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THE EFFECT OF FLUE GAS DESULFURIZATION AVAILABILITY ON ELECTRIC UTILITIES

Volume II. Technical Report

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THE EFFECT OF FLUE GAS DESULFURIZATION AVAILABILITY ON ELECTRIC UTILITIES

Volume II. Technical Report

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1.0 INTRODUCTION

This report presents the results of work performed by Radian Corporation of Austin, Texas, for the Office of Air Quality Planning and Standards and the Industrial Environmental Research Laboratory of the United States Environmental Protection Agency. The purpose of this project was to assess the impact of flue gas desulfurization (FGD) system availability on the ability of individual coal-fired generating stations* and of generating systems** to meet consumer demands. Operating information on utilities and FGD systems from all known sources was analyzed with the major emphasis on the Edison Electric Institute (EEI) data base, PEDCo Environmental's Summary Report--Flue Gas Desulfurization Systems, and contacting utilities with operating FGD systems of interest to this study.

This project was originally to consider the subject of reliability and availability. However, during the course of this investigation it became evident that reliability was not a useful measure of the ability of an individual unit or a generating system to respond to consumer demands for electric power. Furthermore, the term "reliability" was not uniformly defined over the data bases used in this study. As a result, this study is concerned almost exclusively with the quantification and assessment of availability, which was defined in a uniform manner.

Almost all commercial applications of flue gas desulfurization on coal-fired boilers use either the Lime Process or the Limestone Process. Of the other processes of interest in this study, the Magnesium Oxide and Wellman-Lord Processes are

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*Single steam generating plant

**Interconnected pool composed of a mix of numerous generating plants each used at one site while the Double Alkali Process has not been commercially applied to coal-fired boilers. As a result, this study concentrates on the operating experience and data for Lime/Limestone Processes.

At present, many of the measures that lead to a more reliable FGD system include an economic penalty. An assessment of these economic penalties was beyond the scope of this study and is not addressed in this document. As operating experience and technology developments solve some of the problems, these economic penalties may be reduced or eliminated.

1.1 Program Objectives

The objectives of this program were identified in the Work Plan as follows:

- To assess the effect of flue gas desulfurization (FGD) systems on the reliability/availability of electric utility power generation. A comparison of the reliability/availability of existing FGD units with power plant generating equipment was included.

- To define and assess measures which have been or can be used to maintain or improve FGD unit reliability/availability. Emphasis was placed on operating experience at specific installations.

- To report the results of this study in support of EPA's review of the new source performance standards for coal-fired steam generators.

1.2 Definition of Important Terms

- Available - The status of a unit or major piece of equipment which is capable of service, whether or not it is actually in service.

- Availability - The fraction of time that a unit or major piece of equipment is capable of service, whether or not it is actually in service.

- Forced Outage - The occurrence of a component failure or other condition which requires that the unit be removed from service immediately or up to and including the very next weekend.

- Mean Time Between Full Forced Outage - The average time between each occurrence of a component failure or other condition which requires that the unit be removed from service immediately or up to and including the very next weekend. The average time is calculated by dividing the service hours by the number of forced outages.

- Reliability - The probability that a device will not fail or that service is continuous in a specified time period. The term reliability is not defined as a standard in the utility industry. The Mean Time Between Full Forced Outage (MTBFFO) and Loss-of-Load Probability (LOLP) are sometimes used as measures of reliability. The MTBFFO and LOLP can be used to calculate numerical values for reliability.

These terms are commonly used in an examination of the ability of a utility to meet consumer demand. Where possible these terms are in accordance with the Edison Electric Institute (EEI) standard definitions. A complete list of the definitions used by the two primary sources of data for this study, EEI and PEDCo Environmental Inc., is presented in Appendix A.

1.3 Approach

System reliability has been frequently used as an important measure of the performance of that system. The concept of a system being reliable or dependable is relatively straightforward. However, the quantification and application of this concept is relatively complex and is often poorly understood. A reader usually has a preconceived idea of what reliable or reliability means. These preconceived ideas often inhibit communication of the results of a system reliability analysis.

As an exmple, assume a system has a reliability of 99 percent for a 1000 hour time period. This statement means there is a probability of 99 percent that the system will operate for 1000 hours without a failure. This statement of reliability has three elements: (1) a quality of performance, (2) the performance is expected over a period of time, and (3) reliability is expressed as a probability. No information is provided as to how long the system does not operate when a failure occurs. The statement of 99 percent reliability for 1000 hours does <u>not</u> mean that the system will operate 990 hours out of every 1000 hours. Availability, on the other hand, provides information as to how often a system fails and how long it does not operate as a result of a failure. Availability data thus combine the effects of reliability, maintenance, and repair time and are usually expressed as a percentage.

Many different organizations reporting reliability/ availability type data use slightly different definitions for these terms. PEDCo Environmental's measure of reliability in their FGD status reports is not comparable to the parameters used by EEI to quantify reliability. Therefore, an evaluation based on the quantification of "reliabilities" is not possible in this study. However, the definitions of "availability" used by EEI and PEDCo are essentially the same. As a consequence of the preceding discussion, availability was determined to be the most useful measure of the ability of an individual station or a generating system to respond to consumer demand.

The steps taken in the completion of this project were

- Collect and analyze all available data for utility and flue gas desulfurization systems.

- Determine the effect of FGD units on the availability of individual generating stations and generating systems. It was assumed that the generating station cannot bypass the FGD unit. The FGD unit availabilities are at the full load operation of the generating station unless specified otherwise.

- Survey of existing FGD units to determine how they are meeting or can meet necessary availability levels.

- Document the operating experience at specific FGD installations.

- Define and assess measures that have resulted or can result in high levels of FGD unit availability.

The following items should be taken into account to more completely evaluate the effect of FGD availability on power systems:

- Unit use (base load, intermediate load, etc.)
- Unit interactions
- Coincident outages
- Partial outages (generating unit and scrubber)
- FGD unit configurations
- Network configurations
- Reserve policies

In particular, generating unit use and incidence of coincident full and/or partial outage will strongly influence the effect of FGD on system availability and adequacy. Also, in assessing the effect of FGD on power systems, it is important to recognize the requirement for excess generating capability above the maximum demand. Reserve policies, interconnections, and network state would influence whether or not power was available to offset these potential effects of FGD. Such an assessment was beyond the scope of this study.

2.0 RESULTS AND CONCLUSIONS

The effect of FGD availability on power generation was assessed. The results and conclusions of this study are given in this section.

2.1 Results

The results of this project are:

1) Mature coal-fired generating unit components (i.e. boilers, turbines, etc.) are reported to have an average availability between 80 and 97

percent. Mature coal-fired generating units are reported to have an average availability between 70 and 77 percent.

2) The seven FGD units emphasized in this study have reported average modular availabilities between 44 and 95 percent. Five of these have reported average modular availabilities above 70 percent.

3) An individual base loaded generating station with an FGD unit cannot meet consumer demand without FGD module sparing.

4) Generating systems with FGD on new coal-fired plants can meet a 1985 consumer demand equal to about 89 percent of the capability without FGD based on modeling the new coal capacity in a system as a single generating station with one FGD unit composed of one module. However, the systems cannot maintain the excess generating capability above maximum demand that is required to insure the ability to meet demand. Additional generating units or improvements to the FGD unit availability would have to offset the reduction in generating capability due to FGD units.

5) The availability of existing FGD units is maintained by various combinations of the following: (a) use of trained operating and maintenance crews, (b) bringing modules

off-line each night for maintenance, and (c) inclusion of spare modules.

6) FGD unit components subject to high failure rates include slurry pumps, packing gland water systems, nozzles, valves, fans, mist eliminators, and reheaters.

7) Maintenance methods, operating techniques, and design concepts were identified that can or have been used to produce high FGD availabilities.

8) A preliminary and rudimentary examination of the relationship between the effect of FGD and load duration curves was completed.

2.2 Conclusions

The conclusions for this study are:

1) FGD unit availability is a function of the modular availability, the total number of modules and the number of spare modules. The FGD unit availability is associated with a specific operating load (percent of capacity) for the generating unit. The number of effective spare modules varies with the operating load since all modules are not necessarily required for loads of less than 100 percent of capacity.

2) The availability of FGD units has a significant impact on the ability of an individual generating station and a generating system to meet consumer demand. The reduction in generating capability for a single station varies depending on the FGD unit availability. For a system the effect of FGD largely depends on the fraction of new coal plants in that system. These reductions in capability must be offset by adding generating units or by improving the availability of the FGD units.

3) Use of spare FGD modules dramatically improves total unit availability.

4) Significant progress has been made in the last few years in solving the problems experienced by the existing FGD units. The problems which present the greatest challenge to FGD availability are corrosion, erosion, deposits, unstable chemistry, and instrumentation.

5) A substantial committment on the part of a utility to the operation and maintenance of an FGD unit is required to maintain high levels of FGD unit availability.

2.3 Summary

The effect of the availability of flue gas desulfurization (FGD) on a generating unit and system was assessed. The impact on the ability of an individual generating station or a generating system to meet consumer demand was the parameter used to measure the effect of FGD availability. Operating data for generating and FGD units was gathered and analyzed as input to this assessment. Existing FGD units were also surveyed to determine how they are meeting or can meet necessary availability levels.

The problems encountered and solved by operating FGD units were then documented and examined. Unit components with high failure rates were identified and methods to enhance their availability evaluated. Finally, maintenance methods, operating techniques, and design concepts which have or can be used to produce high levels of FGD unit availability were defined and assessed.

3.0 AVAILABILITY ASSESSMENT

An assessment of the effect of flue gas desulfurization units on the availability of individual utility generating stations and utility systems was performed. The effect was quantified by determining the change in the ability of an individual utility or utility system to meet consumer demand. This section of the report includes a description of electric generating components and generating systems (Section 3.1), a presentation of electric generating and flue gas desulfurization operating data (Section 3.2), an analysis of flue gas desulfurization availability (Section 3.3), and an estimation of the effect of FGD availability on an individual generating station (Section 3.4) and on generating systems (Section 3.5).

3.1 Descriptions of Generating Unit Components and Systems

In this section, brief descriptions are presented of the electric generating unit components that were evaluated during this study. These component descriptions are included in order to provide an understanding of the function of each of the equipment items and to illustrate how each item fits into the overall electric generating unit or plant. The equipment is grouped into components following the guidelines of the Edison Electric Institute (ED-060). The systems described are representative of the varying mixes of power plant generating types (i.e., steam boilers, gas turbines, nuclear plants, etc.) found in typical utilities in the United States.

3.1.1 Electric Generating Unit Component Descriptions

The five major utility equipment component groupings of interest to this study are boilers, turbines, generators, condensers, and others (boiler feed water pumps, etc.). These items are currently used by virtually every utility in the United States.

There are two basic reasons for selecting these equipment items for study. First, each is generally accepted by the electric power utility industry as being commercially demonstrated technology. Second, data have been recorded and in many cases are available concerning the reliability, availability, and failure rates of each of these equipment items.

Nuclear unit operating data are not included in this study because nuclear units represent a portion of the electric utility industry in which FGD systems will never be used. Thus a comparison of nuclear unit with FGD system operating parameters will not clarify any portion of the present program objectives. Additionally, the nuclear unit operating data are significantly affected by regulatory constraints. These constraints have no counterpart for non-nuclear units or FGD systems within the electric utility industry.

Modern electric power generating stations are complex units which employ sophisticated mechanical, metallurgical, and electrical technology. Figure 3-1 presents a highly simplified flow scheme which identifies the general equipment categories important in the study. No attempt is made here to distinguish between boiler types, equipment manufacturers, or equipment design or quality. The primary reason for this is because most of the reliability/availability data recorded are also in general categories.

