x	x	x	x
6. Empirical cost equations	x	x	x	-	-	-
7. Annual revenue estimates	x	x	x	x	x	x

have to be developed in order to use the TVA/Bechtel model. Due to the limited published cost data available on these five systems, development of comparable models is not possible at this time.

PEDCo Model²

The PEDCo model utilizes nomographs and/or cost equations to determine component costs of five FGD systems. The model has been developed by normalizing actual installed FGD system component costs and relating these costs to appropriate variable system operating conditions (see Appendix D for further details).

The unique advantages of this model lie in the simplicity for rapid equipment cost estimates. In essence, the PEDCo model presents empirical equipment capital and operating cost equations as functions of six key process variables. These variables are A (ash removal rate), S (SO₂ removal rate), G (flue gas rate), N (number of parallel scrubbing trains), CF (average capacity factor), and BRLY (boiler remaining life in years). These empirical equations have been derived based on specific process design and a detailed equipment cost data base. The disadvantage of this model is threefold:

- 1) The model contains cost equations for only five FGD systems. The aqueous carbonate system and lime spray dryer system have been excluded.
- 2) The process technology and design parameters used in the model reflect an early 1970s development status which does not incorporate the latest mature technology associated with the SO₂ absorption and waste disposal areas.
- 3) The 1973 equipment cost data base used in the model appears to be inappropriate considering the rapid escalation in FGD plant construction costs in recent years.

Evidence shows that neither the TVA/Bechtel model nor the PEDCo model is independently sufficient to be used for the FGD processes cost evaluation. In light of these results, the detailed cost data provided by the third candidate (TVA/EPA^{3,4,5,6}) was evaluated and considered to be a valuable data bank for cost and operating and maintenance information. Another valuable aspect of this source of information is that it provides cost information for all seven FGD systems to be analyzed. As a result, SAI has combined some of the ideas, concepts, and data from all three sets of sources to develop a simplified FGD cost model suitable for assessing regional economic evaluations. For example, incorporated was the approach PEDCo took of having the cost equations be a function of a few key variables (to be identified in Section 4.1.2). Also, the TVA/EPA itemized cost data presented for each of the seven FGD systems was used; and the TVA/Bechtel model was used to identify a method for calculating one of the key variables. Specifically, this final approach was formulated by the following steps:*

- Step 1: Develop conceptual design for the seven FGD processes based on process design parameters drawn from recent TVA/EPA published reports and data published from process vendors.
- Step 2: Evaluate and normalize the TVA/EPA FGD cost data for specific plant capacity, fuel content and process design parameters.
- Step 3: Develop and determine cost equations as a function of key process variables.
- Step 4: Modify cost equations to reflect prevailing FGD technology as identified in other published sources describing FGD system costs.
- Step 5: Develop levelized cost equations based on capital costs, annual revenue requirements, the discount rate, and other economic assumptions.

* See next section for details of the development method.

4.1.2 Cost Model Development and Verification

Before developing any direct capital cost equations, major process areas were identified to include components from all seven FGD systems (see Table 4-3). Excluded from this list is an area for particulate control devices which generally is not considered a part of an FGD system. In order to retain a common basis by which all seven systems are to be analyzed, it is assumed that particulate control devices, having the capability of removing enough particulates to meet the NSPS, are located upstream from the FGD system. Two systems, however, employ particulate removal devices downstream from the absorber, thereby not requiring one upstream. As a result, a credit for a comparable particulate removal device has been deducted from the SO₂ absorption section in the aqueous carbonate system³ and has been itemized for the lime spray dryer system.⁶ The equipment associated with these process areas are identified in Table 4-4.

Also identified in Table 4-3 are the indirect capital cost items and the operating cost items which have been selected for the economic analysis. These items are common to many economic analysis.^{5,10,11}

In order to develop a cost model using TVA's published cost data, dependency variables had to be identified for each cost item. After investigating the effects various operating conditions had on the costs, the PEDCo model assumption that most capital costs and commodity usage rates are largely dependent on three variables (in addition to unit cost quantities) was incorporated. These variables are:

- o SO₂ removal rate (S)
- o Gas flow rate to absorption section (G)
- o Plant/FGD megawatt size (MW)

Other variables which were used (to a lesser extent) to determine costs were coal sulfur content (PSC) and number of absorber trains (N). These and other input variables are discussed in Section 4.2.

<u>Capital Investment</u>	<u>Annual Revenue</u>
<u>Direct Investment</u>	<u>Operating Cost</u>
Materials Handling/Preparation	<u>Variable</u>
Gas Handling	Raw Material
Chloride Purge	- Lime
SO ₂ Absorption (2-4 absorbers plus 1 spare)	- Limestone
Stack Gas Reheat	- Soda Ash
Regeneration	- Magnesium Oxide
Sludge Disposal	- Coal
Sulfuric Acid Production/Storage	- Catalyst
Sulfur Production/Storage	Utilities
ESP Credit	- Electricity
Services, Utilities, Misc.	- Water
Sludge Pond	- Steam
Total Direct Investment	- Fuel Oil
	- Natural Gas
	- Heat Credit
	Total Variable O&M Cost
<u>Indirect Investment</u>	<u>Fixed</u>
Architect and Engineering Design/ Supv. and Contractor Expenses	Waste Disposal (trucking)
Construction Expense	Labor
Contractor Fees	- Operating, Analysis, Supervision
Contingency	Maintenance
Allowance for Shakedown	- Labor and Material
Interest During Construction	Total Fixed O&M Cost
Land	
Working Capital	Overhead
Total Capital Investment	- Plant
	- Administrative
	- Marketing
	Byproduct Sales
	- Sulfuric Acid
	- Sulfur
	Net Operating Cost
<u>Levelized -- 30 Years</u>	
- Levelized Capital Cost (Mills/kWh)	
- Levelized Operating Cost (Mills/kWh)	
Total Levelized Cost (Mills/kWh)	

Table 4-4. IDENTIFICATION OF PROCESS EQUIPMENT GROUPED ACCORDING TO MAJOR PROCESS AREAS OF SEVEN FGD SYSTEMS

Process Area \ FGD System							
	Lime	Limestone	Dual Alkali	Magnesium Oxide	Wellman-Lord	Aqueous Carbonate	Lime Spray Dryer
Materials Handling/Preparation	Feeders Conveyors Elevators Silos Slaker Tanks Agitators Pumps	Hoppers Feeders Conveyors Elevators Bins Shaker Puller Crushers Ball Mills Hoists Tanks Agitators Pumps	Conveyors Elevators Bins Feeders Slakers Tanks Agitators Pumps	Conveyors Silos Bins Feeders Mixer Tank Agitator Pumps	Conveyors Silos Feeders Bins Shaker Tanks Pumps	Silo Conveyors Tanks Pumps	Feeders Conveyors Elevators Vibrators Silos Bin Slaker Tanks Agitators Pumps
Gas Handling	Plenum Booster Fans Gas Ducts and Dampers	Plenum Booster Fans Gas Ducts and Dampers	Plenum Booster Fans Gas Ducts and Dampers	Plenum Booster Fans Gas Ducts and Dampers	Plenum Booster Fans Gas Ducts and Dampers	Plenum Booster Fans Gas Ducts and Dampers	Plenum Booster Fans Gas Ducts and Dampers
Chloride Purge	-	-	-	Chloride Scrubbers Entrainment Separators Tanks Agitators Pumps	Chloride Scrubbers Entrainment Separators Tanks Agitators Pumps	-	-
SO ₂ Absorption	Mobile Bed Scrubbers Presaturator Entrainment Separators Tanks Agitators Pumps	Mobile Bed Scrubbers Presaturator Entrainment Separators Tanks Agitators Pumps	Tray Towers Presaturator Entrainment Separators Tanks Agitators Pumps	Spray Grid Towers Presaturator Entrainment Separators Tanks Agitators Pumps	Absorbers Entrainment Separators Filters Heat Exchangers Agitators Pumps	Cyclones Spray Dryers ESPs Silos Hopper Conveyors	Spray Dryers Baghouse Conveyor Vibrator Bin Silo Feeder Tank Agitator Pumps
Stack Gas Reheat	Indirect Steam Reheaters	Indirect Steam Reheaters	Indirect Steam Reheaters	Indirect Steam Reheaters	Indirect Steam Reheaters	-	-

Table 4-4. IDENTIFICATION OF PROCESS EQUIPMENT GROUPED ACCORDING TO MAJOR PROCESS AREAS OF SEVEN FGD SYSTEMS (Cont'd)

Process Area \ FGD System							
	Lime	Limestone	Dual Alkali	Magnesium Oxide	Wellman-Lord	Aqueous Carbonate	Lime Spray Dryer
Regeneration	-	-	Reaction Tanks Agitators Pumps	Centrifuges Conveyors Dryer Silos Fans Calciner Preheater Solids Cooler Waste Heat Boiler Tanks Agitators Pumps Bins	Evaporator-Crystallizer Heat Exchanger Dryer Conveyors Centrifuge Bin Feeder Silo Evaporators Strippers Blower Condensers Tanks Agitators Pumps	Reducers Compressors Reducer-Recuperator Waste Heat Boilers Reducer Air Heater Venturi Scrubber Cooling Tower Heat Exchangers Precarbonator Crystallizer Carbonator Decomposer Liquid Cyclone Filter Compressor Tanks Agitators Pumps	-
Sludge Disposal	Feed Tank Agitator Pumps	Feed Tank Agitator Pumps	Thickener Drum Filters Conveyor Reslurry Tank Tanks Agitators Pumps	-	-	-	Trucks Earth Moving Equipment
Sulfuric Acid Production/Storage	-	-	-	Sulfuric Acid Production Unit 30 day Storage and Shipping Facilities	-	-	-
Sulfur Production/Storage	-	-	-	-	Reduction Unit (fuel oil) Claus Plant 30 day Storage and Shipping Facilities	Claus Plant Tail Gas Incinerator 30 day Storage and Shipping Facilities	-
ESP Credit	-	-	-	-	-	ESP*	ESP

* Deducted from SO₂ Absorption Area.

Source: Ref. 3, 4, 5, 6

To develop direct capital cost equations for each of the seven FGD systems, TVA's data was plotted on a log-log scale against either G or S, and linearized using a regression analysis. Thus, exponential relationships were developed to describe the cost items in terms of G and/or S. Also, since TVA does not include costs for a spare absorber train, costs for the following three areas have been adjusted accordingly:

- o Gas handling
- o SO₂ absorption
- o Stack gas reheat

Table 4-5 presents the equation formats of the direct investment capital cost items for all seven FGD systems. The constants corresponding to these power law equations are identified in Appendix I, Page I-28.

Equations defining the indirect capital cost items (except land costs) were identified in a TVA publication ⁶ and compared to that stated in Peters and Timmerhaus' Plant Design & Economics for Chemical Engineers. ¹⁰ The relationships were comparable and were included in the model. Land requirements were based on an approximate 20 ft. depth for pond waste disposal, a 40 ft. height for landfill waste disposal, and six additional acres for byproduct production and storage facilities. This is in addition to ten acres set aside for the FGD process and storage areas. A breakdown of the cost equation formats for indirect capital costs is presented in Table 4-6.

Items included in the variable operating costs are the raw materials and utilities required by each FGD system. The raw material usage rates depend on the stoichiometric requirements and raw material characteristics which are presented in Table 4-7. Since raw material usage rate is directly dependent on the SO₂ removal requirement, the cost equations developed for the model are linear relationships in terms of S.

Table 4-5. FUNCTIONAL FORMAT OF DIRECT INVESTMENT CAPITAL COST EQUATIONS

<u>Direct Investment Items</u>	<u>Equation Format*</u>
Materials Handling/Preparation	$(a_1 S^{b_1} + a_2 S^{b_2}) \times K3 \quad (1)$
Gas Handling	$(a_3 G^{b_3}) \times K3 \times K1 \quad (2)$
Chloride Purge	$(a_4 G^{b_4}) \times K3$
SO ₂ Absorption	$(a_5 G^{b_5}) \times K3 \times K1$
Stack Gas Reheat	$(a_6 G^{b_6}) \times K3 \times K1$
Regeneration	$(a_7 G^{b_7}) \times K3$
Sludge Disposal	$(a_8 G^{b_8}) \times K3$
Sulfuric Acid Production/Storage	$(a_9 S^{b_9}) \times K3$
Sulfur Production/Storage	$(a_{10} S^{b_{10}}) \times K3$
Particulate Control (ESP) Credit	$-(a_{11} G^{b_{11}}) \times K3$
Services, Utilities, Miscellaneous	6% of above total
Sludge Pond	$(a_{12} S^{b_{12}}) \times K3$

* "a" and "b" represent constants the values of which are presented in matrix form in Appendix I, page I-28, lines 55-68 for "a" (identified as ARRAY EH) and lines 85-98 for "b" (identified as ARRAY B). The subscripts of "a" and "b" identify the rows of the matrix data. Each row contains seven terms -- each corresponding to one of the seven FGD systems identified in this analysis (lime, limestone, dual alkali, magnesium oxide, Wellman-Lord, aqueous carbonate, and lime spray dryer).

- (1) Since the source data were obtained from 1979 cost information, the values were updated to 1980. K3 represents the cost escalation factor to accomplish this update. The corresponding value used in this analysis is 1.1.
- (2) Since redundancy costs (spare equipment) were not included in the source cost data for the absorption area, K1 was incorporated to include this. Its value is equal to $1 + 1/N$ where N is the number of absorber trains.

Table 4-6. FUNCTIONAL FORMAT OF INDIRECT INVESTMENT
CAPITAL COST EQUATIONS*

<u>Indirect Investment Items</u>	<u>Equation Format</u>
Architect and Engineering Design/ Supervisory and Contractor Expenses	9% of total direct capital costs
Construction Expenses	16% of total direct capital costs
Contractor Fees	5% of total direct capital costs
Contingency	20% of [above 3 items plus total direct capital costs]
Allowance for Shakedown	10% of [above 4 items plus total direct capital costs excluding sludge pond cost]
Interest During Construction	16.64% of [first 4 items above plus total direct capital costs]
Land (acres)	(1) 10 + aS (2) 16
Working Capital	8.33% of total variable annual operating cost

* Applicable to all seven FGD systems identified within this economic analysis, except where specified.

(1) Applicable only to lime, limestone, dual alkali, and lime spray dryer systems.

(2) Applicable only to aqueous carbonate, Wellman-Lord, and magnesium oxide systems.

Table 4-7. STOICHIOMETRIC RATIOS OF RAW MATERIAL TO SO₂ REMOVED

FGD System								
Raw Material	Analysis	Lime	Limestone	Dual Alkali	Magnesium Oxide	Wellman Lord	Aqueous Carbonate	Lime Spray Dryer
Lime	95% CaO	1.05	-	1.00	-	-	-	1.35
Limestone	90% CaCO ₃	-	1.30	-	-	-	-	-
Soda Ash	99.8% Na ₂ SO ₃	-	-	1.00	-	1.00	1.00	-
Magnesium Oxide	98% MgO	-	-	-	1.05	-	-	-

As confirmed by an EPRI publication,⁷ the steam, water, and electricity usage rates are dependent on both S and G. As a result, rate equations have been developed (using TVA data) which generally are linear functions of S ($R = aS + b$), with the intercept (b) an exponential function of G ($b = cG^d$).

According to TVA's data, the fuel oil and natural gas requirements generally are directly dependent on S. This relationship is reasonable because the equipment using these items handles a form of the sulfur-laden material exiting the absorber. The same has been noted for those areas where process heat is used in place of steam (identified as a credit to the variable operating costs). Table 4-8 identifies the functional format of the cost equations associated with the variable operating cost items.

Included in the fixed operating costs are labor, maintenance and sludge trucking (for the Lime Spray Dryer System). Labor requirements have been defined in terms of plant size (MW) and coal sulfur content. The equations which have been developed are linear in terms of coal sulfur content ($R = ax + b$), where b is exponentially dependent on plant size ($b = cMW^d$). Maintenance costs have been defined as being dependent on both direct capital costs and plant size. Using TVA's data, a maintenance cost relationship has been developed in the following form: $axy^b + cz$ where $x + z =$ direct capital costs and $y =$ plant size.

Relationships defining the quantity of waste for disposal and the amount of byproducts produced were developed in terms of S. This is a reasonable approach since both the waste and the byproducts contain most, if not all, the sulfur removed from the flue gas.

Plant and administrative overhead costs are calculated as a percentage of labor or total fixed operating costs. In a similar manner, marketing overhead costs are calculated as a percentage of byproduct sales. A detailed listing of the cost equations for the fixed, overhead, and byproduct operating revenue is presented in Table 4-9.

Table 4-8. FUNCTIONAL FORMAT OF VARIABLE ANNUAL OPERATING COST EQUATIONS*

<u>Variable Operating Cost Items</u>	<u>Equation Format**</u>	
Raw Material		
- Lime	$aS \times (\text{unit cost}) \times CF$	
- Limestone	$aS \times (\text{unit cost}) \times CF$	(1)
	$aMW^b \times (\text{unit cost}) \times CF$	(2)
- Soda Ash	$aS^b \times (\text{unit cost}) \times CF$	
- Magnesium Oxide	$aS \times (\text{unit cost}) \times CF$	
- Coal	$aS \times (\text{unit cost}) \times CF$	
- Catalyst	$aS \times (\text{unit cost}) \times CF$	(2)
	$1\% \text{ of coal cost} \times CF$	(3)
Utilities		
- Electricity	$(aG^b + cS) \times (\text{unit cost}) \times CF$	
- Water	$(aG^b + cS) \times (\text{unit cost}) \times CF$	
- Steam	$(aG^b + cS) \times (\text{unit cost}) \times CF$	
- Fuel Oil	$aS \times (\text{unit cost}) \times CF$	
- Natural Gas	$(aS^b + cS) \times (\text{unit cost}) \times CF$	
- Heat Credit	$(aS^b + cS) \times (\text{unit cost}) \times CF$	

* Table 3-3 identifies which FGD system consumes which item.

** "a", "b" and "c" represent constants (different for each line item): see Appendix I, pages I-20 to I-22, within lines 389-532, for corresponding values.

(1) Applicable to limestone system only.

(2) Applicable to magnesium oxide system only.

(3) Applicable to aqueous carbonate system only.

Table 4-9. FUNCTIONAL FORMAT OF FIXED, OVERHEAD, AND BYPRODUCT
ANNUAL OPERATING REVENUE EQUATIONS*

<u>Fixed Operating Cost Items</u>	<u>Equation Format**</u>
Waste Disposal (trucking)	$(aS + A) \times (\text{unit cost})$
Labor	
- Operating, Analysis, Supervision	$aPSC + bMW^C$
Maintenance	
- Labor and Material	$aMW^b \times [\text{Direct Capital Cost} - \text{Pond Cost}] + 3\% \text{ of Pond Cost}$
Overhead Costs	
Plant	3% of above three items
Administrative	10% of labor (above)
Marketing	10% of byproduct sales (below)
Byproduct Sales	
Sulfuric Acid	$aS \times (\text{unit cost})$
Sulfur	$(aS^b + cS) \times (\text{unit cost})$

* Table 3-3 identifies which cost item applies to which FGD system.

** a, b, and c represent constants (different for each line item);
see Appendix I, pages I-20 to I-22, within lines 389-532, for
corresponding values.

Equations developed by EPRI¹² for levelizing capital and operating costs have been included in the model because of the prospects of comparing total FGD system costs. Each of these equations are characterized basically by one factor; however, this factor is dependent on a variety of economic assumptions. The economic assumptions are stated in Table 4-10.

In addition to the cost equations, relationships have been developed to calculate the SO₂ removal rate (S) and the gas flow rate (G). Both variables are dependent on the characteristics of the coal being burned, the power plant rating and efficiency, and the quantity of sulfur carried over in the flue gas. The S variable is also dependent on the NSPS requirements for SO₂ removal which has been reported in Section 2.2. These standards are used to define the SO₂ removal requirement for a given set of power plant operating conditions. The relationships used to determine G have been obtained from the TVA/Bechtel model¹ identified earlier. These equations compare favorably with those presented in Babcock and Wilcox's Steam book¹³ and incorporate the following assumptions:

- o Combustion product gas is composed of CO₂, SO₂, N₂, O₂, H₂O and HCl
- o Molar volume of flue gas at standard conditions is estimated at 379 ft.³/lb mole

The equations are flexible such that the gas flow rate will change with plant size, overall plant efficiency, and excess air as well as with variations in coal type.

All sets of equations have been verified using data from three recent publications^{3,7,9} reporting FGD cost estimates. Table 4-11 presents a comparison of the S, G, total capital costs, and net annual costs as reported in the three publications and as calculated using the newly developed model. Discrepancies can be attributed to differences in basic assumptions, ie. economic assumptions, stoichiometric ratios, overall coal composition, redundancy, etc.

Table 4-10. BASIS FOR LEVELIZED CHARGES

Debt:Equity Ratio	50:50
Debt Cost	8%/year
Preferred Stock Ratio	15%
Preferred Stock Cost	8.5%/year
Common Stock Ratio	35%
Common Stock Cost	13.5%/year
Weighted Capital Cost	10.0%/year
Federal and State Income Taxes	50%
Property Tax and Insurance	2.0%/year
Investment Tax Credit	None
Book Life	30 years (new) 20 years (retrofit)
Tax Life	20 years (new) 15 years (retrofit)
Iowa Type S ₁ , Retirement Dispersion	
Inflation Rate	6%/year
Discount Rate	10%/year

Source: Reference 7

Table 4-11. COMPARISON OF THE MODEL OUTPUT VS. PUBLISHED DATA --
FIELD SYSTEM COSTS

Variable Source	S (tons/hr)	G (acfm - 300°F)	Variable Source	S (tons/hr)	G (acfm - 300°F)	Variable Source	S (tons/hr)	G (acfm - 300°F)
Model	10.35	1,544,000	Model	17.60	1,790,000	Model	10.27	1,400,000
TVA	10.00	1,543,000	Bechtel	16.81	1,900,000	EPRI	10.35	1,520,000

(thousands of dollars)

FGD System								
Source	Year	Lime	Limestone	Dual Alkali	Magnesium Oxide	Wellman-Lord	Aqueous Carbonate	Lime Spray Dryer
Total Capital Cost								
Model	1979	54,200	58,400	60,000	76,400	85,900	71,200	59,700*
TVA	1979	45,319	48,948	50,551	70,293	74,190	58,793	66,171*
Model	1978	63,300	68,100	70,700	89,900	101,700	-	50,000
Bechtel	1978	74,500	78,500	83,000	88,000	90,000	-	60,500
Model	1977	-	47,800	-	64,400	72,600	60,000	-
EPRI	1977	-	47,229	-	68,204	62,868	106,126	-
Net Operating Cost								
Model	1980	8,750	7,500	7,350	8,650	12,100	8,500	6,180*
TVA	1980	8,406	7,354	7,417	8,154	10,757	8,388	7,310*
Model	1980	10,550	10,100	8,850	15,000	18,250	-	8,050
Bechtel	1980	14,150	13,150	13,650	12,450	15,650	-	10,900
Model	1979	-	7,652	-	10,551	14,273	9,359	-
EPRI	1979	-	11,746	-	10,308	11,125	12,891	-

* Low sulfur coal, 1982 capital cost dollars, and 1984 O&M cost dollars were used by TVA for this FGD system.

Appendix I contains a copy of the entire FGD system cost model described above. It also presents the input data used to produce the detailed FGD cost tables presented in Appendix G.

4.2 Input Variables

The input variables required by the economic model have been identified and defined in Tables 4-12, 4-13, and 4-14 and can be subdivided into the following four areas:

- o Power plant operating characteristics
- o FGD system size and status
- o Regional coal characteristics
- o Operating costs (both regionally dependent and independent)

A detailed explanation of how these variables affect FGD system costs is included in Appendix B.

Those variables identified in Table 4-12 either have been set according to the task requirements or have been defined in accordance with typical power plant and FGD operating conditions identified in various publications.^{1,5,14}

Table 4-13 identifies the heating value, sulfur content, and ash content of coal typically used in each of the 14 regions chosen for the economic analysis. Two types of coal have been chosen per region - one requiring low percent SO₂ removal and another requiring higher percent SO₂ removal. This approach has been taken in order to include two distinct percent sulfur coals which realistically represent that used within each region. Methodology for choosing the coal is presented in Appendix F.

Table 4-14 represents both regionally dependent and independent costs associated with the operating costs and land costs in the economic analysis. These values represent an average commodity cost for each region (where applicable) and are actual 1980 unit costs.

Table 4-12. QUANTIFICATION OF REGIONALLY INDEPENDENT VARIABLES

Variable Definition	Units	Computer Symbol	Variable Quantification				Source
Application	-	-	New		Retrofit		R
Power Plant Size	MW	MW	500	100	500	100	R
Number of Absorber Trains	-	N	4	2	3	2	5
Plant Conversion (Efficiency)	Btu/kWh (%)	CFPE	9,760 (35)	10,350 (33)	10,050 (34)	10,675 (32)	5, 14
Operating Life Remaining	Years	BRLY	30		20		5
Sludge Transport Miles for Disposal	Miles	TMGE	1		50		5
Plant Operating Capacity Factor	Decimal	CF			0.70		14
Fraction of Sulfur in Coal to Flue Gas	Decimal	CSTF			0.95		5, 14
Fraction of Ash in Coal to Flue Gas	Decimal	CATF			0.20		5, 14
Excess Air	Decimal	XSF			0.39		6
N ₂ in Air	%	N2AIR			76.85		1
O ₂ in Air	%	O2AIR			23.15		1
Water in Air	%	H2OAIR			1.30		1
Gas Temperature to Absorber	°F	THG			300		2, 5

R = Required by task statement

Table 4-13. QUANTIFICATION OF REGIONALLY DEPENDENT COAL CHARACTERISTICS

Coal Rating		High (70%-90%) SO ₂ Removal			Low (70%) SO ₂ Removal		
Character- istics of Coal	Heating Value of Coal	Sulfur Content of Coal	Ash Content of Coal	Approx. SO ₂ Removal Requirements	Heating Value of Coal	Sulfur Content of Coal	Ash Content of Coal
Region	(Btu/lb Coal)	(lb S/lb Coal)	(lb Ash/lb Coal)	(%)	(Btu/lb Coal)	(lb S/lb Coal)	(lb Ash/lb Coal)
ECAR	11,500	0.0365	0.142	90	11,450	0.0120	0.130
ERCOT	6,650	0.0100	0.104	80	7,150	0.0075	0.104
MAAC	12,100	0.0190	0.149	80	12,050	0.0125	0.149
MAIN	10,800	0.0340	0.122	90	10,450	0.0110	0.102
MARCA-1	6,050	0.0095	0.091	80	7,500	0.0075	0.091
MARCA-2	11,100	0.0350	0.108	90	9,600	0.0100	0.093
NPCC	12,050	0.0190	0.133	80	12,150	0.0125	0.133
SERC	11,150	0.0350	0.132	90	11,400	0.0120	0.129
SPP-1	8,750	0.0275	0.129	90	8,750	0.0080	0.116
SPP-2	11,900	0.0375	0.126	90	10,250	0.0105	0.089
WSCC-1	8,100	0.0125	0.110	80	9,250	0.0095	0.110
WSCC-2	9,350	0.0095	0.090	70	9,350	0.0050	0.090
WSCC-3	11,050	0.0115	0.102	70	11,050	0.0055	0.102
WSCC-4	9,850	0.0100	0.159	70	9,850	0.0055	0.159
COMPUTER SYMBOL	CHHV	PSC	CASH	-	CHHV	PSC	CASH

Table 4-14. QUANTIFICATION OF REGIONALLY DEPENDENT AND INDEPENDENT COST VARIABLES

Region	ECAR	ERCOT	MAAC	MAIN	MARCA	MARCA	NPCC	SERC	SPP	SPP	WSCC	WSCC	WSCC	WSCC
Computer Symbol **					1	2			1	2	1	2	3	4
LMCO	64.00	65.00	56.00	52.00	60.00	66.00	81.00	75.00	60.00	76.00	89.00	69.00	63.00	66.00
LSCO	11.00	17.00	11.00	11.00	22.00	22.00	18.00	8.00	15.00	14.00	34.00	20.00	32.00	24.00
SACO	123.00	124.00	137.00	114.00	117.00	115.00	141.00	134.00	123.00	127.00	110.00	109.00	139.00	160.00
MGCO	206.00	191.00	212.00	203.00	195.00	197.00	212.00	206.00	188.00	197.00	163.00	173.00	173.00	176.00
CATC	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
SULC	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00
ACDC	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
WTRC	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
STMC	1.85	1.80	1.80	1.90	1.10	1.75	2.20	2.25	1.50	1.90	1.20	1.00	1.10	1.05
ELCO														
- 100 MW	37.90	37.50	37.30	38.00	32.00	36.90	40.60	40.90	34.80	38.10	32.80	31.30	31.70	31.40
- 500 MW	32.10	31.80	31.60	32.20	26.50	31.20	34.70	35.00	29.30	32.40	27.30	25.90	26.30	26.00
COLC	31.50	18.50	32.00	29.50	11.00	26.50	39.50	37.50	19.00	31.00	15.50	14.00	17.50	15.00
FOLC	0.84	0.88	0.83	1.11	1.00	0.95	0.80	0.66	0.85	0.62	1.00	1.10	0.95	0.90
GASC	1.01	2.27	3.01	2.75	1.66	2.66	2.71	2.33	2.19	2.48	2.38	2.59	3.60	2.50
LBCO	12.50	11.00	11.00	11.50	11.00	11.00	10.50	11.00	10.50	10.50	13.00	11.00	13.50	12.00
LNDC	4030	860	5370	5300	1070	6650	5370	1630	1020	2260	2740	1350	3400	1350

* 1980 dollars.

** See next page for variable definition and source identification.

Table 4-14. DEFINITION OF REGIONALLY DEPENDENT AND INDEPENDENT COST VARIABLES (Cont'd)

Variable Definition	Units	Computer Symbol	Source of Cost Data
Lime Cost	\$/ton	LMCO	a
Limestone Cost	\$/ton	LSCO	a
Sodium Carbonate Cost	\$/ton	SACO	a
Magnesium Oxide Cost	\$/ton	MGCO	a
Catalyst Cost	\$/liter	CATC	Ref. 3
Sulfur Sales Credit	\$/ton	SULC	b
Sulfuric Acid Sales Credit	\$/ton	ACDC	Ref. 16, 17
Water Cost	\$/1000 gal	WTRC	Ref. 3
Steam Cost	\$/10 ⁶ Btu	STMC	c
Electricity Cost	Mills/kWh	ELCO	Ref. 18
Coal Cost	\$/ton	COLC	Ref. 19
Fuel Oil Cost	\$/gal	FOLC	Ref. 19
Natural Gas Cost	\$/1000 scf	GASC	Ref. 19
Labor Cost	\$/hr	LBCO	Ref. 20, 21
Land Cost	\$/acre	LNDC	Ref. 22

a. Cost includes both transportation and commodity costs. Transportation costs were obtained from originating railroads and ICC published tariffs. Commodity costs were determined by SAI telephone survey of commodity vendors throughout the U. S.

b. Price represents 75% of market price due to penetration effects.^{18,19}

c. Assumed 87% efficiency for boiler and 85% efficiency for heat exchanger.²⁵

Additional miscellaneous input data include a cost index factor (K3), molecular weights (M) of the coal constituents and combustion products, and percentage breakdowns (WPX) of the combustion products. The third item incorporates three sets of combustion product composition data which are classified according to coal heating value. This classification has been selected to parallel that which characterizes coal (shown below).

<u>Coal Type</u>	<u>Heating Value (Btu/lb)</u>
Lignite	<u><</u> 8300
Subbituminous	8,300 to 11,000
Bituminous	<u>></u> 11,000

The input values associated with K3 (unitless), M (lb/lb mole), and WPX (weight percent) have been defined within the model (see Appendix I) at lines 112, 114, 128, respectively.

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5. SUMMARY AND COMPARISON OF FGD SYSTEM COSTS

Regional FGD cost variations have been calculated using the SAI developed cost model. For each FGD process these calculations encompass a total of 112 base cases which include combinations of:

- o 14 National Electric Reliability Council (NERC) regions in the U. S.
- o Two power plant sizes: 500 MW and 100 MW
- o Two coal types for each region: high sulfur dioxide removal requirement (70%-90%) and low sulfur dioxide removal requirement (70%)
- o New and retrofit applications.