The three major flowpaths shown in Figure 3-1 are water/steam, combustion gas, and electrical. Many design constraints are placed on the equipment which handle each of

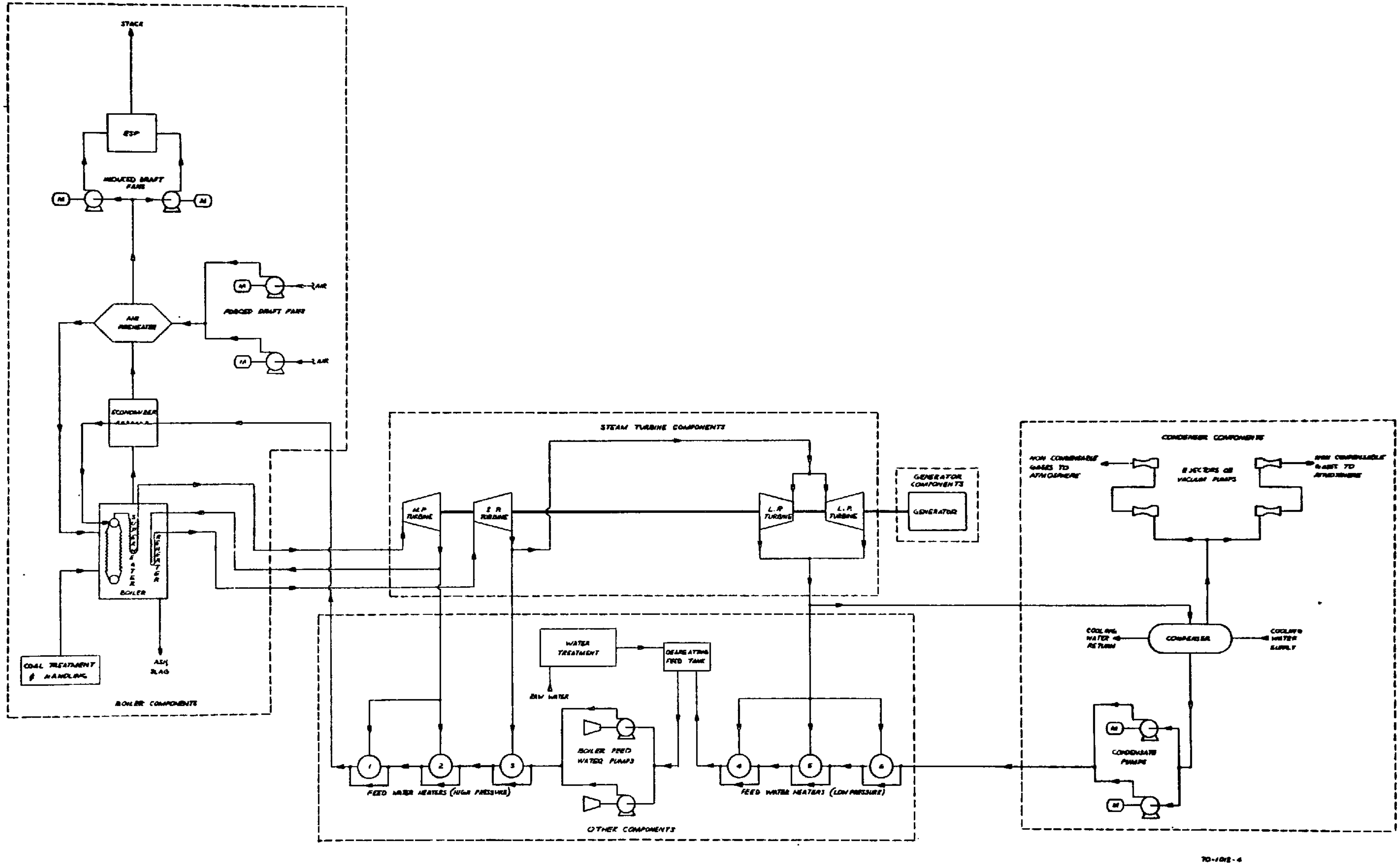

Figure 3-1. Simplified flow diagram for an electric power generating station.

these flows. Exceeding design limitations, insufficient design safety, and metallurgical flaws can lead to premature operational failure of any equipment item. In cases where more than one stream is handled in one piece of equipment, e.g., boilers and electrostatic precipitators, equipment failures due to both streams have occurred. The following five sections briefly describe the major components mentioned above.

3.1.1.1 Utility Boilers

A modern water tube drum-type boiler consists of steel drums or headers connected by a number of steel tubes, and arranged in a furnace so that (1) radiant heat from the fire-ball is transferred to the tubes, and (2) the hot gases also pass through an additional bank of tubes on their way to the stack. Hot combustion gases flow around the tubes, transferring their heat to the water or steam within the tubes. The steam in turn is collected and may be heated to a temperature well above the saturation temperature (superheated) before being used. In other separate portions of the boiler, steam which has been partially expanded through a turbine may be reheated to a temperature very near the original superheat temperature.

As steam flows out of the boiler it becomes necessary to replenish the water that was evaporated. For this reason feed pumps are necessary to supply water to the boiler. These pumps must operate at a pressure high enough to overcome the pressure in the boiler. In the operation of any boiler, it is essential always to keep water in the boiler. If the boiler should run low on water, the tube metal would become hot, soften, and rupture. At the same time, the boiler should not be filled to a point where there is insufficient room for the steam to collect. Typically, level control devices or steam and water flow devices are used to insure that the amount of water entering the boiler equals the amount of steam leaving.

Boiler feed water is usually heated before being delivered to the boiler. A steam preheater (using low pressure exhaust steam) and an economizer are used to do this. An economizer is a separate bank of boiler tubes through which the feed water passes before it enters the main boiler tubes. This bank of tubes is usually placed in the convective section of the boiler ahead of the air preheater to absorb some additional heat from the combustion gases and thus improve the economy of the boiler.

3.1.1.2 Turbines

Turbines provide a means for converting energy in the steam into useful shaft work. Simply stated, a turbine is a shaft mounted on two or more sets of bearings. Attached to the shaft are a set of wheels or stages which have blades attached to the rim. These blades, or buckets as they are commonly called, are shaped such that the passage of steam forces the wheel to turn thus turning the shaft. Stationary nozzles set between the rotating stages direct the steam so that it continually drives the buckets.

Turbines are designed to turn at a fixed speed and are equipped with automatic controls to accomplish this. The rotating turbine shaft is coupled to an electric generator rotor which is the means for converting shaft work into electricity.

3.1.1.3 Generators

A generator consists of wire coils turning through the lines of flux from a magnet. As the wire coil interrupts the magnetic flux lines a voltage is produced in the wire, thus generating electricity. A central station generator consists principally of a magnetic circuit, d-c field winding, a-c armature, and mechanical structure including cooling and lubricating systems. The steam turbine, coupled to the generator rotor, provides the shaft power necessary to turn either the coil through the magnetic flux or to turn the magnet within the coil.

3.1.1.4 Condensers

The steam exiting the turbine is condensed to create a vacuum at the turbine exhaust. The efficiency of the turbine is improved by allowing it to exhaust into a vacuum rather than to the atmosphere. The condensed steam is then returned to the boiler as feed water.

The condenser uses cooling water passing through a bank of tubes to cool and condense the turbine exhaust steam. The steam condensate collects in a "hot well" which serves as a reservoir for a pump returning condensate to the boiler feed water heaters and boiler feed pump.

3.1.1.5 Other Components

Some of the major items included in this classification are the boiler feedwater pumps, pump drives, feedwater heaters, and water treatment facilities. The boiler feedwater pumps supply water to the boiler to replace the water converted to steam. Large high pressure pumps are required due to the quantity of water required and the pressure in the boiler that must be overcome. These pumps are typically driven by steam turbines. The feedwater heaters take steam from various points on the turbines to heat the boiler feedwater. The steam is usually injected directly into the feedwater. Water treatment is necessary to provide makeup water of an adequate quality. Impurities in the water are deposited in the boiler when steam is generated. Makeup water is usually a very small percentage of the total feed to the boiler.

3.1.2 Description of Utility Systems

Systems of varying mixes of power plant generating types were identified. The 1985 projections by the National Electric Reliability Council (NA-325) were the basis for the mix of generating types specified in these systems. The National Electric Reliability Council (NERC) consists of nine Regional Reliability Councils and encompasses essentially all of the power systems of the United States. A map of the U.S. indicating the geographical bounds for the nine Reliability Councils is presented in Figure 3-2. The ten systems shown in Table 3-1 represent the projected generation mixes for the nine regional councils and the total projected mix for the nation for 1985.

A varying mix of generating equipment and fuels is presented. The 1985 system projections (Table 3-1) range from predominantly gas-fired or oil-fired steam turbine systems (Systems 2 and 6); to a primarily coal-fired steam turbine system (System 1); to a predominantly hydro system (System 9); to a more balanced system (System 3).

The column titled New Coal under Fossil-Fired Steam Turbines is of particular interest. These numbers state the percentage of total capacity resulting from coal-fired steam turbines completed between 1976 and 1985. Some of this New

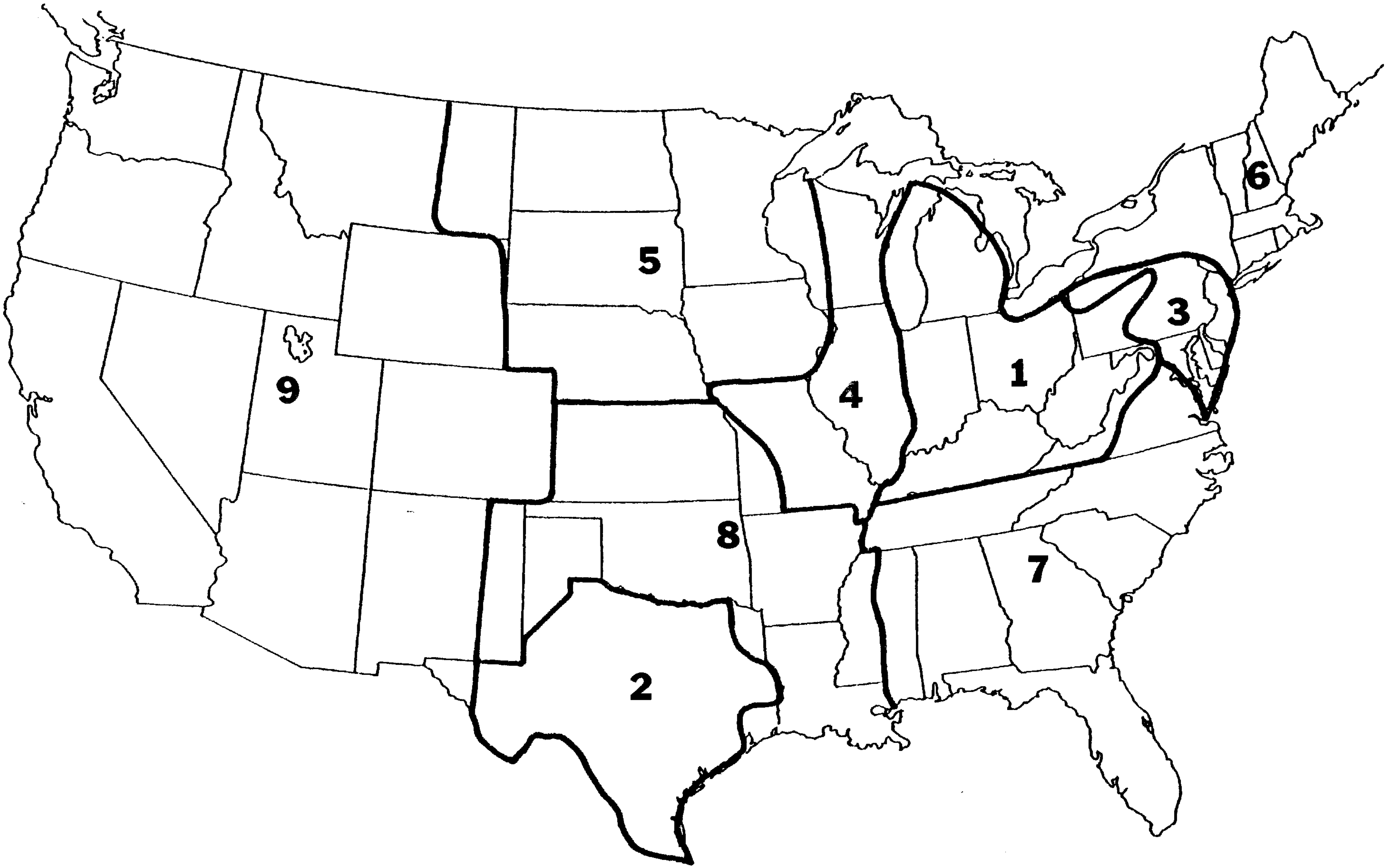

Figure 3-2. Location of the nine Reliability Councils (Systems 1 through 9).