Capital investment costs and first year operating and maintenance costs have been calculated for each base case. One such case is illustrated in Tables 5-1 and 5-2. These tables summarize the cost model output for each of the seven FGD systems for a 500 MW power plant located in the SERC region, the region with the greatest planned capacity growth. Similarly, detailed results of all 112 case variations are tabulated in Appendix G. A summary of capital investment (\$/KW) and total levelized costs (mill/kWh) for all case variations are shown in Table 5-3.

5.1 CAPITAL INVESTMENT COSTS

5.1.1 Base Case

The base case calculations for a new 500-MW power plant requiring high sulfur removal efficiency shows that total capital investments of the seven FGD processes differ by as much as 100 percent.

The differences in capital investments can best be analyzed by examining specific sub-areas of the processes for a sample base case (see Table 5-1). The comparison of capital costs reveals that for the wet, non-regenerative processes, approximately 40 percent of direct investment is

Table 5-1. TOTAL CAPITAL COST FOR FGD SYSTEMS, IN THOUSANDS OF 1980 DOLLARS

APPLICATION: NEW		REGION: SERC		PLANT SIZE: 500 MW		COAL: 3.50 % SULFUR	
	LINE	LIMESTONE	DUAL ALKALI	MAGNESIA SLURRY	WELLMAN- LORD	AQUEOUS CARBONATE	LINE SPRAY DRYER
DIRECT INVESTMENT							
MATERIALS HANDLING/PREPARATION	3512	4399	3404	1307	1407	1619	3783
GAS HANDLING	4805	4807	4676	7274	7388	7897	7897
CHLORIDE PURGE	---	---	---	6392	3333	---	---
SO ₂ ABSORPTION	13313	14040	14328	8591	13161	15039	21653
STACK GAS REHEAT	2023	2009	2009	1886	1857	---	---
REGENERATION	---	---	462	11413	12807	12403	---
SLUDGE DISPOSAL	1962	2049	4626	---	---	---	1110
SULFURIC ACID PRODUCTION/STORAGE	---	---	---	9290	---	---	---
SULFUR PRODUCTION/STORAGE	---	---	---	---	11946	4803	---
ESP CREDIT	---	---	---	---	---	---	10857)
SERVICES, UTILITIES, MISC	1657	1758	1902	2769	3114	2506	1415
SLUDGE POND	4705	5409	4306	---	353	---	294
TOTAL DIRECT INVESTMENT	33976	36472	37914	48921	55366	44267	25295
INDIRECT INVESTMENT							
ARCHITECT & ENGINEERING DESIGN/ SUPV. & CONTRACTOR EXPENSES	3058	3283	3412	4403	4983	3984	2277
CONSTRUCTION EXPENSE	5436	5836	6066	7827	8859	7083	4047
CONTRACTOR FEES	1699	1824	1896	2446	2768	2213	1265
CONTINGENCY	8834	9483	9858	12720	14395	14387	9630
ALLOWANCE FOR SHAKEDOWN	4830	5149	5484	7632	8602	6906	3917
INTEREST DURING CONSTRUCTION	8820	9468	9842	12699	14372	11491	6566
LAND	798	970	795	26	26	26	677
WORKING CAPITAL	780	390	743	778	648	659	736
TOTAL CAPITAL INVESTMENT	68230	72874	76009	97452	110019	91016	54409

Note: Aqueous Carbonate System: SO₂ absorption cost includes the ESP credit.

Table 5-2. ANNUAL OPERATING COST, IN THOUSANDS OF 1980 DOLLARS

APPLICATION: NEW		REGION: SERC		PLANT SIZE: 500 MW		COAL: 3.50 % SULFUR		
		LIME	LIMESTONE	DUAL ALKALI	MAGNESIA SLURRY	WELLMAN- LORD	AQUEOUS CARBONATE	LIME SPRAY DRYER
OPERATING COST		-----	-----	-----	-----	-----	-----	-----
(VARIABLE)								
RAW MATERIAL								
-LIME		6658	---	6340	---	---	---	7331
-LIMESTONE		---	1657	---	482	---	---	---
-SODA ASH		---	---	449	---	1275	1838	---
-MAGNESIUM OXIDE		---	---	---	442	---	---	---
-COAL		---	---	---	---	---	2429	---
-CATALYST		---	---	---	6	---	24	---
UTILITIES								
-ELECTRICITY		1573	1832	998	2150	1623	2287	1510
-WATER		33	35	34	364	760	377	12
-STEAM		1132	1199	1132	1164	3651	---	---
-FUEL OIL		---	---	---	5451	---	2171	---
-NATURAL GAS		---	---	---	---	1282	---	---
-HEAT CREDIT		---	---	---	358)	57)	840)	---
TOTAL VARIABLE O&M COST		9396	4723	8954	9701	8534	8286	8852
(FIXED)								
WASTE DISPOSAL (TRUCKING)		---	---	---	---	---	---	10
LABOR								
-OPERATING, ANALYSIS, SUPERVISION		380	380	505	726	718	781	380
MAINTENANCE								
-LABOR & MATERIAL		2478	2643	1472	3416	3852	3073	1505
TOTAL FIXED O&M COST		2858	3022	1976	4142	4570	3854	1895
OVERHEAD								
-PLANT		1429	1511	988	2071	2285	1927	947
-ADMINISTRATIVE		38	38	50	73	72	78	38
-MARKETING		---	---	---	502	347	367	---
BYPRODUCT SALES								
-SULFURIC ACID		---	---	---	5020)	---	---	---
-SULFUR		---	---	---	---	3473)	3671)	---
NET OPERATING COST		13721	9294	11969	11469	12334	10842	11732
LEVELIZED - 30 YEARS								
-LEVELIZED CAPITAL COST (MILL./KWH)		3.50	3.74	3.90	5.01	5.65	4.68	2.80
-LEVELIZED OPERATING COST (MILL./KWH)		7.39	5.00	6.44	6.17	6.64	5.84	6.31
TOTAL LEVELIZED COST (MILL./KWH)		10.89	8.75	10.35	11.18	12.29	10.51	9.11

Table 5-3. TOTAL CAPITAL COST (\$/KW), LEVELIZED CAPITAL AND OPERATING COSTS (mills/kWh)

APPLICATION: NEW			PLANT SIZE: 500 MW					COAL: HIGH SULFUR							
			REGION												

FGD SYSTEM	COST CATEGORY	ECAR	ERCOT	MAAC	MAIN	MARCA-1	MARCA-2	NPCC	SERC	SPP-1	SPP-2	WSCC-1	WSCC-2	WSCC-3	WSCC-4
LINE	-CAP/KW	135.32	136.19	97.36	135.19	149.36	144.20	99.23	136.46	149.59	132.25	115.04	123.94	117.22	111.88
	-LEVCAP	3.48	3.50	2.50	3.47	3.84	3.70	2.55	3.50	3.84	3.40	2.95	3.18	3.01	2.87
	-LEVOP	6.78	4.77	3.45	6.14	5.17	7.06	3.64	7.39	7.54	7.29	4.20	4.70	4.41	4.27
	-LEVTOT	10.26	8.26	5.95	9.61	9.01	10.77	6.19	10.89	11.38	10.69	7.15	7.89	7.42	7.15
LIMESTONE	-CAP/KW	145.30	143.14	103.25	145.56	156.72	155.26	105.16	145.75	159.49	141.72	121.44	131.46	124.80	119.09
	-LEVCAP	3.73	3.68	2.65	3.74	4.03	3.99	2.70	3.74	4.10	3.64	3.12	3.38	3.21	3.06
	-LEVOP	5.23	4.88	3.45	5.18	5.40	6.67	3.60	5.00	6.25	5.51	4.35	4.67	4.77	4.36
	-LEVTOT	8.96	8.55	6.10	8.92	9.43	10.66	6.30	8.75	10.35	9.15	7.46	8.04	7.98	7.42
DUAL ALKALI	-CAP/KW	150.67	144.96	102.84	150.39	159.33	159.99	104.85	152.02	166.29	147.44	121.96	133.11	125.85	120.07
	-LEVCAP	3.87	3.72	2.64	3.86	4.09	4.11	2.69	3.90	4.27	3.79	3.13	3.42	3.23	3.08
	-LEVOP	5.89	3.36	2.50	5.27	3.62	6.07	2.67	6.44	6.43	6.39	3.03	3.52	3.33	3.25
	-LEVTOT	9.76	7.09	5.15	9.13	7.71	10.18	5.36	10.35	10.70	10.18	6.16	6.94	6.56	6.33
MAGNESIA SLURRY	-CAP/KW	191.75	161.65	117.38	190.60	176.60	198.87	119.45	194.90	210.72	189.53	137.54	155.64	147.77	142.01
	-LEVCAP	4.93	4.15	3.01	4.90	4.54	5.11	3.07	5.01	5.41	4.87	3.53	4.00	3.80	3.65
	-LEVOP	6.85	5.30	3.97	7.95	5.78	7.53	4.10	6.17	7.41	5.84	4.73	5.41	5.00	4.78
	-LEVTOT	11.78	9.45	6.98	12.84	10.32	12.64	7.17	11.18	12.82	10.71	8.26	9.41	8.80	8.43
WELLMAN-LORD	-CAP/KW	216.29	176.85	128.82	214.74	193.05	223.94	131.05	220.04	236.91	214.30	150.60	171.58	163.22	156.93
	-LEVCAP	5.56	4.54	3.31	5.52	4.96	5.75	3.37	5.65	6.09	5.50	3.87	4.41	4.19	4.03
	-LEVOP	6.00	7.76	5.78	6.41	8.42	6.79	5.88	6.64	7.24	6.40	6.56	6.83	6.65	6.44
	-LEVTOT	11.56	12.30	9.08	11.93	13.38	12.54	9.25	12.29	13.33	11.90	10.43	11.24	10.85	10.47
AQUEOUS CARBONATE	-CAP/KW	178.64	156.55	113.11	177.32	171.22	185.52	115.13	182.03	197.19	176.68	132.83	148.99	141.27	135.68
	-LEVCAP	4.59	4.02	2.91	4.55	4.40	4.77	2.96	4.68	5.06	4.54	3.41	3.83	3.63	3.48
	-LEVOP	5.78	4.73	3.59	6.06	5.14	5.92	3.67	5.84	5.84	5.35	4.06	4.46	4.27	4.10
	-LEVTOT	10.36	8.75	6.49	10.61	9.53	10.68	6.63	10.51	10.90	9.88	7.48	8.28	7.89	7.58
LINE SPRAY DRYER	-CAP/KW	107.53	118.42	83.63	106.92	130.97	115.09	85.14	108.82	120.81	104.80	99.19	103.92	97.86	92.96
	-LEVCAP	2.76	3.04	2.15	2.75	3.36	2.96	2.19	2.80	3.10	2.69	2.55	2.67	2.51	2.39
	-LEVOP	5.70	3.17	2.32	5.02	3.42	5.91	2.50	6.31	6.27	6.29	2.87	3.34	3.13	3.05
	-LEVTOT	8.47	6.21	4.47	7.76	6.78	8.87	4.69	9.11	9.38	8.98	5.42	6.01	5.64	5.44

Table 5-3. TOTAL CAPITAL COST (\$/KW), LEVELIZED CAPITAL AND OPERATING COSTS (mills/kWh)
(Cont'd)

APPLICATION: NEW			PLANT SIZE: 500 MW					COAL: LOW SULFUR							
			REGION												
FGD SYSTEM	COST CATEGORY	ECAR	ERCOT	NAAC	MAIN	MARCA-1	MARCA-2	NPCC	SERC	SPP-1	SPP-2	WSCC-1	WSCC-2	WSCC-3	WSCC-4
LIME	-CAP/KW	111.54	135.49	105.72	113.85	131.49	122.75	106.55	111.45	126.49	115.80	123.38	118.47	110.82	106.74
	-LEVCAP	2.86	3.48	2.72	2.92	3.38	3.15	2.74	2.86	3.25	2.97	3.17	3.04	2.85	2.74
	-LEVOP	4.24	5.05	3.93	4.15	4.83	4.60	4.26	4.39	4.73	4.52	4.92	4.24	3.93	3.85
	-LEVTOT	7.10	8.53	6.65	7.08	8.21	7.75	7.00	7.26	7.97	7.49	8.09	7.28	6.77	6.59
LIMESTONE	-CAP/KW	118.80	143.35	112.88	121.28	139.25	130.54	113.69	118.53	133.91	123.05	131.00	125.10	117.26	113.09
	-LEVCAP	3.05	3.68	2.90	3.12	3.58	3.35	2.92	3.04	3.44	3.16	3.36	3.21	3.01	2.90
	-LEVOP	3.97	4.99	3.76	4.04	4.98	4.64	3.98	3.90	4.59	4.21	5.03	4.31	4.19	3.97
	-LEVTOT	7.02	8.68	6.65	7.15	8.56	8.00	6.90	6.94	8.03	7.37	8.40	7.52	7.20	6.88
DUAL ALKALI	-CAP/KW	119.71	145.74	113.39	122.19	141.27	131.76	114.25	119.68	135.64	124.30	132.48	125.94	117.53	113.32
	-LEVCAP	3.07	3.74	2.91	3.14	3.63	3.38	2.93	3.07	3.48	3.19	3.40	3.23	3.02	2.91
	-LEVOP	3.22	3.75	2.99	3.11	3.57	3.45	3.30	3.37	3.50	3.44	3.74	3.04	2.82	2.81
	-LEVTOT	6.29	7.49	5.91	6.25	7.19	6.83	6.23	6.44	6.98	6.63	7.14	6.28	5.84	5.72
MAGNESIA SLURRY	-CAP/KW	141.28	169.15	134.29	143.71	164.04	153.14	135.04	141.78	157.27	146.15	154.67	142.95	133.46	130.07
	-LEVCAP	3.63	4.34	3.45	3.69	4.21	3.93	3.47	3.64	4.04	3.75	3.97	3.67	3.43	3.34
	-LEVOP	4.70	5.55	4.46	5.04	5.51	5.17	4.53	4.55	5.17	4.63	5.34	4.87	4.47	4.36
	-LEVTOT	8.33	9.90	7.91	8.73	9.73	9.10	8.00	8.19	9.21	8.39	9.31	8.54	7.90	7.70
WELLNAN-LORD	-CAP/KW	156.14	186.42	148.61	158.72	180.70	168.98	149.39	156.81	173.23	161.49	170.56	156.69	146.39	142.89
	-LEVCAP	4.01	4.79	3.82	4.08	4.64	4.34	3.84	4.03	4.45	4.15	4.38	4.02	3.76	3.67
	-LEVOP	6.10	7.49	5.98	6.27	7.22	6.72	6.02	6.26	7.04	6.47	6.76	6.69	6.45	6.31
	-LEVTOT	10.11	12.27	9.80	10.35	11.86	11.06	9.86	10.29	11.49	10.61	11.14	10.72	10.21	9.98
AQUEOUS CARBONATE	-CAP/KW	134.92	162.25	128.10	137.24	157.31	146.55	128.87	135.45	150.93	139.80	148.02	137.88	128.72	125.20
	-LEVCAP	3.47	4.17	3.29	3.53	4.04	3.76	3.31	3.48	3.88	3.59	3.80	3.54	3.31	3.22
	-LEVOP	4.13	4.79	3.97	4.28	4.63	4.44	4.05	4.14	4.47	4.17	4.40	4.16	3.92	3.81
	-LEVTOT	7.60	8.96	7.26	7.81	8.67	8.20	7.36	7.62	8.35	7.76	8.20	7.70	7.22	7.02
LIME SPRAY DRYER	-CAP/KW	92.92	114.58	88.00	94.89	110.98	103.39	88.54	92.38	106.72	96.35	103.76	100.62	94.01	89.88
	-LEVCAP	2.39	2.94	2.26	2.44	2.85	2.66	2.27	2.37	2.74	2.47	2.67	2.58	2.41	2.31
	-LEVOP	3.03	3.55	2.79	2.91	3.37	3.27	3.14	3.20	3.32	3.27	3.60	2.87	2.64	2.62
	-LEVTOT	5.42	6.49	5.05	5.35	6.22	5.92	5.41	5.57	6.06	5.74	6.26	5.45	5.06	4.93

Table 5-3. TOTAL CAPITAL COST (\$/KW), LEVELIZED CAPITAL AND OPERATING COSTS (mills/kWh)
(Cont'd)

APPLICATION: NEW			PLANT SIZE: 100 MW					COAL: HIGH SULFUR							
			REGION												
FGD SYSTEM	COST CATEGORY	ECAR	ERCOT	MAAC	MAIN	MARCA-1	MARCA-2	NPCC	SERC	SPP-1	SPP-2	WSCC-1	WSCC-2	WSCC-3	WSCC-4
LIME	-CAP/KW	214.72	205.58	149.29	214.14	224.73	226.76	151.99	216.96	236.28	210.68	174.89	190.61	180.90	173.10
	-LEVCAP	5.52	5.28	3.83	5.50	5.77	5.82	3.90	5.57	6.07	5.41	4.49	4.90	4.65	4.45
	-LEVOP	9.43	7.11	5.29	8.72	7.71	9.80	5.51	10.11	10.38	9.96	6.26	6.90	6.51	6.30
	-LEVTOT	14.95	12.39	9.12	14.22	13.48	15.62	9.42	15.68	16.45	15.38	10.75	11.80	11.16	10.74
LINESTONE	-CAP/KW	239.18	220.01	161.92	238.97	239.82	252.45	164.70	240.70	260.90	234.54	188.37	207.31	197.60	189.26
	-LEVCAP	6.14	5.65	4.16	6.14	6.16	6.48	4.23	6.18	6.70	6.02	4.84	5.32	5.08	4.86
	-LEVOP	8.00	7.27	5.35	7.91	7.98	9.59	5.53	7.78	9.21	8.28	6.47	6.96	7.00	6.49
	-LEVTOT	14.14	12.92	9.51	14.05	14.14	16.07	9.76	13.96	15.91	14.31	11.31	12.28	12.07	11.35
DUAL ALKALI	-CAP/KW	230.93	207.35	148.93	230.18	227.35	243.16	151.71	233.19	253.24	226.72	175.41	194.47	184.50	176.34
	-LEVCAP	5.93	5.33	3.83	5.91	5.84	6.25	3.90	5.99	6.50	5.82	4.51	5.00	4.74	4.53
	-LEVOP	8.20	5.14	3.98	7.51	5.53	8.44	4.17	8.80	8.83	8.73	4.62	5.22	4.98	4.84
	-LEVTOT	14.13	10.47	7.80	13.42	11.37	14.68	8.06	14.79	15.34	14.56	9.13	10.22	9.72	9.37
MAGNESIA SLURRY	-CAP/KW	309.16	229.51	171.11	307.41	249.44	318.69	173.86	312.78	333.73	305.84	197.63	230.46	220.58	212.32
	-LEVCAP	7.94	5.90	4.40	7.90	6.41	8.19	4.47	8.03	8.57	7.86	5.08	5.92	5.67	5.45
	-LEVOP	10.77	7.77	6.09	11.87	8.41	11.52	6.25	10.05	11.40	9.69	6.98	7.98	7.51	7.20
	-LEVTOT	18.71	13.67	10.48	19.77	14.82	19.71	10.71	18.09	19.97	17.55	12.06	13.90	13.18	12.65
WELL-KAN-LORD	-CAP/KW	351.30	255.37	190.85	348.93	277.33	361.63	193.89	355.71	378.51	348.10	219.94	257.69	247.09	238.09
	-LEVCAP	9.02	6.56	4.90	8.96	7.12	9.29	4.98	9.14	9.72	8.94	5.65	6.62	6.35	6.12
	-LEVOP	12.86	12.98	10.73	12.96	13.74	13.49	10.95	13.67	14.16	13.25	11.24	11.88	12.13	12.25
	-LEVTOT	21.88	19.53	15.63	21.92	20.86	22.77	15.93	22.80	23.88	22.19	16.89	18.50	18.48	18.37
AQUEOUS CARBONATE	-CAP/KW	293.16	229.85	169.97	291.22	250.26	302.85	172.78	297.31	318.38	290.08	197.09	226.82	216.60	208.30
	-LEVCAP	7.53	5.90	4.37	7.48	6.43	7.78	4.44	7.64	8.18	7.45	5.06	5.83	5.56	5.35
	-LEVOP	9.49	7.18	5.70	9.73	7.74	9.68	5.81	9.55	9.58	9.03	6.29	6.94	6.70	6.44
	-LEVTOT	17.02	13.08	10.07	17.21	14.17	17.46	10.25	17.19	17.76	16.48	11.35	12.77	12.26	11.79
LIME SPRAY DRYER	-CAP/KW	164.98	177.48	125.61	163.85	196.03	175.68	127.93	167.45	185.34	161.39	148.80	157.04	147.98	140.67
	-LEVCAP	4.24	4.56	3.23	4.21	5.04	4.51	3.29	4.30	4.76	4.15	3.82	4.03	3.80	3.61
	-LEVOP	7.63	4.84	3.62	6.87	5.23	7.91	3.84	8.30	8.33	8.24	4.33	4.88	4.60	4.47
	-LEVTOT	11.87	9.40	6.85	11.08	10.26	12.42	7.12	12.60	13.09	12.39	8.15	8.92	8.41	8.08

Table 5-3. TOTAL CAPITAL COST (\$/KW), LEVELIZED CAPITAL AND OPERATING COSTS (mills/kWh)
(Cont'd)

APPLICATION: NEW			PLANT SIZE: 100 MW					COAL: LOW SULFUR							
FGD SYSTEM	COST CATEGORY	REGION													
		ECAR	ERCOT	HAAC	HAIN	HARCA-1	HARCA-2	NPCC	SERC	SPP-1	SPP-2	WSCC-1	WSCC-2	WSCC-3	WSCC-4
LIME	-CAP/KW	172.66	207.55	164.14	176.01	201.54	188.86	165.28	172.60	193.90	178.79	189.78	180.36	169.08	163.44
	-LEVCAP	4.43	5.33	4.22	4.52	5.18	4.85	4.25	4.43	4.98	4.59	4.87	4.63	4.34	4.20
	-LEVOP	6.26	7.40	5.87	6.19	7.12	6.76	6.22	6.43	6.95	6.61	7.12	6.29	5.86	5.74
	-LEVTOT	10.70	12.74	10.08	10.71	12.30	11.61	10.46	10.87	11.93	11.20	11.99	10.93	10.21	9.93
LIMESTONE	-CAP/KW	188.94	224.90	180.18	192.53	218.58	205.87	181.29	188.71	210.25	195.08	206.60	194.49	182.72	177.17
	-LEVCAP	4.85	5.78	4.63	4.95	5.61	5.29	4.66	4.85	5.40	5.01	5.31	5.00	4.69	4.55
	-LEVOP	6.08	7.43	5.78	6.17	7.36	6.91	6.03	6.01	6.89	6.38	7.33	6.42	6.20	5.93
	-LEVTOT	10.93	13.21	10.41	11.11	12.98	12.19	10.68	10.86	12.29	11.39	12.64	11.42	10.89	10.48
DUAL ALKALI	-CAP/KW	176.00	212.24	167.14	179.47	205.76	192.70	168.27	175.99	197.42	182.25	193.63	181.52	169.63	164.13
	-LEVCAP	4.52	5.45	4.29	4.61	5.28	4.95	4.32	4.52	5.07	4.68	4.97	4.66	4.36	4.22
	-LEVOP	4.82	5.55	4.53	4.71	5.32	5.14	4.86	4.98	5.21	5.07	5.45	4.60	4.30	4.25
	-LEVTOT	9.34	11.00	8.82	9.32	10.61	10.09	9.18	9.50	10.28	9.76	10.42	9.26	8.66	8.47
MAGNESIA SLURRY	-CAP/KW	212.11	248.85	202.82	215.54	241.40	228.12	203.70	212.58	231.20	218.09	229.49	206.19	193.15	189.46
	-LEVCAP	5.45	6.39	5.21	5.54	6.20	5.86	5.23	5.46	5.94	5.60	5.89	5.30	4.96	4.87
	-LEVOP	7.15	8.24	6.83	7.51	8.14	7.72	6.91	6.99	7.70	7.09	7.90	7.09	6.59	6.46
	-LEVTOT	12.59	14.63	12.04	13.04	14.34	13.58	12.14	12.45	13.64	12.69	13.80	12.39	11.55	11.32
WELLMAN-LORD	-CAP/KW	237.65	278.31	227.46	241.27	269.85	255.18	228.42	238.37	258.45	244.34	256.64	229.64	215.34	211.64
	-LEVCAP	6.10	7.15	5.84	6.20	6.93	6.55	5.87	6.12	6.64	6.28	6.59	5.90	5.53	5.44
	-LEVOP	11.35	12.99	11.29	11.27	12.54	11.85	11.43	11.65	12.34	11.74	11.83	11.34	11.44	11.72
	-LEVTOT	17.45	20.13	17.13	17.47	19.47	18.41	17.29	17.77	18.98	18.02	18.42	17.24	16.98	17.16
AQUEOUS CARBONATE	-CAP/KW	207.91	245.55	198.47	211.33	238.16	224.31	199.43	208.43	228.29	214.24	225.75	205.22	192.18	187.95
	-LEVCAP	5.34	6.31	5.10	5.43	6.12	5.76	5.12	5.35	5.86	5.50	5.80	5.27	4.94	4.83
	-LEVOP	6.51	7.40	6.27	6.67	7.17	6.91	6.36	6.53	6.93	6.56	6.87	6.34	5.99	5.86
	-LEVTOT	11.85	13.70	11.37	12.10	13.28	12.67	11.49	11.88	12.80	12.07	12.67	11.61	10.93	10.69
LIME SPRAY DRYER	-CAP/KW	140.49	172.86	132.97	143.44	167.46	155.88	133.85	139.93	160.99	145.80	156.58	151.33	141.38	135.33
	-LEVCAP	3.61	4.44	3.42	3.68	4.30	4.00	3.44	3.59	4.14	3.74	4.02	3.89	3.63	3.48
	-LEVOP	4.45	5.20	4.14	4.33	4.97	4.78	4.51	4.63	4.87	4.73	5.14	4.30	3.99	3.94
	-LEVTOT	8.05	9.64	7.55	8.01	9.27	8.78	7.95	8.22	9.01	8.48	9.16	8.19	7.62	7.41

Table 5-3. TOTAL CAPITAL COST (\$/KW), LEVELIZED CAPITAL AND OPERATING COSTS (mills/kWh)
(Cont'd)

APPLICATION: RETROFIT			PLANT SIZE: 500 MW					COAL: HIGH SULFUR								
FGD SYSTEM	COST CATEGORY	REGION														
		ECAR	ERCOT	NAAC	MAIN	MARCA-1	MARCA-2	NPCC	SERC	SPP-1	SPP-2	WSCC-1	WSCC-2	WSCC-3	WSCC-4	
LINE	-CAP/KW	153.20	159.42	113.38	152.50	174.95	162.44	115.58	155.71	171.50	150.43	134.37	144.15	135.93	129.94	
	-LEVCAP	4.15	4.32	3.07	4.13	4.74	4.40	3.13	4.22	4.65	4.08	3.64	3.91	3.69	3.52	
	-LEVOP	6.24	4.50	3.25	5.67	4.89	6.50	3.42	6.78	6.95	6.69	3.95	4.41	4.13	4.00	
	-LEVTOT	10.39	8.82	6.32	9.80	9.63	10.90	6.56	11.00	11.60	10.77	7.59	8.32	7.82	7.52	
LIMESTONE	-CAP/KW	163.61	167.19	119.87	163.22	183.19	173.80	122.11	165.60	182.11	160.44	141.47	152.43	144.21	137.85	
	-LEVCAP	4.44	4.53	3.25	4.43	4.97	4.71	3.31	4.49	4.94	4.35	3.84	4.13	3.91	3.74	
	-LEVOP	4.87	4.61	3.26	4.82	5.11	6.16	3.39	4.67	5.81	5.11	4.09	4.39	4.46	4.09	
	-LEVTOT	9.30	9.14	6.51	9.24	10.07	10.88	6.70	9.16	10.75	9.46	7.93	8.52	8.37	7.83	
DUAL ALKALI	-CAP/KW	170.62	169.53	119.69	169.76	186.44	180.38	122.04	173.37	190.47	167.66	142.33	154.65	145.81	139.30	
	-LEVCAP	4.63	4.60	3.24	4.60	5.05	4.89	3.31	4.70	5.16	4.55	3.86	4.19	3.95	3.78	
	-LEVOP	5.34	3.13	2.32	4.79	3.37	5.52	2.47	5.84	5.84	5.79	2.80	3.24	3.07	2.99	
	-LEVTOT	9.97	7.72	5.56	9.39	8.42	10.41	5.78	10.54	11.01	10.34	6.66	7.44	7.02	6.77	
MAGNESIA SLURRY	-CAP/KW	211.21	183.21	132.44	209.89	200.34	219.38	134.81	214.92	233.02	208.75	155.56	174.88	165.80	159.26	
	-LEVCAP	5.73	4.97	3.59	5.69	5.43	5.95	3.65	5.83	6.32	5.66	4.22	4.74	4.50	4.32	
	-LEVOP	6.24	4.90	3.65	7.21	5.35	6.85	3.77	5.64	6.76	5.34	4.36	4.97	4.60	4.39	
	-LEVTOT	11.97	9.86	7.24	12.90	10.78	12.80	7.43	11.47	13.08	11.00	8.57	9.71	9.09	8.71	
WET LKAL- LORD	-CAP/KW	239.20	202.26	146.55	237.44	221.05	248.09	149.13	243.63	263.19	236.94	171.82	194.23	184.44	177.24	
	-LEVCAP	6.49	5.48	3.97	6.44	5.99	6.73	4.04	6.61	7.14	6.42	4.66	5.27	5.00	4.81	
	-LEVOP	5.51	7.12	5.28	5.87	7.73	6.22	5.38	6.08	6.65	5.86	6.01	6.26	6.09	5.88	
	-LEVTOT	11.99	12.60	9.25	12.31	13.73	12.95	9.42	12.68	13.78	12.28	10.67	11.53	11.09	10.69	
AQUEOUS CARBONATE	-CAP/KW	201.93	183.37	131.73	200.38	200.79	210.12	134.13	206.04	224.06	199.67	155.18	172.68	163.42	156.86	
	-LEVCAP	5.47	4.97	3.57	5.43	5.44	5.70	3.64	5.59	6.07	5.41	4.21	4.68	4.43	4.25	
	-LEVOP	5.33	4.45	3.36	5.58	4.84	5.47	3.44	5.39	5.42	4.95	3.82	4.18	3.99	3.83	
	-LEVTOT	10.81	9.43	6.93	11.01	10.29	11.17	7.07	10.98	11.50	10.36	8.02	8.86	8.42	8.08	
LIME SPRAY DRYER	-CAP/KW	130.78	148.42	103.98	129.61	164.03	139.39	106.00	133.55	148.80	128.26	123.94	129.77	121.78	115.88	
	-LEVCAP	3.55	4.02	2.82	3.51	4.45	3.78	2.87	3.62	4.03	3.48	3.36	3.52	3.30	3.14	
	-LEVOP	5.63	3.30	2.40	5.00	3.54	5.79	2.55	6.17	6.21	6.12	2.95	3.35	3.14	3.17	
	-LEVTOT	9.18	7.32	5.22	8.51	7.99	9.57	5.42	9.79	10.25	9.59	6.31	6.86	6.44	6.31	

Table 5-3. TOTAL CAPITAL COST (\$/KW), LEVELIZED CAPITAL AND OPERATING COSTS (mills/kWh)
(Cont'd)

APPLICATION: RETROFIT		PLANT SIZE: 500 MW						COAL: LOW SULFUR								
		REGION														
FGD SYSTEM	COST CATEGORY	ECAR	ERCOT	MAAC	HAIN	MARCA-1	MARCA-2	NPCC	SERC	SPP-1	SPP-2	WSCC-1	WSCC-2	WSCC-3	WSCC-4	
S-9	LINE	-CAP/KW	129.15	157.79	122.14	131.71	153.11	142.05	123.13	129.34	147.33	134.43	143.29	138.37	129.28	124.50
	-LEVCAP	3.50	4.28	3.31	3.57	4.15	3.85	3.34	3.51	3.99	3.64	3.88	3.75	3.50	3.38	
	-LEVOP	3.97	4.74	3.68	3.90	4.54	4.31	3.97	4.11	4.44	4.23	4.60	3.99	3.70	3.62	
	-LEVTOT	7.47	9.02	7.00	7.47	8.69	8.16	7.31	7.61	8.43	7.87	8.48	7.75	7.20	7.00	
	LINESTONE	-CAP/KW	137.06	166.48	129.90	139.79	161.68	150.51	130.87	137.11	155.52	142.38	151.65	145.73	136.39	131.53
	-LEVCAP	3.72	4.51	3.52	3.79	4.38	4.08	3.55	3.72	4.22	3.86	4.11	3.95	3.70	3.57	
	-LEVOP	3.74	4.70	3.53	3.80	4.68	4.36	3.73	3.68	4.33	3.96	4.71	4.06	3.94	3.74	
	-LEVTOT	7.45	9.22	7.06	7.59	9.06	8.44	7.28	7.39	8.55	7.82	8.82	8.02	7.64	7.30	
	DUAL ALKALI	-CAP/KW	138.50	169.53	130.91	141.26	164.32	152.37	131.93	138.75	157.82	144.15	153.71	146.96	136.99	132.06
	-LEVCAP	3.74	4.60	3.55	3.83	4.46	4.13	3.58	3.76	4.28	3.91	4.17	3.98	3.71	3.58	
	-LEVOP	2.96	3.46	2.76	2.87	3.30	3.18	3.03	3.09	3.23	3.16	3.44	2.82	2.62	2.60	
	-LEVTOT	6.72	8.06	6.30	6.70	7.75	7.31	6.60	6.86	7.51	7.07	7.60	6.81	6.33	6.18	
	MAGNESIA SLURRY	-CAP/KW	158.34	190.30	150.35	161.10	184.55	171.94	151.23	158.93	176.99	164.00	173.74	161.52	150.75	146.70
	-LEVCAP	4.29	5.16	4.08	4.37	5.00	4.66	4.10	4.31	4.80	4.45	4.71	4.38	4.09	3.98	
	-LEVOP	4.32	5.12	4.10	4.62	5.08	4.75	4.16	4.19	4.77	4.27	4.90	4.48	4.12	4.02	
	-LEVTOT	8.61	10.28	8.17	8.99	10.08	9.42	8.26	8.50	9.56	8.71	9.62	8.86	8.21	8.00	
	WELLMAN-LORD	-CAP/KW	176.23	211.34	167.50	179.19	204.86	191.11	168.43	176.99	196.46	182.50	193.01	178.57	166.74	162.47
	-LEVCAP	4.78	5.73	4.54	4.86	5.55	5.18	4.57	4.80	5.33	4.95	5.23	4.84	4.52	4.40	
	-LEVOP	5.58	6.87	5.47	5.74	6.62	6.16	5.50	5.73	6.46	5.92	6.20	6.14	5.91	5.76	
	-LEVTOT	10.36	12.60	10.01	10.60	12.17	11.34	10.07	10.53	11.78	10.87	11.43	10.98	10.43	10.17	
	AQUEOUS CARBONATE	-CAP/KW	155.86	188.34	147.78	158.59	182.60	169.67	148.70	156.49	175.25	161.73	171.49	160.90	150.13	145.76
	-LEVCAP	4.23	5.11	4.01	4.30	4.95	4.60	4.03	4.24	4.75	4.38	4.65	4.36	4.07	3.95	
	-LEVOP	3.86	4.50	3.70	4.00	4.35	4.16	3.78	3.87	4.20	3.91	4.12	3.91	3.68	3.57	
	-LEVTOT	8.09	9.61	7.71	8.30	9.30	8.76	7.81	8.12	8.95	8.29	8.77	8.27	7.75	7.53	
	LIME SPRAY DRYER	-CAP/KW	115.29	143.10	108.70	117.64	138.62	128.00	109.54	115.18	133.35	120.15	129.13	126.11	117.55	112.45
	-LEVCAP	3.13	3.88	2.95	3.19	3.76	3.47	2.97	3.12	3.62	3.26	3.50	3.42	3.19	3.05	
	-LEVOP	3.07	3.64	2.86	2.94	3.43	3.28	3.15	3.22	3.39	3.25	3.61	2.90	2.67	2.76	
	-LEVTOT	6.20	7.52	5.81	6.13	7.18	6.75	6.12	6.34	7.00	6.51	7.11	6.32	5.86	5.81	

Table 5-3. TOTAL CAPITAL COST (\$/KW), LEVELIZED CAPITAL AND OPERATING COSTS (mills/kWh)
(Cont'd)

APPLICATION: RETROFIT			PLANT SIZE: 100 MW					COAL: HIGH SULFUR							
			REGION												

FGD SYSTEM	COST CATEGORY	ECAR	ERCOT	MAAC	HAIN	MARCA-1	MARCA-2	NPCC	SERC	SPP-1	SPP-2	WSCC-1	WSCC-2	WSCC-3	WSCC-4
LINE	-CAP/KW	233.67	226.92	164.38	232.52	248.10	245.86	167.36	237.22	258.86	229.98	192.85	209.92	198.91	190.55
	-LEVCAP	6.34	6.15	4.46	6.30	6.73	6.67	4.54	6.43	7.02	6.24	5.23	5.69	5.39	5.17
	-LEVOP	8.62	6.58	4.88	7.98	7.13	8.96	5.08	9.23	9.50	9.09	5.78	6.37	6.01	5.81
	-LEVTOT	14.96	12.73	9.33	14.29	13.86	15.63	9.62	15.66	16.52	15.33	11.01	12.06	11.40	10.97
LINESTONE	-CAP/KW	259.49	242.46	177.94	258.61	264.35	272.75	181.00	262.49	285.12	255.32	207.35	227.87	216.81	207.91
	-LEVCAP	7.04	6.57	4.82	7.01	7.17	7.39	4.91	7.12	7.73	6.92	5.62	6.18	5.88	5.64
	-LEVOP	7.36	6.73	4.95	7.28	7.39	8.79	5.11	7.17	8.48	7.61	5.98	6.43	6.45	5.99
	-LEVTOT	14.39	13.31	9.77	14.29	14.56	16.18	10.02	14.29	16.21	14.53	11.60	12.61	12.33	11.63
DUAL ALKALI	-CAP/KW	252.02	229.02	164.14	250.68	251.13	264.43	167.22	255.59	278.03	248.15	193.58	214.40	203.10	194.34
	-LEVCAP	6.83	6.21	4.45	6.80	6.81	7.17	4.53	6.93	7.54	6.73	5.25	5.81	5.51	5.27
	-LEVOP	7.44	4.72	3.63	6.82	5.08	7.66	3.80	7.98	8.02	7.91	4.23	4.78	4.56	4.42
	-LEVTOT	14.27	10.93	8.08	13.62	11.89	14.83	8.34	14.91	15.56	14.64	9.48	10.59	10.06	9.69
MAGNESIA SLURRY	-CAP/KW	332.09	250.14	185.99	330.17	272.00	342.53	189.01	336.17	359.15	328.54	215.12	249.99	239.08	230.09
	-LEVCAP	9.00	6.78	5.04	8.95	7.37	9.29	5.12	9.11	9.74	8.91	5.83	6.78	6.48	6.24
	-LEVOP	9.75	7.10	5.54	10.74	7.69	10.44	5.68	9.12	10.34	8.79	6.36	7.27	6.84	6.55
	-LEVTOT	18.76	13.88	10.58	19.69	15.06	19.72	10.80	18.24	20.08	17.70	12.19	14.05	13.32	12.79
WELLMAN-LORD	-CAP/KW	377.52	278.88	207.78	374.95	303.05	388.89	211.12	382.47	407.57	374.06	239.86	279.93	268.15	258.32
	-LEVCAP	10.24	7.56	5.63	10.17	8.22	10.54	5.72	10.37	11.05	10.14	6.50	7.59	7.27	7.00
	-LEVOP	11.57	11.69	9.61	11.66	12.40	12.14	9.81	12.29	12.76	11.91	10.11	10.70	10.90	10.98
	-LEVTOT	21.80	19.25	15.24	21.83	20.62	22.69	15.54	22.66	23.81	22.05	16.62	18.29	18.17	17.99
AQUEOUS CARBONATE	-CAP/KW	319.12	254.55	187.62	316.96	277.34	329.92	190.75	323.85	347.39	315.76	217.95	249.80	238.30	229.13
	-LEVCAP	8.65	6.90	5.09	8.59	7.52	8.94	5.17	8.78	9.42	8.56	5.91	6.77	6.46	6.21
	-LEVOP	8.66	6.63	5.23	8.87	7.16	8.84	5.33	8.73	8.78	8.25	5.79	6.39	6.16	5.92
	-LEVTOT	17.31	13.53	10.32	17.46	14.68	17.79	10.50	17.51	18.20	16.81	11.70	13.16	12.62	12.13
LIME SPRAY DRYER	-CAP/KW	186.72	203.18	143.06	185.04	224.33	198.19	145.84	190.56	211.21	183.41	170.03	179.65	168.93	160.78
	-LEVCAP	5.06	5.51	3.88	5.02	6.08	5.37	3.95	5.17	5.73	4.97	4.61	4.87	4.58	4.36
	-LEVOP	7.39	4.80	3.57	6.69	5.16	7.60	3.74	7.98	8.09	7.90	4.26	4.73	4.46	4.45
	-LEVTOT	12.45	10.30	7.45	11.71	11.24	12.97	7.70	13.15	13.82	12.87	8.87	9.60	9.04	8.81

Table 5-3. TOTAL CAPITAL COST (\$/KW), LEVELIZED CAPITAL AND OPERATING COSTS (mills/kWh)
(Cont'd)

APPLICATION: RETROFIT			PLANT SIZE: 100 MW				COAL: LOW SULFUR									
			REGION													
FGD SYSTEM	COST CATEGORY	ECAR	ERCOT	HAAC	HAIN	MARCA-1	MARCA-2	NPCC	SERC	SPP-1	SPP-2	WSCC-1	WSCC-2	WSEC-3	WSCC-4	
LINE	-CAP/KW	189.72	228.71	180.14	193.27	222.06	207.33	181.40	189.94	213.67	196.73	208.82	198.92	186.34	180.19	
	-LEVCAP	5.14	6.20	4.88	5.24	6.02	5.62	4.92	5.15	5.79	5.33	5.66	5.39	5.05	4.89	
	-LEVOP	5.77	6.84	5.41	5.71	6.58	6.24	5.72	5.93	6.41	6.09	6.56	5.82	5.42	5.30	
	-LEVTOT	10.91	13.04	10.29	10.95	12.60	11.86	10.64	11.07	12.20	11.42	12.22	11.21	10.47	10.18	
LIMESTONE	-CAP/KW	207.15	247.36	197.29	210.93	240.37	225.49	198.52	207.25	231.25	214.22	226.87	214.13	200.99	194.96	
	-LEVCAP	5.62	6.71	5.35	5.72	6.52	6.11	5.38	5.62	6.27	5.81	6.15	5.81	5.45	5.29	
	-LEVOP	5.62	6.88	5.35	5.71	6.81	6.38	5.57	5.56	6.38	5.90	6.76	5.95	5.73	5.49	
	-LEVTOT	11.24	13.58	10.70	11.42	13.32	12.49	10.95	11.18	12.65	11.71	12.91	11.75	11.18	10.77	
DUAL ALKALI	-CAP/KW	193.63	234.09	183.67	197.31	226.92	211.78	184.93	193.90	217.76	200.76	213.29	200.37	187.11	181.11	
	-LEVCAP	5.25	6.35	4.98	5.35	6.15	5.74	5.01	5.26	5.90	5.44	5.78	5.43	5.07	4.91	
	-LEVOP	4.40	5.09	4.14	4.31	4.88	4.70	4.43	4.55	4.77	4.64	4.98	4.22	3.94	3.89	
	-LEVTOT	9.65	11.43	9.12	9.66	11.03	10.44	9.44	9.80	10.67	10.08	10.76	9.65	9.01	8.81	
MAGNESIA SLURRY	-CAP/KW	229.76	270.12	219.57	233.49	262.03	247.30	220.55	230.31	251.00	236.40	248.88	224.34	210.10	205.94	
	-LEVCAP	6.23	7.32	5.95	6.33	7.10	6.70	5.98	6.24	6.81	6.41	6.75	6.08	5.70	5.58	
	-LEVOP	6.50	7.52	6.21	6.83	7.42	7.03	6.28	6.37	7.02	6.46	7.19	6.47	6.01	5.89	
	-LEVTOT	12.73	14.84	12.16	13.16	14.52	13.73	12.26	12.61	13.83	12.87	13.94	12.55	11.70	11.47	
WELLMAN-LORD	-CAP/KW	257.74	302.55	246.52	261.71	293.35	277.02	247.60	258.55	281.01	265.19	278.73	250.31	234.63	230.39	
	-LEVCAP	6.99	8.20	6.68	7.10	7.95	7.51	6.71	7.01	7.62	7.19	7.56	6.79	6.36	6.25	
	-LEVOP	10.19	11.70	10.12	10.14	11.30	10.67	10.25	10.46	11.11	10.56	10.66	10.22	10.28	10.50	
	-LEVTOT	17.18	19.91	16.81	17.24	19.25	18.18	16.96	17.47	18.73	17.74	18.21	17.00	16.64	16.75	
AQUEOUS CARBONATE	-CAP/KW	228.58	270.66	218.04	232.36	262.51	246.85	219.12	229.20	251.67	235.72	248.56	226.82	212.32	207.47	
	-LEVCAP	6.20	7.34	5.91	6.30	7.12	6.69	5.94	6.21	6.82	6.39	6.74	6.15	5.76	5.62	
	-LEVOP	5.98	6.82	5.76	6.13	6.61	6.36	5.84	6.00	6.39	6.04	6.33	5.85	5.52	5.40	
	-LEVTOT	12.18	14.16	11.67	12.43	13.73	13.05	11.78	12.21	13.21	12.43	13.07	12.00	11.28	11.02	
LINE SPRAY DRYER	-CAP/KW	160.10	197.73	151.11	163.35	191.57	177.33	152.25	159.98	184.19	166.66	178.74	173.29	161.64	154.83	
	-LEVCAP	4.34	5.36	4.10	4.43	5.19	4.81	4.13	4.34	4.99	4.52	4.85	4.70	4.38	4.20	
	-LEVOP	4.35	5.13	4.07	4.22	4.87	4.64	4.38	4.51	4.79	4.56	5.00	4.18	3.88	3.94	
	-LEVTOT	8.69	10.49	8.17	8.65	10.06	9.45	8.51	8.84	9.78	9.08	9.85	8.88	8.26	8.14	

attributed to the SO₂ absorption area (i.e., for lime \$13.3 million out of \$33.9 million, and for limestone \$14.0 out of \$36.4 million). Gas handling (17 to 22 percent) and sludge pond (15 percent) sub-areas are also significant portions of the direct investment for those systems. For the regenerative processes the SO₂ absorption area costs contribute from 17 percent for the magnesia process to 34 percent for the aqueous carbonate process. The regeneration cost accounts for 23 percent to 28 percent of the total direct investment. Sulfuric acid and sulfur production capital costs for the magnesia, Wellman-Lord, and aqueous carbonate processes contribute 19 percent, 22 percent, and 11 percent, respectively, to the total direct investment.

A comparison of capital costs among different FGD processes can be summarized as follows:

- o Although the SO₂ absorption area cost for the lime spray dryer is approximately 50 percent higher than those for the lime slurry process, the significantly (25 percent) lower total capital cost for lime spray dryer is primarily due to the large ESP equipment credit claimed for the system.
- o The capital cost difference (10 percent) between the lime slurry and limestone slurry processes is the result of lower costs in the material handling/preparation, SO₂ absorption, and sludge pond areas for the lime slurry process.
- o The capital investment costs for limestone slurry and dual alkali processes are quite close (<5 percent). The relatively expensive sludge disposal equipment cost is offset by a smaller pond requirement for the dual alkali process.
- o The higher capital cost for the aqueous carbonate process is due to the additional process costs for the sulfur production and sodium carbonate regeneration areas.
- o The higher capital cost for the magnesia process is due to the additional process costs for the chloride purge, sulfuric acid production and MgO regeneration areas.
- o The capital cost differences between the Wellman-Lord and the magnesia processes are due to higher direct costs associated with the SO₂ absorption and the sulfur production process areas.

5.1.2 Base Case Variations

Table 5-4 shows a gross ranking of FGD systems based on increasing capital costs for new, 500 MW, high SO₂ removal FGD applications. The range in regional capital costs is due primarily to regional variations in the coal characteristics such as sulfur content and heating value. These characteristics affect the system design specifications which influence the direct capital costs.

Table 5-4. RANGE OF CAPITAL COSTS FOR FGD PROCESSES
(New, 500 MW, High SO₂ Removal)

<u>Process</u>	<u>Regional Capital Cost Range (\$/KW)</u>
Lime Spray Dryer	84-121
Lime Slurry	97-150
Limestone Slurry	103-159
Dual Alkali	103-166
Aqueous Carbonate	113-197
Magnesia Slurry	117-210
Wellman-Lord	129-237

The effects of power plant size, regional coal variation and new or retrofit applications on the capital investment costs of various FGD processes are summarized in Table 5-5. The regional cost data presented in this table identifies the high-low average capital costs (in \$/KW) and the percent variation across the regions. The capital cost effects of base case variations can be summarized as follows:

- o The average capital cost of each process increases approximately 50 percent as the power plant size decreases from 500 MW to 100 MW
- o For a 500 MW size plant, the regional capital costs range from 18 percent to 30 percent for high sulfur coal variation and from 11 percent to 13 percent for low sulfur coal variations

Table 5-5. SUMMARY OF TOTAL CAPITAL COSTS (\$/KW) FOR FGD SYSTEMS —
BASE CASE VARIATION OVER ALL REGIONS

<u>Process</u>	New Plant				Retrofit Plant			
	500 MW		100 MW		500 MW		100 MW	
	<u>HS</u>	<u>LS</u>	<u>HS</u>	<u>LS</u>	<u>HS</u>	<u>LS</u>	<u>HS</u>	<u>LS</u>
Lime	124 ± 21%	121 ± 12%	193 ± 23%	186 ± 14%	142 ± 20%	140 ± 12%	222 ± 22%	204 ± 12%
Limestone	131 ± 21%	128 ± 12%	212 ± 23%	203 ± 14%	151 ± 20%	148 ± 11%	232 ± 23%	222 ± 11%
Dual Alkali	134 ± 24%	129 ± 12%	201 ± 26%	190 ± 12%	155 ± 23%	150 ± 12%	221 ± 25%	209 ± 12%
Magnesia	164 ± 28%	152 ± 12%	253 ± 32%	226 ± 10%	183 ± 28%	170 ± 12%	273 ± 32%	245 ± 10%
Wellman-Lord	183 ± 30%	168 ± 11%	285 ± 33%	253 ± 10%	205 ± 29%	189 ± 10%	308 ± 32%	275 ± 10%
Aqueous Carbonate	155 ± 27%	145 ± 12%	245 ± 30%	222 ± 11%	178 ± 26%	168 ± 11%	268 ± 30%	244 ± 11%
Lime Spray Dryer	102 ± 18%	101 ± 13%	155 ± 19%	153 ± 13%	126 ± 18%	126 ± 13%	177 ± 19%	174 ± 13%

Legend:

HS - High SO₂ removal (70% - 90%)

LS - Low SO₂ removal (70%)

- o For the 100 MW size plant, the regional capital cost spread is nearly identical to that for the 500 MW size plant
- o The retrofit plant costs are between 12 percent and 25 percent higher than the comparable new plant costs.

5.2 ANNUAL OPERATING COSTS

5.2.1 Base Case

A sample breakdown of annual operating costs of the seven FGD systems for a new, 500 MW plant in the SERC region requiring high sulfur removal is shown in Table 5-2. The total annual operating costs are categorized into variable operating costs, fixed operating costs, overhead costs and byproduct sales credit.

The ranking of annual operating costs for the FGD processes differs somewhat from the capital investment rankings, with the limestone slurry process having the lowest cost and lime slurry process having the highest cost. For a new 500 MW plant, the annual operating costs range from \$9.2 million (5.0 mills/kWh) for the limestone slurry process to \$13.7 million (7.37 mills/kWh) for the lime slurry process.

The following summarizes a comparison of the variable operating costs among the different FGD processes.

- o The most significant difference between the limestone slurry process and the lime slurry process is in raw material costs. The lime material cost is approximately 4 times that of the limestone cost.
- o The difference between the dual alkali and lime slurry process costs is due mostly to the different electricity costs.
- o A comparison of the lime slurry process with the lime spray dryer process shows that the steam cost difference may be the major factor which has produced a slightly higher variable operating cost for the lime slurry process.

- o The sulfuric acid-producing magnesia process has the highest variable operating costs, mainly due to its dependency on fuel oil.
- o The variable operating cost for the sulfur-producing Wellman-Lord and aqueous carbonate processes are very competitive. The natural gas cost for the Wellman-Lord process is offset by the fuel oil cost and the slightly higher electricity cost for the aqueous carbonate process.
- o For the fixed operating costs, the maintenance labor and material costs vary up to 50 percent. The lower maintenance labor and material costs for the lime spray dryer and dual alkali processes resulted in an overall lower fixed operating cost.
- o The sulfuric acid byproduct sales credit for the magnesia process accounts for 21 percent of the total annual operating costs.
- o The sulfur byproduct credit for the Wellman-Lord and aqueous carbonate processes are somewhat less, accounting for 12 percent and 14 percent of the total costs, respectively.

5.2.2 Base Case Variations

The effects of power plant size, regional coal variation, and new and retrofit applications on annual operating costs are summarized in Table 5-6. The regional cost data presented in this table show the regional levelized operating costs (in mills/kWh) and the percent variation (+%) across the regions. Detailed operating cost components of all base case variations are contained in Appendix G. Some effects of these base case variations have on operating costs are summarized below.

- o The regional operating costs of each process increase approximately 45 percent as the power plant size decreases from 500 MW to 100 MW.
- o For the 500 MW size plant, the regional operating cost variations range from 18 percent for the Wellman-Lord process to 44 percent for the dual alkali process under high SO₂ removal conditions. For low SO₂ removal conditions, the range of regional cost variations reduces to 11 percent and 14 percent for the same processes.

Table 5-6. SUMMARY OF LEVELIZED ANNUAL OPERATING COSTS (MILLS/KWH) FOR FGD SYSTEMS —
BASE CASE VARIATION OVER ALL REGIONS

Process	New Plant				Retrofit Plant			
	500 MW		100 MW		500 MW		100 MW	
	HS	LS	HS	LS	HS	LS	HS	LS
Lime	5.50 ± 37.2%	4.45 ± 13.5%	7.84 ± 32.5%	6.57 ± 12.6%	5.10 ± 36.3%	4.18 ± 13.4%	7.19 ± 32.1%	6.07 ± 12.7%
Limestone	5.06 ± 31.8%	4.40 ± 14.4%	7.47 ± 28.4%	6.61 ± 12.5%	4.71 ± 30.8%	4.12 ± 14.3%	6.87 ± 27.9%	6.12 ± 12.5%
Dual Alkali	4.47 ± 44.1%	3.28 ± 14.3%	6.41 ± 37.9%	4.90 ± 13.3%	4.08 ± 43.1%	3.03 ± 14.2%	5.83 ± 37.7%	4.49 ± 13.4%
Magnesia	5.96 ± 33.4%	4.96 ± 12.0%	8.98 ± 32.2%	7.35 ± 12.1%	5.43 ± 32.8%	4.57 ± 12.0%	8.14 ± 31.9%	6.71 ± 12.2%
Wellman-Lord	7.10 ± 18.6%	6.74 ± 11.2%	12.45 ± 13.8%	12.13 ± 7.1%	6.51 ± 18.8%	6.17 ± 11.3%	11.19 ± 14.1%	10.91 ± 7.2%
Aqueous Carbonate	4.83 ± 25.6%	4.3 ± 11.4%	7.72 ± 26.1%	6.63 ± 11.6%	4.47 ± 24.8%	4.04 ± 11.5%	7.05 ± 25.8%	6.11 ± 11.6%
Lime Spray Dryer	4.32 ± 46.2%	3.11 ± 15.8%	5.98 ± 39.4%	4.57 ± 13.8%	4.31 ± 44.3%	3.56 ± 15.4%	5.83 ± 38.8%	4.51 ± 13.9%

Legend:

HS - High SO₂ removal (70% - 90%)

LS - Low SO₂ removal (70%)

- o For the 100 MW size plant, the regional operating cost variations range from 13 percent for the Wellman-Lord process to 38 percent for the dual alkali process under high SO₂ removal conditions. For low SO₂ removal conditions, the range of regional cost variations reduces to 7 percent and 13 percent for the same processes.
- o The retrofit plant levelized operating costs are slightly lower than the comparable new plant costs. However, net operating costs for retrofit plants are always higher than for new plants before levelization. This effect is due to levelizing over a shorter period of time for the retrofit plants.

5.3 TOTAL LEVELIZED REVENUE COSTS

The total levelized costs consist of two cost components: levelized capital costs and levelized operating costs. Regional total levelized costs (mills/kWh) are summarized in Table 5-7. These calculations are based on the design factor and economic premises described in the previous sections. The regional cost variation for each process is expressed as a percent deviation from the midpoint of the range. Some significant results of these comparisons are summarized below.

- o The regional total levelized costs for each process increase approximately 47 percent as the power plant size decreases from 500 MW to 100 MW.
- o For a 500 MW size plant, the regional total levelized cost variations range from 19 percent for the Wellman-Lord process to 35 percent for the dual alkali process for high SO₂ removal conditions. For low SO₂ removal conditions, the regional cost variations reduce to 11² percent and 13 percent for the same processes.
- o For the 100 MW size plant, the regional total levelized cost variations range from 20 percent for the Wellman-Lord process to 33 percent for the dual alkali process under high SO₂ removal conditions. For low SO₂ removal conditions, the regional cost variations reduce² to 9 percent and 13 percent for the same processes.
- o The total levelized retrofit plant costs are generally 3 percent to 6 percent greater than those for new plants.

Table 5-7. SUMMARY OF TOTAL LEVELIZED COST (MILL/KWH) -- BASE CASE VARIATIONS OVER ALL REGIONS

	New Plant				Retrofit Plant			
	500 MW	500 MW	100 MW	100 MW	500 MW	500 MW	100 MW	100 MW
	HS (%)	LS (%)	HS (%)	LS (%)	HS (%)	LS (%)	HS (%)	LS (%)
Lime	8.67 ± 31.3	7.56 ± 12.8	12.79 ± 28.7	11.34 ± 12.4	8.96 ± 29.5	8.01 ± 12.6	12.93 ± 27.8	11.61 ± 12.3
Limestone	8.38 ± 27.2	7.67 ± 13.2	12.79 ± 25.6	11.81 ± 11.9	8.70 ± 25.1	8.14 ± 13.3	12.99 ± 24.8	12.14 ± 11.9
Dual Alkali	7.93 ± 35.0	6.61 ± 13.4	11.57 ± 32.6	9.74 ± 13.0	8.29 ± 32.9	7.12 ± 6.6	11.82 ± 31.6	10.12 ± 12.9
Magnesia	9.91 ± 29.6	8.80 ± 12.5	15.23 ± 31.2	12.98 ± 12.8	10.16 ± 28.7	9.14 ± 12.5	15.33 ± 31.0	13.16 ± 12.8
Wellman-Lord	11.23 ± 19.1	11.04 ± 11.2	19.76 ± 20.9	18.56 ± 8.5	11.52 ± 19.7	11.31 ± 11.5	19.53 ± 21.9	18.28 ± 8.9
Aqueous Carbonate	8.70 ± 25.4	7.99 ± 12.1	13.92 ± 27.6	12.20 ± 12.3	9.22 ± 24.8	8.57 ± 12.1	14.26 ± 27.6	12.59 ± 12.5
Lime Spray Dryer	6.93 ± 35.5	5.71 ± 13.7	9.97 ± 31.3	8.53 ± 13.1	7.74 ± 32.5	6.67 ± 12.9	10.64 ± 29.9	9.32 ± 12.6

Legend: HS = High SO₂ removal (70% to 90%); LS = Low SO₂ removal (70%).

Table 5-8 presents the total levelized costs for all seven FGD systems and ranks the five advanced FGD systems (for each base case variation) according to increased levelized costs. As is evident, the ranking of each system is basically independent of the power plant size, coal sulfur variations and new or retrofit applications. The advanced FGD systems are ranked as follows: 1) Lime Spray Dryer, 2) Dual Alkali, 3) Aqueous Carbonate, 4) Magnesia, 5) Wellman-Lord. The major exception to this basic order occurs when the ranking of the magnesia and Wellman-Lord processes is reversed. This situation occurs only for a new 500 MW plant burning high sulfur coal (high SO₂ removal) in the ECAR, MAIN, and MARCA-2 regions. It should also be noted that for the majority of regions burning high sulfur coal, a sulfur removal efficiency of greater than 70 percent is required. Since greater than 70 percent SO₂ removal efficiency has not been demonstrated for a lime spray dryer system, the ranking of the lime spray dryer process is contingent upon further improvements in SO₂ absorption efficiency for this process.

5.4 EFFECTS OF SELECTED VARIABLES ON FGD COSTS

Selected operating cost and capital equipment cost components were varied from the base-case value to determine the effect changes in design and economic factors may have on total system costs. The factors evaluated and the ranges of variations are presented in Table 5-9. Each range corresponds to differences in design improvement or cost fluctuation which might be encountered in different regions.

The typical effects these selected design and economic variables have on levelized costs for a new 500 MW plant (SERC region) are graphically displayed in Figures 5-1 through 5-12. Specific values associated with these figures have been identified in Appendix H.

TABLE 5-8.