Source: NA-325

TABLE 3-1. PERCENTAGE BREAKDOWN OF SYSTEM GENERATING CAPABILITY BY PRIMARY FUEL AND EQUIPMENT--1985

System Number	Fossil-Fired - By Type of Primary Fuel: Steam Turbines: New Coal	Total Coal	Oil	Gas	Combust. Turb.	Comb. Cycle	Nuclear	Hydro	Pump Storage and Other
1	18.4	72.5	5.0	0.5	3.4	0.3	14.7	0.8	2.8
2	33.6	37.8	10.6	38.1	1.8	1.3	8.5	0.5	1.4
3	3.5	26.4	22.3	0	14.0	0.4	31.5	1.5	3.9
4	14.5	52.7	6.7	0.2	8.1	0	30.5	0.9	0.9
5	29.2	58.7	2.0	0.5	8.9	0.2	21.1	8.6	0
6	4.4	9.9	37.7	0	8.4	0.9	30.0	7.8	5.3
7	11.7	42.0	11.7	0	6.5	0.6	30.4	5.8	3.0
8	30.0	36.1	11.4	28.4	5.5	1.6	13.5	3.2	0.3
9	13.5	24.5	16.6	1.2	5.1	2.1	14.9	30.6	5.0
10 (Nation)	16.0	40.1	13.8	5.7	6.4	0.9	21.8	8.4	2.9

Source: NA-325

Coal capacity will come under EPA's New Source Performance Standards. For this study, all of this New Coal generating capacity is assumed to be required to use flue gas desulfurization as the method of SO_2 control. As a result, the effect of FGD on each system follows directly from its effect on the New Coal steam generators in that system.

3.2 Utility and Flue Gas Desulfurization Operating Data

A significant disparity exists between the quality and quantity of data available for utility systems as compared to flue gas desulfurization systems. Detailed performance data for equipment used in the electric utility industry have been collected on a continuing basis since 1965. There are at least four data banks for utility systems in the United States. Performance data for operating FGD systems, however, is sparse. At persent the PEDCo Summary Report--Flue Gas Desulfurization Systems (PE-259) is the primary source. The PEDCo report, which is prepared under EPA contract, provides a continual update of the status and performance of operational FGD systems. In addition, the report summarizes the status of FGD systems in the construction or planning stages. The PEDCo report which is primarily a status report does not contain the detailed data which are available for the utility industry.

3.2.1 Utility Operating Data

There are four primary systems in operation in the United States which collect and report utility system performance data. These systems are the Edison Electric Institute (EEI) Prime Movers Committee; the Nuclear Plant Reliability Data System (NPRDS) under the direction of the American National

Standards Institute (ANSI) subcommittee N18-20; the Gray Book I, issued by the Nuclear Regulatory Commission (NRC Gray Book); and the Federal Power Commission (FPC). The FPC publishes special reports on many different facets of the electric utility industry but does not issue routine reports on equipment components. The NRC Gray Book publishes performance data on the reactor systems for nuclear plants.

The NPRDS System is concerned with reliability-type data for the components in the nuclear safety systems of nuclear central station electric units. The EEI data is the only major data bank which is directly applicable to this study (i.e., major utility equipment performance data). These data are published in the EEI Prime Movers Committee Reports (ED-043, ED-059).

In addition to the four data sources previously mentioned, equipment performance data are scattered throughout the open literature, in many different journals, and in government reports. Most notable of the latter is WASH 1400, Reactor Safety Study--An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants (US-391). Additional data are recorded and maintained by many individual utilities, and by insurance companies. Much of the data in the open literature were not applicable to this study because of the short time spans reported or because of incomplete data sets. Insurance company data cover only major outages above the policy deductibles and do not contain operating time, and thus are not particularly useful to this study.

The EEI reports were found to be the best sources of data that are relevant to this study. Particularly useful was a special report issued in October 1976 on mature* fossil units

* A mature unit has completed the breakin period and has operated long enough to have a known incidence of outage.

categorized by fuel (ED-059). Data from this report are presented in Table 3-2. Other EEI reports combine all fossil-fired units as one category preventing any distinction between coal-fired and gas- and oil-fired units. Data from the most recent summary report are shown in Table 3-3. The major differences between the coal-fired and other fossil-fired units are for the boiler and the entire unit (including the boiler). The other components which do not vary with the type of fuel have comparable values for availability. Coal-fired units require more equipment for fuel preparation and transporting and for ash disposal. They also experience more erosion and corrosion in the boiler and in equipment in the flue gas path due to the ash and sulfur in the coal.

The range of component availabilities for coal-fired units is of primary interest. Average availabilities vary from a low of about 80 percent for boilers to a high of about 97 percent for condensers. The average availability of a coal-fired generating unit which results from the combined availabilities of the components varies from about 70 to 77 percent. These ranges are important in the comparison of utility component and unit operation with that of flue gas desulfurization units.

3.2.2 Flue Gas Desulfurization Operating Data

As previously stated, operating data for FGD systems are limited. The PEDCo summary reports are the only industry inclusive source of information. Reports on operating experience at a few specific installations are also available. However, none of these sources is comparable in scope to the EEI data base. Specifically, the type of information which has

TABLE 3-2. OPERATING DATA FOR MATURE COAL-FIRED UNITS (390-599 MW)

	Year	Units in Service	Operating Availability (%)
Unit			
Coal Only	1972	32	75.1
	1973	19	74.3
	1974	20	69.9
Coal Primary	1972	36	74.2
	1973	30	77.3
	1974	35	71.5
Boilers			
Coal Only	1972	32	79.6
	1973	19	83.0
	1974	20	76.7
Coal Primary	1972	36	79.0
	1973	30	84.0
	1974	35	77.6
Turbines			
Coal Only	1972	32	86.3
	1973	19	88.4
	1974	20	89.7
Coal Primary	1972	36	86.4
	1973	30	90.6
	1974	35	89.5
Condensers			
Coal Only	1972	32	96.7
	1973	19	97.4
	1974	20	97.3
Coal Primary	1972	36	96.0
	1973	30	97.6
	1974	35	97.7
Generators			
Coal Only	1972	32	91.0
	1973	19	96.3
	1974	20	94.0
Coal Primary	1972	36	90.2
	1973	30	96.1
	1974	35	94.4
Other			
Coal Only	1972	32	95.0
	1973	19	98.3
	1974	20	96.2
Coal Primary	1972	36	94.3
	1973	30	98.0
	1974	35	97.0

Source: ED-059

TABLE 3-3. OPERATING DATA FOR ALL FOSSIL-FIRED UNITS (GAS, OIL, COAL) 1965 - 1974 (390-599 MW, 111 UNITS)

Component	Operating Availability (%)
Boiler	84.6
Turbine	89.2
Condenser	95.3
Generator	93.4
Other	95.1
Total Unit	78.9

Source: ED-043

traditionally been collected by EEI for boilers, turbines, condensers, etc., has not been gathered for FGD systems. However, EEI's 1976 revised Equipment Availability Data Reporting Instruction (ED-060) has been modified to include FGD systems.

There are four parameters used by PEDCo in their bi-monthly FGD status reports which are commonly used in reporting FGD system operating data. These four parameters as used by PEDCo are defined below:

1) $\text{Availability} = \dfrac{\text{Hours the FGD system was available for operation}}{\text{Hours in the period}}$

2) $\text{Reliability} = \dfrac{\text{Hours the FGD system was operated}}{\text{Hours the system was required to operate}}$

3) $\text{Operability} = \dfrac{\text{Hours the FGD system was operated}}{\text{Hours the boiler was operated}}$

4) $\text{Utilization} = \dfrac{\text{Hours the FGD system was operated}}{\text{Hours in the period}}$

Of these parameters, availability is the only one which can be compared with utility data and which is relevant to this study. As stated in Section 1.2, reliability is not defined by the utility industry. The term used as a measure of reliability in the utility industry, Mean Time Between Full Forced Outage, is not comparable to PEDCo's reliability. Furthermore, since PEDCo's definition is inconsistent with traditional scientific definitions of reliability, the usefulness is still more limited. Operability, which is a measure of the degree to which the FGD system is actually used relative to boiler operating time, has no counterpart in the utility data bases. Although utilization, a relative stress factor for the FGD system, is comparable to EEI's Service Factor, a comparison of these parameters is not useful in this study. However, Utilization Factors will be reported for FGD systems to provide some indication of the operating duty on these systems.

An initial screening of PEDCo's Summary Report--Flue Gas Desulfurization Systems (PE-259) for the January to March, 1977, period identified 16 operational lime/limestone wet scrubbing systems and 1 operational system using magnesium oxide. No sites using double alkali or Wellman-Lord were listed. The criteria for selecting units for inclusion in this study were: (1) the system treats flue gas from a utility generating station greater than 50 MWe in size, (2) the system has been operating approximately one year or more, and (3) the system is not a test or demonstration unit. After application of these criteria to the operating systems, only 12 lime/limestone units remained for analysis.

The average modular availabilities and the utilizations were determined for 7 of these 12 systems for the time periods shown in Table 3-4. The average modular availability is the average of the availabilities of each module in an FGD system. Table 3-5 illustrates average modular availabilities for the units for which these performance indicators were available. A brief description of each of these seven boiler-scrubber systems is presented in Tables 3-6 through 3-12.

These availability data represent a total of about 13 unit-years of experience for the 7 systems with data reported. This compares with about 173 unit-years of experience behind the

TABLE 3-4. FGD OPERATING DATA CONCERNING AVAILABILITY AND UTILIZATION

Lime/Limestone Systems	Start-up Date	Dates of Availability	Dates of Utilization
Will County No. 1 Commonwealth Edison	2/27	3/75-1/77	3/75-1/77
La Cygne No. 1 Kansas City Power & Light	2/73	1/74-3/77	N.A.[a]
Paddy's Run No. 6 Louisville Gas & Electric	4/73	N.A.[a]	N.A.[a]
Phillips Duquesne Light	7/73	8/73-10/76	8/73-10/76
Cholla No. 1 Arizona Public Service	10/73	12/73-5/75	N.A.[a]
Green River Kentucky Utilities	9/75	12/75-3/77	12/75-3/77
Colstrip No. 1 Montana Power	10/75	N.A.[a]	N.A.[a]
Elrama Duquesne Light	10/75	N.A.[b]	N.A.[b]
Sherburne County No. 1 Northern States Power	3/76	5/76-3/77	5/76-3/77
Bruce Mansfield No. 1 Pennsylvania Power	4/76	5/76-8/77	5/76-12/76
Colstrip No. 2 Montana Power	7/76	N.A.[a]	N.A.[a]
Cane Run No. 4 Louisville Gas & Electric	8/76	N.A.[a]	8/76-3/77

N.A. - Not Available

[a]System is operational, but data were not reported.

[b]Only 2 of 4 boilers have been connected to FGD system.

Sources: DI-R-161, HE-258, KR-115, PE-250, PE-267, PE-288.

TABLE 3-5. FGD MODULE PERFORMANCE DATA - AVERAGE VALUES

System	MW	No. of Modules	Average Modular Availability (%)	Utilization[a] (%)
Will County No. 1	167	2	44.2	33.6
La Cygne No. 1	874	7	88.6	N.A.
Phillips	413	4	60.6	49.7
Cholla No. 1	126	2	91.5	N.A.
Green River	64	1	72.6[b]	62.1
Sherburne County No. 1	720	11(+1 spare)	90.9	70.9
Bruce Mansfield No. 1	825	6	77.8[c]	76.8

[a] Utilization is the hours the FGD unit operated divided by the hours in the period expressed as a percentage.

[b] Includes two-month outage in March-April, 1977, to reline stack.

[c] Including reduction to half-load from March-July, 1977, due to repairs to stack lining. Bruce Mansfield reports that the repairs were necessary due to the improper installation of the original lining.

Sources: AN-184, BE-478, HE-258, KR-115, MU-155, PE-259, PE-267, PE-287, PE-288

TABLE 3-6. OPERATING CHARACTERISTICS OF THE WILL COUNTY UNIT NO. 1 BOILER-SCRUBBER SYSTEM

Item	Description	Parameter	Value
1. Boiler	Unit No. 1 of the Will County Power Generating Station is a wet-bottom, coal-fired boiler which has been retro-fitted with an FGD system. The boiler was manufactured by Babcock and Wilcox and installed in 1955.	Power Rating	
		Gross	167 Mw
		Net Without FGD	153 Mw
		Net With FGD	146 Mw
		Average Capacity Factor	-
2. Fuel	Medium Sulfur Coal	Sulfur Content	2.14
		Ash Content	10.0 Percent
		Heating Value	9463 Btu/lb
3. Particulate Control	The FGD system is used as the primary means of controlling particulates. An electrostatic precipitator-(ESP) manufactured by Joy Western Precipitation Division is used when the FGD system is inoperable.	Removal Efficiency	
		FGD System	98.0 Percent Removal
		ESP	79.0 Percent Removal
4. Absorbent Preparation	Limestone slurry absorbs SO_2 from the flue gas. The limestone milling facilities consist of a limestone rock conveyer, two 260-ton limestone bunkers, two wet ball mills, and a slurry storage tank.	Composition	
		Silica	0.5 Percent
		Calcium Carbonate	97.5 Percent
		Magnesium Carbonate	1.0 Percent
		Other	1.0 Percent
		Stoichiometry	1.3 - 1.5
5. SO_2 Control	The FGD system is used to control SO_2 emissions in order to meet air quality regulations.	Removal Efficiency	82 - 90 Percent
6. FGD System	The FGD system consists of two identical modules, each capable of processing 50 percent of the maximum flue gas flow from the boiler. The FGD modules are comprised of a venturi prescrubber in series with a two-stage perforated tray absorber.	System Vendor	Babcock and Wilcox
		Type	Retrofit
		Start-up Date	
		Module A	4/72
		Module B	2/72
		Prescrubber Type	Variable Throat Venturi
		Module Size	385,000 acfm @ 355°F
		L/G	34 gal/1000 cf
7. Demister	A two-stage, chevron-type demister is located 7 feet above the second absorber-tray. The demister is washed continuously from below and intermittently from above. Demisters are constructed of fiber reinforced plastic.	Demister Wash	
		Top	3,000 gpm Pond Supernatant/ 40 sec. every hr.
		Bottom	120 gpm Fresh Water/Continuous
8. Fan	There is an induced draft (ID) fan located at the reheater outlet on each module. These ID fans are in series with the boiler ID fans.	System Pressure Drop	25 in. H_2O
9. Reheater	The gas exiting the absorber is rehated by a bare tube reheater comprised of 9 sections. The bottom three sections are stainless steel and the other six sections are of corten steel construction. Each reheater has four soot blowers. Heat is supplied by saturated steam at 350 PSIG pressure.	Flue Gas Temperature	
		Inlet	128°F
		Outlet	165°F
10. Sludge Disposal	Sludge is fixed by mixing with lime and flu ash. Approximately 200 lbs. of lime and 400 lbs. of fly ash are requested to stabilize 1 ton of sludge (dry basis).	Pond/Landfill Requirements	150 Acre - ft/yr
11. Water Make-up	Both fresh water and recycle pond water are used in the open-loop system.	Fresh Water Make-up	300 gpm

Source: DI-R-161, PE-259

TABLE 3-7. OPERATING CHARACTERISTICS OF THE LA CYGNE BOILER-SCRUBBER SYSTEM

Item	Description	Parameter	Value
1. Boiler	The La Cygne Power Generating Station has a single coal-fired boiler integrated with an FGD system. Both are of Babcock and Wilcox design and construction. The boiler is a wet-bottom cyclone-fired unit which began commercial operation on 6/1/73.	Power Rating Gross Net Without FGD Net With FGD Average Capacity Factor	 874 Mw 844 Mw 820 Mw 42 Percent (1976)
2. Fuel	Low-grade, high-sulfur, sub-bituminous coal.	Sulfur Content Ash Content Heating Value	5.4 Percent 24.4 Percent 9420 Btu/lb
3. Particulate Control	The FGD system is the particulate control device for the La Cygne boiler. The venturi scrubber which precedes each of the seven absorbers removes most of the particulates from the flue gas.	Removal Efficiency	97 to 99 Percent
4. Absorbent Preparation	Limestone slurry absorbs SO_2 from the flue gas. The limestone milling facilities consist of two wet ball mills rated at 108 ton/hr and two limestone holding tanks.	Composition Silicates Calcium Carbonate Magnesium Carbonate Stoichiometry	 5-7 Percent 85-93 Percent 2.5 Percent 1.7
5. SO_2 Control	The FGD system is used to control SO_2 emissions.	Removal Efficiency	70-83 Percent
6. FGD System	The FGD system consists of seven identical modules, each capable of processing approximately one-seventh of the maximum flue gas flow from the boiler. The FGD modules are comprised of a venturi prescrubber in series with a two-stage sieve tray absorber.	System Vendor Type Start-up Date Prescrubber Type Module Size L/G	Babcock and Wilcox New 6/1/76 Variable Throat Venturi 394,300 Acfm @ 285^{o}F 33 gal/1000 cf
7. Demister	A single stage Chevron type demister is located above a third sieve tray in each absorber. Two of the modules have a second demister. The demisters are washed continuously from below and intermittently from above. Demisters are constructed of fiberglass.	Demister Wash Top Bottom	 2100 gpm Pond Supernatent-Fresh Water/1 min. every 8 hr. 130 gpm Pond Supernatent/Continuous
8. Fan	There are 6 ID fans located between the reheaters and the stack. The suction side of these fans draws gas from a common header connecting all seven FGD modules.	System Pressure Drop	21-24 in. H_2O
9. Reheater	Flue gas exiting the absorber is reheated by heat exchange with steam coils. This is supplemented by injection of hot air into the flue gas stream.	Flue Gas Temperature Inlet Outlet	 121^{o}F 175^{o}F
10. Sludge Disposal	Limestone slurry is removed continuously from the absorber recirculation tank and pumped directly to the sludge pond. This slurry is about 20 wt. percent solid and no treatment is used.	Pond/Landfill Requirements	400 Acre - Ft/yr
11. Make-up Water	La Cygne operates as a open-loop system. Fresh water is added to make up for evaporative losses and water retained in the sludge.	Make-up Rate	1148 gpm

Source: CO-596, DI-R-161, MC-293, PE-259, RO-243

TABLE 3-8. OPERATING CHARACTERISTICS OF THE PHILLIPS BOILER-SCRUBBER SYSTEM

Item	Description	Parameter	Value
1. Boiler	The Phillips Station consists of six dry-bottom, pulverized coal-fired boilers. The entire station has been retrofitted with an FGD system. The boilers were manufactured by Foster-Wheeler and installed during the period 1942 to 1956.	Power Rating Gross Net Without FGD Net With FGD Average Capacity Factor	 413 MW 367 MW 373 MW 66 Percent (1976)
2. Fuel	Medium-sulfur coal is burned in the boiler.	Sulfur Content Ash Content Heating Value	2.03 Percent 16.6 Percent 11,375 Btu/lb
3. Particulate Control	Particulates are controlled by Research-Cottrell Mechanical Collectors in series with electrostatic precipitators. The FGD system also removes particulates from the flue gas.	Removal Efficiency Mechanical Collector-ESP FGD system	 80.0 Percent 95.0 Percent
4. Absorbent Preparation	Lime is used to absorb the SO_2. Lime is fed from a storage silo at a controlled rate to a lime slaker where it is mixed with fresh make-up water. The slaked lime overflows to a slaker transfer tank where make-up water is added to provide a constant flow of lime slurry with a 15-percent solids concentration.	Composition Calcium Oxide Other Stoichiometry	 95.0 Percent 5.0 Percent 1.3
5. SO_2 Control	Only one of the four scrubber trains is used exclusively for SO_2 from processed flue gas.	Removal Efficiency Module 1 Module 2, 3 & 4	 90 Percent 50 Percent
6. FGD System	The FGD system consists of four modules of wet venturi-type scrubbers. Three of the trains are single-stage venturi scrubbers originally intended for particulate removal. The fourth train is a dual-stage venturi scrubber-absorber and is the prototype for determining the feasibility of two-stage scrubbing for compliance with SO_2 emission limits.	System Vendor Type Start-up Date Prescrubber Type Module Size L/G	Chemico Retrofit 7/73 Variable-Throat Venturi 547,000 acfm @ 340°F 30 gal/1000 cf
7. Demister	Two single-stage, horizontal chevron demisters remove entrained mist. One is an integral part of the Chemico venturi scrubbers. The second is downstream of the induced draft fan.	Demister Wash	Internal Automatic Spray
8. Fan	There is a booster fan downstream of each of the pre-scrubbers. The fans are equipped with fresh water sprays to remove any accumulation of solids from scrubber carryover.	System Pressure Drop Module 1 Module 2, 3 & 4	- 16 in. H_2O 10 in. H_2O
9. Reheater	A 316-C stainless steel section of the duct preceeding the stack is equipped with a direct oil-fired reheater unit that can raise stack gas temperatures as much as 30°F. Normal reheat is about 20°F.	Flue Gas Temperature Inlet Outlet	 110-120°F 140°F
10. Sludge Disposal	The waste sludge is stabilized by the addition of 200 pounds of calcilox per ton of dry solids in the sludge. The fixed sludge is transported to experimental plastic-lined ponds located about one mile from the station, where the material solidifies.	Pond/Landfill Requirements	-
11. Water Make-up	Both fresh water and recycle clarifier overflow are used in the system. The system operates open-loop with 300 gpm of the thickener overflow diverted.	Fresh Water Make-Up	635 gpm