FGD SYSTEMS RANKED BY TOTAL LEVELIZED COST : BASE CASE ANALYSIS

APPLICATION: NEW

PLANT SIZE: 500 MW

REGION	REMOVAL REQUIRED	LINE	LINE- STONE	RANK>	FGD SYSTEM/LEVELIZED TOTAL COST(MILLS/KWH)				
					1	2	3	4	5
HIGH SULFUR COAL									
ECAR	70%	10.26	8.96		*LSD/ 8.47	DA/ 9.76	AC/10.36	WL/11.56	HGO/11.78
ERCOT	30%	8.26	8.55		*LSD/ 6.21	DA/ 7.09	AC/ 8.75	HGO/ 9.45	WL/12.30
MAAC	30%	5.95	6.10		*LSD/ 4.47	DA/ 5.15	AC/ 6.49	HGO/ 6.98	WL/ 9.08
MAIN	90%	9.61	8.92		*LSD/ 7.76	DA/ 9.13	AC/10.61	WL/11.93	HGO/12.84
MARCA-1	80%	9.01	9.43		*LSD/ 6.78	DA/ 7.71	AC/ 9.53	HGO/10.32	WL/13.38
MARCA-2	90%	10.77	10.66		*LSD/ 8.87	DA/10.18	AC/10.68	WL/12.54	HGO/12.64
NPCC	80%	6.19	6.30		*LSD/ 4.69	DA/ 5.36	AC/ 6.63	HGO/ 7.17	WL/ 9.25
SERC	90%	10.89	8.75		*LSD/ 9.11	DA/10.35	AC/10.51	HGO/11.18	WL/12.29
SPP-1	90%	11.38	10.35		*LSD/ 9.38	DA/10.70	AC/10.90	HGO/12.82	WL/13.33
SPP-2	90%	10.69	9.15		*LSD/ 8.98	AC/ 9.88	DA/10.18	HGO/10.71	WL/11.90
WSEC-1	80%	7.15	7.46		*LSD/ 5.42	DA/ 6.16	AC/ 7.48	HGO/ 8.26	WL/10.43
WSEC-2	70%	7.89	8.04		LSD/ 6.01	DA/ 6.94	AC/ 8.28	HGO/ 9.41	WL/11.24
WSEC-3	70%	7.42	7.98		LSD/ 5.64	DA/ 6.56	AC/ 7.89	HGO/ 8.80	WL/10.85
WSEC-4	70%	7.15	7.42		LSD/ 5.44	DA/ 6.33	AC/ 7.58	HGO/ 8.43	WL/10.47
LOW SULFUR COAL									
ECAR	70%	7.10	7.02		LSD/ 5.42	DA/ 6.29	AC/ 7.60	HGO/ 8.33	WL/10.11
ERCOT	70%	8.53	8.68		LSD/ 6.49	DA/ 7.49	AC/ 8.96	HGO/ 9.90	WL/12.27
MAAC	70%	6.65	6.65		LSD/ 5.05	DA/ 5.91	AC/ 7.26	HGO/ 7.91	WL/ 9.80
MAIN	70%	7.08	7.15		LSD/ 5.35	DA/ 6.25	AC/ 7.81	HGO/ 8.73	WL/10.35
MARCA-1	70%	8.21	8.56		LSD/ 6.22	DA/ 7.19	AC/ 8.67	HGO/ 9.73	WL/11.86
MARCA-2	70%	7.75	8.00		LSD/ 5.92	DA/ 6.83	AC/ 8.20	HGO/ 9.10	WL/11.06
NPCC	70%	7.00	6.90		LSD/ 5.41	DA/ 6.23	AC/ 7.36	HGO/ 8.00	WL/ 9.86
SERC	70%	7.26	6.94		LSD/ 5.57	DA/ 6.44	AC/ 7.62	HGO/ 8.19	WL/10.29
SPP-1	70%	7.97	8.03		LSD/ 6.06	DA/ 6.98	AC/ 8.35	HGO/ 9.21	WL/11.49
SPP-2	70%	7.49	7.37		LSD/ 5.74	DA/ 6.63	AC/ 7.76	HGO/ 8.39	WL/10.61
WSEC-1	70%	8.09	8.40		LSD/ 6.26	DA/ 7.14	AC/ 8.20	HGO/ 9.31	WL/11.14
WSEC-2	70%	7.28	7.52		LSD/ 5.45	DA/ 6.28	AC/ 7.70	HGO/ 8.54	WL/10.72
WSEC-3	70%	6.77	7.20		LSD/ 5.06	DA/ 5.84	AC/ 7.22	HGO/ 7.90	WL/10.21
WSEC-4	70%	6.59	6.88		LSD/ 4.93	DA/ 5.72	AC/ 7.02	HGO/ 7.70	WL/ 9.98

*GREATER THAN 70% SO₂ REMOVAL HAS NOT BEEN DEMONSTRATED FOR LSD SYSTEM

LEGEND: DA - DUAL ALKALI HGO - MAGNESIA SLURRY WL - WELLMAN LORD
AC - AQUEOUS CARBONATE LSD - LINE SPRAY DRYER

TABLE 5-8. (CONT'D) FGD SYSTEMS RANKED BY TOTAL LEVELIZED COST : BASE CASE ANALYSIS

APPLICATION: NEW

PLANT SIZE: 100 MW

REGION	REMOVAL REQUIRED	LIME	LIME- STONE	RANK>	FGD SYSTEM/LEVELIZED TOTAL COST (MILLS/KWH)				
					1	2	3	4	5
HIGH SULFUR COAL									
ECAR	90%	14.95	14.14		\$LSD/ 11.87	DA/ 14.13	AC/ 17.02	HGO/ 18.71	WL/ 21.88
ERCOT	80%	12.39	12.92		\$LSD/ 9.40	DA/ 10.47	AC/ 13.08	HGO/ 13.67	WL/ 19.53
HAAC	80%	9.12	9.51		\$LSD/ 6.85	DA/ 7.80	AC/ 10.07	HGO/ 10.48	WL/ 15.63
MAIN	90%	14.22	14.05		\$LSD/ 11.08	DA/ 13.42	AC/ 17.21	HGO/ 19.77	WL/ 21.92
MARCA-1	80%	13.48	14.14		\$LSD/ 10.26	DA/ 11.37	AC/ 14.17	HGO/ 14.82	WL/ 20.86
MARCA-2	90%	15.62	16.07		\$LSD/ 12.42	DA/ 14.68	AC/ 17.46	HGO/ 19.71	WL/ 22.77
NPCC	80%	9.42	9.76		\$LSD/ 7.12	DA/ 8.06	AC/ 10.25	HGO/ 10.71	WL/ 15.93
SERC	90%	15.68	13.96		\$LSD/ 12.60	DA/ 14.79	AC/ 17.19	HGO/ 18.09	WL/ 22.80
SPP-1	90%	16.45	15.91		\$LSD/ 13.09	DA/ 15.34	AC/ 17.76	HGO/ 19.97	WL/ 23.88
SPP-2	90%	15.38	14.31		\$LSD/ 12.39	DA/ 14.56	AC/ 16.48	HGO/ 17.55	WL/ 22.19
WSCC-1	80%	10.75	11.31		\$LSD/ 8.15	DA/ 9.13	AC/ 11.35	HGO/ 12.06	WL/ 16.89
WSCC-2	70%	11.80	12.28		LSD/ 8.92	DA/ 10.22	AC/ 12.77	HGO/ 13.90	WL/ 18.50
WSCC-3	70%	11.16	12.07		LSD/ 8.41	DA/ 9.72	AC/ 12.26	HGO/ 13.18	WL/ 18.48
WSCC-4	70%	10.74	11.35		LSD/ 8.08	DA/ 9.37	AC/ 11.79	HGO/ 12.65	WL/ 18.37
LOW SULFUR COAL									
ECAR	70%	10.70	10.93		LSD/ 8.05	DA/ 9.34	AC/ 11.85	HGO/ 12.59	WL/ 17.45
ERCOT	70%	12.74	13.21		LSD/ 9.64	DA/ 11.00	AC/ 13.70	HGO/ 14.63	WL/ 20.13
HAAC	70%	10.08	10.41		LSD/ 7.55	DA/ 8.82	AC/ 11.37	HGO/ 12.04	WL/ 17.13
MAIN	70%	10.71	11.11		LSD/ 8.01	DA/ 9.32	AC/ 12.10	HGO/ 13.04	WL/ 17.47
MARCA-1	70%	12.30	12.98		LSD/ 9.27	DA/ 10.61	AC/ 13.28	HGO/ 14.34	WL/ 19.47
MARCA-2	70%	11.61	12.19		LSD/ 8.78	DA/ 10.09	AC/ 12.67	HGO/ 13.58	WL/ 18.41
NPCC	70%	10.46	10.68		LSD/ 7.95	DA/ 9.18	AC/ 11.49	HGO/ 12.14	WL/ 17.29
SERC	70%	10.87	10.86		LSD/ 8.22	DA/ 9.50	AC/ 11.88	HGO/ 12.45	WL/ 17.77
SPP-1	70%	11.93	12.29		LSD/ 9.01	DA/ 10.28	AC/ 12.80	HGO/ 13.64	WL/ 18.98
SPP-2	70%	11.20	11.39		LSD/ 8.48	DA/ 9.76	AC/ 12.07	HGO/ 12.69	WL/ 18.02
WSCC-1	70%	11.99	12.64		LSD/ 9.16	DA/ 10.42	AC/ 12.67	HGO/ 13.80	WL/ 18.42
WSCC-2	70%	10.93	11.42		LSD/ 8.19	DA/ 9.26	AC/ 11.61	HGO/ 12.39	WL/ 17.24
WSCC-3	70%	10.21	10.89		LSD/ 7.62	DA/ 8.66	AC/ 10.93	HGO/ 11.55	WL/ 16.98
WSCC-4	70%	9.93	10.48		LSD/ 7.41	DA/ 8.47	AC/ 10.69	HGO/ 11.32	WL/ 17.16

*GREATER THAN 70% SO₂ REMOVAL HAS NOT BEEN DEMONSTRATED FOR LSD SYSTEM

LEGEND: DA - DUAL ALKALI HGO - MAGNESIA SLURRY WL - WELLMAN LORD
AC - AQUEOUS CARBONATE LSD - LIME SPRAY DRYER

TABLE S-8. (CONT'D) FGD SYSTEMS RANKED BY TOTAL LEVELIZED COST : BASE CASE ANALYSIS

APPLICATION: RETROFIT

PLANT SIZE: 500 MW

REGION	REMOVAL REQUIRED	LINE	LINE- STONE	RANK>	FGD SYSTEM/LEVELIZED TOTAL COST (MILLS/KWH)				
					1	2	3	4	5
HIGH SULFUR COAL									
ECAR	90%	10.39	9.30		*LSD/ 9.18	DA/ 9.97	AC/10.81	MGO/11.97	WL/11.99
ERCOT	80%	8.82	9.14		*LSD/ 7.32	DA/ 7.72	AC/ 9.43	MGO/ 9.86	WL/12.60
MAAC	80%	6.32	6.51		*LSD/ 5.22	DA/ 5.56	AC/ 6.93	MGO/ 7.24	WL/ 9.25
MAIN	90%	9.80	9.24		*LSD/ 8.51	DA/ 9.39	AC/11.01	WL/12.31	MGO/12.90
MARCA-1	80%	9.63	10.07		*LSD/ 7.98	DA/ 8.42	AC/10.29	MGO/10.78	WL/13.73
MARCA-2	50%	10.90	10.88		*LSD/ 9.57	DA/10.41	AC/11.17	MGO/12.80	WL/12.95
NPCC	60%	6.56	6.70		*LSD/ 5.42	DA/ 5.78	AC/ 7.07	MGO/ 7.43	WL/ 9.42
SERC	50%	11.00	9.16		*LSD/ 9.79	DA/10.54	AC/10.98	MGO/11.47	WL/12.68
SPP-1	50%	11.60	10.75		*LSD/10.25	DA/11.01	AC/11.50	MGO/13.08	WL/13.78
SPP-2	50%	10.77	9.46		*LSD/ 9.59	DA/10.34	AC/10.36	MGO/11.00	WL/12.28
WSCC-1	60%	7.59	7.93		*LSD/ 6.31	DA/ 6.66	AC/ 8.02	MGO/ 8.57	WL/10.67
WSCC-2	70%	8.32	8.52		LSD/ 6.86	DA/ 7.44	AC/ 8.86	MGO/ 9.71	WL/11.53
WSCC-3	70%	7.82	8.37		LSD/ 6.44	DA/ 7.02	AC/ 8.42	MGO/ 9.09	WL/11.09
WSCC-4	70%	7.52	7.83		LSD/ 6.31	DA/ 6.77	AC/ 8.08	MGO/ 8.71	WL/10.69
LOW SULFUR COAL									
ECAR	70%	7.47	7.45		LSD/ 6.20	DA/ 6.72	AC/ 8.09	MGO/ 8.61	WL/10.36
ERCOT	70%	9.02	9.22		LSD/ 7.52	DA/ 8.06	AC/ 9.61	MGO/10.28	WL/12.60
MAAC	70%	7.00	7.06		LSD/ 5.81	DA/ 6.30	AC/ 7.71	MGO/ 8.17	WL/10.01
MAIN	70%	7.47	7.59		LSD/ 6.13	DA/ 6.70	AC/ 8.30	MGO/ 8.99	WL/10.60
MARCA-1	70%	8.69	9.06		LSD/ 7.18	DA/ 7.75	AC/ 9.30	MGO/10.08	WL/12.17
MARCA-2	70%	8.16	8.44		LSD/ 6.75	DA/ 7.31	AC/ 8.76	MGO/ 9.42	WL/11.34
NPCC	70%	7.31	7.28		LSD/ 6.12	DA/ 6.60	AC/ 7.81	MGO/ 8.26	WL/10.07
SERC	70%	7.61	7.39		LSD/ 6.34	DA/ 6.86	AC/ 8.12	MGO/ 8.50	WL/10.53
SPP-1	70%	8.43	8.55		LSD/ 7.00	DA/ 7.51	AC/ 8.95	MGO/ 9.56	WL/11.78
SPP-2	70%	7.87	7.82		LSD/ 6.51	DA/ 7.07	AC/ 8.29	MGO/ 8.71	WL/10.87
WSCC-1	70%	8.48	8.82		LSD/ 7.11	DA/ 7.60	AC/ 8.77	MGO/ 9.62	WL/11.43
WSCC-2	70%	7.75	8.02		LSD/ 6.32	DA/ 6.81	AC/ 8.27	MGO/ 8.86	WL/10.98
WSCC-3	70%	7.20	7.64		LSD/ 5.86	DA/ 6.33	AC/ 7.75	MGO/ 8.21	WL/10.43
WSCC-4	70%	7.00	7.30		LSD/ 5.81	DA/ 6.18	AC/ 7.53	MGO/ 8.00	WL/10.17

*GREATER THAN 70% SO2 REMOVAL HAS NOT BEEN DEMONSTRATED FOR LSD SYSTEM

LEGEND: DA - DUAL ALKALI MGO - MAGNESIA SLURRY WL - WELLMAN LORD
AC - AQUEOUS CARBONATE LSD - LIME SPRAY DRYER

TABLE 5-8. (CONT'D) FGD SYSTEMS RANKED BY TOTAL LEVELIZED COST : BASE CASE ANALYSIS

APPLICATION: RETROFIT

PLANT SIZE: 100 MW

REGION	REMOVAL	LIME	LIME-	RANK>	FGD SYSTEM/LEVELIZED TOTAL COST (MILLS/KWH)				
	REQUIRED		STONE		1	2	3	4	5
HIGH SULFUR COAL									
ECAR	90%	14.96	14.39		*LSB/12.45	DA/14.27	AC/17.31	HGO/18.76	WL/21.80
ERCOT	80%	12.73	13.31		*LSB/10.30	DA/10.93	AC/13.53	HGO/13.88	WL/19.25
MAAC	80%	9.33	9.77		*LSB/ 7.45	DA/ 8.08	AC/10.32	HGO/10.58	WL/15.24
MAIN	90%	14.29	14.29		*LSB/11.71	DA/13.62	AC/17.46	HGO/19.69	WL/21.83
MARCA-1	80%	13.86	14.56		*LSB/11.24	DA/11.89	AC/14.68	HGO/15.06	WL/20.62
MARCA-2	90%	15.63	16.18		*LSB/12.97	DA/14.83	AC/17.79	HGO/19.72	WL/22.69
NPCC	80%	9.62	10.02		*LSB/ 7.70	DA/ 8.34	AC/10.50	HGO/10.80	WL/15.54
SERC	90%	15.66	14.29		*LSB/13.15	DA/14.91	AC/17.51	HGO/18.24	WL/22.66
SPP-1	90%	16.52	16.21		*LSB/13.82	DA/15.56	AC/18.20	HGO/20.08	WL/23.81
SPP-2	90%	15.33	14.53		*LSB/12.87	DA/14.64	AC/16.81	HGO/17.70	WL/22.05
WSCC-1	80%	11.01	11.60		*LSB/ 8.87	DA/ 9.48	AC/11.70	HGO/12.19	WL/16.62
WSCC-2	70%	12.06	12.61		LSB/ 9.60	DA/10.59	AC/13.16	HGO/14.05	WL/18.29
WSCC-3	70%	11.40	12.33		LSE/ 9.04	DA/10.06	AC/12.62	HGO/13.32	WL/18.17
WSCC-4	70%	10.97	11.63		LSE/ 8.81	DA/ 9.69	AC/12.13	HGO/12.79	WL/17.99
LOW SULFUR COAL									
ECAR	70%	10.91	11.24		LSB/ 8.69	DA/ 9.65	AC/12.18	HGO/12.73	WL/17.18
ERCOT	70%	13.04	13.58		LSB/10.49	DA/11.43	AC/14.16	HGO/14.84	WL/19.91
MAAC	70%	10.29	10.70		LSB/ 8.17	DA/ 9.12	AC/11.67	HGO/12.16	WL/16.81
MAIN	70%	10.95	11.42		LSB/ 8.65	DA/ 9.66	AC/12.43	HGO/13.16	WL/17.24
MARCA-1	70%	12.60	13.32		LSB/10.06	DA/11.03	AC/13.73	HGO/14.52	WL/19.25
MARCA-2	70%	11.86	12.49		LSB/ 9.45	DA/10.44	AC/13.05	HGO/13.73	WL/18.18
NPCC	70%	10.64	10.95		LSB/ 8.51	DA/ 9.44	AC/11.78	HGO/12.26	WL/16.96
SERC	70%	11.07	11.18		LSB/ 8.84	DA/ 9.80	AC/12.21	HGO/12.61	WL/17.47
SPP-1	70%	12.20	12.65		LSB/ 9.78	DA/10.67	AC/13.21	HGO/13.83	WL/18.73
SPP-2	70%	11.42	11.71		LSB/ 9.08	DA/10.08	AC/12.43	HGO/12.87	WL/17.74
WSCC-1	70%	12.22	12.91		LSB/ 9.85	DA/10.76	AC/13.07	HGO/13.94	WL/18.21
WSCC-2	70%	11.21	11.75		LSB/ 8.88	DA/ 9.65	AC/12.00	HGO/12.55	WL/17.00
WSCC-3	70%	10.47	11.18		LSB/ 8.26	DA/ 9.01	AC/11.28	HGO/11.70	WL/16.64
WSCC-4	70%	10.18	10.77		LSB/ 8.14	DA/ 8.81	AC/11.02	HGO/11.47	WL/16.75

*GREATER THAN 70% SO₂ REMOVAL HAS NOT BEEN DEMONSTRATED FOR LSD SYSTEM

LEGEND: DA - DUAL ALKALI HGO - MAGNESIA SLURRY WL - WELLMAN LORD
AC - AQUEOUS CARBONATE LSD - LINE SPRAY DRYER

Table 5-9. Selected Sensitivity Variations Studied For FGD System Costs

Raw Material price	<u>Range of Variations</u>
Lime	±50%
Limestone	±50%
Soda Ash	±50%
Magnesia	±50%
Utility Price	
Fuel Oil	±50%
Natural Gas	±50%
By Product Revenue	
Sulfuric Acid	±50%
Sulfur	±50%
Capital Cost Components	
SO ₂ Absorption Area	- 50%
Regeneration Area	- 50%
Acid Production Area	- 50%
Sulfur Production Area	- 50%

Variation of the capital and operating cost components shown in Table 5-9 leads to the following points of interest.

- o The sensitivities of the lime slurry, lime spray dryer and dual alkali process costs to lime cost variations are generally the same for all three processes. The lime cost variations provide insignificant changes in the magnesia process costs and do not affect limestone, aqueous carbonate, and Wellman-Lord process costs. (Figure 5-1)
- o The limestone cost variations result in relatively small changes (<5%) in the limestone process costs, with no cost effects for the rest of the processes. (Figure 5-2)
- o The soda ash cost variations result in a small change (<5%) in the aqueous carbonate and Wellman-Lord process costs. The effect on the dual alkali process is insignificant (<1%). The basic ranking of the FGD systems is not affected by the variation of soda ash costs. (Figure 5-3)
- o The increase and decrease (50%) in the cost of magnesium oxide (MgO) has a relatively small (<5%) effect on the levelized costs for the magnesium slurry process. The overall ranking of FGD systems is not affected. (Figure 5-4)
- o A change in the price of fuel oil will have a relatively significant effect on the magnesia slurry process costs (+15%), whereas a smaller effect (+5%) is anticipated for the aqueous carbonate process. As a result, these price variations will alter the ranking of four FGD processes as follows: dual alkali, aqueous carbonate, magnesia slurry, and Wellman-Lord. (Figure 5-5)
- o The change of the natural gas price will have little effect on the Wellman-Lord process. No effect on the FGD system ranking is anticipated. (Figure 5-6)
- o The increase and decrease of byproduct sulfur credit will have a moderate effect on both the aqueous carbonate and Wellman-Lord processes. When the byproduct sulfur price is increased, the rank of the dual alkali and aqueous carbonate processes is reversed. (Figure 5-7)
- o The change of the byproduct sulfuric acid credit has a relatively significant effect on magnesia slurry process costs. When the low sulfuric acid credit is assumed, the magnesia process costs are nearly as high as for the Wellman-Lord process. However, if a high sulfuric acid credit is assumed, the magnesia process costs drop below both the dual alkali and aqueous carbonate process costs. (Figure 5-8)

- o The decrease in SO₂ absorption area capital costs generally has a similar but modest effect on the cost of each FGD process. The cost reduction is more pronounced for the lime spray dryer and aqueous carbonate processes. (Figure 5-9)
- o The decrease in regeneration area capital costs reduces the Wellman-Lord process cost dramatically and makes it the most cost competitive FGD process. A smaller magnitude but similar cost reduction occurs for the aqueous carbonate and magnesia process costs. (Figure 5-10)
- o The decrease in sulfuric acid plant capital costs reduces the magnesia process cost to the same level as the aqueous carbonate process. It does not significantly change the ranking of FGD process costs. (Figure 5-11).
- o The decrease in sulfur production plant capital costs results in a relatively small reduction in the Wellman-Lord and aqueous carbonate process costs. (Figure 5-12)

More detailed cost effects for each of the cost factor variations listed in Table 5-9 are tabulated in Appendix H for each region, FGD plant size, and application.

Figure 5-1. Effect Of A 50 Percent Change In Lime Price On New, 500-MW FGD System Rankings In SERC Region

Figure 5-2. Effect Of A 50 Percent Change In Limestone Price On New, 500-MW FGD System Rankings In SERC Region

Figure 5-3. Effect Of A 50 Percent Change In Soda Ash Price On New, 500-MW FGD System Rankings In SERC Region

Figure 5-4. Effect Of A 50 Percent Change In MgO Price On New, 500-MW FGD System Rankings In SERC Region

Figure 5-5. Effect Of A 50 Percent Change In Fuel Oil Price On New, 500-MW FGD System Rankings in SERC Region

Figure 5-6. Effect Of A 50 Percent Change In Natural Gas Price On New, 500-MW FGD System Rankings In SERC Region

Figure 5-7. Effect Of A 50 Percent Change In Sulfur Price On New, 500-MW FGD System Rankings In SERC Regions

Figure 5-8. Effect Of A 50 Percent Change In Sulfuric Acid Price On New 500-MW FGD System Rankings In SERC Region

Figure 5-9. Effect Of A 50 Percent Decrease In SO₂ Absorption Unit Cost On New, 500-MW FGD System Rankings In SERC Region

Figure 5-10. Effect Of A 50 Percent Decrease In Regeneration Unit Cost On New, 500-MW FGD System Rankings In SERC Region

Figure 5-11. Effect Of A 50 Percent Decrease In Acid Production Cost On New, 500-MW FGD System Rankings In SERC Region

Figure 5-12. Effect Of A 50 Percent Decrease In Sulfur Production Cost On New, 500-MW FGD System Rankings In SERC Region

APPENDIX A

MARKET ASSESSMENT DATA BASE

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD					LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP		
MEROM #2	HOOSIER ENERGY, IND. STATEWIDE	ECAR	IN	500	81	NEW PLANT	LIMESTONE	441	81	NSPS ORIG	
MEROM #1	HOOSIER ENERGY, IND. STATEWIDE	ECAR	IN	500	82	NEW PLANT	LIMESTONE	441	82	NSPS ORIG	
GIBSON #5	PUBLIC SERVICE CO. IF INDIANA	ECAR	IN	650	82	NEW PLANT	LIMESTONE	650	82	NSPS ORIG	
ROCKPORT(PROJ.2601) #1	INDIANA & MICH. POWER CO.	ECAR	IN	1300	83	NEW PLANT	UNSPECFD	1300	83	NSPS REV	
PETERSBURG #4	INDIANAPOLIS PWR & LT. CO.	ECAR	IN	515	83	NEW PLANT	LIMESTONE	515	83	NSPS REV	
A.B. BROWN #2	SO. INDIANA GAS & ELECTRIC CO	ECAR	IN	250	83	NEW PLANT	UNSPECFD	250	83	NSPS REV	
R.M., SCHAFER #17	NO. INDIANA PUBLIC SERVICE CO.	ECAR	IN	344	83	NEW PLANT	DUAL ALK	344	83	NSPS REV	
ROCKPORT(PROJ.2601) #2	INDIANA & MICH. PWR. CO.	ECAR	IN	1300	84	NEW PLANT	UNSPECFD	1300	84	NSPS REV	
PATRIOT #1	INDIANAPOLIS PWR & LT CO	ECAR	IN	650	87	NEW PLANT	LIMESTONE	650	87	NSPS REV	
R.M., SCHAFER #18	NO. INDIANA PUBLIC SERVICE CO.,	ECAR	IN	344	85	NEW PLANT	DUAL ALK	344	85	NSPS REV	
WHITEWATER VALLEY #3	RICHMOND POWER & LT	ECAR	IN	100	85	NEW PLANT	UNSPECFD	100	85	NSPS REV	
PATRIOT #2	INDIANAPOLIS PWR & LT.	ECAR	IN	650	87	NEW PLANT	LIMESTONE	650	87	NSPS REV	
PATRIOT #3	INDIANAPOLIS PWR & LT.	ECAR	IN	650	87	NEW PLANT	LIMESTONE	650	87	NSPS REV	
A.B. BROWN #3	SO. INDIANA GAS & ELEC. CO.	ECAR	IN	500	86	NEW PLANT	UNSPECFD	500	86	NSPS REV	
UNKNOWN #UNK	HOOSIER ENERGY DIV.(IND.) COOP	ECAR	IN	500	86	NEW PLANT	UNSPECFD	500	86	NSPS REV	
UNKNOWN #UNK	NO. INDIANA PUBLIC SERVICE CO.	ECAR	IN	500	88	NEW PLANT	UNSPECFD	500	88	NSPS REV	
GREEN #2	BIG RIVERS ELECTRIC CORP.	ECAR	KY	210	80	NEW PLANT	LIME	210	80	NSPS ORIG	
EAST BEND #3	CINCINNATI GAS & ELCT. CO	ECAR	KY	700	88	NEW PLANT	UNSPECFD	700	88	NSPS REV	
EAST BEND #2	CINCINNATI GAS & ELCT. CO	ECAR	KY	600	84	NEW PLANT	UNSPECFD	600	84	NSPS REV	
H.L. SPURLOCK #2	EAST KENTUCKY PWR COOP.	ECAR	KY	500	80	NEW PLANT	LIME	500	80	NSPS ORIG	
GHENT #4	KY. UTILITIES CO.	ECAR	KY	500	83	NEW PLANT	UNSPECFD	500	83	NSPS REV	
MILL CREEK #4	LOUISVILLE GAS & ELEC. CO.	ECAR	KY	495	81	NEW PLANT	LIME	495	81	NSPS ORIG	
TRIBBLE COUNTY #1	LOUISVILLE GAS & ELECTRIC CO.	ECAR	KY	495	84	NEW PLANT	UNSPECFD	495	83	NSPS REV	
TRIBBLE COUNTY #2	LOUISVILLE GAS & ELECTRIC CO.	ECAR	KY	495	86	NEW PLANT	UNSPECFD	495	85	NSPS REV	
TRIBBLE COUNTY #3	LOUISVILLE GAS & ELECTRIC CO.	ECAR	KY	675	87	NEW PLANT	UNSPECFD	675	87	NSPS REV	

STATION # &	UTILITY	REGION	STATE V	BOILER		APPLICATION	FGD		LEGIS- LATIVE STATUS	
				MW	START UP		TYPE	MW		START UP
TRIBBLE COUNTY #4	LOUISVILLE GAS & ELECTRIC CO.	ECAR	KY	675	89	NEW PLANT	LIME	675	89	NSPS REV
BREC STATION 4 #1	BIG RIVERS ELECTRIC CORP.	ECAR	KY	440	84	NEW PLANT	UNSPECFD	440	84	NSPS REV
BREC STATION 4 #2	BIG RIVERS ELECTRIC CORP.	ECAR	KY	440	85	NEW PLANT	UNSPECFD	440	85	NSPS REV
COLEMAN #4	BIG RIVERS ELECTRIC CORP.	ECAR	KY	240	83	NEW PLANT	UNSPECFD	240	83	NSPS REV
HANCOCK #1	KY. UTILITIES CO.	ECAR	KY	650	85	NEW PLANT	UNSPECFD	650	85	NSPS REV
HANCOCK #2	KY. UTILITIES CO.	ECAR	KY	650	87	NEW PLANT	UNSPECFD	650	85	NSPS REV
J.K. SMITH #1	E. KY. POWER COOP	ECAR	KY	600	85	NEW PLANT	UNSPECFD	600	85	NSPS REV
J.K. SMITH #2	E. KY. POWER COOP	ECAR	KY	600	86	NEW PLANT	UNSPECFD	600	86	NSPS REV
UNKNOWN #UNK	E. KY. POWER COOP	ECAR	KY	500	84	NEW PLANT	UNSPECFD	500	84	NSPS REV
BELLE RIVER #1	DETROIT EDISON CO.	ECAR	MI	676	84	NEW PLANT	UNSPECFD	676	84	NSPS REV
BELLE RIVER #2	DETROIT EDISON CO.	ECAR	MI	676	85	NEW PLANT	UNSPECFD	676	85	NSPS REV
KILLEN STATION #1	DAYTON PWR & LT. CO.	ECAR	OH	600	86	NEW PLANT	UNSPECFD	600	86	NSPS REV
UNKNOWN #UNK	BUCKEYE RURAL ELEC. COOP	ECAR	OH	600	86	NEW PLANT	UNSPECFD	600	86	NSPS REV
NWEBURY #UNK	COLUMBUS & SO. OHIO ELEC.	ECAR	OH	403	87	NEW PLANT	UNSPECFD	403	87	NSPS REV
POSTON #5	COLUMBUS & SO. OHIO ELEC.	ECAR	OH	375	87	NEW PLANT	UNSPECFD	375	87	NSPS REV
POSTON #6	COLUMBUS & SO. OHIO ELEC.	ECAR	OH	444	90	NEW PLANT	UNSPECFD	444	90	NSPS REV
UNKNOWN #UNK	BUCKEYE PWR. INC.	ECAR	OH	650	87	NEW PLANT	UNSPECFD	650	87	NSPS REV
BRUCE MANSFIELD #3	PENN POWER CO, OHIO EDISON CO.	ECAR	PA	814	80	NEW PLANT	LIME	814	80	NSPS ORIG
D.B. WILSON #2	BIG RIVERS ELECTRIC COOP	ECAR	WV	440	85	NEW PLANT	LIME	440	85	NSPS REV
LEWIS #2	AMERICAN ELEC. PWR. CO.	ECAR		1300	88	NEW PLANT	UNSPECFD	1300	88	NSPS REV
LEWIS #1	AMERICAN ELEC. PWR. CO.	ECAR		1300	86	NEW PLANT	UNSPECFD	1300	86	NSPS REV
UNKNOWN #UNK	ALLEGHENY PWR. SYSTEMS	ECAR	NY	630	88	NEW PLANT	UNSPECFD	630	88	NSPS REV
D.B. WILSON #1	BIG RIVERS ELECTRIC COOP	ECAR	WV	440	84	NEW PLANT	LIME	440	84	NSPS REV
PLEASENTS #2	MONONGAHELA POWER	ECAR	WV			NEW PLANT	LIME	618	80	NSPS ORIG

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
MITCHELL #3	WEST PENNSYLVANIA POWER	ECAR	PA	300		RETRO KNOWN	LIME	300	82	SIP EXST
PARADISE #2	TENNESSEE VALLEY AUTHORITY	ECAR	KY	704		RETRO KNOWN	LIMESTONE	704	82	SIP EXST
PARADISE #1	TENNESSEE VALLEY AUTHORITY	ECAR	KY	704		RETRO KNOWN	LIMESTONE	704	82	SIP EXST