Source: CO-596, DI-R-161, PE-258, PE-281, RO-243

TABLE 3-9. OPERATING CHARACTERISTICS OF THE CHOLLA BOILER-SCRUBBER SYSTEM

Item	Description	Parameter	Value
1. Boiler	The power station has one dry-bottom pulverized-coal-fired boiler which has been operating since 1962. The unit is base load operated and has historically had trouble-free operation.	Power Rating Gross Net Without FGD Net With FGD Average Capacity Factor	 126 Mw 115 Mw 112 Mw 85.3 Percent (1976)
2. Fuel	A low-sulfur coal is burned at the power plant.	Sulfur Content Ash Content Heating Value	0.60 Percent 12.0 Percent 10,000 Btu/lb
3. Particulate Control	A Research-Cottrell multicyclone-type collector provides primary control of particulate emissions. The FGD system also removes particulates from the gas stream.	Removal Efficiency Multicyclone FGD system	 75 Percent 99.2 Percent
4. Absorbent/Preparation	Limestone is used to absorb SO_2 from the gas. Finely ground limestone is purchased from a mine near Kingman, Arizona. No milling facilities are at the Cholla station. An additive containing a minimum of 52.5% CaO and a maximum of 2.0% MgO is used.	Composition Stoichiometry	- 1.1
5. SO_2 Control	The FGD system is used to control SO_2 emissions in order to comply with air quality regulations.	Removal Efficiency	58.5 Percent
6. FGD System	The FGD system consists of two scrubbing modules (A and B), each handling 50 percent of the boiler's flue gas load. Module A is packed and circulates limestone slurry. Module B is a spray-tower which circulates make-up water.	System Vendor Type Start-up Date Prescrubber Type Module Size L/G	Research-Cottrell Retrofit 7/73 Flooded-Disc, Variable Throat Venturi 260,000 acfm @ 276°F 49 gal/1000 cf
7. Demister	A two-stage, polypropylene slat demister is located 12-15 feet above the absorption section of both A and B absorbers. The first stage demister is washed intermittently from above with fresh water sprays.	Demister wash	-
8. Fan	A forced-draft booster fan is located upstream of the venturi prescrubber on each module.	System Pressure Drop	25 in. H_2O
9. Reheater	The desulfurized flue gas is reheated as it passes through two shell-and-tube heat exchangers. Heat is supplied by 200 psig steam.	Flue Gas Temperature Inlet Outlet	 121°F 165°F
10. Sludge Disposal	The plant has no sludge treatment or fixation systems. The sludge is pumped to the fly ash disposal pond on an intermittent basis. Because of light rainfall and a high evaporation rate in this area, no liquor is recirculated from the pond.	Pond/Landfill Requirements	-
11. Water Make-Up	No water is recycled from the sludge disposal pond to the FGD system. Make-up water for the system is boiler water blowdown.	Fresh Water Make-Up	285 gpm

Source: CO-596, DI-R-161, MU-155, PE-259, RO-243

TABLE 3-10. OPERATING CHARACTERISTICS OF THE GREEN RIVER BOILER-SCRUBBER SYSTEM

Item	Description	Parameter	Value
1. Boiler	The Green River Station has four coal-fired boilers which have been retrofitted with an FGD system. Green River is a peak load station which normally operates five days a week.	Power Rating Net with FGD Average Capacity Factor	 64 Mw 44.2 Percent (1976)
2. Fuel	A high-sulfur, western Kentucky coal is burned in the boilers.	Sulfur Content Ash Content Heating Value	3.7 Percent 12.7 Percent 11,154 Btu/lb
3. Particulate Control	The FGD system is used in conjunction with mechanical collectors.	Removal Efficiency Mechanical Collectors FGD System	 - 99.7 Percent
4. Absorbent/Preparation	Lime slurry is used to absorb SO_2 from the flue gas. Pebble lime is purchased and stored in a 500-ton capacity bin. Lime is slaked in an agitated tank to produce a 20 percent solids slurry.	Composition Stoichiometry	- 1.1 - 1.2
5. SO_2 Control	The FGD system controls SO_2 emissions in order to meet air quality regulations.	Removal Efficiency	80 Percent
6. FGD System	The FGD system consists of a single module capable of treating all of the flue gas from boilers 1, 2, and 3. The module consists of a venturi prescrubber in series with a mobile-bed absorber.	System Vendor Type Start-Up Date Prescrubber Type Module Size L/G	American Air Filter Co. Retrofit 9/75 Venturi 360,000 acfm @ 300°F 35 gal/1000 cf
7. Demister	A centrifugal vane type demister is used to remove entrained mist from the flue gas stream leaving the absorber. The demister is of coated mild steel and stainless steel construction and is 10-15 feet above the absorber bed.	Demister Wash Top	- 45 gpm fresh water
8. Fan	A forced draft booster fan is located upstream of the venturi prescrubber.	System Pressure Drop	9.2-12.2 in. H_2O
9. Reheater	There was no reheater on the original system. AAF has been authorized to design and install a reheater using exchange with external steam coils.	-	-
10. Sludge Disposal	Sludge is pumped to an unlined pond. Clear pond over-flow is returned from the pond to the reactant tank.	Pond Landfill Require-ments	22.5 Acre - ft/yr
11. Water Make-Up	Make-up water is added to the open-loop system to replace evaporative losses and water which is retained in the sludge.	Fresh water make-up Rate	105 gpm

Source: BE-478, CO-596, DI-R-161, PE-259

TABLE 3-11. OPERATING CHARACTERISTICS OF THE SHERBURNE COUNTY NO. 1 BOILER-SCRUBBER SYSTEM

Item	Description	Parameter	Value
1. Boiler	Unit No. 1 of the Sherburne County (SherCo) generating plant is a pulverized coal-fired-boiler manufactured by Combustion Engineering. The FGD system was constructed concurrently with the generating plant.	Power Rating Gross Net With FGD Average Capacity Factor	 720 Mw 663 Mw 69 Percent (1976)
2. Fuel	Low sulfur sub-bituminous coal from the Colstrip area of Montana is fired.	Sulfur Content Ash Content Heating Value	0.8 Percent 9 Percent 8,500 Btu/lb
3. Particulate Control	The FGD system is also the particulate control device for the SherCo No. 1 boiler. The venturi scrubber which precedes each of the 12 absorbers removes most of the particulates from the flue gas.	Removal Efficiency FGD System	 98-99 Percent
4. Absorbent/Preparation	Limestone is ground in two wet ball mills with a combined rating of 48 tons/hr and delivered as a 4 percent slurry to each module's reaction tank. SO_2 removal is achieved by using two additive sources: calcium oxide in the fly ash and tail-end addition of limestone. The allcalinty of the ash is depended upon for the bulk of the SO_2 removal.	Composition Stoichiometry	- 1.25
5. SO_2 Control	The FGD system is used to control SO_2 emissions to meet state air quality regulations.	Removal Efficiency	50-55 Percent
6. FGD System	The FGD system consists of 12 identical modules, each capable of treating 200,000 ACFM of flue gas. Each module is comprised of a venturi prescrubber and a single-stage marble bed absorber.	System Vendor Type Start-Up Date Prescrubber Type Module Size L/G	Combustion Engineering New 6/76 Venturi Rod 200,000 acfm @ 310°F 27 gal/1000 cf
7. Demister	A two-stage chevron slanted (v-shape) demister is located 10.5 feet above the marble bed. Demisters are molded from a fiberglass reinforced polyester material. Intermittent wash of top and bottom of first stage and bottom of second stage with a mixture of thickener overflow and cooling tower blowdown.	Demister Wash Top & Bottom	 2 min. every 24 hr.
8. Fan	An induced draft (ID) fan is located downstream of the reheater on each module.	System Pressure Drop	17 in. H_2O
9. Reheater	The gas leaving the absorber is reheated by four rows of finned carbon steel tubes. Heat is supplied by water at 358°F.	Flue Gas Temperatures Inlet Outlet	 131°F 171°F
10. Sludge Disposal	Unstabilized sludge of about 30 wt. percent solids is transferred to a lined pond for disposal.	Pond/Landfill Requirements	-
11. Water Make-Up	Both fresh water and recycle pond water are used as make-up in the open-loop system.	Fresh Water Make-Up	2,000 gpm

Source: CO-596, KR-115, PE-259, RO-243

TABLE 3-12. OPERATING CHARACTERISTICS OF THE BRUCE MANSFIELD NO. 1 BOILER-SCRUBBER SYSTEM

Item	Description	Parameter	Value
1. Boiler	Unit No. 1 is a coal-fired, once-through, supercritical steam generator.	Power Rating Net Average Capacity Factor	 825 Mw 36 Percent (1977)
2. Fuel	Medium to high sulfur coal is burned.	Sulfur Content Ash Content Heating Value	3.3 Percent 16.8 Percent -
3. Particulate Control	A Chemico variable-throat venturi provides primary particulate control on Unit No. 1. This venturi is the first stage of the FGD system.	Removal Efficiency	
4. Absorbent/Preparation	A thiosorbic lime slurry is used to absorb SO_2 from the flue gas. The lime is slaked before being fed to the absorber.	Composition Calcium Oxide Magnesium Oxide Acid insoluble Stoichiometry	 86-89 Percent 2.8-5.7 Percent 4-8 Percent 1.58 Percent
5. SO_2 Control	The FGD system is used to control SO_2 emissions to meet state air quality regulations.	Removal Efficiency	85-93 Percent
6. FGD System	The FGD system consists of 6 identical modules. Each module is composed of a variable-throat venturi in series with a fixed throat venturi.	System Vendor Type Start-Up Date Prescrubber Type Module Size L/G	Chemico New 4/76 Venturi 560,000 acfm 56 (total)
7. Demister	A four-stage horizontal Chevron mist eliminator is located downstream of the absorber. The bottom is washed by a sequence of nozzle, continuously with clarifier overflow and fresh water while the top is washed once per shift with clarifier overflow.	Demister Wash Top Bottom	 1/shift 40 min/hr clarifier overflow and 20 min/hr fresh water
8. Fan	An induced draft fan is located between the venturi scrubber and the venturi absorber.	System Pressure Drop Scrubber Absorber	 20 in. H_2O 4 in. H_2O
9. Reheater	Not Available.	Flue Gas Temperature Inlet Outlet	 - -
10. Sludge Disposal	Scrubber-recycle bleed is combined with fly ash and fed to a thickener. Sludge from the thickener is pumped to a waste disposal system and mixed with Calcilox, a stabilizing agent. The sludge is then pumped to an offsite disposal area.	Pond/Landfill Requirements	-
11. Water Make-Up	Both fresh water and thickener overflow are used as make-up in the open-loop system.	Fresh Water Make-up	-

Source: FL-090, PE-259, PE-288

performance data previously reported for coal-fired units in Table 3-2 and about 555 unit-years for the utility operating data in Table 3-3. The disparity between FGD and utility data is again evident in the unit-years of operating experience which serve as the basis for an availability determination. The FGD data were previously determined to not yet represent a statistically valid sample that would allow extrapolation to new Lime or Limestone FGD systems (DI-R-161).

The average modular availabilities vary from one unit to the next. However, five of the seven units have average modular availabilities greater than 70 percent. Furthermore, three are greater than 88 percent. Four units also have utilization of about 50 percent or more. These utilizations indicate the load on the FGD units has been large enough to reasonably quantify the operating history of the specific individual units.