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD					LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP		
UNKNOWN #UNK	HOUSTON LIGHTING & PWR	ERCOT	TX	750	85	NEW PLANT	UNSPECFD	750	85	NSPS REV	
MARTIN LAKE #4	TEXAS PWR & LT. CO	ERCOT	TX	750	85	NEW PLANT	LIMESTONE	750	85	NSPS REV	
FREESTONE PROJ. #2	HOUSTON LIGHTING & PWR. CO	ERCOT	TX	750	86	NEW PLANT	LIMESTONE	750	86	NSPS REV	
TWIN OAK #2	TEXAS PWR. & LT. CO.	ERCOT	TX	793	86	NEW PLANT	LIMESTONE	793	86	NSPS REV	
UNKNOWN #UNK	HOUSTON LIGHTING & PWR.	ERCOT	TX	750	86	NEW PLANT	UNSPECFD	750	86	NSPS REV	
SEYMOUR #3	LOWER COLORADO RIVER AUTH.	ERCOT	TX	400	86	NEW PLANT	UNSPECFD	400	86	NSPS REV	
DIVERSION/KEMP #1	WEST TEXAS UTILITIES CO.	ERCOT	TX	540	87	NEW PLANT	UNSPECFD	540	87	NSPS REV	
UNKNOWN #UNK	TEXAS UTILITIES	ERCOT	TX	750	87	NEW PLANT	UNSPECFD	750	87	NSPS REV	
UNKNOWN #UNK	TEXAS MUNICIPAL POWER POOL	ERCOT	TX	400	87	NEW PLANT	UNSPECFD	400	87	NSPS REV	
UNDESIGNATED #1	SAN ANTONIO PUBLIC SERVICE BD.	ERCOT	TX	500	88	NEW PLANT	UNSPECFD	500	88	NSPS REV	
COLETO CREEK #2	CONTRAL PWR. & LT. CO.	ERCOT	TX	345	88	NEW PLANT	UNSPECFD	345	88	NSPS REV	
KARNACK #UNK	CENTRAL PWR. & LT. CO.	ERCOT	TX	345	88	NEW PLANT	UNSPECFD	345	88	NSPS REV	
UNKNOWN #UNK	TEXAS UTILITIES	ERCOT	TX	500	88	NEW PLANT	UNSPECFD	500	88	NSPS REV	
UNKNOWN #UNK	TEXAS UTILITIES	ERCOT	TX	400	88	NEW PLANT	UNSPECFD	400	88	NSPS REV	
UNKNOWN #UNK	TEXAS MUNICIPAL POWER POOL	ERCOT	TX	400	88	NEW PLANT	UNSPECFD	400	88	NSPS REV	
SAN MIGUEL #2	SO. TEXAS ELEC. COOP. INC	ERCOT	TX	400	84	NEW PLANT	UNSPECFD	400	84	NSPS REV	
TWIN OAK #1	TEXAS PWR & LT CO.	ERCOT	TX	750	84	NEW PLANT	LIMESTONE	750	84	NSPS REV	
FOREST GROVE #1	TEXAS PWR & LT CO.	ERCOT	TX	750	84	NEW PLANT	UNSPECFD	750	84	NSPS REV	
FREESTONE PROJ. #1	HOUSTON LIGHTING & PWR CO.	ERCOT	TX	750	84	NEW PLANT	LIMESTONE	750	84	NSPS REV	
W.A. PARISH #8	HOUSTON LIGHTING & PWR CO.	ERCOT	TX	540	82	NEW PLANT	LIMESTONE	492	82	NSPS ORIG	
W.A. PARISH #8	HOUSTON LIGHTING & PWR CO.	ERCOT	TX	540	82	NEW PLANT	LIMESTONE	540	82	NSPS ORIG	
GIBBONS CREEK #1	TEXAS MUNC. PWR. AGENCY	ERCOT	TX	400	82	NEW PLANT	LIMESTONE	400	82	NSPS ORIG	
SANDOW #4	TEXAS PWR & LT. CO.	ERCOT	TX	545	81	NEW PLANT	LIMESTONE	382	80	NSPS ORIG	
SAN MIGUEL #1	SAN MIGUEL ELEC COOP, S. TEXAS ELEC COOP	ERCOT	TX	400	80	NEW PLANT	LIMESTONE	400	80	NSPS ORIG	

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
MILL CREEK #1	TEXAS UTILITIES	ERCOT	TX	750	85	NEW PLANT	UNSPECFD	750	85	NSPS REV
MILL CREEK #2	TEXAS UTILITIES	ERCOT	TX	750	87	NEW PLANT	UNSPECFD	750	87	NSPS REV

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD					LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP		
SEWARD #7	PENN. ELEC. CO	MAAC	PA	625	88	NEW PLANT	UNSPECFD	625	88	NSPS REV	
COHO #1	PENN ELEC. CO	MAAC	PA	625	88	NEW PLANT	UNSPECFD	625	88	NSPS REV	
UNKNOWN #UNK	W. PENN. PWR. CO	MAAC	PA	630	88	NEW PLANT	UNSPECFD	630	88	NSPS REV	
DICKERSON #4	POTOMIC ELEC PWR CO	MAAC	MD	800	87	NEW PLANT	UNSPECFD	800	87	NSPS REV	
BC COAL UNIT #1	BALTIMORE GAS & ELEC CO.	MAAC	MD	800	87	NEW PLANT	UNSPECFD	800	87	NSPS REV	
VIENNA #9	DELMARVA PWR & LT CO. OF VA	MAAC	MD	400	87	NEW PLANT	UNSPECFD	400	87	NSPS REV	
EDDYSTONE #1	PHILADELPHIA ELECTRIC	MAAC	PA	301		RETRO KNOWN	MAGNESIA	240	82	SIP EXST	
EDDYSTONE #2	PHILADELPHIA ELECTRIC	MAAC	PA	334		RETRO KNOWN	MAGNESIA	334	82	SIP EXST	
LOWER ARMSTRONG #3	ALLEGHENY PWR SYSTEMS,INC	MAAC	PA	630	86	NEW PLANT	UNSPECFD	630	86	NSPS REV	
LOWER ARMSTRONG #2	ALLEGHENY PWR SYSTEMS,INC	MAAC	PA	630	85	NEW PLANT	UNSPECFD	630	85	NSPS REV	
LOWER ARMSTRONG #1	ALLEGHENY PWR SYSTEMS,INC	MAAC	PA	630	84	NEW PLANT	UNSPECFD	630	84	NSPS REV	
GILBERT #9	JERSEY CENTRAL PWR. & LT. CO.	MAAC	NJ	800	90	NEW PLANT	UNSPECFD	800	90	NSPS REV	
DEEPWATER #8	ATLANTIC CITY ELEC. CO.	MAAC	NJ	300	87	NEW PLANT	UNSPECFD	300	87	NSPS REV	
CROMBY #1	PHILADELPHIA ELECTRIC	MAAC	PA	150		RETRO KNOWN	MAGNESIA	150	83	ESECA VOL	
CROMBY #2	PHILADELPHIA ELECTRIC	MAAC	PA	201		RETRO POTEN	MAGNESIA	201		ESECA NON	
SAYREVILLE #5	JERSEY CENTRAL POWER & LIGHT	MAAC	NJ	127	58	RETRO POTEN	UNSPECFD	127		FUA VOL	
SAYREVILLE #4	JERSEY CENTRAL POWER & LIGHT	MAAC	NJ	122	55	RETRO POTEN	UNSPECFD	122		FUA VOL	

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
HAVEN #2	WISC. ELEC. PWR.CO.	MAIN	WI	400	85	NEW PLANT	UNSPECFD	400	85	NSPS REV
EDGEWATER #5	WISC PWR & LT	MAIN	WI	400	83	NEW PLANT	UNSPECFD	400	83	NSPS REV
WESTON #4	WISC. PUBLIC SERVICE CORP	MAIN	WI	350	86	NEW PLANT	UNSPECFD	350	86	NSPS REV
COLLINS #4	COMMONWEALTH EDISON CO.	MAIN	IL	505	78	RETRO POTEN	UNSPECFD	505		FUA VOL
COLLINS #5	COMMONWEALTH EDISON CO.	MAIN	IL	530	79	RETRO POTEN	UNSPECFD	530		FUA VOL
KANKANNA #1	KAUKAUNA, ELEC. & WTR. DEPT.	MAIN	WI	150	86	NEW PLANT	UNSPECFD	150	86	NSPS REV
THOMAS HILL #3	ASSOC. ELEC. COOP. INC	MAIN	MO	630	82	NEW PLANT	LIMESTONE	630	82	NSPS ORIG
SIKESTON #1	SIKESTON BRD OF MUNC. UTILITIES	MAIN	MO	235	81	NEW PLANT	LIMESTONE	235	81	NSPS ORIG
UNKNOWN #UNK	UPPER PENN PWR CO.	MAIN	MI	90	87	NEW PLANT	UNSPECFD	90	87	NSPS REV
WESTON #2	WISCONSIN PUBLIC SERVICES CORP.	MAIN	WI	75		RETRO POTEN	UNSPECFD	75		ESECA VOL
UNKNOWN #UNK	UPPER PENN. PWR. CO.	MAIN	MI	90	85	NEW PLANT	UNSPECFD	90	85	NSPS REV
UNKNOWN #UNK	UPPER PENN. PWR. CO.	MAIN	MI	90	84	NEW PLANT	UNSPECFD	90	84	NSPS REV
DUCK CREEK #3	CEN. ILL. LT. CO.	MAIN	IL	550	89	NEW PLANT	UNSPECFD	550	89	NSPS REV
UNKNOWN #UNK	COMMONWEALTH EDISON CO.	MAIN	IL	550	87	NEW PLANT	UNSPECFD	550	87	NSPS REV
UNKNOWN #UNK	CENTRAL ILL. PUBLIC SERVICE CO.	MAIN	IL	600	87	NEW PLANT	UNSPECFD	600	87	NSPS REV
DALLMAN #3	SPRINGFIELD WATER, LIGHT & PWR DEPT	MAIN	IL			NEW PLANT	LIMESTONE	205	80	NSPS ORIG
ERICKSON #	LANSING BOARD OF WTR & LIGHT	MAIN	MI	160	87	NEW PLANT	UNSPECFD	160	87	NSPS REV
UNKNOWN #UNK	COMMONWEALTH EDISON CO.	MAIN	IL	550	86	NEW PLANT	UNSPECFD	550	86	NSPS REV
UNKNOWN #UNK	CITY OF SPRINGFIELD	MAIN	IL	192	86	NEW PLANT	UNSPECFD	192	86	NSPS REV
PEARL STATION #2	W. ILL. PWR. COOP	MAIN	IL	100	86	NEW PLANT	UNSPECFD	100	86	NSPS REV
MARION #5	S. ILL. PWR. COOP	MAIN	IL	350	85	NEW PLANT	UNSPECFD	350	85	NSPS REV
DUCK CREEK #2	CEN. ILL. LT. CO.	MAIN	IL	400	84	NEW PLANT	LIMESTONE	400	84	NSPS REV

STATION & #	UTILITY	REGION	STATE V	BOILER		APPLICATION	FGD			LEGIS- LATIVE STATUS
				MW	START UP		TYPE	MW	START UP	
COLSTRIP #3	MONTANA PWR CO.	MARCA-1	MT	778	82	NEW PLANT	LIME	700	83	NSPS ORIG
COLSTRIP #4	MONTANA PWR CO.	MARCA-1	MT	778	83	NEW PLANT	LIME	778	83	NSPS REV
UNKNOWN #UNK	MONTANA DAKOTA UTILITIES	MARCA-1	MT	120	86	NEW PLANT	UNSPECFD	120	86	NSPS REV
UNKNOWN #UNK	NEBRASKA PUBLIC PWR DIST.	MARCA-1	NE	600	86	NEW PLANT	UNSPECFD	600	86	NSPS REV
COAL CREEK #2	COOPERATIVE PWR ASSOCIATION	MARCA-1	ND	490	80	NEW PLANT	LIME	327	80	NSPS ORIG
COYOTE #1	OTTER TAIL PWR CO.	MARCA-1	ND	410	81	NEW PLANT	AQUE CARB	410	81	NSPS ORIG
SHELDON #1	NEBRASKA PUBLIC POWER DISTRICT	MARCA-1	NE	105		RETRO POTEN	UNSPECFD	105		ESECA VOL
SHELDON #2	NEBRASKA PUBLIC POWER DISTRICT	MARCA-1	NE	115		RETRO POTEN	UNSPECFD	115		ESECA VOL
ANTELOPE VALLEY #1	BASIN ELEC. PWR COOP	MARCA-1	ND	416	82	NEW PLANT	L SPRY DRY	416	83	NSPS ORIG
ANTELOPE VALLEY #2	BASIN ELEC. PWR COOP	MARCA-1	ND	416	83	NEW PLANT	L SPRY DRY	416	83	NSPS REV
UNKNOWN #UNK	BASIN ELEC. PWR COOP	MARCA-1	ND	500	86	NEW PLANT	UNSPECFD	500	86	NSPS REV
UNKNOWN #UNK	BASIN ELEC. PWR COOP	MARCA-1	ND	500	88	NEW PLANT	UNSPECFD	500	88	NSPS REV

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
MUSCATINE #9	MUSCATIEN PWR & WTR	MARCA-2	IA	150	82	NEW PLANT	LIMESTONE	150	82	NSPS ORIG
LOUISA #1	IOWA-ILL. GAS & ELECTRIC. CO.	MARCA-2	IA	650	83	NEW PLANT	UNSPECFD	650	83	NSPS REV
UNKNOWN #UNK	CENTRAL IOWA PWR COOP	MARCA-2	IA	550	85	NEW PLANT	UNSPECFD	550	85	NSPS REV
UNKNOWN #UNK	ALLIED PWR COOP	MARCA-2	IA	550	85	NEW PLANT	UNSPECFD	550	85	NSPS REV
GUTHRIE COUNTY #1	IOWA ELEC. LT. & PWR. CO	MARCA-2	IA	600	84	NEW PLANT	LIMESTONE	600	84	NSPS REV
ALLIED #1	IOWA PUBLIC SERVICE CO.	MARCA-2	IA	400	86	NEW PLANT	UNSPECFD	400	86	NSPS REV
GEORGE NEAL #1	IOWA PUBLIC SERVICES CO.	MARCA-2	IA	147		RETRO POTEN	UNSPECFD	147		ESECA VOL
SHERBURNE COUNTY #3	NORTHERN STATES PWR CO.	MARCA-2	MN	800	84	NEW PLANT	LIMESTONE	800	84	NSPS REV
UNKNOWN #UNK	MINNESOTA PWR. & LT. CO.	MARCA-2	MN	500	86	NEW PLANT	UNSPECFD	500	86	NSPS REV
SHERBURNE COUNTY #4	NORTHERN STATES PWR. CO.	MARCA-2	MN	800	87	NEW PLANT	UNSPECFD	800	87	NSPS REV
CLAYBOSWELL #4	MINN. PWR & LT. CO	MARCA-2	MN	500	80	NEW PLANT	LIME	500	80	NSPS REV
JOHN P. MUDGETT #2	DAIRYLAND PWR COOP.	MARCA-2	WI	500	88	NEW PLANT	UNSPECFD	500	88	NSPS REV
UNKNOWN #UNK	NORTHERN STATES PWR. CO.	MARCA-2	MN	800	89	NEW PLANT	UNSPECFD	800	89	NSPS REV

STATION #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
BRIDGEPORT HARBOR #3	UNITED ILLUMINATING CO.	NPCC	CT	375	68	RETRO POTEN	UNSPECFD	375		FUA VOL
LOVETT #5	ORANGE & ROCKLAND UTILITIES	NPCC	NY	201	69	RETRO POTEN	UNSPECFD	201		FUA VOL
LOVETT #4	ORANGE & ROCKLAND UTILITIES	NPCC	NY	196	66	RETRO POTEN	UNSPECFD	196		FUA VOL
RAVENSWOOD #3	CONSOLIDATED EDISON	NPCC	NY	1000	65	RETRO POTEN	UNSPECFD	1000		FUA VOL
ARTHUR KILL #3	CONSOLIDATED EDISON	NPCC	NY	491	69	RETRO POTEN	UNSPECFD	491		FUA VOL
ARTHUR KILL #2	CONSOLIDATED EDISON	NPCC	NY	335	59	RETRO POTEN	UNSPECFD	335		FUA VOL
BARRETT #1	LONG ISLAND LIGHTING CO.	NPCC	NY	175	56	RETRO POTEN	UNSPECFD	175		FUA VOL
BARRETT #2	LONG ISLAND LIGHTING CO.	NPCC	NY	175	63	RETRO POTEN	UNSPECFD	175		FUA VOL
UNKNOWN #UNK	POWER AUTHORITY OF THE STATE OF N.Y.	NPCC	NY	700	87	NEW PLANT	UNSPECFD	700	87	NSPS REV
LAKE ERIE #1	NIAGRA MOHAWK PWR. CORP.	NPCC	NY	850	87	NEW PLANT	UNSPECFD	850	87	NSPS REV
MTA-AUTHUR KILL #1	PWR. AUTH OF STATE OF N.Y.	NPCC	NY	760	84	NEW PLANT	UNSPECFD	760	84	NSPS REV
SOMERSET #1	N.Y. STATE ELEC. & GAS CORP.	NPCC	NY	850	84	NEW PLANT	LIMESTONE	850	84	NSPS REV
SEARS ISLAND #1	CONTRAL MAINE POWER CO.	NPCC	ME	568	87	NEW PLANT	UNSPECFD	568	87	NSPS REV

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
UNKNOWN #	S.C. PUBLIC SERVICE AUTH.	SERC	SC	450	85	NEW PLANT	LIMESTONE	450	85	NSPS REV
UNKNOWN #	S.C. ELEC. & GAS CO.	SERC	SC	500	85	NEW PLANT	UNSPECFD	500	85	NSPS REV
UNKNOWN #	S.C. ELEC. & GAS CO.	SERC	SC	500	87	NEW PLANT	UNSPECFD	500	87	NSPS REV
UNKNOWN #	S.C. PUBLIC SERVICE AUTH.	SERC	SC	450	87	NEW PLANT	UNSPECFD	450	87	NSPS REV
UNKNOWN #	VA. ELEC. PWR CO	SERC	VA	840	87	NEW PLANT	UNSPECFD	840	87	NSPS REV
UNKNOWN #	VA. ELEC. PWR CO	SERC	VA	840	88	NEW PLANT	UNSPECFD	840	88	NSPS REV
ELLIS #1	GULF PWR. CO	SERC	VA	503	85	NEW PLANT	UNSPECFD	503	85	NSPS REV
UNKNOWN #	S.C. PUBLIC SERVICE AUTH.	SERC	SC	450	83	NEW PLANT	LIMESTONE	450	83	NSPS REV
WINYAH #4	S.C. PUBLIC SERVICE AUTH.	SERC	SC	280	82	NEW PLANT	LIMESTONE	280	82	NSPS ORIG
WIDOWS CREEK #7	TENNESSEE VALLEY AUTHORITY	SERC	AL	575		RETRO KNOWN	LIMESTONE	575	81	SIP EXST
WINYAH #3	S.C. PUBLIC SERVICE AUTH.	SERC	SC	280	80	NEW PLANT	LIMESTONE	280	80	NSPS ORIG
MAYO #2	CAROLINA PWR. & LT. CO	SERC	NC	720	85	NEW PLANT	UNSPECFD	720	85	NSPS REV
UNKNOWN #	MISS. PWR. CO	SERC	MS	548	86	NEW PLANT	UNSPECFD	548	86	NSPS REV
SCHERER #4	GEORGIA PWR. CO.	SERC	GA	808	87	NEW PLANT	UNSPECFD	808	87	NSPS REV
EFFINGHAM STATION #2	SAVANNAH ELEC. & PWR. CO	SERC	GA	239	86	NEW PLANT	UNSPECFD	239	86	NSPS REV
SCHERER #3	GEORGIA PWR. CO.	SERC	GA	808	85	NEW PLANT	UNSPECFD	808	85	NSPS REV
SCHERER #2	GEORGIA PWR. CO.	SERC	GA	891	84	NEW PLANT	UNSPECFD	891	84	NSPS REV
UNKNOWN #	FLA. PWR. & LT. CO	SERC	FL	600	87	NEW PLANT	UNSPECFD	600	87	NSPS REV
UNKNOWN #	CITY OF LAKE LAND	SERC	FL	350	87	NEW PLANT	UNSPECFD	350	87	NSPS REV
MARTIN COAL #2	FLA. PWR. & LT. CO	SERC	FL	720	87	NEW PLANT	UNSPECFD	720	87	NSPS REV
MARTIN COAL #2	FLA. PWR. & LT. CO	SERC	FL	720	85	NEW PLANT	UNSPECFD	720	85	NSPS REV
SEMINOLE #2	SEMINOLE ELEC COOP	SERC	FL	600	85	NEW PLANT	LIMESTONE	600	85	NSPS REV
SEMINOLE #1	SEMINOLE ELEC COOP	SERC	FL	600	83	NEW PLANT	LIMESTONE	600	83	NSPS REV
GANNON #1	TAMPA ELECTRIC CO	SERC	FL	98	57	RETRO POTEN	UNSPECFD	98		FUA VOL
GANNON #2	TAMPA ELECTRIC CO	SERC	FL	108	58	RETRO POTEN	UNSPECFD	108		FUA VOL

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
GANNON #3	TAMPA ELECTRIC CO	SERC	FL	150	60	RETRO POTEN	UNSPECFD	150		FUA VOL
GANNON #4	TAMPA ELECTRIC CO	SERC	FL	169	63	RETRO POTEN	UNSPECFD	169		FUA VOL
UNKNOWN #	FLA. PWR. CORP.	SERC	FL	660	89	NEW PLANT	UNSPECFD	660	89	NSPS REV
UNKNOWN #	FLA. PWR. CORP.	SERC	FL	640	87	NEW PLANT	UNSPECFD	640	87	NSPS REV
UNKNOWN #	FLA. PWR. CORP	SERC	FL	660	85	NEW PLANT	UNSPECFD	660	85	NSPS REV
UNKNOWN #	JACKSONVILLE ELEC. AUTH.	SERC	FL	563	86	NEW PLANT	LIMESTONE	563	86	NSPS REV
YORKTOWN #1	VIRGINIA ELECTRIC POWER CO	SERC	VA	188	57	RETRO POTEN	UNSPECFD	188		FUA VOL
YORKTOWN #2	VIRGINIA ELECTRIC POWER CO	SERC	VA	188	59	RETRO POTEN	UNSPECFD	188		FUA VOL
SUTTON #1	CAROLINA POWER & LIGHT CO.	SERC	NC	97		RETRO POTEN	UNSPECFD	97		ESECA VOL
SUTTON #2	CAROLINA POWER & LIGHT CO.	SERC	NC	106		RETRO POTEN	UNSPECFD	106		ESECA VOL
SUTTON #3	CAROLINA POWER & LIGHT CO.	SERC	NC	385		RETRO POTEN	UNSPECFD	385		ESECA VOL
CARYVILLE #	GULF PWR. CO	SERC	FL	553	85	NEW PLANT	UNSPECFD	553	85	NSPS REV
BIG BEND #4	TAMPA ELEC.CO	SERC	FL	417	85	NEW PLANT	LIMESTONE	417	85	NSPS REV
BOSTWICK #2	SEMINOLE ELEC. COOP INC.	SERC	FL	600	85	NEW PLANT	UNSPECFD	600	85	NSPS REV
PORT WENTWORTH #3	SAVANNAH ELECTRIC POWER CO.	SERC	GA	104		RETRO POTEN	UNSPECFD	104		ESECA VOL
CRYSTAL RIVER #5	FLA. PWR. CORP.	SERC	FL	640	84	NEW PLANT	UNSPECFD	640	84	NSPS REV
ST. CLAIR #5	DETROIT EDISON CO.	SERC	MI	300		RETRO POTEN	UNSPECFD	300		ESECA VOL
MCMONUS #2	GEORGIA POWER CO.	SERC	GA	75		RETRO POTEN	UNSPECFD	75		ESECA VOL
BOSTWICK #1	SEMINOLE ELEC. COOP INC.	SERC	FL	600	83	NEW PLANT	UNSPECFD	600	83	NSPS REV
MCINTOSH,C.D. #3	LAKELAND UTILITIES	SERC	FL	334	81	NEW PLANT	LIMESTONE	334	81	NSPS ORIG
UNKNOWN #UNK	ALABAMA PWR CO.	SERC	AL	783	90	NEW PLANT	UNSPECFD	783	90	NSPS REV
UNKNOWN #UNK	ALABAMA PWR CO.	SERC	AL	783	88	NEW PLANT	UNSPECFD	783	88	NSPS REV
UNKNOWN #UNK	ALABAMA PWR CO.	SERC	AL	783	87	NEW PLANT	UNSPECFD	783	87	NSPS REV
UNKNOWN #UNK	ALABAMA ELEC. COOP INC.	SERC	AL	400	85	NEW PLANT	UNSPECFD	400	85	NSPS REV

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
MILLER #4	ALABAMA PWR CO.	SERC	AL	654	84	NEW PLANT	UNSPECFD	654	84	NSPS REV
MILLER #3	ALABAMA PWR CO.	SERC	AL	654	83	NEW PLANT	UNSPECFD	654	83	NSPS REV
UNKNOWN #UNK	JACKSONVILLE ELEC AUTHORITY	SERC	FL	600	87	NEW PLANT	LIMESTONE	600	87	NSPS REV

STATION #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
JEFFREY #5	KANSAS PWR. & LT. CO.	SPP-1	KS	680	80	NEW PLANT	LIMESTONE	490	80	NSPS ORIG
JEFFREY #4	KANSAS PWR. & LT. CO.	SPP-1	KS	680	84	NEW PLANT	UNSPECFD	680	84	NSPS REV
HOLCOMB #1	SUNFLOWER ELEC. COOP	SPP-1	KS	280	83	NEW PLANT	L SPRY DRY	280	83	NSPS REV
DORRANCE #1	CENTRAL TELEPHONE & UTIL. CORP	SPP-1	KS	400	85	NEW PLANT	UNSPECFD	400	85	NSPS REV
SOUTHWEST #2	SPRINGFIELD UTIL. (MO)	SPP-1	MO	250	85	NEW PLANT	UNSPECFD	250	85	NSPS REV
EMPIRE ENERGY CENTER #3	EMPIRE DISTRIC ELEC CO	SPP-1	MO	300	86	NEW PLANT	UNSPECFD	300	86	NSPS REV
UNKNOWN #	MISSOURI PUBLIC SERVICE CO	SPP-1	MO	100	88	NEW PLANT	UNSPECFD	100	88	NSPS REV
IUTAN #2	KANSAS CITY PWR & LT	SPP-1	MO	650	88	NEW PLANT	UNSPECFD	650	88	NSPS REV
MUSKOGEE #6	OKLAHOMA GAS & ELEC. CO	SPP-1	OK	515	83	NEW PLANT	UNSPECFD	515	83	NSPS REV
SOONER #3	OKLAHOMA GAS & ELEC. CO	SPP-1	OK	700	83	NEW PLANT	UNSPECFD	700	83	NSPS REV
LAKE ROAD #5	ST. JOSEPH POWER AND LIGHT	SPP-1	MO	85		RETRO POTEN	UNSPECFD	85		ESECA VOL
SOONER #4	OKLAHOMA GAS & ELEC. CO	SPP-1	OK	500	85	NEW PLANT	UNSPECFD	500	85	NSPS REV
UNKNOWN #	OKLAHOMA GAS & ELEC CO	SPP-1	OK	500	85	NEW PLANT	UNSPECFD	500	85	NSPS REV
UNKNOWN #UNK	OKLAHOMA GAS & ELEC CO	SPP-1	OK	500	86	NEW PLANT	UNSPECFD	500	86	NSPS REV
UNKNOWN #UNK	OKLAHOMA GAS & ELEC CO	SPP-1	OK	500	87	NEW PLANT	UNSPECFD	500	87	NSPS REV
UNKNOWN #UNK	OKLAHOMA GAS & ELEC CO	SPP-1	OK	500	88	NEW PLANT	UNSPECFD	500	88	NSPS REV
TOLK STATION #2	S.W. PUBLIC SERVICE CO	SPP-1	TX	508	85	NEW PLANT	UNSPECFD	508	85	NSPS REV
TECUMSEH #UNK	KANSAS POWER & LIGHT CO.	SPP-1	KS	132		RETRO POTEN	UNSPECFD	132		ESECA VOL
LAWRENCE #5	KANSAS POWER AND LIGHT COMPANY	SPP-1	KS	375		RETRO POTEN	UNSPECFD	375		ESECA VOL
LAWRENCE #4	KANSAS POWER AND LIGHT COMPANY	SPP-1	KS	115		RETRO POTEN	UNSPECFD	115		ESECA VOL

STATION & #	UTILITY	REGION	STATE V	BOILER		APPLICATION	FGD		START UP	LEGIS- LATIVE STATUS
				MW	START UP		TYPE	MW		
UNKNOWN #UNK	MISS. PWR. & LT.	SPP-2	MS	700	85	NEW PLANT	UNSPECFD	700	85	NSPS REV
LOUISIANA COAL #10	LOUISIANA PWR. & LT.	SPP-2	LA	700	88	NEW PLANT	UNSPECFD	700	88	NSPS REV
LOUISIANA COAL #7	LA. PWR & LT.	SPP-2	LA	700	86	NEW PLANT	UNSPECFD	700	86	NSPS REV
UNKNOWN #UNK	LA. PWR & LT.	SPP-2	LA	700	88	NEW PLANT	UNSPECFD	700	88	NSPS REV
DOLET HILLS #1	S.W. ELEC. PWR. CO.	SPP-2	LA	640	86	NEW PLANT	UNSPECFD	640	86	NSPS REV
UNKNOWN #UNK	LOUISIANA PWR. & LT.	SPP-2	LA	700	86	NEW PLANT	UNSPECFD	700	86	NSPS REV
BIG CAJUN4 #1	CAJUN ELEC. PWR COOP	SPP-2	LA	540	86	NEW PLANT	UNSPECFD	540	86	NSPS REV
BIG CAJUN3 #1	CAJUN ELEC. PWR COOP	SPP-2	LA	540	85	NEW PLANT	UNSPECFD	540	85	NSPS REV
BIG CAJUN2 #3	CAJUN ELEC. PWR COOP	SPP-2	LA	540	83	NEW PLANT	UNSPECFD	540	83	NSPS REV
R.S. NELSON #5	GULF STATES UTIL. CO	SPP-2	LA	540	84	NEW PLANT	UNSPECFD	540	84	NSPS REV
ARKANSAS COAL #9	ARK. PWR. & LT.	SPP-2	AR	700	88	NEW PLANT	UNSPECFD	700	88	NSPS REV
ARKANSAS COAL #6	ARK. PWR. & LT.	SPP-2	AR	700	88	NEW PLANT	UNSPECFD	700	88	NSPS REV
INDEPENDENCE #2	ARK. PWR. & LT.	SPP-2	AR	700	85	NEW PLANT	UNSPECFD	700	85	NSPS REV
INDEPENDENCE #1	ARK. PWR. & LT.	SPP-2	AR	700	83	NEW PLANT	UNSPECFD	700	83	NSPS REV
UNKNOWN #UNK	MISS. PWR. & LT.	SPP-2	MS	700	87	NEW PLANT	UNSPECFD	700	87	NSPS REV
LOVELADY #1	GULF STATES UTILITY CO	SPP-2	MS	600	85	NEW PLANT	UNSPECFD	600	85	NSPS REV
LOVELADY #2	GULF STATES UTILITY CO.	SPP-2	MS	600	87	NEW PLANT	UNSPECFD	600	87	NSPS REV
UNKNOWN #UNK	GULF STATES UTILITY CO.	SPP-2	MS	500	86	NEW PLANT	UNSPECFD	500	86	NSPS REV
UNKNOWN #UNK	GULF STATES UTILITY CO.	SPP-2	MS	600	88	NEW PLANT	UNSPECFD	600	88	NSPS REV
LAKE DIVERSION #1	S.W. ELEC. PWR. CO	SPP-2		100	87	NEW PLANT	UNSPECFD	100	87	NSPS REV
ROBERTS COUNTY #1	S.W. PUBLIC SERVICE	SPP-2		600	87	NEW PLANT	UNSPECFD	600	87	NSPS REV
COLETO CREEK #UNK	S.W. ELEC. PWR. CO	SPP-2		295	88	NEW PLANT	UNSPECFD	295	88	NSPS REV
KARNACK #1	S.W. ELEC. PWR. CO	SPP-2		245	88	NEW PLANT	UNSPECFD	245	88	NSPS REV
PIRKEY #1	S.W. ELEC. PWR. CO	SPP-2		640	84	NEW PLANT	UNSPECFD	640	84	NSPS REV
UNKNOWN #UNK	MIDDLE SDUTH UTILITIES	SPP-2	?	890	87	NEW PLANT	UNSPECFD	890	87	NSPS REV