One factor of importance is the change in the modular availability of an FGD unit as experience operating the system is acquired. The Will County unit, which is the oldest of the seven, has experienced rather erratic performance including 10 one-month periods in which the FGD unit was not available at all. The availability data for Will County are plotted in Figure 3-3. The five other units for which data were available have shown a more consistent and successful operating experience. The modular availability of the Phillips unit has improved to an average of about 73 percent for the last 2 years with relatively consistent operation in the high 60 to high 80 percent range (Figure 3-4). The remaining units: La Cygne, Green River, Sherburne County, and Bruce Mansfield have experienced relatively stable operation with modular availabilities consistently between 80 and 100 percent (Figures 3-5 to 3-8). In particular, La Cygne No. 1 and Sherburne County No. 1 have increased their average

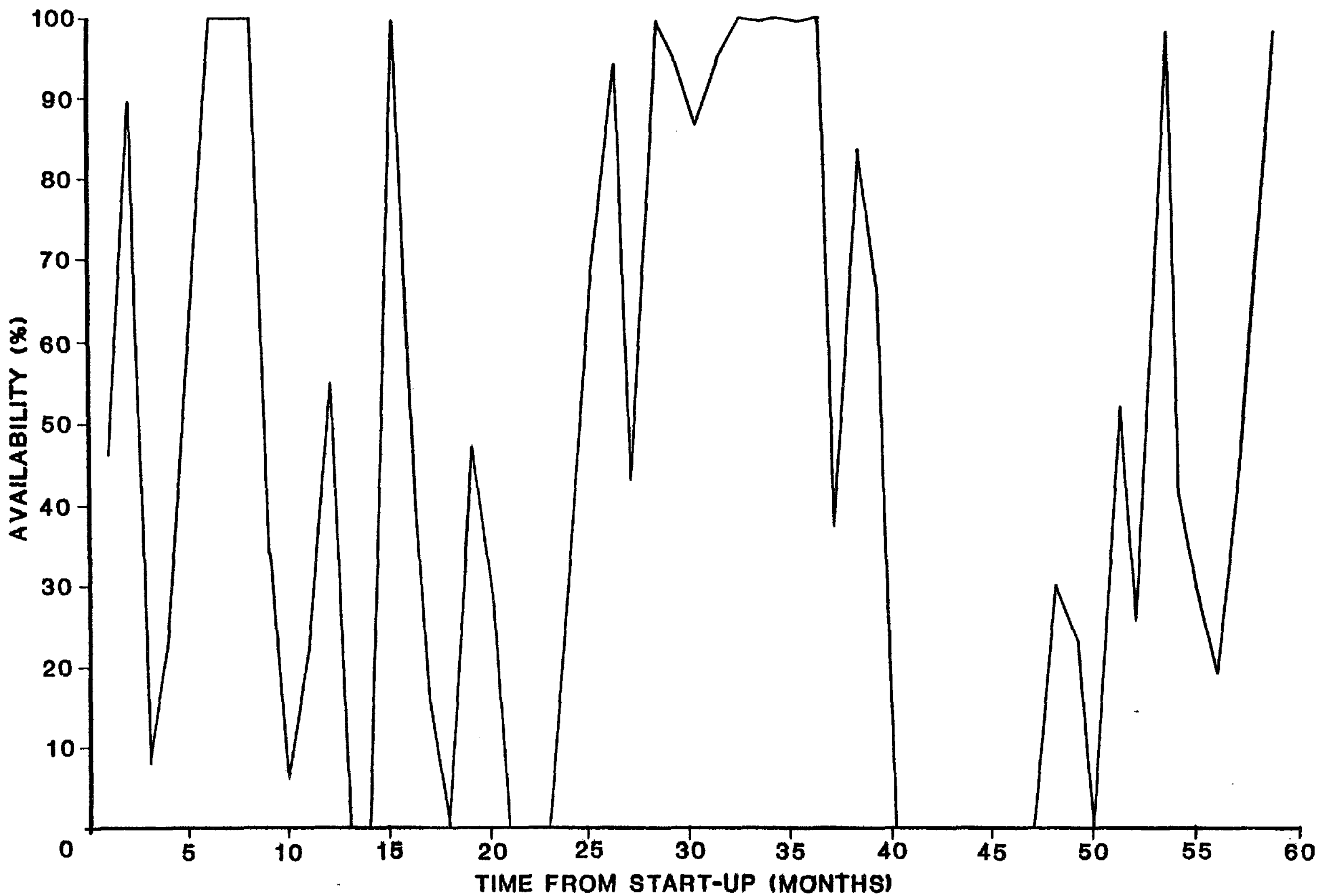

Figure 3-3. Will County No. 1 FGD average modular availability.

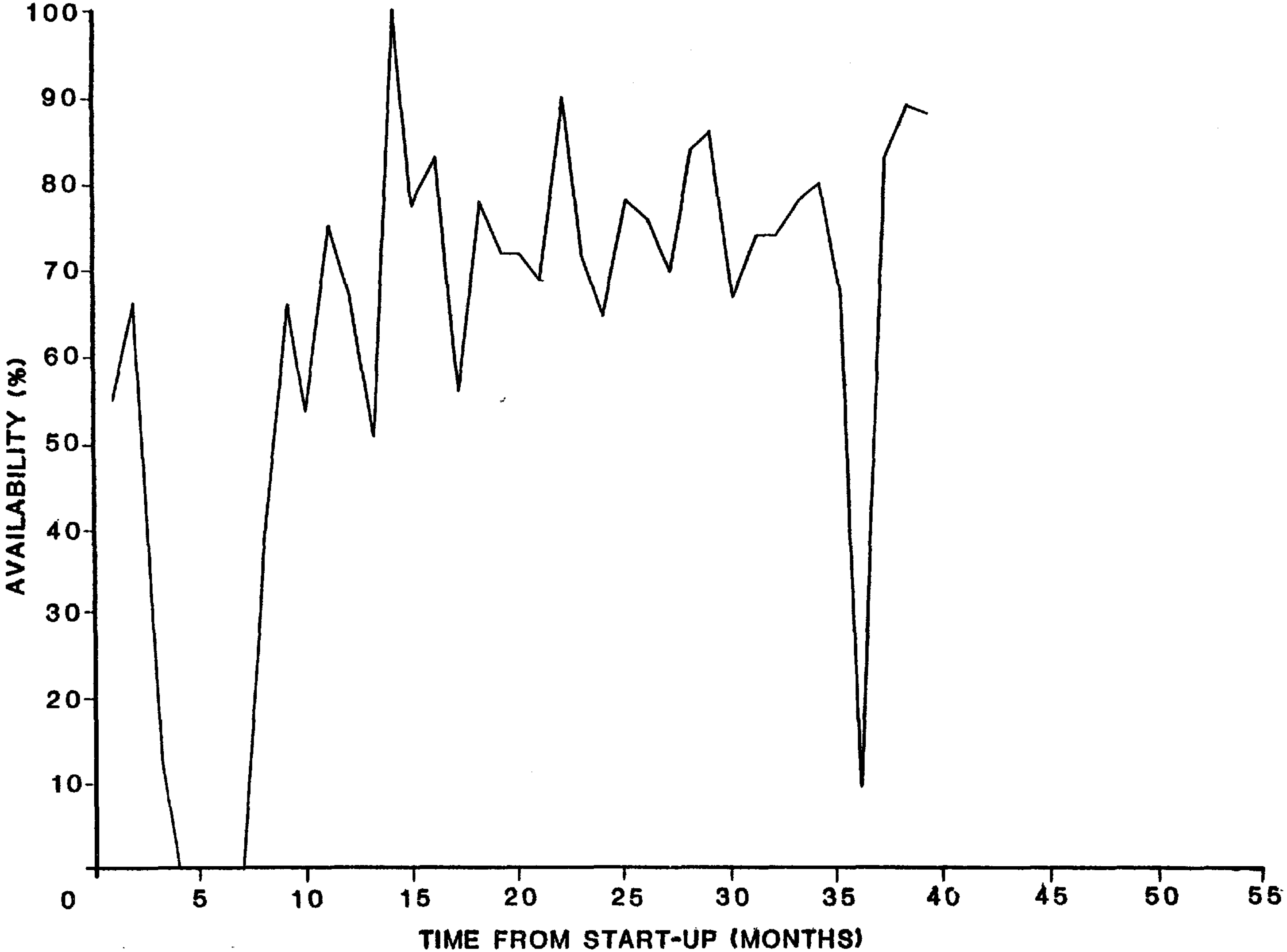

Figure 3-4. Phillips FGD average modular availability (average all modules).

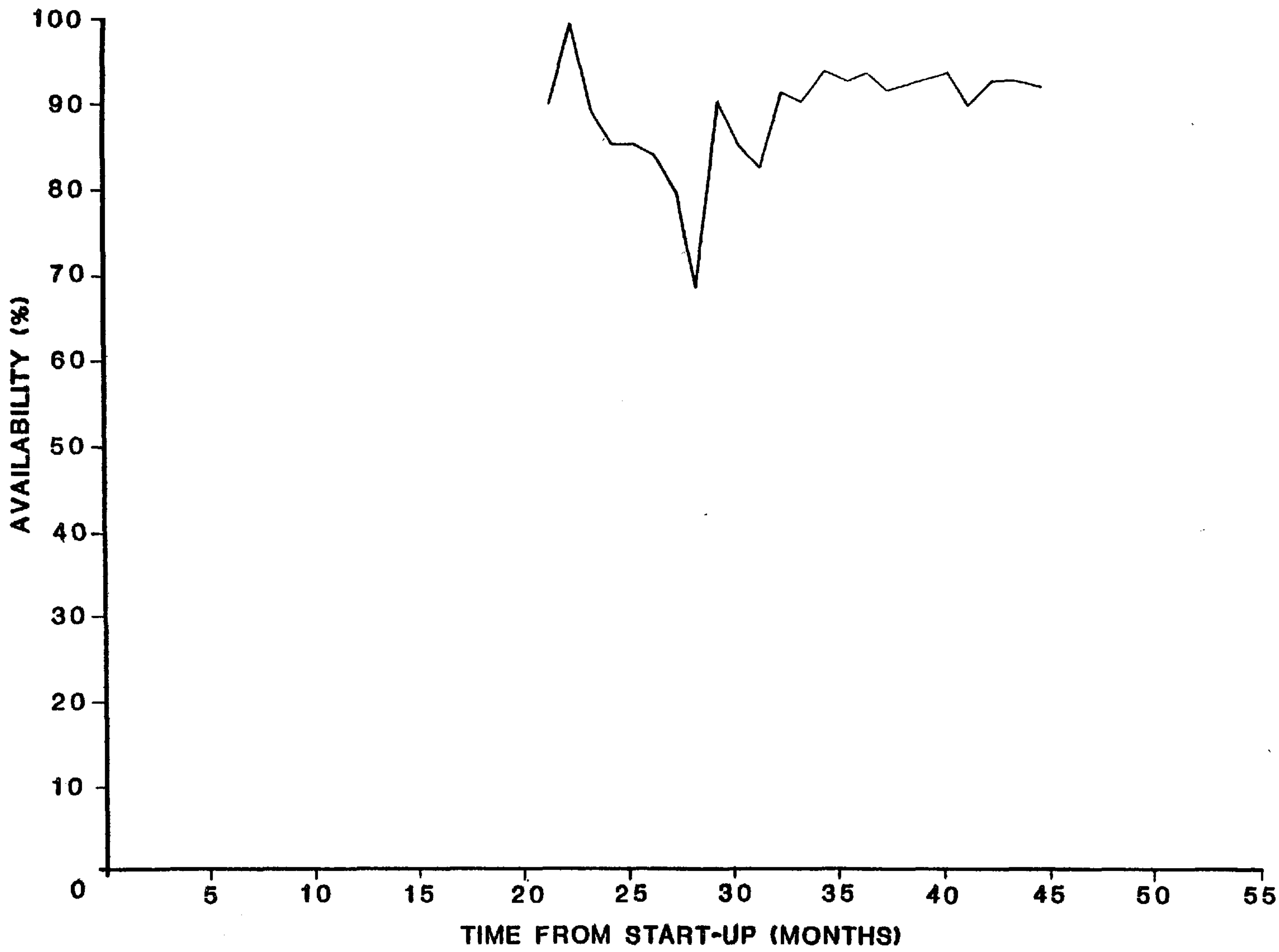

Figure 3-5. La Cygne FGD average modular availability (average all modules).