STATION #	UTILITY	REGION	STATE V	BOILER		FGD					LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP		
UNKNOWN #UNK	MIDDLE SOUTH UTILITIES	SPP-2	?	890	85	NEW PLANT	UNSPECFD	890	85	NSPS REV	
UNKNOWN #UNK	MIDDLE SOUTH UTILITIES	SPP-2	?	890	88	NEW PLANT	UNSPECFD	890	88	NSPS REV	
UNKNOWN #UNK	MIDDLE SOUTH UTILITIES	SPP-2	?	890	86	NEW PLANT	UNSPECFD	890	86	NSPS REV	
WILTON #2	MIDDLE SOUTH UTILITIES	SPP-2	?	890	88	NEW PLANT	UNSPECFD	890	88	NSPS REV	
WILTON #1	MIDDLE SOUTH UTILITIES	SPP-2	?	890	86	NEW PLANT	UNSPECFD	890	86	NSPS REV	

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
INTERMOUTAIN #4	LA DEPT. OF WTR. & PWR.	WSCC-1	UT	820	89	NEW PLANT	LIME	820	89	NSPS REV
WELLINGTON #1	UTAH PWR & LT CO	WSCC-1	UT	500	88	NEW PLANT	UNSPECFD	500	88	NSPS REV
UNKNOWN #UNK	UTAH PWR & LT CO	WSCC-1	UT	500	86	NEW PLANT	UNSPECFD	500	86	NSPS REV
UNKNOWN #UNK	UTAH PWR & LT CO	WSCC-1	UT	500	88	NEW PLANT	UNSPECFD	500	88	NSPS REV
HUNTER #2	UTAH PWR & LT	WSCC-1	UT	400	80	NEW PLANT	LIME	360	80	NSPS ORIG
HUNTER #3	UTAH PWR & LT	WSCC-1	UT	400	83	NEW PLANT	LIMESTONE	400	83	NSPS REV
HUNTER #4	UTAH PWR & LT	WSCC-1	UT	400	85	NEW PLANT	LIMESTONE	400	85	NSPS REV
MOONLAKE #1	DESERET GENERATING & TRANS.	WSCC-1	UT	360	85	NEW PLANT	LIMESTONE	360	85	NSPS REV
INTERMOUNTAIN #1	LA DEPT. OF WTR. & PWR.	WSCC-1	UT	750	86	NEW PLANT	LIME	750	86	NSPS REV
INTERMOUNTAIN #2	LA DEPT. OF WTR. & PWR.	WSCC-1	UT	750	87	NEW PLANT	LIME	750	87	NSPS REV
INTERMOUNTAIN #3	LA DEPT. OF WTR. & PWR.	WSCC-1	UT	750	88	NEW PLANT	LIME	750	88	NSPS REV

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
PAWNEE #2	PUBLIC SERVICE CO OF COLORADO	WSCC-2	CO	470	87	NEW PLANT	UNSPECFD	470	87	NSPS REV
CRAIG #3	COLORADO UTE EL. ASSO.	WSCC-2	CO	400	83	NEW PLANT	L SPRY DRY	400	83	NSPS REV
SOUTHEASTERN #1	PUBLIC SERVICE CO OF COLORADO	WSCC-2	CO	470	84	NEW PLANT	UNSPECFD	470	84	NSPS REV
UNKNOWN #UNK	TRI-STATE GEN. & TRANS. ASSN.	WSCC-2	CO	500	83	NEW PLANT	UNSPECFD	500	83	NSPS REV
OAK CREEK #UNK	OAK CREEK PWR CO.	WSCC-2	CO	800	84	NEW PLANT	UNSPECFD	800	84	NSPS REV
SOUTHEASTERN #2	PUBLIC SERVICE CO. OF COLORADO	WSCC-2	CO	470	85	NEW PLANT	UNSPECFD	470	85	NSPS REV
UNKNOWN #UNK	TRI-STATE GEN. & TRANS. ASSN.	WSCC-2	CO	500	84	NEW PLANT	UNSPECFD	500	84	NSPS REV
OAK CREEK ST 1 #	OAK CREEK PWR. CO.	WSCC-2	CO	800	85	NEW PLANT	UNSPECFD	800	85	NSPS REV
OAK CREEK ST 2 #	OAK CREEK PWR. CO.	WSCC-2	CO	800	85	NEW PLANT	UNSPECFD	800	85	NSPS REV
RAWHIDE #1	PLATTE RIVER PWR. AUTH	WSCC-2	CO	230	85	NEW PLANT	L SPRY DRY	230	85	NSPS REV
UNKNOWN #UNK	TRI-STATE GEN. & TRANS. ASSN.	WSCC-2	CO	500	85	NEW PLANT	UNSPECFD	500	85	NSPS REV
UNKNOWN #UNK	PUBLIC SERVICE CO. OF COLORADO	WSCC-2	CO	470	88	NEW PLANT	UNSPECFD	470	88	NSPS REV
UNKNOWN #UNK	PUBLIC SERVICE CO. OF COLORADO	WSCC-2	CO	470	87	NEW PLANT	UNSPECFD	470	87	NSPS REV
SOUTHWEST #1	COLORADO UTE ELEC ASSN.	WSCC-2	CO	400	88	NEW PLANT	UNSPECFD	400	88	NSPS REV
WYODAK #UNK	PACIFIC PWR & LT CO	WSCC-2	WY	330	83	NEW PLANT	UNSPECFD	330	83	NSPS REV
LARAMIE RIVER #3	BASIN ELEC PWR COOP	WSCC-2	WY	500	82	NEW PLANT	L SPRY DRY	500	82	NSPS ORIG
LARAMIE RIVER #2	BASIN ELEC PWR COOP	WSCC-2	WY	500	80	NEW PLANT	LIMESTONE	500	81	NSPS ORIG
LARAMIE RIVER #1	BASIN ELEC PWR COOP	WSCC-2	WY	500	80	NEW PLANT	LIMESTONE	500	80	NSPS ORIG
OSAGE #UNK	BLACK HILLS PWR & LT CO	WSCC-2	SD	100	85	NEW PLANT	UNSPECFD	100	85	NSPS REV
RAY D. NIXON #UNK	COLORADO SPRINGS, CITY OF	WSCC-2	CO	200	86	NEW PLANT	UNSPECFD	200	86	NSPS REV
TRI-STATE PLANT #UNK	TRI-STATE GEN. & TRANS. ASSN.	WSCC-2	CO	350	88	NEW PLANT	UNSPECFD	350	88	NSPS REV

STATION & #	UTILITY	REGION	STATE V	BOILER		APPLICATION	FGD			LEGIS- LATIVE STATUS
				MW	START UP		TYPE	MW	START UP	
UNKNOWN #UNK	PACIFIC GAS & ELEC CO	WSCC-3	CA	800	86	NEW PLANT	UNSPECFD	800	86	NSPS REV
UNKNOWN #UNK	PACIFIC GAS & ELEC CO	WSCC-3	CA	800	87	NEW PLANT	UNSPECFD	800	87	NSPS REV
CALIFORNIA COAL #1	SOUTHERN CAL. EDISON CO.	WSCC-3	CA	250	87	NEW PLANT	UNSPECFD	250	87	NSPS REV
UNKNOWN #UNK	PACIFIC GAS & ELEC. CO.	WSCC-3	CA	800	88	NEW PLANT	UNSPECFD	800	88	NSPS REV
CALIFORNIA COAL #2	SOUTHERN CAL. EDISON CO.	WSCC-3	CA	250	88	NEW PLANT	UNSPECFD	250	88	NSPS REV
NORTH VALMY #2	SIERRA PACIFIC PWR CO	WSCC-3	NV	250	84	NEW PLANT	UNSPECFD	250	84	NSPS REV
HARRY ALLEN #1	NEVADA PWR CO	WSCC-3	NV	500	85	NEW PLANT	UNSPECFD	500	85	NSPS REV
HARRY ALLEN #2	NEVADA PWR CO	WSCC-3	NV	500	86	NEW PLANT	UNSPECFD	500	86	NSPS REV
HARRY ALLEN #3	NEVADA PWR CO	WSCC-3	NV	500	87	NEW PLANT	UNSPECFD	500	87	NSPS REV
HARRY ALLEN #4	NEVADA PWR CO	WSCC-3	NV	500	88	NEW PLANT	UNSPECFD	500	88	NSPS REV
REID GARDNER #4	NEVADA PWR CO	WSCC-3	NV	250	83	NEW PLANT	AQUE CARB	250	83	NSPS REV
ST. GEORGE #1	NEVADA PWR CO	WSCC-3	NV	250	83	NEW PLANT	UNSPECFD	250	83	NSPS REV
ST. GEORGE #2	NEVADA PWR CO	WSCC-3	NV	250	84	NEW PLANT	UNSPECFD	250	84	NSPS REV
UNKNOWN #UNK	SIERRA PACIFIC PWR	WSCC-3	NV	125	87	NEW PLANT	UNSPECFD	125	87	NSPS REV
WARNER VALLEY #1	NEVADA POWER CO.	WSCC-3	?	295	85	NEW PLANT	UNSPECFD	295	85	NSPS REV
WARNER VALLEY #2	NEVADA POWER CO.	WSCC-3	?	295	86	NEW PLANT	UNSPECFD	295	86	NSPS REV
MONTEZUMA #1	PACIFIC GAS & ELECTRIC	WSCC-3	CA	800	89	NEW PLANT	LIMESTONE	800	89	NSPS REV
MONTEZUMA #2	PACIFIC GAS & ELECTRIC	WSCC-3	CA	800	90	NEW PLANT	LIMESTONE	800	90	NSPS REV

STATION & #	UTILITY	REGION	STATE V	BOILER		FGD				LEGIS- LATIVE STATUS
				MW	START UP	APPLICATION	TYPE	MW	START UP	
CORONADO #2	SALT RIVER PROJ. AGRI. IMP. PWR. DIST.	WSCC-4	AZ	350	80	NEW PLANT	LIMESTONE	280	80	NSPS ORIG
FOUR CORNERS #5	ARIZONA PUBLIC SERVICES	WSCC-4	NM	800		RETRO POTEN	LIME	755	84	SIP EXST
FOUR CORNERS #4	ARIZONA PUBLIC SERVICES	WSCC-4	NM	800		RETRO POTEN	LIME	755	84	SIP EXST
CHOLLA #4	ARIZONA PUBLIC SERVICE CO	WSCC-4	AZ	347	81	NEW PLANT	LIMESTONE	126	81	NSPS ORIG
SPRINGERVILLE #1	TUCSON ELEC PWR CO	WSCC-4	AZ	330	85	NEW PLANT	L SPRY DRY	330	85	NSPS REV
SPRINGERVILLE #2	TUCSON ELEC PWR CO	WSCC-4	AZ	330	87	NEW PLANT	UNSPECFD	330	87	NSPS REV
ESCALANTE #1	PLAINS ELC. GEN. & TRANS. COOP	WSCC-4	NM	210	84	NEW PLANT	LIMESTONE	210	84	NSPS REV
ESCALANTE #2	PLAINS ELC. GEN. & TRANS. COOP	WSCC-4	NM	210	88	NEW PLANT	WELMN LORD	210	88	NSPS REV
SAN JUAN #4	PUBLIC SERVICE CO. OF N.M.	WSCC-4	NM	472	82	NEW PLANT	WELMN LORD	472	82	NSPS ORIG
UNKNOWN #UNK	PLAINS ELEC. GEN. & TRANS. COOP	WSCC-4	NM	330	84	NEW PLANT	UNSPECFD	330	84	NSPS REV
NEW MEXICO #1	PUBLIC SERVICE CO. OF N.M.	WSCC-4	NM	500	90	NEW PLANT	UNSPECFD	500	90	NSPS REV

APPENDIX B

FACTORS AFFECTING FGD COSTS

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APPENDIX B

FACTORS AFFECTING FGD COSTS

INTRODUCTION

Once a scrubber design has been selected, the life cycle cost of a particular FGD system for a specific site depends upon several major factors. These factors can be grouped into the following categories:

- 1) Expenditures due to specific power plant conditions (i.e., new versus retrofit installations)
- 2) Chemical properties of the coal
- 3) Commodity and byproduct properties
- 4) Plant location - effects on commodity availability/costs

The following material discusses these factors in more detail.

NEW VERSUS RETROFIT FGD SYSTEMS

The focus here is on the likely additional cost requirements for adapting an FGD system to an existing utility (i.e., cost items over and above these required for a system at a new plant). For example, the purchase of land for sludge disposal in a retrofit situation would be excluded from consideration, since land would also be required for sludge disposal from a new system. In general, a retrofitted FGD system is more costly due to a site-specific need to adapt it to existing equipment layouts. This may require the development of a customized FGD system or extensive modifications to the existing power plant equipment. These modifications include ductwork, induced draft fans, and possibly stacks.

Modifications to ducts must be undertaken to allow passage of flue gases through the FGD system. Induced draft fan requirements usually increase due to pressure drops across the scrubber. A second cost element, associated with the induced draft fan requirements, would be the use of more corrosion-resistant materials. Stacks and/or liners sometimes require

modifications due to the corrosive nature of post-scrubber gases and lower exit temperatures. The corrosive gases may require more resistant stack liners while the lower exit temperatures could require smaller diameter and/or higher stacks to counteract the lower effective height of the stack created by reduced temperatures.

EPA's Utility FGD Surveys¹ have been including FGD cost data since 1978. Cost data exist for both new and retrofitted FGD units. EPA has analyzed the data and delineated all cost elements in order to put each FGD system on an equal comparable basis. Within these surveys, EPA has also adjusted all costs to July 1, 1977, dollars using the Chemical Engineering Index. In addition, cost values have been adjusted for plant capacity (@ 65%) and for other factors in order to place the reported data on a comparable standardized basis. As a check, SAI has screened the new and retrofit systems to ensure that all cost elements being represented will be identical for each system covered by this study.

Table B-1 presents selected EPA survey data on costs for 26 operational FGD systems. The capital and annual costs shown indicate the range of costs for 13 new systems and for 13 retrofit systems. Adjusted costs were higher on retrofit systems than on new systems for both capital and annual costs (4.5% and 7.6%, respectively).

Table B-1. ADJUSTED CAPITAL AND ANNUAL COSTS FOR OPERATIONAL FGD SYSTEMS

Type of	Capital Costs (\$/kW)		Annual Costs (mills/kWh)	
System	Range	Average	Range	Average
Retrofit	56.0-140.6	90.0	2.6-12.4	5.6
New	66.4-117.6	86.1	2.8- 8.7	5.2
All	56.0-140.6	88.0	2.6-12.4	5.4

Source: Reference 1.

Table B-2 describes how variations in coal composition affect the operating requirements and efficiencies of an FGD system and, thereby, influence the final costs. The classification and distribution of coal reserves in the contiguous United States is presented in Figure B-1.

Table B-2. COAL AND SORBENT FACTORS INFLUENCING FGD COSTS

Coal Composition Factors	Effects
o Heating value	- determines the coal throughput which, in turn, dictates the quantity of SO ₂ and other gases produced overhead; therefore, affects SO ₂ removal requirements and FGD system size and efficiency
o Sulfur content	- determines the quantity of SO ₂ produced overhead; therefore, affects SO ₂ removal requirements and FGD system size and efficiency
o Ash content	- determines size of electrostatic precipitator - if added to scrubber sludge (L&LS), aids in stabilization; therefore, can reduce disposal pond design requirements
o Alkalinity of flyash	- alkali fly ash may be used for partial adsorption of SO ₂ , thereby lowering sorbent throughput requirements
o Chloride content	- excessive accumulation may cause material corrosion or degradation within the FGD system; therefore, materials selection and cost are affected

Figure B-1. COAL FIELDS IN THE UNITED STATES

Lime^{2,3,4}

Lime is produced by calcining some form of calcite, CaCO_3 . The most common form of calcite is limestone. Oyster shells, marble, aragonite and coral also contain high amounts of CaCO_3 . The calcining of lime can produce several different products, depending upon the temperature at which the calcining takes place. At about 2000°F , the calcining process produces quicklime (calcium oxide, CaO) by driving off carbon dioxide gas. At 3000°F , the quicklime will be deadburned. This deadburned quicklime, also called refractory lime, is no longer reactive with water. Dolomite is usually used to produce deadburned lime.

Quicklime is the basic sorbent used in wet lime scrubbing systems. When calcined, it may have anywhere from 1 to 10 percent unreactive materials, called grit. This grit is usually made up of: iron and aluminum oxides or silicates, and calcium and magnesium carbonates (not converted during calcining). This material must be washed out to produce a quicklime with 1 to 2 percent grit. The quicklime is reacted with water to produce a hydrate, $\text{Ca}(\text{OH})_2$ containing 24 percent water. This then becomes the scrubbing sorbent. The leading consuming states for hydrate are Texas, Pennsylvania, Ohio, Illinois, and Louisiana.

Lime consumption in general can be subdivided as follows: Chemicals (81%), construction (10%), refractories (8%), and agriculture (1%). Major individual uses are: BOF steel furnaces, alkalies, water purification, refractories, and paper and pulp. In 1978, $20,443 \times 10^3$ short tons of lime were sold or used by U. S. producers. Of this amount, $2,582 \times 10^3$ short tons were hydrated lime, with most of the rest being quicklime. A total of 384×10^3 short tons of lime were used for sulfur removal. In 1978, 155 plants were producing lime within the United States. The location of a majority of these production facilities is presented in Figure B-2.

Figure B-2. LIME: PRODUCTION FACILITIES IN THE UNITED STATES

The average cost of lime in 1978 was \$36.67/short ton (f.o.b.). The majority of this cost is due to energy consumed during calcining, and to transportation of the raw material. The Bureau of Mines forecast suggests a demand for lime of between $32,200 \times 10^3$ to $44,600 \times 10^3$ tons in 2000. Supply is unlimited and U. S. production is deemed capable of meeting demand.

Limestone*

Limestone reserves are of an extreme importance since they supply the sorbents for lime, limestone, dual alkali, and lime spray dryer FGD systems. For limestone scrubbing, the calcium carbonate (CaCO_3) content is of prime importance. Limestone can be found relatively close to the surface in over 10 percent of the continental U. S. The reserves are extremely large, with the reserves expected to last hundreds or even thousands of years. Due to this abundant supply, detailed information regarding these reserves (location, depth, quality, and quantity) does not exist at the Federal level.

About two thirds of all limestones mined is used for its physical properties, the major consumer being the construction industry. The stone is used as an aggregate, fill, and road material. The other third is used for chemical purposes, including: portland cement (15 %), fluxes (5%), lime (5%), refractory dolomite (0.5%), agriculture (4%), and others (8%).

Since limestone is so abundant, most mining is done in open pits and quarries. Room and pillar mining is only conducted when high purity is required (usually > 95 percent or 97 percent CaCO_3). For such cases most operations are within 500 feet of the surface.

For FGD applications, two questions had to be answered: 1) what is the minimum CaCO_3 content required in limestone scrubbing systems, and 2) what reserves should be plotted? The literature on FGD avoids

* References 5, 6, 7, 8, 9, 10, 11, 12

specifying a minimum CaCO_3 content. Tests have been conducted with limestone having a purity as low as 54 percent, while other literature identifies 95 percent purity limestone as the sorbent. Several contacts were made with EPA personnel at IERL to explore this issue. The consensus was that a 90 percent CaCO_3 limestone would be the minimum suitable purity.

Information on limestone reserves with a minimum CaCO_3 content of 90 percent was located at the USGS where limestone reserves are currently being worked on. The USGS was able to provide unpublished information showing limestone reserves with a minimum CaCO_3 content of 90 percent, which lie within 50 feet of the surface and have a minimum thickness of 10 feet. For other reserves, the USGS could not provide the CaCO_3 content. Hence, the reserves shown in Figure B-3 indicate the most readily available limestone having the minimum CaCO_3 requirements.

Magnesium Oxide^{2,13}

Magnesium oxide (MgO) is produced mainly by the treatment of seawater or brine with calcined dolomite or by the calcination of magnesite (a naturally occurring ore -- MgCO_3). Companies which produced MgO from seawater or brine are located in Florida, Michigan, California, New Jersey, Delaware, Mississippi, Texas, and Utah. Magnesite is mainly found and processed in Gabbs, Nevada with very small reserves identified in California and Washington.

Reports show that vast world reserves of magnesium compounds exist in seawater and brines and that magnesite reserves are considered abundant. On a domestic level, seawater is considered an inexhaustable source of magnesium compounds while magnesite reserves are limited to 65 million tons (15 million tons magnesium content). The U. S. magnesite reserves represent only 0.4 percent of world reserves. Despite this limitation on magnesite ore, in 1973, domestic production supplied 92.4 percent of the total U. S. demand for non-metallic magnesium compounds. Demand for such compounds is predicted to increase at an annual rate of 1.9 percent through 1985.

Figure B-3. LIMESTONE AVAILABILITY IN THE UNITED STATES

MgO from seawater is produced first by treating the seawater or brine with calcined dolomite or oyster shells in order to precipitate magnesium hydroxide ($\text{Mg}(\text{OH})_2$). Also, magnesium lime may be added to seawater to produce the magnesium hydroxide and some calcium chloride. The filtered $\text{Mg}(\text{OH})_2$ is then sent to rotary kilns and calcined at 3360°F . The resulting product contains 97 percent MgO.

To produce MgO from magnesite, the ore is first crushed to sizes averaging 5/8 inch to minus 3/8 inch, screened, and washed. Slime is removed, and ball mills further grind the ore into 98 percent minus 100 mesh. After talc and other impurities are removed in flotation cells, the solids are filtered, dried, and calcined (2600°F - 3200°F). Generally, about a 95 percent MgO product results.

Overall prices of non-metallic magnesium compounds have shown an approximate average 3 percent per year increase through 1975. FOB prices for MgO obtained from various suppliers indicate a large cost difference between that produced from seawater and that produced from magnesite. It appears the MgO from magnesite is approximately half the cost of MgO from seawater or brine.

Sodium Carbonate^{14,15,16}

Sodium carbonate, also known as soda ash, has the following chemical formula: Na_2CO_3 . It can be found in a number of the dried lakebeds located in California and Utah, but is primarily located in the Green River Basin of Wyoming. Sodium carbonate can also be synthetically produced via the Solvay process, which was developed in the 1860s.

Natural reserves of sodium carbonate are the basis for most of the production in the United States (see Figure B-4 for location within the U. S. In 1979, total capacity for natural production was 8,670 thousand short tons per year. This will rise to 12,300 short tons by 1983. Synthetic capacity was 900,000 short tons per year in 1979. By 1983,

Sodium Carbonate:
Production Facilities (1978)
 ★ Natural Sodium Carbonate
 ☆ Synthetic Sodium Carbonate

Figure B-4. SODIUM CARBONATE: PRODUCTION FACILITIES IN THE UNITED STATES

synthetic production (from the only currently operating facility, in New York State), may drop to zero as economics favor natural production. Therefore, it was not considered in determining sodium carbonate's availability.

Natural production of sodium carbonate from trona currently involves four companies in the Wyoming region. The trona is mined and calcined in rotary kilns, giving off water and carbon dioxide. The sodium carbonate is then dissolved in water to either filter or settle out a concentrated sodium carbonate monohydrate. The sodium crystals are removed via a centrifuge and calcined a second time to remove the water of crystallization. This produces a sodium carbonate of greater than 99.8 percent purity. Sodium chloride and sodium sulfate are the main trace impurities.

Sodium carbonate produced at Searles Lake in California is currently the only other center for natural production. The brine in Searles Lake is approximately 4.3 to 4.8 percent sodium carbonate. The brine is treated with carbon dioxide gas to convert the sodium carbonate to sodium bicarbonate. The sodium bicarbonate can then be precipitated and filtered from the brine. It is then calcined to convert the material back to sodium carbonate. These steps are repeated a second time to produce the purity required.

Domestic demand for sodium has been estimated at 8,400 thousand tons in 1985 and 11,000 thousand tons in 2000. Flue gas desulfurization was considered a miscellaneous use of sodium carbonate and was included as such when developing these forecasts. Existing reserves can meet our domestic needs for 3700 years at the 1978 consumption rate. The price of natural sodium carbonate was quoted at between \$55 and \$61 per short ton during 1978. The 1978 price of synthetic sodium carbonate ranged from \$85 to \$96 per short ton.

In terms of a scrubber absorber, sodium bicarbonate must also be considered for application. Tests are currently being conducted to evaluate its use. Sodium bicarbonate is found in nahcolite. Nahcolite, associated with oil shale, is found in the Piceance Creek Basin of

Colorado, Utah, and Wyoming. Tremendous quantities of nahcolite exist and may be liberated during oil shale development. Currently, the Multi-Mineral Corporation, of Grand Junction, Colorado, is mining small amounts of nahcolite for testing in scrubbers. The material is mined, crushed and screened. Via this process, an 80 percent purity can be achieved. If current testing goes well, a 1 million ton per year production facility could be in place during the early 1980s. At present, no price is quoted for the material.

Water^{17,18,19}

Water supply and demand data for the United States has been compiled by the Oak Ridge National Laboratory (ORNL). They have developed an input/output model which calculates total future available surface supply and demand in each of 99 Aggregated Subareas (ASA) (Figure A-1) as defined by the Water Resources Council (WRC). Supply forecasting was based on the 1975 Present Modified Flows developed by the USGS, U. S. Water Resources Council, and the University of Texas at Austin. Demand forecasts were developed using energy forecasts made by DOE's PIES model and data obtained from the WRC.

In order to determine the location and degree of possible water use conflicts and, therefore, availability, SAI conducted a literature investigation to establish criteria for such an assessment. In essence, such criteria could take the form of: stream problems as a function of depletion, and/or withdrawal limitation based on state regulations. Such criteria were contained in the WRC's publication The Nation's Water Resources, 1975-2000, which states, "Thirty percent of average flow (70 percent depletion) -- a base flow that sustains good survival habitat for most aquatic life forms," (p. 56). Since most states have not yet identified allowable maximum stream withdrawal, it was felt that this criteria could become a limiting factor should such regulations come to pass. Hence, the following criteria were developed to predict conflicting water uses and resultant availability:

- o Less than 70 percent withdrawal of available surface supplies
-- no availability problems anticipated at the ASA level

- o Between 70 and 100 percent withdrawal of available surface supplies -- some availability problems could be anticipated at the ASA level.
- o Greater than 100 percent withdrawal of available surface supplies -- severe availability problems could be anticipated at the ASA level.

The results were plotted on a U. S. map, on an ASA basis. (Figure B-5).

Figure B-5. WATER AVAILABILITY IN THE UNITED STATES -- 1985

Land is one of several commodities every FGD system will require. As with other commodities, the availability of land will partially determine its value. However, more important is the concept of the land's highest and best use. This concept has been established by eminent domain. Briefly stated, the value of land is equal to its highest and best value regardless of its present use. For example, in an area where farm land is selling for \$1,000 an acre, a specific piece of farm land may be worth considerably more if it is zoned and may be used as commercial/industrial property. Hence, in projecting land values, both the availability and its highest and best use must be accounted for.

In the contiguous United States there are approximately $1,896,959 \times 10^3$ Acres. Of this amount approximately $1,042,723 \times 10^3$ acres are classified as farm land. This accounts for 55 percent of the total land area and 58 percent of the non-urban land area. Forested areas not grazed are the largest non-agricultural use of land and covers 22 percent of the contiguous United States. Federal lands cover $401,867 \times 10^3$ acres or approximately 21 percent of the contiguous United States. These data suggest that agricultural land will be adequate to describe the type of land that will likely be selected for siting future power plants.

The estimated value of agricultural land and buildings for each state is noted in Table B-3. Following this is the average price of such land during recent sales.²¹ One can note that the value increases dramatically for land which can be used for commercial/industrial purposes (i.e., land which a power plant may be built on). Table B-4 indicates how this unit sale price changes with purchase size. These data determine the per acre price of farm land which may be developed as commercial/industrial property for each NERC region and subregion.

Table B-3. AGRICULTURAL LAND VALUES

Region/State	Overall Estimated Value (\$/Acre)		Average Value When Sold As:			
	1979	1980	Agr. Land		Commercial/Industrial Land	
			1979	1980	1979	1980
Northwest						
Maine	485	524				
New Hampshire	802	866				
Vermont	657	710				
Massachusetts	1,366	1,475				
Rhode Island	2,133	2,304				
Connecticut	2,158	2,331				
New York	642	681				
New Jersey	2,222	2,400				
Pennsylvania	1,245	1,370				
Delaware	1,725	2,018				
Maryland	1,799	2,249				
Average			718	1,139	3,385	----
Lake States						
Michigan	955	1,089				
Wisconsin	807	928				
Minnesota	854	1,008				
Average			1,080	1,218	7,098	----
Corn Belt						
Ohio	1,516	1,713				
Indiana	1,498	1,723				
Illinois	1,786	1,929				
Iowa	1,458	1,706				
Missouri	674	816				
Average			1,647	1,774	3,653	3,957
Northern Plains						
North Dakota	306	352				
South Dakota	257	292				
Nebraska	470	536				
Kansas	437	498				
Average			404	451	875	----
Appalachian						
Virginia	864	942				
West Virginia	472	519				
North Carolina	819	885				
Kentucky	792	879				
Tennessee	669	743				
Average			1,131	1,196	1,117	2,114

Source: Reference 21.

Table B-3. AGRICULTURAL LAND VALUES (Cont'd)

Region/State	Overall Estimated Value (\$/Acre)		Average Value When Sold As:			
	1979	1980	Agr. Land 1979	1980	Commercial/Industrial Land 1979	1980
<u>Southeast</u>						
South Carolina	582	629				
Georgia	609	682				
Florida	930	1,097				
Alabama	515	639				
Average			983	1,036	1,055	----
<u>Delta States</u>						
Mississippi	520	629				
Arkansas	691	829				
Louisiana	763	984				
Average			858	987	1,962	----
<u>Southern Plains</u>						
Oklahoma	442	522				
Texas	354	411				
Average			453	550	711	----
<u>Mountain</u>						
Montana	186	218				
Idaho	485	553				
Wyoming	119	127				
Colorado	332	388				
New Mexico	100	112				
Arizona	134	150				
Utah	265	297				
Nevada	104	116				
Average			228	239	1,285	----
<u>Pacific</u>						
Washington	586	615				
Oregon	330	363				
California	936	1,123				
Average			423	1,004	4,874	----
<u>48 States</u>	559	641	647	753	2,576	2,290

Source: Reference 21.

**Table B-4. UNIT SALES PRICE OF AGRICULTURE LAND
AS A FUNCTION OF SIZE OF SALE**

Acre-Size Land Class	Price In Dollars Per Acre	Sold as Agr. Land		Sold as Comm./Ind. Land	
		1979	1980	1979	1980
10-49		2,266	2,566	4,912	5,515
50-69		1,445	1,753	3,477	2,186
70-99		1,543	1,756	2,136	6,282
100-139		1,381	1,436	2,648	2,495
140-179		1,141	1,256	976	1,821
180-219		1,105	1,151	2,010	2,108
220-259		1,040	1,240	-----	-----
260-499		901	1,020	1,010	1,846
500-999		762	836	-----	2,198
1000+		272	334	-----	-----
All Classes		647	753	2,576	2,290

Source: Reference 21.

Sulfur is one of the most abundant elements in the earth. It occurs both combined with other elements and in its native state (elemental sulfur). In the U.S., large deposits of elemental sulfur are located in the Gulf Coast states. Other large deposits occur as sulfate deposits, sulfide deposits, and as components of natural gas, petroleum, coal and oil shale. Current U.S. reserves total 175 million tons. The reserve estimates have excluded sulfur resources in coal and oil shale because of uncertainties in the technologies used for its recovery. Identified coal resources contain approximately 20 billion tons of sulfur.

The industry that produces sulfur is divided into two sectors. One sector derives its production solely from the deposits of elemental sulfur; the other produces sulfur as a byproduct or coproduct from other operations. In 1979 nearly all U.S. output from deposits of elemental sulfur (sometimes referred to as Frasch sulfur) was produced by five companies. Frasch sulfur production from these companies accounted for approximately half of all domestic production. Frasch mines, as shown in Figure B-6, are located in Texas and Louisiana. The Frasch sulfur industry distributes its sulfur through a network of liquid sulfur terminals (Figure B-7). Sulfur sales are consummated at the supply terminals. The terminals are owned either by the producers or by the consumers. The terminals (800,000 to 200,000-ton capacity) provide consumers with a convenient and reliable supply source. The very large consumers of sulfur (e.g., the agricultural chemicals industry) have located their process facilities near the sources of production to reduce the transportation component cost of sulfur.

In sharp contrast to the Frasch sulfur industry, the production of elemental sulfur as a byproduct is distributed by many companies (57 companies in 1979). The production of byproduct sulfur is obtained from natural gas and petroleum (36%) and from nonferrous metals (12%). Unlike the Frasch industry, the byproduct industry is not well integrated. Byproduct sulfur producers do not own large liquid storage facilities.

Figure B-6. LOCATION OF FRASCH SULFUR MINES IN THE U. S.

Figure B-7. LOCATION OF LIQUID SULFUR TERMINALS IN THE U. S.

(Source: Ref. 23)

Sales from byproduct producers are made directly to the consumers. Deliveries are generally made by tank car and sales are consummated at the point of consumption.

There is a tendency for byproduct sulfur producers to sell in local markets, a practice that frequently results in a less favorable price due to excess production in regions where there is little consumption. In 1977 the reported average f.o.b. plant price for byproduct elemental sulfur was \$37.50 per ton while the average Frasch, f.o.b. mine, was \$49.66. The percentage discount (25%) was typical for the preceding four years.

Both the producers and consumers of byproduct sulfur are widely distributed across the United States. Byproduct sulfur is obtained in elemental form from natural gas producers in the southern and western states. It is obtained in the form of sulfuric acid from metal smelters in the western and central states and from petroleum refining operations across the U. S.

Approximately 85% of sulfur is converted to sulfuric acid for use as a chemical reagent. In 1974 there were 152 plants producing sulfuric acid in 42 states. The sources of sulfur used in the acid production process were both Frasch and byproduct sulfur. Since it is more cost-effective to ship crude sulfur than sulfuric acid, sulfuric acid plants are generally located close to the industries they serve. Sulfuric acid plants located in the southern states rely heavily on Frasch as their basic source of sulfur; those in the western states rely more on byproduct sulfur. Sulfuric acid is consumed in the production of agricultural chemicals which provides 56% of domestic sulfur demand. The remaining consumption is scattered among many industries. These include producers of synthetic products, paper products, petroleum products, drugs, mineral ores and steel.

Based upon historical consumption, the U. S. demand for sulfur is forecast to be 32 million tons in the year 2000. This is up from 13 million tons in 1979 and represents an annual growth rate of 4 to 5 percent. Potential new uses of sulfur are sulfur-asphalt paving and sulfur

concrete. These applications of sulfur apparently result in materials with superior qualities.

Recent trends show increasing production of byproduct sulfur from 20% of total production 10 years ago to approximately 50% today. This trend is projected to continue, with byproduct sulfur accounting for 82 percent of U. S. production by 2000. The declining market share of Frasch sulfur is a direct result of the inherent economic advantage of byproduct production. This forecast would indicate market penetration of byproduct sulfur into the area of agricultural chemicals which is currently serviced by the Frasch sulfur industry. Other consumers of sulfur, not having the close ties to the sulfur mines, would be even more probable users of byproduct sulfur if price, quality, and supply are adequate.

Future production of byproduct sulfur is expected from coal, petroleum, natural gas, nonferrous metal smelting and other metal sulfides. Coal gasification, liquifaction and coal burning currently provide negligible byproduct sulfur. However, byproduct sulfur from coal utilization is potentially the largest source of future production. Due to the changing supply pattern of the producing industries, it is expected that the sulfur supply/demand relationships will become more regional. Such events will be advantageous for the sale of byproduct sulfur from FGD systems.

Imports of sulfur amounted to 2.4 million tons in 1979. They came from Canada as byproduct sulfur and from Mexico as Frasch. Imports from these sources are expected to continue and will likely serve regional markets near their respective borders.

PLANT LOCATION -- EFFECTS ON COMMODITY AVAILABILITY/COSTS

In order to perform cost evaluations, plant location becomes an extremely important factor. Location will affect both the capital and annual cost. The price of land and type of coal will affect capital expenditures; while water availability, required input commodities, and potential by-product markets will affect annual revenue requirements.

Since cumulative annual costs will far exceed capital costs over the life of an FGD system (assumed to be 30 years), it is important to know to what degree power plant location affects the availability and costs of required input commodities and potential by-product sales. To accomplish this, the contiguous United States has been subdivided into 14 regions (see Figure B-8).

The conventional and advanced FGD (AFGD) systems chosen for this study require different commodities for installation and operation. Table B-5 identifies the FGD systems and associated commodities for which detailed availability/cost investigations have been undertaken on a regional basis.

Most of the commodity costs have been obtained from published data and averaged on a regional basis. However, the availability and transportation cost associated with four FGD commodities (lime, limestone, magnesium oxide, and sodium carbonate) has been determined in accordance with how far the commodity must be moved to reach the centroid of each region. FOB prices have been determined and transportation costs have been developed using rail transit.

For each of these four commodities, points of origin have been established as a function of the number and density of locations from which the commodity could be purchased. For a commodity having only a few production facilities in the United States and where interregional transport will be required, the closest production facility to the destination point was chosen to determine the transportation cost. For a commodity having several production facilities within each region, the closest facility to the destination point gave biased results. In such cases other methods for calculating average travel distances within a region were developed. Each commodity and methodology for determining the origin to destination routes are described as follows.

Figure B-8. ELECTRIC RELIABILITY COUNCIL REGIONS

Table B-5. FGD COMMODITIES* FOR VARIOUS SYSTEMS

Commodity	FGD System						
	Lime	Limestone	Dual Alkali	Magnesium Oxide	Wellman-Lord	Aqueous Carbonate	Lime Spray Dryer
<u>Raw Material</u>							
Lime	x		x				x
Limestone		x		x			
Magnesium Oxide				x			
Sodium Carbonate			x		x	x	
<u>Fuel</u>							
Coal						x	
Fuel Oil				x			
Natural Gas					x		
<u>Utilities</u>							
Electricity	x	x	x	x	x	x	x
Steam	x	x	x	x	x		
Water	x	x	x	x	x	x	x
Land	x	x	x	x	x	x	x

* These are the commodities for which detailed availability/cost investigations were undertaken.

Lime

Table B-6 is a tabulation of the origin and destination points for the transportation of lime within each region. Each destination point is represented by the centroid of its corresponding region/subregion. Since there are several lime facilities within each region, the closest facility was often located within several miles of the centroid. Hence, taking the closest lime facility to the centroid would give an unrealistically low average travel distance. Several scenarios were investigated and it was decided to use both the closest and farthest lime facility from the centroid to establish two travel routes. Origins 1 and 2 represent lime production facilities within each region which are, respectively, located closest to and farthest from the centroid of the region. The concept is to take an average of the transportation costs for the two routes. This value is expected to be representative of the transportation cost for lime within each region.

Limestone

Table B-7 is a tabulation of the origin and destination for the transportation of limestone within each region. Each destination point is represented by the centroid of its corresponding region/subregion. As with lime, limestone quarries are situated throughout the United States, making the development of an average transportation route within a given region a complicated task. Hence, the origin was obtained through various steps. First, all counties containing active limestone quarries²⁴ in the United States were identified for each region. Second, the farthest distance from any United States county containing a limestone quarry was identified. Next, the straight-line distance between these two points was measured and halved. The resulting distance was chosen to represent the approximate straight-line distance from a limestone quarry (the origin) to the region/subregion's centroid (the destination). Finally, a large city located approximately this distance from the centroid was chosen as the point of origin for each region/subregion.

Table B-6. ORIGIN AND DESTINATION POINTS FOR LIME

<u>ERC Region</u>	<u>ORIGIN 1^a</u>	<u>ORIGIN 2^b</u>	<u>DESTINATION^c</u>
WSCC (subregion 1)	Twin Falls, ID	Tacoma, WA	Mackey, ID
WSCC (subregion 2)	Greeley, CO	Rapid City, SD	Steamboat Springs, CO
WSCC (subregion 3)	Oakdale, CA	Niland, CA	Tuolumne, CA
WSCC (subregion 4)	Prescott, AZ	Lordsburg, NM	Holbrook, AZ
MARCA (subregion 1)	Rapid City, SD	Drayton, ND	Pierre, SD
MARCA (subregion 2)	Renville, MN	Davenport, IA	Litchfield, MN
SPP (subregion 1)	Goodland, KS	Springfield, MO	Dodge City, KS
SPP (subregion 2)	Bauxite, AZ	Ste. Genevieve, MO	Ruston, LA
ERCOT	Waco, TX	Houston, TX	Brownwood, TX
MAIN	Chicago, IL	Greenbay, WI	La Salle, IL
ECAR	Findlay, OH	Walkersville, MD	Columbus, OH
SERC	Tacoia, AL	Pascagoula, MI	Macon, GA
MAAC	Lebanon, PA	Norristown, PA	Sunbury, PA
NPCC	Adams, MA	Lackawana, NY	Brattleboro, VT

a. Closest lime production facility to centroid within region

b. Farthest lime production facility from centroid within region

c. Centroid of region/subregion

Table B-7. ORIGIN AND DESTINATION POINTS FOR LIMESTONE

<u>ERC Region</u>	<u>ORIGIN</u>	<u>DESTINATION</u> [*]
WSCC (subregion 1)	Butte, MT	Mackey, ID
WSCC (subregion 2)	Boulder, CO	Steamboat Springs, CO
WSCC (subregion 3)	Reno, NV	Toulumne, CA
WSCC (subregion 4)	Gallup, NM	Holbrook, AZ
MARCA (subregion 1)	Yankton, SD	Pierre, SD
MARCA (subregion 2)	La Cross, MN	Litchfield, MN
SPP (subregion 1)	Great Bend, KS	Dodge City, KS
SPP (subregion 2)	Vicksburg, MI	Ruston, LA
ERCOT	Temple, TX	Brownwood, TX
MAIN	Aurora, IL	La Salle, IL
ECAR	Springfield, OH	Columbus, OH
SERC	Cordele, GA	Macon, GA
MAAC	Harrisburg, PA	Sunbury, PA
NPCC	Rutland, VT	Brattleboro, VT

* Centroid of region/subregion

Magnesium Oxide

The only domestic source of magnesium oxide produced from magnesite ore is Gabbs, Nevada. As a result, this location is considered the origin for transport of this commodity and the centroid of each region/subregion will be the destination points (Table B-8).

Sodium Carbonate

Table B-9 is a tabulation of the origin and destination for the transportation of sodium carbonate within each region. Each destination point is represented by the centroid of its corresponding region/subregion. As described in the introduction, where interregional transport of a commodity is necessary, the closest production point to each region's centroid was used. Hence, the origin is the sodium carbonate production facility located nearest the centroid of each region/subregion.

Table B-8. ORIGIN AND DESTINATION POINTS FOR MAGNESIUM OXIDE

<u>ERC Region</u>	<u>ORIGIN</u>	<u>DESTINATION</u> [*]
WSCC (subregion 1)	Gabbs, NV	Mackey, ID
WSCC (subregion 2)	Gabbs, NV	Steamboat Springs, CO
WSCC (subregion 3)	Gabbs, NV	Tuolumne, CA
WSCC (subregion 4)	Gabbs, NV	Holbrook, AZ
MARCA (subregion 1)	Gabbs, NV	Pierre, SD
MARCA (subregion 2)	Gabbs, NV	Litchfield, MN
SPP (subregion 1)	Gabbs, NV	Dodge City, KS
SPP (subregion 2)	Gabbs, NV	Ruston, LA
ERCOT	Gabbs, NV	Brownwood, TX
MAIN	Gabbs, NV	LA Salle, IL
ECAR	Gabbs, NV	Columbus, OH
SERC	Gabbs, NV	Macon, GA
MAAC	Gabbs, NV	Sunbury, PA
NPCC	Gabbs, NV	Brattleboro, VT

* Centroid of region/subregion

Table B-9. ORIGIN AND DESTINATION POINTS FOR SODIUM CARBONATE

<u>ERC Region</u>	<u>ORIGIN</u>	<u>DESTINATION</u> *
WSCC (subregion 1)	Green River, WY	Mackey, ID
WSCC (subregion 2)	Green River, WY	Steamboat Springs, CO
WSCC (subregion 3)	Trona, CA	Tuolumne, CA
WSCC (subregion 4)	Trona, CA	Holbrook, AZ
MARCA (subregion 1)	Green River, WY	Pierre, SD
MARCA (subregion 2)	Green River, WY	Litchfield, MO
SPP (subregion 1)	Green River, WY	Dodge City, KS
SPP (subregion 2)	Green River, WY	Ruston, LA
ERCOT	Green River, WY	Brownwood, TX
MAIN	Green River, WY	La Salle, IL
ECAR	Green River, WY	Columbus, OH
SERC	Green River, WY	Macon, GA
MAAC	Green River, WY	Sunbury, PA
NPCC	Green River, WY	Brattleboro, VT

* Centroid of region/subregion

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APPENDIX C

PERFORMANCE AND COST ANALYSIS COMPARISONS FOR CANDIDATE ADVANCED FGD PROCESSES

APPENDIX C

PERFORMANCE AND COST ANALYSIS COMPARISONS
FOR CANDIDATE ADVANCED FGD PROCESSES

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Table C-1. DEVELOPMENT STATUS OF MAJOR ADVANCED FGD PROCESSES
IN THE UNITED STATES — 1980

Process	Developer	Current Development Level	Use of Commercial Technology	Projected Near-Term Process Capacity
Aqueous carbonate	Rockwell International	Full scale application not yet demonstrated. 100 MW demonstration system planned in 1980.	Technology for SO ₂ absorption utilizing spray dryer, carbonation and molten salt reduction are being developed.	500 MW
Absorption/Steam Stripping + RESOX	Peabody Engineering Group Foster Wheeler Energy Corp.	No full scale demonstration has yet been planned. Specific gas/liquid equilibrium data needs to be generated.	Design of absorbers and strippers are generally available for commercial application, but integration of specific absorption and stripping designs needs further development.	--
Activated Char + RESOX	Foster Wheeler Energy Corp. Bergbau-Forschung GmbH	20 MW test program at Scholz Station was terminated. No further development of the system in U.S. reported. Further evaluation of the RESOX system is in progress in Germany	Most of the process component areas have been demonstrated using commercially available material and equipment. No exotic metals or lined equipment other than carbon steel is required.	--
Magnesium oxide	Chemico	Process demonstrated on full-scale oil- and coal-fired boilers. System now offered for commercial application.	All the Process Technologies are considered commercially available.	1446 MW
	United Engineers	Eddystone 120-MW prototype test program still in progress. A full-scale 600-MW system is now planned for TVA's Johnsonville station.		
Sodium carbonate	A.D. Little/Combustion Equipment Associates	Three full-scale sodium carbonate (trona) FGD systems have been in service on coal-fired boilers at the Reid Gardner Station (Nevada Power). System performance has been good.	Large size Sodium Carbonate process has been commercially practical in U. S. (375 MW) and in Japan (335 MW).	884 MW
	Universal Oil Products	A full-scale sodium carbonate (30% carbonate purge solution from soda ash plant) FGD system is now being planned for the Jim Bridger station.		

Table C-1. DEVELOPMENT STATUS OF MAJOR ADVANCED FGD PROCESSES
IN THE UNITED STATES — 1980 (Cont'd)

Process	Developer	Current Development Level	Use of Commercial Technology	Projected Near-Term Process Capacity
Aluminum Sulfate	Dowa Mining Co., Japan	Dowa process has been demonstrated on commercial-size units treating acid plant tail gas, metallurgical furnace waste gas and industrial boiler flue gas. Plans have been underway to demonstrate Dowa process at TVA's 10MW Shawnee site.	The processes generally use commercially available equipment. However, the process technology has not been tested at sufficiently large scale for coal-fired utility plant.	--
Catalytic oxidation	Monsanto Chemical Co.	A 100 MW test program at Wood River was terminated due to technical problems. No further process development is planned.	Process concept is quite complex but process component can be considered commercially available.	--
Copper Oxide Adsorption	Shell/UOP	Pilot plant test at Big Bend Station continued. Process available for prototype or demonstration application. No systems planned at present.	Copper oxide bed is commercial technology. The process has not been operated as an integrated unit to be considered commercial technology.	--
Chiyoda Thoroughbred 121	Chiyoda International	Full Scale application not yet demonstrated. Successful tests on a 23 MW unit at Scholz station in 1979.	The mechanical and structural units are commercially available. The process chemistry has yet to be proven in full-scale.	500 MW
Double-alkali	A.D. Little/C.E.A. FMC Corporation Buell Envirotech.	Fullscale units are being demonstrated; a 270 MW demonstration system by AD Little/C.E., a 250 MW demonstration unit by FMC, and a 575 MW unit by Buell/Envirotech. since 1979.	Process adopted commercial technology developed for Lime/Limestone.	1102 MW

Table C-1. DEVELOPMENT STATUS OF MAJOR ADVANCED FGD PROCESSES
IN THE UNITED STATES — 1980 (Cont'd)

Process	Developer	Current Development Level	Use of Commercial Technology	Projected Near- Term Process Capacity
Weilman Lord	Davy Powergas	115-MW NIPSCO/EPA test program still in progress at Mitchell. Two full-scale systems have recently started operations at Public Service of New Mexico's San Juan Station.	All the technologies are considered commercially available, with a total of 18 plants now in operation	1855 MW
Dry Collection	Wheelabrator-Fry Rockwell International	Successful testing has resulted in the planning of a full-scale spray dryer and fabric filter FGD system at the Coyote Station.	Spray dryer components are being developed. The ESP and fabric filter systems are commercial technology. The integration of spray dryer and fabric filter or ESP are yet considered as commercial Technology.	410 MW
	Babcock & Wilcox	Successful pilot plant testing has resulted in the planning of a full-scale system at Laramie River. This system will use lime slurry as the reagent in a configuration which employs an ESP as the second stage collector.		455 MW
	Carborundum/Delaval	Process similar in design to the Wheelabrator-Frye/R. I. and Joy/Niro processes. No full-scale applications have yet been announced.	" "	550 MW

Table C-2. FGD PROCESS PERFORMANCE AND TECHNICAL CONSIDERATION (BASIS: 500 MW PLANT SIZE)

Process	SO ₂ removal eff. %	Multiple emission control	Secondary pollution problem	Raw material lb/hr	Water requirement, M gal/hr	Land requirement, acre	Energy consumption
Aqueous carbonate	90-95	SO ₂ , part.	Low stock emission of part, H ₂ S small range liquid stream containing chloride	Na ₂ CO ₃ :960 Coke:14000	283	6	Elect:10.6 MW No.6 oil:230 gal/hr Steam:80 Mlb/hr
Absorption/steam stripping & RESOX	95 ⁺	SO ₂	Fume formation with NH ₃ & other absorbents, disposal of gypsum wastes (550-2750 lb/hr)	Various absorbents CaO:1000	1025-2500	10	Elect: 10-15 MW Steam:150-340 Mlb/hr
Activated char & RESOX	97	SO ₂ , part., NO _x , chloride, HC	Small stack emission of coal ash	Sand:800 Char:3100	3	7	Elect:7.8 MW Coal:370 MMBTU/hr
Aluminum sulfate	95-99	SO ₂	Disposal of large quantity of gypsum waste(33.4 ton/hr)	Aluminum sulfate (57%):266 limestone: 3980	43	55	Elect:13.4 MW Steam:52 MMBTU/hr
Chiyoda 121	90-95	SO ₂	Disposal of large quantity of gypsum waste(45 ton/hr)	Lime:4000	104	97	Elect:12 MW
Double alkali	95	SO ₂ , part.	Disposal of 50 ton/hr of CaSO ₃ mixed with CaSO ₄ and Na salts	Lime:2140	38	290	Elect:8.5 MW Steam:48.6 MMBTU/hr
Magnesium oxide	90-97	SO ₂ , part, SO ₃	Small magnesium compounds in stack emissions and purge liquid stream	Lime:1800 MgO:320 Coke:220	315	8	Elect:10.4 MW Steam:44.5 MMBTU/hr No.6 oil:120 MMBTU/hr
Wellman-Lord	95-99	SO ₂ , part, HCl	Solid purge stream containing 2900 lb/hr sodium sulfate salts	Lime:1800 Sodium carbonate: 2880	1410-1710	8	Elect:10.8-11.7 MW Steam:232-241 MMBTU/hr Methane:78.6 Mcf/hr

Source: Ref. 1

Table C-3. PROCESS APPLICABILITY AND CONTROLLABILITY

<u>PROCESS</u>	<u>UTILITY APPLICATION</u>	<u>INDUSTRIAL APPLICATION</u>	<u>PROCESS CONTROLLABILITY</u>
AQUEOUS CARBONATE	NO TECHNICAL DIFFICULTY EXCEPT THE LARGE SPRAY DRYER EQUIPMENT SIZE MAY PRECLUDE THE RETROFIT APPLICATION	COMPLEX REGENERATION EQUIPMENT REQUIRED THUS NOT AVAILABLE FOR SMALL INDUSTRIAL BOILER APPLICATION	COMPLEX PROCESS WHICH MAY POSE CONTROL PROBLEM FOR UTILITY OPERATOR
ACTIVATED CHAR & RESOX	LIMITED APPLICATION TO RETROFIT APPLICATION BECAUSE OF LARGE ABSORBER AND SOLID CONVEYER SYSTEM	COMPLEX PROCESS NOT ECONOMIC FOR SMALL BOILER APPLICATION	REQUIRES SENSITIVE PROCESS CONTROL AND EXTENSIVE SOLID HANDLING EQUIPMENT
CHIYODA 121	SIMPLE MECHANICAL AND PROCESS CHEMISTRY CONCEPT SHOULD BE EASILY ACCEPTED IN BOTH NEW AND RETROFIT APPLICATION	RETROFIT APPLICATION IS LIMITED BECAUSE OF SPACE REQUIREMENT FOR GYPSUM HANDLING AND DISPOSAL	PROCESS EASY TO CONTROL
ALUMINUM SULFATE	FAIRLY APPLICABLE TO NEW UTILITY APPLICATION; PROCESS EQUIPMENTS ARE EASY TO RETROFIT, BUT APPLICATION MAY BE LIMITED; DEPENDS ON GYPSUM MARKETABILITY	SUCCESSFUL APPLICATION TO SMALL INDUSTRIAL BOILER - RETROFIT APPLICATION DEPENDS ON GYPSUM MARKETABILITY	PROCESS POSES NO CONTROL PROBLEM

Table C-3. PROCESS APPLICABILITY AND CONTROLLABILITY (Cont'd)

<u>PROCESS</u>	<u>UTILITY APPLICATION</u>	<u>INDUSTRIAL APPLICATION</u>	<u>PROCESS CONTROLLABILITY</u>
MAGNESIUM OXIDE	FAIRLY ACCEPTABLE TO UTILITY INDUSTRY - RE- LATIVELY COMPLEX PRO- CESS BUT PROCESS CAN BE MODULARIZED TO SEPARATE ABSORPTION AND REGENERATION PRO- CESS COMPONENTS	LIMITED INDUSTRIAL SMALL BOILER APPLICATION BECAUSE OF COMPLEX REGENERATION PROCESS	PROCESS IS FAIRLY EASY TO CONTROL
DOUBLE ALKALI	EASY TO RETROFIT BE- CAUSE OF SMALLER PROCESS EQUIPMENT - HOWEVER, LARGE LAND AREA IS REQUIRED FOR SOLID WASTE DISPOSAL	GOOD POTENTIAL FOR RETROFIT APPLICATION	EXTENSIVE CONTROL IS REQUIRED TO PREVENT SCALE FORMATION, SULFATE BUILDUP AND TO CONTROL SLUDGE QUALITY
ABSORPTION/ STEAM STRIPPING & RESOX	NOT YET ACCEPTED BY UTILITY INDUSTRY	NOT APPLICABLE FOR SMALL BOILER APPLICATION	PROCESS CONTROL UN- CERTAINTY BECAUSE OF THE LACK OF PROCESS DATA
WELLMAN-LORD	WELL SUITED FOR NEW & RETROFIT UTILITY APPLICATIONS - EASY DECOUPLING OF ABSORP- TION & REGENERATION PROCESS COMPONENTS - HAS FLEXIBILITY TO PRO- DUCE ACID OR ELEMENTAL SULFUR	WELL SUITED FOR SMALL INDUSTRIAL BOILER APPLICATION	PROCESS IS EASY TO CONTROL

APPENDIX C

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APPENDIX D
FGD SYSTEM DESCRIPTIONS

APPENDIX D

FGD SYSTEM DESCRIPTIONS

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APPENDIX D

FGD SYSTEM DESCRIPTIONS

This appendix presents a description of each of the seven FGD systems to be costed. These descriptions include system schematics, an explanation of the operation of each system, and the chemical reactions associated with each process. Also, a list of raw material and utility requirements for each process is included.

LIME^{1,2,3,4,5,6}

The lime FGD system is an established technology and is one of the most widely used FGD systems on the market today. This is due to its long operating history during which valuable experience has been obtained and system improvements have been made.

In this system, a calcium oxide (lime) slurry absorbs the sulfur dioxide (SO_2) from the flue gas and reacts producing a calcium sulfite/sulfate product. The product slurry, which also contains unreacted calcium oxide, is recycled to the absorption unit in order to increase the lime utilization efficiency. A portion of this product slurry is withdrawn, dewatered, and sent to a landfill or a pond for disposal.

A lime slurry process can be designed to produce marketable gypsum; however, this system improvement will not be employed for this report. Figure D-1 presents a schematic diagram of a lime slurry process.

In addition to "raw materials handling, preparation, and storage," the lime slurry process is comprised of the following two major process areas:

- o Prescrubbing/Absorption
- o Sludge Disposal

Figure D-1. LIME SLURRY PROCESS FLOW DIAGRAM

(Source: Ref. 1)

The specific activities occurring in these areas are presented in the following sections.

Prescrubbing/Absorption

Flue gas from the power plant passes through an electrostatic precipitator and then on to the FGD system where it first enters a presaturator where the gas is cooled and saturated. The gas then enters the absorber unit where the SO₂ contained in the gas contacts a lime slurry, is absorbed into the slurry, and undergoes the following reactions:

The cleaned gas exits the absorber and is reheated before being sent out the stack.

Sludge Disposal

The calcium sulfite and sulfate solids slurry is sent to a settling pond where it is concentrated to approximately 40 percent solids. The recovered water is sent to the lime slurry preparation area, thereby completing the closed loop cycle for water.

Raw Materials and Utilities

The lime slurry process uses the following raw materials and utilities:

- o Lime
- o Process water
- o Steam
- o Electricity

The limestone FGD system (like the lime system) is one of the most established FGD systems on the market today. This is primarily due to its early development, improved understanding of the process chemistry, and progressive improvements in the system over the years.

A basic limestone process uses a calcium carbonate (limestone) solution to absorb SO_2 from the flue gas, thereby producing a calcium sulfite/sulfate slurry product. Some of this slurry is recycled to the absorber to utilize the unreacted carbonate. However, the majority of the product is disposed of in a landfill or a settling pond.

This is not a regenerable process. The byproduct may be manipulated such that it is a marketable product but due to the economics, this is not commonly done. This report will not include a marketable byproduct. Figure D-2 presents a schematic diagram of a limestone slurry process.

In addition to "raw materials handling, preparation, and storage," the limestone process is generally divided into the following two areas:

- o Prescrubbing/Absorption
- o Sludge Disposal

The functional role of these process areas are presented in the following sections.

Prescrubbing/Absorption

Flue gas from the powerplant generally goes through an electrostatic precipitator (ESP) or baghouse before entering the FGD system. The first unit contacted in the FGD system is a presaturator. At this stage the flue gas is cooled and saturated.

Figure D-2. LIMESTONE SLURRY PROCESS FLOW DIAGRAM

(Source: Ref. 1)

The flue gas then enters the absorber unit (mobile bed) where it contacts the limestone slurry (calcium carbonate -- CaCO_3). The SO_2 in the flue gas is absorbed into the slurry and undergoes the following reactions:

This solids slurry is sent to a hold tank to allow sufficient time for the sulfites and sulfates to precipitate out and for the dissolution of the unreacted calcium carbonate. This slurry is then recycled to the absorber to increase the calcium carbonate utilization efficiency. A slip stream from this recycle stream is sent to the sludge disposal area.

Sludge Disposal

The sulfate- and sulfite-rich slurry is first sent to a settling pond where it is dewatered to about 40 percent solids. The recovered water is sent to the limestone slurry preparation area, thereby having a close loop operation for water.

Raw Materials and Utilities

The following raw materials and utilities are required by the limestone process:

- o Limestone
- o Cooling water
- o Process water
- o Steam
- o Electricity

Process Description

Dual alkali process is a generic term used to describe the flue gas desulfurization systems involving the absorption of SO_2 using a soluble sodium-based alkali, followed by reaction with lime or limestone to regenerate the alkali and produce a calcium-sulfur salt for disposal.

The dual alkali system described below represents a CEA/ADL process design which operates as a concentrated-mode system. The term concentrated mode indicates the high concentration of alkaline sodium salts in the absorbent liquor (active sodium > 0.15 molar) in contrast to a dilute mode (active sodium < 0.15 molar). Due to the high concentration of the absorbent solution, in a concentrated-mode system, the precipitation of gypsum as a separate crystalline does not occur during absorbent regeneration.

Figure D-3 shows a schematic flow diagram of a dual alkali process. The process can be broken down into four major areas: SO_2 scrubbing, regeneration of absorbent, solid separation and disposal, and raw material handling and preparation. Descriptions of these major areas are presented below.

Figure D-3. DUAL ALKALI PROCESS FLOW DIAGRAM

(Source: Ref. 7)

SO₂ Scrubbing

In the scrubbing area, SO₂ is absorbed from the flue gas by using an alkaline solution of sodium salts. The alkaline solution contains Na₂SO₃, NaOH, Na₂CO₃ and Na₂SO₄. The overall reactions between SO₂ and these sodium compounds can be represented by:

Sodium sulfite plays the most important role in the absorption of SO₂ since it is usually present in the greatest concentration. The hydroxide and carbonate are present only in small amounts. The concentration of these three alkaline components is a measure of the SO₂ removal capacity of the absorbing liquor. This capacity is usually regarded as active sodium concentration. Sodium sulfate and sodium chloride do not participate in the SO₂ absorption process and thus are considered to be inactive sodium components. The presence of Na₂SO₄ and NaCl is principally the result of secondary absorption reactions. Sodium sulfate is formed by the oxidation of sodium sulfite via reaction with oxygen absorbed from the flue gas. Sodium chloride is formed in the absorber by the reaction of the HCl vapor in the flue gas with the alkaline sodium solution.

Absorbent Regeneration

The regeneration of acidic sodium sulfite/sulfate scrubber effluent solution can be regarded as a two-step process involving neutralization of bisulfite to sulfite followed by conversion of sulfite to hydroxide:

Simultaneously with the neutralization and precipitation reactions indicated above, a limited amount of calcium sulfate will also be precipitated.

In a concentrated-mode system, the sulfate co-precipitates with the calcium sulfite, resulting in a mixed crystal of calcium-sulfur salts. The relatively high sulfite concentrations in the solution prevent soluble calcium concentrations from forming gypsum.

Solids Separation

The solids separation is principally a mechanical process involving thickening of the reactor effluent slurry to 15 to 30 wt percent solids, followed by filtration to produce a waste filter cake. The filter cake is washed with fresh water to recover sodium salts. The solids content and chemical composition of the waste cake produced will depend primarily upon the amount of oxidation, the quality of lime, and the chloride content of the coal. Typical solid wastes produced from utility operations contain a 55 to 70 wt percent insoluble solids with the majority being (>80 percent) $\text{CaSO}_3 \cdot 1/2 \text{H}_2\text{O}$. The amount of sodium lost in the cake will depend upon the total sodium concentration in the process liquor and the extent of cake washing. A minimum loss of approximately 1 percent has been reported.

Raw Material Preparation

Two raw materials are required to operate a dual alkali system: lime and soda ash. Lime is generally slaked and hydrated prior to being fed to the reactor system. The addition of soda ash to the system is normally adjusted to compensate for the sodium losses in the cake which amounts to 1 to 3 percent of the total alkali requirement.

Clarified liquor from the thickener hold tank is added to soda ash to prepare the makeup solution in the soda ash tank. The resulting solution may be fed directly to the absorbers, thereby increasing the SO_2 absorbing capability.