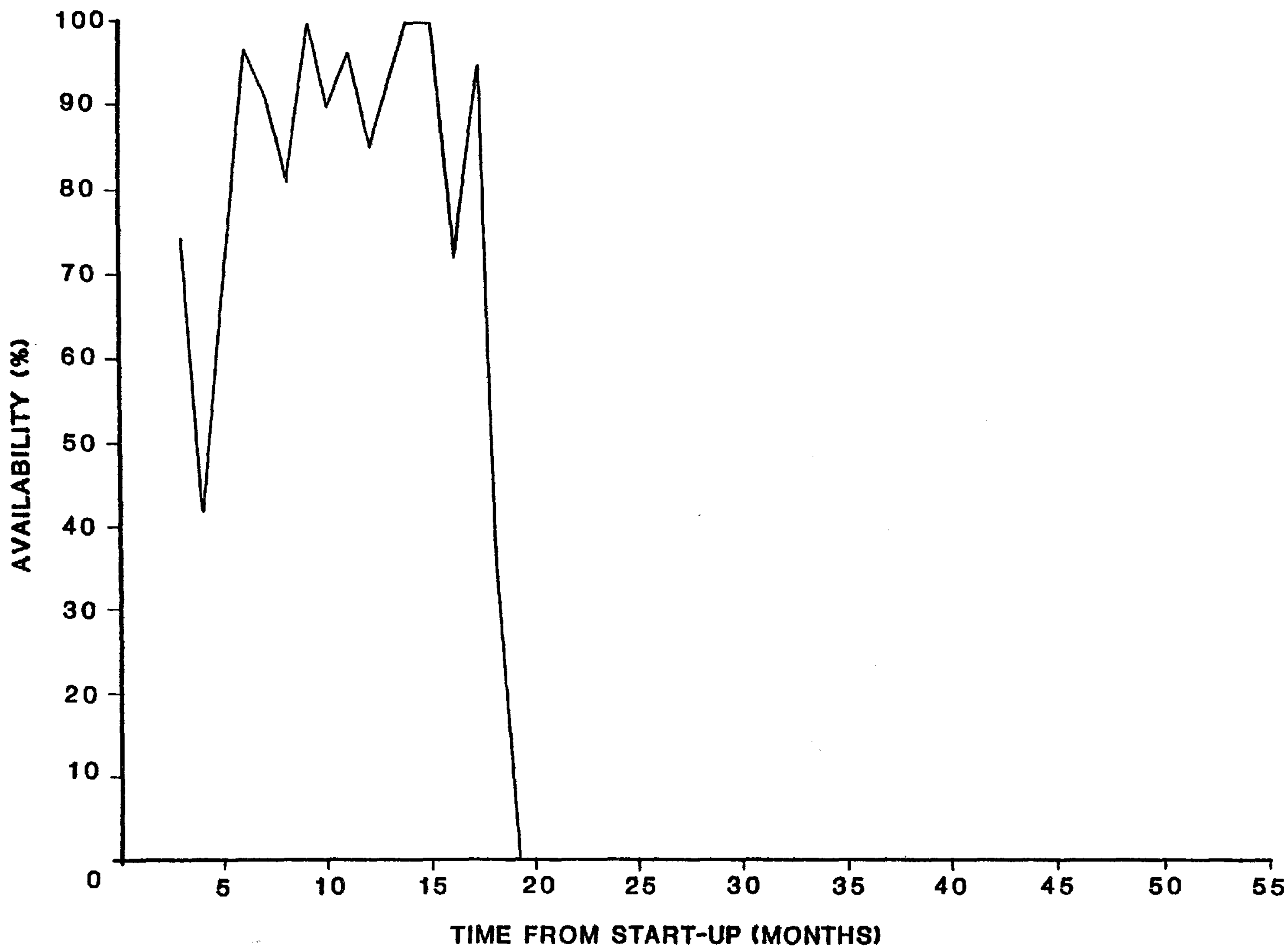

Figure 3-6. Green River FGD modular availability.

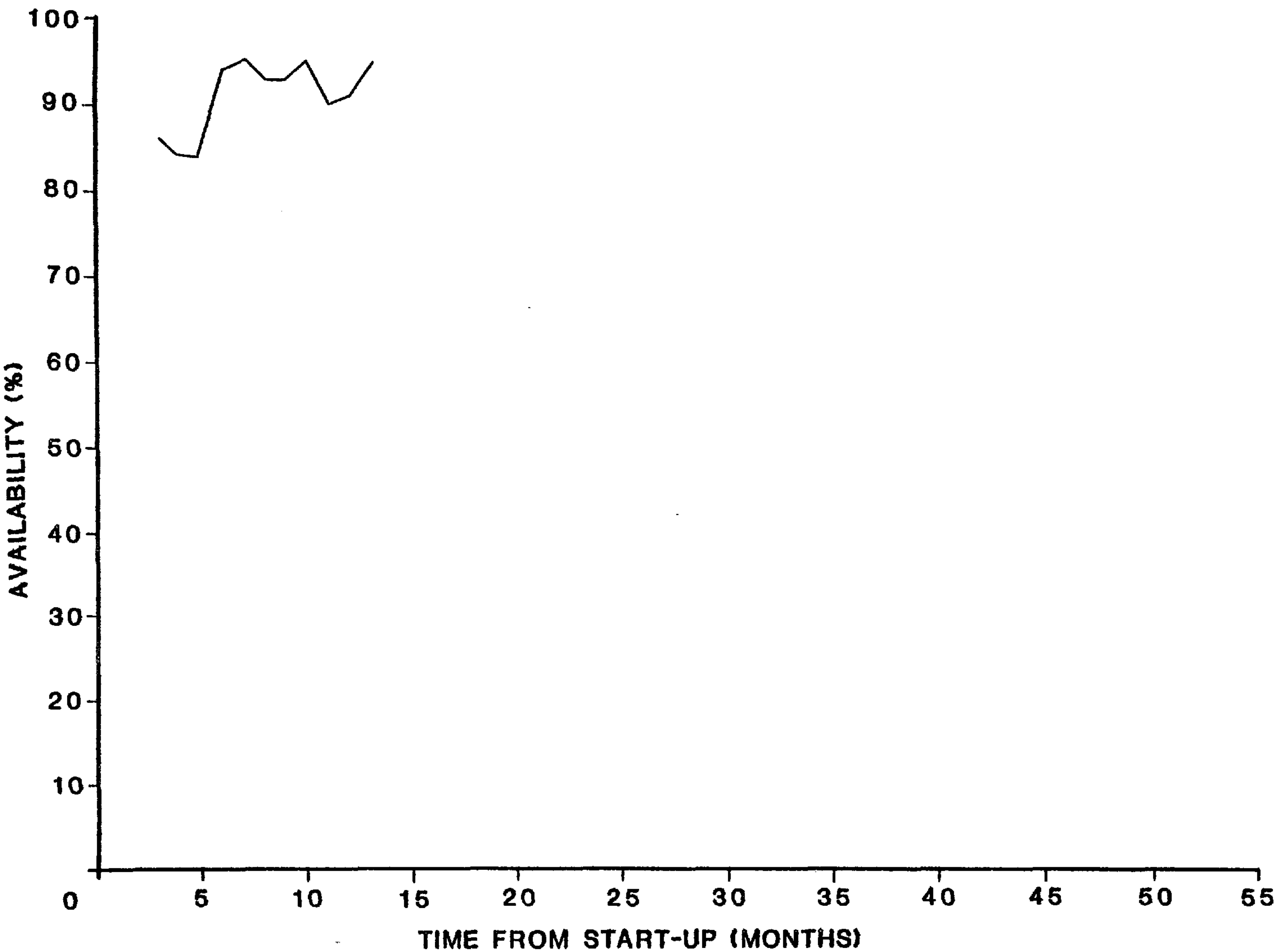

Figure 3-7. Sherburne County No. 1 FGD average modular availability (average all modules).

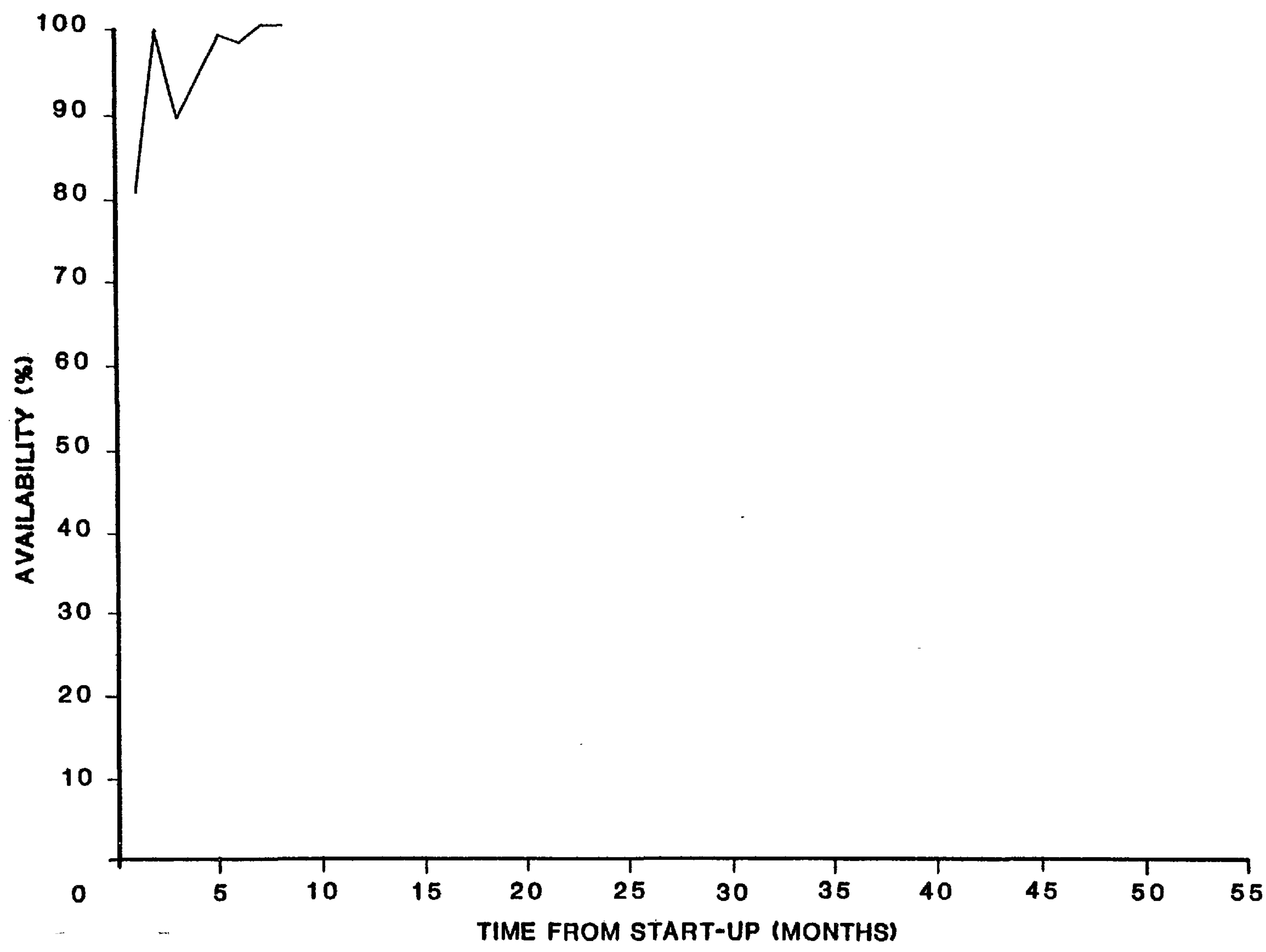

Figure 3-8. Bruce Mansfield No. 1 FGD average modular availability (average all modules).

modular availability to consistently greater than 90 percent after the start-up phase of operation. Green River and Bruce Mansfield No. 1 have also reported several monthly average modular availabilities above 90 percent but repairs to the stacks at these plants have resulted in the total unavailability of some modules during the stack repairs. A reduction in the average modular availability thus resulted (PE-288). It should be noted that these modular availabilities do not reflect the performance of the FGD system as a whole; no data were reported as to whether the modules failed singly or in groups, or whether the generating unit was experiencing a coincident outage.