Raw Material and Utility Requirements

The following raw materials and utilities are required by the dual alkali process:

- o Soda ash
- o Lime
- o Process water
- o Electricity
- o Steam

LIME SPRAY DRYER SYSTEM^{10,11,12}

Process Description

Dry scrubbing FGD technology, particularly that using a spray dryer, is receiving increasing attention in the utility industry. The dry scrubbing technology has several potential advantages over wet FGD systems because it eliminates the problems associated with the scrubbing liquid used and the liquid waste disposal. Conversely, high removal efficiencies are more difficult to attain and highly reactive absorbent must be used.

The dry scrubbing FGD system consists of three basic processes: the spray dryer system, solids collection and disposal, and the absorbent storage and feeding system.

Figure D-4 shows a simplified dry scrubbing FGD system which utilizes rotary atomizers, a lime absorbent, and a fabric filter baghouse system such as is offered by Joy/NIRO.

Figure D-4. LIME SPRAY DRYER PROCESS FLOW DIAGRAM

(Source: Ref. 12)

Spray Dryer System

In this system, a hot flue gas passes downward through a cylindrical vessel, mixing with a lime slurry atomized by rotary atomizers into an extremely fine mist. The liquid is evaporated while the droplets are in suspension. The dried particles are dropped to the bottom and collected in a dust collecting devices. The reactions of SO_x and HCl with the lime proceed rapidly while surface liquid is present, but more slowly when the absorbent is dry.

The basic absorption reactions occurred are:

An important design consideration for the spray dryer is that the saturation temperature be approached as closely as possible and particles remain in contact with the flue gas as long as possible. The approach to saturation is controlled by the water addition rates.

Solids Removal

The dry insoluble wastes of calcium sulfites and sulfates produced from the spray dryer are removed by a baghouse filter system. In practice, some warm air from the air heater may bypass the spray dryers and recombine with the cleaned gas for reheating before the flue gas enters the baghouse. In extreme cases, requiring high SO_2 removal efficiency, some hot flue gas may bypass the air heater and the spray dryer to attain sufficient reheating.

Lime Feeding and Storage System

In a lime spray dryer system, the lime is first slaked and then slurried with water prior to feeding to the spray dryer. At higher SO_2

removal efficiency (> 85%), the solid waste is usually recycled and re-slurried to achieve higher utilization of lime.

Raw Material and Utility Requirements

The lime spray dryer FGD system will typically require the following raw materials and utility items.

- o Lime of 90 percent purity
- o Process water
- o Electricity
- o Compressed air

MAGNESIA PROCESS^{1,2,3,5,6,13,}

United Engineers Corporation's magnesia process uses a magnesium hydroxide ($\text{Mg}(\text{OH})_2$) solution (obtained via the reaction of magnesium oxide and water: $\text{MgO} + \text{H}_2\text{O} \rightarrow \text{Mg}(\text{OH})_2$) to absorb the SO_2 from the flue gas exiting a power plant. The MgO is regenerated and sulfuric acid is generally produced as a byproduct. Figure D-5 presents a schematic diagram of the magnesia process.

In addition to the "raw materials handling, preparation, and storage," the following four basic process areas make up this magnesia system:

- o Prescrubbing/Absorption
- o SO_2 Reduction (drying)
- o SO_2 Regeneration (calcining)
- o Byproduct Production and Storage

The interaction of these four process areas are discussed in the following sections.

Figure D-5. MAGNESIA SLURRY PROCESS FLOW DIAGRAM

(Source: Ref. 1)

Prescrubbing/Absorption

Flue gas enters the prescrubber where particulates and chlorides are removed. The gas then goes on to the absorber where it is contacted with a magnesia slurry (MgO , Mg(OH)_2 , and MgSO_3). The following reactions take place in the absorber:

The absorber bottoms are sent to centrifuges.

SO_2 Reduction (Drying)

The centrifuge dewateres the sulfite and sulfate solids. The centrate is pumped to the MgO make-up slurry tank and onto the absorber.

The concentrated solids are sent to a rotary dryer where combustion gases dry and dissociate the solid hydrates according to the following reactions:

* This reaction occurs to a lesser extent.

The off-gases are sent through a dust collector and fabric filter to collect residual particles before being sent through the stack. The dried solids are then sent to the SO₂ Regeneration area.

SO₂ Regeneration (Calciner)

The dried solids are injected into an oil-fired fluid-bed calciner. Here, the sulfates and sulfites decompose at 1600^oF according to the following reactions:

The regenerated MgO and residual MgSO₃ are returned to the MgO slurry tank where the following reaction occurs:

The SO₂-rich off-gas from the calciner is sent through a dust collector, a waste heat boiler, and a fabric filter (for recovery of entrained MgO) before being sent to the byproduct production area.

Byproduct Production and Storage

Either sulfur or sulfuric acid can be produced from the SO₂ stream. However, since this concentrated SO₂ stream is not well suited for sulfur production (due to excess oxygen in the stream),⁶ only sulfuric acid production will be included in this system.

The general reaction which occurs for sulfuric acid production is:

Raw Materials and Utilities

The following raw materials and utilities are required by United Engineers Corporation's magnesia process:

- o Magnesium oxide (MgO)
- o Other consumables
 - lime or limestone
 - catalyst
- o Cooling water
- o Process water
- o Steam
- o Fuel oil
- o Electricity

AQUEOUS CARBONATE^{2,5,6,13}

The aqueous carbonate process (ACP), developed by Atomics International (Rockwell), uses an aqueous sodium carbonate (Na_2CO_3) solution to absorb the SO_2 from the flue gas exiting a power plant. This process is also designed to regenerate the sorbent solution. A hydrogen sulfide (H_2S) rich gas (produced when the sorbent solution is regenerated) is then sent to a sulfur recovery plant which produces elemental sulfur as a byproduct. Figure D-6 presents a schematic diagram of the aqueous carbonate process.

In addition to the "raw materials handling, preparation, and storage," the ACP can be divided into the following four major process areas:

- o Absorption and Product Collection
- o Reduction, Quench, and Filtration
- o Carbonation
- o Sulfur Production and Storage

Figure D-6. AQUEOUS CARBONATE PROCESS FLOW DIAGRAM

(Source: Ref. 13)

Simplified chemical reactions associated with each of these four processing areas are subsequently presented.

Absorption and Product Collection

Flue gas from the boiler air preheater proceeds through a set of cyclones for ash removal and continues on to the spray dryers. Here, the SO_2 laden flue gas contacts atomized droplets of aqueous carbonate and undergoes the following basic reactions:

The product sodium salts and unreacted carbonates are dried by the resulting gas temperature (approximately $150\text{--}250^\circ\text{F}$) and are suspended in the gas. The entrained particles (including some residual ash) are recovered by directing the gas through cyclones and an electrostatic precipitator before sending the cleaned gas to the stack. Stack gas temperatures should be sufficient not to require reheat. The dry product is then blown to a storage silo and on to the reduction section.

Reduction, Quench, and Filtration

Coal or coke, combined with the sodium salts from the absorption area, is sent to the sulfate reducer where air is bubbled through and a melt product is produced. The following reactions occur within the reducer:

The sodium sulfide (Na_2S) melt is quenched and filtered (to remove residual ash) before being sent to a precarbonation unit. The CO_2 -rich gas from the

sulfate reducer is sent to the carbonation unit after being cooled using a series of heat recovery units.

Carbonation

The sodium sulfide melt from the quench/filtration unit enters the precarbonator and contacts a slip stream of H_2S and CO_2 off-gas from the carbonation unit. The following reactions occur:

The off-gas from the precarbonator is combined with the quench off-gas, sent to the tail gas incineration unit, and then out the stack. The precarbonator bottoms (NaHS and Na_2CO_3 solution) is sent to the carbonation unit with a purge stream recycled to the melt quench unit.

Within the carbonation unit, the CO_2 -rich gas from the reducer contacts the precarbonator bottoms stream and undergoes the following reactions:

The bicarbonate (NaHCO_3) slurry is sent to the decomposer where the following reaction takes place:

While the CO_2 gases are recycled to the carbonator, the regenerated sodium carbonate solution is recycled to the fuel tank and on to the absorption unit.

A majority of the H_2S and residual CO_2 off-gases from the carbonation unit is sent to a Claus plant for sulfur recovery, while a slip stream is sent to the precarbonator.

Sulfur Production and Storage

As the H_2S -rich gas enters the Claus recovery unit, it contacts air and undergoes the following overall reaction:

The sulfur product is collected and the tail gases are incinerated and sent to the absorption unit for treatment.

Raw Materials and Utilities

The following raw materials and utilities are required by the ACP:

- o Soda ash
- o Coal feedstock
- o Filter aid (catalyst)
- o Fuel oil
- o Cooling water
- o Process water
- o Electricity

WELLMAN-LORD^{2,3,5,6,13}

The Wellman-Lord (W-L) process, developed and marketed by Davy Powergas, Inc., uses a sodium sulfite (Na_2SO_3) solution to extract the sulfur dioxide (SO_2) and sulfur trioxide (SO_3) from the flue gas stream.

from a power plant. The Na_2SO_3 and SO_2 are regenerated and the SO_2 is generally reduced to an elemental sulfur byproduct. Figure D-7 presents a schematic diagram of the Wellman-Lord process.

In addition to the "raw materials handling, preparation, and storage," the W-L process can be divided into the following four process areas:

- o Scrubbing/Absorption
- o Purge Treatment
- o SO_2 Regeneration
- o Byproduct Production and Storage

The interrelationship of each of the four process areas follows.

Scrubbing/Absorption

Downstream of the electrostatic precipitator, flue gas enters the venturi scrubber for chlorides and ash removal before proceeding on to the absorber. In the absorber, the SO_2 laden flue gas contacts the sodium carbonate (Na_2CO_3) and Na_2SO_3 solution and undergoes the following reactions:

The cleaned gas is reheated before exiting through the stack.

The bottoms product (spent solution) is heated and divided into two streams. One stream is sent to the purge treatment section while the other stream is sent to the SO_2 regeneration section.

Figure D-7. WELLMAN-LORD PROCESS FLOW DIAGRAM

Purge Treatment

The spent liquor enters a crystallizer where the sulfate is precipitated and separated out of the liquor. The sulfate particles are then centrifuged and dried before being stored and prepared for shipping. The purged liquor is sent to the double effect evaporators in the SO₂ regeneration section.

SO₂ Regeneration

The other portion of the spent liquor from the absorber unit is sent to the double effect evaporators where SO₂ and water vapor are released according to the following reaction:

At high temperatures, the following reactions also occur:

The resulting slurry is sent to a dissolving tank where make-up sodium carbonate is added and undergoes the following reaction:

This regenerated solution is then sent to the absorber.

The wet SO₂ exiting the evaporators is sent to condensers to extract most of the water. The condensate is then sent to a stripper to recover any dissolved SO₂. The stripped condensate is returned to the dissolving tank and the recovered SO₂ is combined with the concentrated SO₂ stream from the condensers. This SO₂ stream is compressed, separated from its residual moisture, and sent to the byproduct recovery unit.

Byproduct Production and Storage

Depending upon the geographic location of the powerplant, the Wellman-Lord process can produce three separate byproducts:

- o Compressed and liquified SO_2
- o Sulfuric acid
- o Elemental sulfur

These options are ordered according to increasing processing costs.⁶ This report will only include the production of elemental sulfur.

To produce elemental sulfur, the SO_2 stream from the compressor/separator is sent to a reduction unit where it contacts methane gas (CH_4), resulting in the following reaction:

The H_2S gas and unreacted SO_2 is then sent to a Claus plant for final sulfur recovery according to the following overall reaction:

The sulfur byproduct is then sent to storage while the tail gases are incinerated and sent to the scrubber for treatment.

Raw Materials and Utilities

The following raw materials and utilities are required by the Wellman-Lord process:

- o Soda ash
- o Cooling water
- o Process water
- o Steam
- o Natural gas
- o Electricity

APPENDIX D

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APPENDIX E
FGD COST MODEL CANDIDATES

APPENDIX E

FGD COST MODEL CANDIDATES

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APPENDIX E

FGD COST MODEL CANDIDATES

TVA/BECHTEL COST MODEL¹

The most comprehensive FGD model is the Shawnee Lime-Limestone computer economic program being developed by TVA and Bechtel Corporation. This program is developed to project a complete conceptual design package for lime or limestone scrubbing utilizing either a TCA, venturi-spray tower, or spray tower absorber, with four different sludge disposal options. The overall program consists of the following submodels:

- o Detailed material balances
- o Particulate removal equipment and cost
- o Major equipment specifications and cost
- o Capital investment requirements
- o Annual and lifetime revenue requirements

The material balance submodel performs the material balance calculations for the process flow streams in a limestone or lime FGD system. The outputs of this model consist of information on the following system:

- o Hot gas to scrubber
- o Wet gas from scrubber
- o Flue gas to stack
- o Steam reheater
- o Water balance
- o Scrubber system
- o Solid disposal system
- o System sludge discharge
- o Flow rates and compositions of system internal flow streams

The particulate removal submodel has the capability to size and predict the flange-to-flange installed costs of several particulate removal

devices including a cold ESP, a hot ESP, a baghouse, and a wet scrubber. The model, however, does not include costs for the ash disposal system or ductwork to and from the unit.

The major equipment specification submodel can size and price the major equipment and provides equipment specifications according to process area. Appropriate equations for predicting equipment costs were also developed and will periodically be updated based on new cost data.

The capital investment requirement submodel projects the overall capital investment requirements. The capital investment costs are divided into three distinct areas: 1) the raw material handling and preparation area, 2) scrubber area, and 3) waste disposal area. The raw material handling and preparation area includes costs for all of the raw material receiving and preparation equipment and field materials up to and including the slurry feed tank. The scrubbing area includes costs for all of the flue gas equipment and field materials downstream of the air heater, up to but excluding the stack plenum, and all slurry equipment. The waste disposal area includes costs for the equipment and field materials downstream of the pond feed tank. Costs for field materials are based on the materials of construction including piping, ductwork, foundations, structural, electrical, instrumentation, buildings, and pond construction.

The annual and lifetime revenue requirements submodel estimates the revenue requirements of both recovery and throwaway processes. The model calculates the annual revenue requirements cost breakdown for the first year of plant operation, and the lifetime revenue requirements.

Most of the existing TVA submodels can be equally applied to other advanced FGD systems, with the exception of material balance and process equipment sizing models. However, due to the process complexity and diversity of different FGD processes, extensive efforts will be required to modify the existing models for costing other advanced FGD processes.

The PEDCo study which describes its model actually represents three separate pieces of work. The first reviewed existing cost data on FGD units. This data originally was compiled by the Edison Electric Institute (EEI), from extensive questionnaires returned by 43 utilities having FGD units. PEDCo adjusted these cost data using common cost elements and time frames. However, only 30 of the 43 questionnaires contained sufficient data for the adjustment to be made. Table E-1 is a reprint from the PEDCo report describing the common cost elements. Once the costs of the 30 systems were adjusted, PEDCo reported its findings on average and extreme FGD capital cost.

PEDCo then costed 12 model plants for each of five systems. Table E-2 represents typical cost data for one of these systems. The five systems were: wet lime, limestone, magnesium oxide, Wellman-Lord, and a sodium based dual alkali. It is not clear how these costs were derived.

The third piece of work was the development of individual manuals to cost each of these five types of systems for specific sites. Table E-3 represents typical data input requirements for these manuals. The actual determinations of removal requirements, raw material requirements, unit sizing, and unit costing is done in discrete steps using equations and nomographs. Table E-4 presents the individual steps as noted in the lime manual. The following two lime manual steps are described in full detail below:

- o Determination of SO₂ emissions (Step 1)
- o Determination of absorber costs (Step 6)

The SO₂ emissions, in lb SO₂/10⁶ BTU, are calculated using a nomograph. The percent sulfur in the fuel (by weight) and the heating value of the fuel, in BTU/lb, are each entered on separate scales. A line connecting these two points is then extended to read SO₂ emissions. The nomograph is based on a 95 percent conversion of sulfur to SO₂ for coal and a 100 percent conversion for oil.

Table E-1. COMMON COST ELEMENTS

Common Cost Elements and Time Frames Used in PEDCo Study

- o Costs are adjusted to January 1975 dollars. Costs are reported in dollar values ranging from the years 1970 to 1980.
- o Costs of particulate control are excluded. Since the purpose of the study is to estimate the incremental cost for SO₂ control, particulate control costs are deducted either on the basis of data contained in the cost breakdowns or as a percentage of the total direct equipment cost. The percentage reduction varies with system design.
- o Indirect charges are adjusted, usually upward, to provide adequate funds for engineering, field expenses, overhead, interest during construction, start-up, and contingency.
- o Replacement power costs are deducted, since only a few utilities report such costs and these are determined by a variety of methods. Thus the adjusted costs do not include replacement power.
- o Sludge disposal costs are adjusted to reflect the costs of SO₂ scrubber sludge disposal only (i.e., not disposal of fly ash) and to provide for disposal over the anticipated lifetime of the FGD system. This latter correction is necessary because several utilities report costs for demonstration sludge disposal systems that would last only a fraction of the FGD system life.
- o Costs of a regeneration facility and acid or sulfur recovery facility are added for those regenerable systems not reporting such costs.

Source: Reprint from Reference 2.

Table E-2. LIME SCRUBBING COSTS

Model plant characteristics	Capital,		Operating and maintenance, mills/kWh	Annualized Fuel and electricity, mills/kWh	Fixed costs, mills/kWh	Total,	
	\$/kW	\$ MM				mills/kWh	\$ MM
250 megawatt capacity							
Retrofit, 3.5% S	76.64	19.16	2.785	0.484	3.885	7.154	9.400
New, 3.5% S	64.29	16.07	2.256	0.484	2.483	5.223	6.863
Retrofit, 0.6% S	63.78	15.95	1.696	0.566	3.241	5.503	7.231
New, 0.6% S	51.92	12.98	1.230	0.566	2.000	3.796	4.988
500 megawatt capacity							
Retrofit, 3.5% S	62.52	31.27	2.137	0.466	2.416	5.020	13.193
New, 3.5% S	53.90	26.95	2.024	0.466	2.082	4.572	12.015
Retrofit, 0.6% S	53.42	26.71	1.155	0.532	2.063	3.751	9.858
New, 0.6% S	48.17	24.09	1.086	0.532	1.860	3.478	9.140
1000 megawatt capacity							
Retrofit, 3.5% S	53.08	53.08	1.903	0.476	2.050	4.429	23.279
New, 3.5% S	48.94	48.94	1.849	0.476	1.890	4.215	22.154
Retrofit, 0.6% S	50.44	50.44	1.053	0.544	1.948	3.545	18.633
New, 0.6% S	44.21	44.21	0.971	0.544	1.708	3.223	16.940

Source: Reference 2.

Table E-3. TYPICAL DATA INPUT REQUIREMENTS
FOR PEDCO COST PROCEDURES

Boiler No.						
Type of furnace						
MW at maximum continuous						
Age of unit, years						
Life, years remaining						
Capacity factor, yr. ____						
Maximum continuous fuel, ton/hr or gal/min						
Maximum continuous, MM BTU/hr						
acfm at ____ °F						
Fly ash/total ash, %						
Efficiency of existing particulate control, %						

Cost of electricity/KW (Plant) = \$ _____. Cost of water/M gal

Coal, cost/ton \$ _____ (Plant) = \$ _____

% sulfur by weight _____

% ash by weight _____

HHV, BTU/lb _____

Oil, cost/bbl _____

% sulfur by weight _____

BTU/gal _____

Specific gravity _____

SO₂ permissible _____ 1b SO₂/MM BTU

Fly ash permissible _____ 1b fly ash/MM BTU

State or
Federal regulations

Table E-3. TYPICAL DATA INPUT REQUIREMENTS FOR
PEDCO COST PROCEDURES (Cont'd)

Estimated land cost per acre (current) \$ _____

possible interference determining the location
of flue gas desulfurization (FGD) system:

Congestion between stack and plant ☐ Yes ☐ No

Congestion between stack and/or plant with
property line, coal pile, etc., ☐ Yes ☐ No

Identify problem areas and location: _____

Terrain _____

Conduits _____

Possible obstructions _____

Source of CaO available _____

and % purity _____

Source: Reprint from Ref. 2.

**Table E-4. STEP-BY-STEP PROCEDURE FOR COSTING A WET LIME
SYSTEM USING PEDCO'S MANUAL**

Step No. -- To Determine:	Method of Determination:	
	Nomograph	Equation
1. SO ₂ Emissions	X	
2. SO ₂ Removal Requirements		X
3. Lime Requirements	X	X
4. Fly Ash Emissions		X
5. Amount of Sludge Generated	X	X
6. Venturi and/or Absorber Cost	X	X
7. Holding Tank Capacity	X	
8. Holding Tank Agitator Cost	X	X
9. Holding Tank Cost	X	X
10. Holding Tank Pump Cost	X	X
11. Fan Cost	X	
12. Heat Exchanger Cost	X	
13. Soot Blower Cost	X	X
14. Reheat Cost	X	X
15. Duct Cost		X
16. Lime Preparation Area Cost	X	X
17. Flue Gas Shutoff and Bypass Valves Cost		X
18. Lime Operating and Storage Silo Cost	X	X
19. Slurry Tanks, Mixers and Pump Cost	X	X
20. Slaker and Pump Cost	X	
21. Solid Disposal (Equipment) Costs	X	X
22. Pond Acreage and Pond Excavating/Diking Costs	X	X
23. Mobile Equipment		X
24. Total Equipment Costs	COMPONENTS	
25. Cost Prediction For A Given Year	X	
26. Capital Investment Costs	X	X
27. Total Annual Operating Costs	X	X

* Also includes charts and graphs. Source: Reference 2.

To determine absorber costs, one must first determine the number of scrubber trains (done externally to this manual). For each boiler, the ACFM and $^{\circ}\text{F}$ are entered on a nomograph and extended to read an ACFM at 125°F (saturated). The number of absorber modules per train is then calculated by dividing the ACFM (@ 125°F saturated) by 375,000, which is the maximum air flow per absorber module. The calculated ACFM (@ 125°F saturated) per absorber module is then entered on one side of a nomograph and a cost factor (which is given in the manual) is entered on the center scale. A line connecting these two values and extended to the third scale will then yield the cost for each absorber module.

In the five manuals, PEDCo also presents simplified procedures for estimating each type of system. PEDCo does not specify how these procedures were developed and gives no data indicating how well they correlate with the more sophisticated models.

OTHER ALTERNATIVES

In terms of FGD cost information, much data exists in addition to the FGD cost models previously described. Table E-5 presents a bibliography of studies which contain cost information for various systems. The alternative to using the two models described previously would be to standardize this reservoir of data such that cost equations can be developed.

Table E-5. FGD COST STUDIES

STUDY	SYSTEM	Wet Lime	Lime- stone	Dual Alkali	Magnesium Oxide	Aqueous Carbonate	Wellman Lord	Lime Spray Dryer
PEDCo; <u>EPA Utility FGD Survey, April-June 1980; July 1980</u>		X	X	X			X	
PEDCo; <u>Simplified Procedures for Estimating Flue Gas Desulfurization System Costs; June 1976</u>		X	X	X	X		X	
AEROSPACE CORP.; <u>Feasibility of Installing Sulfur Dioxide Scrubbers on Stationary Sources in the South Coast Air Basin of California; August 1978</u>		X						
ADL, CEA, LG&E; <u>Full-Scale Dual-Alkali Demonstration System at Louisville Gas and Electric Co. -- Final Design and System Costs; September 1979</u>				X				
TENNESSEE VALLEY AUTHORITY; <u>Preliminary Economic Analysis of a Lime Spray Dryer FGD System; March 1980</u>								X
SOUTHERN COMPANY SERVICES; <u>Evaluation of Three 20 MW Prototype Flue Gas Desulfurization Processes; March 1978</u>				X				
TENNESSEE VALLEY AUTHORITY; <u>Economic Evaluation Techniques, Results, and Computer Modeling for Flue Gas Desulfurization, 1977-1978</u>		X	X					
U. S. EPA; <u>A Standard Procedure for Cost Analysis of Pollution Control Operations, Vol. I & II, January 1979</u>			X					
TENNESSEE VALLEY AUTHORITY; <u>Definitive SO₂ Control Process Evaluations: Limestone, Double Alkali, and Citrate FGD Processes; August 1979</u>			X	X				
BATTELLE, COLUMBUS LABS; <u>Analysis of Variations in Costs of FGD Systems, October 1978</u>		X	X					
RADIAN CORP.; <u>Interagency Flue Gas Desulfurization Vol. II - Appendices, Draft report revised November 30, 1977</u>		X	X	X	X	X	X	X
U. S. EPA; <u>Flue Gas Desulfurization and Sulfuric Acid Production via Magnesia Scrubbing Capsule Report, May 1975</u>					X			
ARTHUR D. LITTLE, Inc.; <u>Evaluation of the General Motors Double Alkali SO₂ Control System, January 1977</u>				X				
STONE & WEBSTER ENGINEERING CORP.; <u>Comparative Economics of Advanced Flue Gas Desulfurization Processes, March 1980</u>			X		X	X	X	

Table E-5. FGD COST STUDIES (Cont'd)

STUDY	SYSTEM	Wet Lime	Lime Stone	Dual Alkali	Magnesium Oxide	Aqueous Carbonate	Wellman Lord	Lime Spray Dryer
C. S. BAINS; <u>Chemical Engineering Progress</u> , "Economics of FGD in the Refining Industry," May 1980		X	X	X				
TENNESSEE VALLEY AUTHORITY; <u>Definitive SO Control Process Evaluations: Limestone, Lime, and Magnesia FGD Processes</u> , January 1980		X	X		X			
PEDCO ENVIRONMENTAL, INC.; <u>Cost Analysis^a of Lime-Based Flue Gas Desulfuri- zation Systems for New 500-MW Utility Boilers</u> , January 1979		X						
TENNESSEE VALLEY AUTHORITY; <u>Detailed Cost Estimates for Advanced Effluent Desulfurization Processes</u> , January 1975		X	X		X			
TENNESSEE VALLEY AUTHORITY; <u>Design Guide- lines for an Optimum Scrubber System</u> , January 1979		X	X					
RESEARCH TRIANGLE INSTITUTE; <u>Proceedings: Symposium on Flue Gas Desulfuri- zation, Hollywood, Fla., Nov. 1977, Vol. I and II</u> , July 1978					X	X	X	X
DRAVO LIME COMPANY; <u>Flue Gas Desulfurization^a Reagent Comparison Lime, Limestone, or Thioisorbic^b Lime</u> , March 1979		X	X					

APPENDIX E

REFERENCES

1. Stephenson, C. D., and R. I. Torstrick, "The Shawnee Lime/Limestone Computer Program," paper presented at Fifth Industry Briefing Conference, December 5, 1979.
2. U. S. Environmental Protection Agency, Simplified Procedures for Estimating Flue Gas Desulfurization System Costs, by PEDCo Environmental, Inc., for EPA, EPA-600/2-76-150, June 1975.

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APPENDIX F

METHODOLOGY FOR REGIONAL COAL SELECTION

BACKGROUND

To maintain regionally realistic FGD design conditions, the coal quality has been defined as regionally dependent. Within each region two coal types has been used in the economic analysis -- one producing a flue gas requiring 70 percent SO₂ removal and the other producing a flue gas requiring the maximum percent removal for coal used in that region (70 percent, 80 percent, or 90 percent).

METHODOLOGY

Actual 1978 data pertaining to coal used by utilities was identified in the following source:

Cost and Quality of Fuels for Electric Utility Plants -- 1978
DOE/EIA-0191(78) Order No. 796, October, 1979

The data consisted of a state by state weighted average of the coal sulfur content, ash content, heating value, and consumption rate. To utilize this information, these state averages were grouped according to NERC regions. Within each region, the coal was identified as belonging to one of the following three categories:

- o Only 70 percent SO₂ removal required
- o 70 percent to 90 percent SO₂ removal required
- o ≥ 90 percent SO₂ removal required

Within each of these categories and for each region, a weighted average was taken for sulfur content, ash content, and heating value of the coal (See Table F-1). As can be seen, some regions did not use any coal belonging to one or two of the categories.

Table F-1. REGIONAL WEIGHTED AVERAGE COAL CHARACTERISTICS ACCORDING TO THREE SO₂ REMOVAL CATEGORIES

Region	Removal Category (%)	Coal Rate (10 ⁶ ton/yr)	Heating Value (Btu/lb)	Sulfur (%)	Ash (%)
ECAR	70	42,965.4	10,794	0.85	11.8
	70-90	91,913.8	11,774	2.33	13.6
	>90	46,130.4	10,994	3.76	15.3
ERCOT	70	6,241.8	8,533	0.83	6.5
	70-90	18,163.0	6,625	0.70	11.8
	>90	-	-	-	-
MAAC	70	2,465.2	11,262	0.94	17.7
	70-90	38,421.0	12,126	2.06	14.7
	>90	-	-	-	-
MAIN	70	23,001.6	9,819	0.62	8.1
	70-90	36,688.3	10,854	2.97	11.5
	>90	5,777.4	10,491	4.26	16.9
MARCA-1	70	14,761.9	7,777	0.65	9.5
	70-90	2,862.3	6,081	0.78	7.3
	>90	-	-	-	-
MARCA-2	70	20,764.9	8,878	0.73	8.9
	70-90	9,188.4	11,152	2.88	10.1
	>90	2,176.9	10,953	3.74	13.5
NPCC	70	437.0	13,181	1.09	6.0
	70-90	6,278.4	12,066	1.82	13.8
	>90	-	-	-	-
SERC	70	27,781.3	12,011	1.02	12.6
	70-90	61,699.2	11,117	1.90	13.0
	>90	5,410.5	11,272	3.85	15.4
SPP-1	70	27,141.2	9,019	0.53	11.6
	70-90	30,944.7	8,483	1.56	11.6
	>90	5,385.9	10,041	4.65	20.3
SPP-2	70	1,718.0	8,851	0.39	5.8
	70-90	1,455.2	11,906	2.06	12.6
	>90	1.7	10,717	3.93	13.1

Table F-1. REGIONAL WEIGHTED AVERAGE COAL CHARACTERISTICS ACCORDING TO THREE SO₂ REMOVAL CATEGORIES (Cont'd)

Region	Removal Category (%)	Coal Rate (10 ⁶ ton/yr)	Heating Value (Btu/lb)	Sulfur (%)	Ash (%)
WSCC-1	70	20,802.0	9,504	0.56	9.9
	70-90	4,800.0	8,100	0.97	16.1
	>90	-	-	-	-
WSCC-2	70	19,574.5	9,325	0.48	9.0
	70-90	-	-	-	-
	>90	-	-	-	-
WSCC-3	70	3,694.7	11,031	0.56	10.2
	70-90	-	-	-	-
	>90	-	-	-	-
WSCC-4	70	16,048.9	9,856	0.56	15.9
	70-90	-	-	-	-
	>90	-	-	-	-

For each region which reported the use of coal from each of three categories, the following method was used to determine the coal characteristics which require low and high percent SO₂ removal:

Low Percent SO₂ Removal

- A weighted average for coal heating value and ash content between the 70 percent and 70 percent - 90 percent SO₂ removal categories were calculated.
- A percent sulfur content corresponding to 70 percent SO₂ removal was determined from these results.

High SO₂ Removal

- A weighted average for coal heating value and ash content between the 90 percent and 70 percent to 90 percent SO₂ removal categories were calculated.
- A percent sulfur content corresponding to 90 percent SO₂ removal was determined from these results.

For each region which reported coal being used from only two categories (70 percent and 70 percent - 90 percent) the following methods were used in determining the coal characteristics:

Low SO ₂ Removal	- Same as described above
High SO ₂ Removal	- A percent sulfur content corresponding to 80 percent SO ₂ removal was determined using the average coal heating value of the 70 percent to 90 percent removal category.

For each region which uses coal only from the 70 percent removal category, the following methods were used to determine the coal characteristics:

Low SO ₂ Removal	- The average values in the 70 percent removal category were used to define the coal characteristics.
High SO ₂ Removal	- A percent sulfur corresponding to 70 percent SO ₂ removal was determined using the average coal heating value of the 70 percent removal category.

Thus, the coal for each region has been defined.