For this study, an average modular availability in the range of 70 to 90 percent was assumed for a mature FGD unit. This 70 to 90 percent modular availability range will receive primary emphasis in evaluating the effect of the availability of FGD systems on individual generating stations and on generating systems in Sections 3.4 and 3.5, respectively. It should be noted again that this is a modular and not an FGD unit availability.

One comparison of interest is that of the availability for the initial operating period for older units with the availability for the initial operating period for newer units. This comparison is particularly interesting for units by the same vendor. Table 3-13 presents the first year average modular availabilities for the seven FGD units emphasized in this study. This table points out the substantial improvements in the initial operating experience of units installed by the same vendor. The newer B&W and Chemico units show significant improvements relative to the older units by the same vendor. Furthermore, the newer units in general show improved average modular availabilities during the initial operating period. These improvements

TABLE 3-13. THE INITIAL AVAILABILITY OF SEVEN FGD SYSTEMS

System	Start-up	Vendor	First Year Modular Availability (%)
Will County No. 1	2/72	B & W[a]	~49
La Cygne No. 1	2/73	B & W[a]	~87*
Phillips	7/73	Chemico	~36
Bruce Mansfield No. 1	4/76	Chemico	~80
Cholla No. 1	10/73	R - C[b]	N.A.
Green River	9/75	AAF[c]	~85
Sherburne County No. 1	3/76	CE[d]	~90

N.A. - Not Available

* - Second year availability is reported because data for the first year were not available.

[a]Babcock and Wilcox

[b]Research Cottrell

[c]American Air Filter

[d]Combustion Engineering

might be expected as a result of general advances in the state-of-the-art and particularly due to increased design and operating experience in the FGD industry. Radian has previously examined this "learning curve" effect in a study for EPA (DI-R-116).

3.3 Analysis of Flue Gas Desulfurization Availability

Numerical parameters that measure the performance of an FGD system must be carefully analyzed prior to any general application. The possible existence of factors that might influence general application must be considered. Some of these factors of interest for an FGD system include the size of the unit, the boiler load, the type of FGD process, the number of scrubber modules and of spare modules, the water balance, the sulfur content of the coal, the SO_2 removal efficiency, the maintenance effort, and the capability to bypass the FGD unit.

Table 3-14 summarizes this information for the seven systems identified in the previous section for which data was obtained. Consideration of additional items such as scrubber design, type of scrubber, mist eliminator design and operation, reheater design and operation, scrubber operation and control, etc., would be necessary for a detailed analysis of the operating data. However, that is beyond the time frame established for this study. The operating seven systems will be analyzed individually with a general discussion at the conclusion of this section. The problems which caused system failures initially and the actions taken which improved the modular availability as shown in Figures 3-3 through 3-8 are also addressed. Further discussion of operating problems and solutions is presented in Section 4.1.

TABLE 3-14. FACTORS FOR CONSIDERATION IN FGD AVAILABILITY ANALYSIS

System	Boilers No./MWe[a]	Load	FGD Process	Total Modules (B-Bypass)	Spares	Water Balance	Coal % S	% SO_2 Removal	Maintenance
Will County No. 1	1/167	Intermediate[c] or Cycling	Limestone	2-B	0	Open Loop-with recycle	0.4-4.0	80-85	N.A.
La Cygne No. 1	1/874	Intermediate[c] or Cycling	Limestone	7	0	Open Loop-with recycle	5.3	80	Special crew. Clean 1 module per night.
Phillips	6/413	Peaking[d]	Lime	4-B	0	Open Loop-with recycle	2.2	50	Special crew for FGD unit.
Cholla No. 1	1/126	Base[b]	Limestone	2-B	0	Open Loop-no recycle	0.5	50[f]	Separate crew for FGD unit.
Green River No. 1 & 2	3/64[e]	Peaking[d]	Lime	1-B	0	Open Loop-with recycle	2.5-3.0	Up to 90	Utility maintenance.
Sherburne County No. 1	1/720	Intermediate[c] or Cycling	Limestone	12	1	Open Loop-with recycle	0.8	50	Special crew. Clean 2 modules per night
Bruce Mansfield No. 1	1/825[e]	Intermediate[c] or Cycling	Lime	6[g]	0	Open Loop-with recycle	4.0	N.A.	N.A.

[a] Gross MWe; does not include FGD.

[b] Base load: Unit operation at high capacity factor and high output factor throughout the daily period. Average annual service hours normally exceed 5500. (CO-RF-700)

[c] Intermediate Load: Unit synchronized during the daily period but at moderate to low capacity and output factor due to generation following daily load requirement cycles. Average annual service hours are normally in the range 1500-5500. (CO-RF-700)

[d] Peak Load: Unit startup, operation, and shutdown determined by daily load cycle. Average annual service hours are normally less than 1500. (CO-RF-700)

[e] Net MWe with FGD.

[f] Module A scrubs about 92% SO_2 from 50% of the flue gas; Module B scrubs about 25% SO_2 from 50% of the flue gas.

[g] Six total modules with 1 being a spare were planned. However, all 6 modules are required for satisfactory operation at full load. Another module is being added to serve as a spare.

N.A. - Not Available.

Sources: AN-184, HE-258, KN-039, KR-115, KR-116, MC-293, MC-295, MU-155, PE-259, PE-287, PE-288, WO-130.

Will County No. 1, the oldest system, started up in 1972 about one year before La Cygne No. 1, the next oldest. The system was designed for high sulfur coal but has never operated very successfully on high sulfur coal. However, operation with low sulfur coal has been satisfactory. The stage of development of flue gas desulfurization technology at the time this system was designed and constructed is a major contribution to the relatively low availability and to the limited success operating with high sulfur coal. In the future, Will County No. 1 is expected to use only low sulfur coal to make the FGD system operate more reliably. Some of the initial problems included buildup on demisters, reheater vibration, and corrosion. The demister was modified and an overspray added to reduce buildup. Rebracing the reheater solved the vibration problem. Reheater corrosion declined after installation of a second stage mist eliminator to reduce the deposits on the reheaters.

La Cygne No. 1 has had a successful operating experience. The system has had stable operation with no major failures (massive scaling, etc.). There were some initial problems, however. These problems included vibration of the I.D. fans, plugging in demisters and strainers, nozzle wear, corrosion of reheater tubes, and restriction of the mobility of the Turbulent Contact Absorber (TCA) balls. Fan vibration was a fabrication defect corrected by the vendor. Demister and strainer plugging and nozzle wear were reduced by installing a hydrodome in the slurry recirculation line. Hot air from the preheater was injected upstream of the reheater to reduce condensation on reheater tubes. The TCA was replaced with a sieve tray to eliminate the ball mobility concerns (PE-259, RO-243).

The FGD system for La Cygne No. 1 is on an intermediate load boiler burning high sulfur coal. An important factor which is not considered in determining availability for La Cygne is the maintenance effort. Current operating practice is to shut down one module each night and have a maintenance crew inspect and clean the module. A large well-trained operating crew is used. The high system availability is partly attributable to this maintenance and operating effort and to establishment of a separate well-trained crew (47 operation, 15 maintenance) for the FGD system. Better control of the chemistry may result in a manpower reduction in the future. Experience at La Cygne indicates that a scrubber can be operated reliably with sufficient expenditure of money and effort.

Phillips has experienced lower availabilities than most of the other systems. Some of the initial problems included plugging of absorbers, acid condensation in the stack, corrosion and erosion in I.D. fans and scrubbers, and inadequate pond capacity. Absorber plugging has required a complete cleaning of a scrubber vessel about every 1400 service hours. Each cleaning with minor maintenance requires 1400-1700 man-hours. The cleaning is required due to deposits that increase the pressure drop to levels such that the scrubber cannot treat flue gas from all six boilers. In the past, one or more boilers have been routed around the FGD system when this occurred. The corroded steel bands around the inner stack were repaired. Corrosion and erosion were reduced by operation at a higher pH and by use of resistant materials. More pond capacity was installed to handle the increased sludge.

More recently, testing at Phillips has included the use of magnesium modified lime rather than high calcium lime. The results of this testing indicate reduced deposits and, therefore, more reliable operation are achievable. Further modifications include addition of a redundant lime feed system and automatic pH control with the redundancy required for continuous control. Boilers at the Phillips unit burn a medium sulfur coal.

Cholla No. 1 is somewhat unique compared to the other systems in that low sulfur coal is burned and the water balance is open loop with no recycle. The use of 0.5 percent sulfur coal with only 50 percent SO_2 removal results in Cholla scrubbing a much lower quantity of SO_2 per ton of coal than most of the other systems. The open loop operation with no recycle virtually eliminates the chemical scaling and plugging problems that have plagued many other systems. The success of Cholla seems to indicate that control of the process chemistry is of foremost importance to insure the reliable operation of an FGD system.

Problems which occurred during initial operation at Cholla No. 1 include reheater vibration and corrosion, solids buildup in the gland boxes, plugged lines, fan vibration due to buildup, solids settling out in standby pumps, and demister plugging. Baffles reduced reheater vibration while insulation upstream of the reheater and a baffle to divert acid condensation from the tubes reduced corrosion. The packing gland was installed upside down to stop solids buildup. Fans were sandblasted to remove the buildup. Standby pumps were flushed after removal from service to remove solids. Finally, the demisters required redesigning (MU-074, PE-259, RO-243).

Green River is another system that has been relatively successful. The availability from startup averaged about 82 percent until a two month outage in March-April, 1977, was necessary to reline the stack. This system was reportedly overdesigned and given an abnormal amount of attention since it was the vendor's first system. System design was 4 to 5 percent sulfur while the unit averages 2.5 to 3 percent sulfur. Onsite chemical work was also emphasized including the use of extensive monitoring. Green River is normally a peaking unit which would allow maintenance when the unit was down but the unit has been maintained at a higher load to test the scrubber. At present the system has no reheat. Addition of reheat is planned due to corrosion problems downstream from the scrubber. A separate operating crew operates the scrubber but the utility maintenance crew is used to service the scrubber.

Initial problems included erosion of fan blades and pump linings, scale downstream of the mist eliminator, and plugging of recycle pumps. Resistant materials were installed in the pumps and fans to reduce erosion. The area downstream of the mist eliminator is cleaned of scale semi-annually. Backup screens were placed in recycle pump lines to stop plugging (PE-259, BE-478).

Sherburne County No. 1 (Sherco No. 1) uses an approach to successful operation that is similar to that at La Cygne. A separate operating and maintenance crew was set up for the FGD system. Each night when the load drops, two of the twelve modules are inspected and cleaned. The crew at Sherburne County is smaller than at La Cygne, 35 men for Sherco No. 1 and No. 2 versus La Cygne's 51 for one unit. However, reliable operation is enhanced at Sherco No. 1 due to use of low sulfur coal (0.8 percent S), low SO_2 removal (50 percent), and the presence of a spare module.

The major initial problems were spray nozzles and plugging in the scrubber. Plastic nozzles were changed to a ceramic spinner vane type to overcome the nozzle problem. Plugging in the scrubber was reduced by modifying the strainer system and nozzle configuration (KR-115, PE-259).

Bruce Mansfield No. 1 is a system that apparently has been very successful on high sulfur coal, without a spare module[a], and without a special operating and maintenance crew. Operating experience has not been as trouble-free as the system's reported modular availability might indicate, however. As previously reported, the unit will be at half load for about three months in March-July 1977, while half of the stack is relined. Another three-month load reduction will be required later in 1977 to reline the other half of the stack. When the first reduction in load was included in the Bruce Mansfield data, availability for the system dropped to about 78 percent.

Some of the initial problem areas were the excessive maintenance for the fan housings, excessive carryover causing an acid rain problem, reheat burner problems, and failure of the stack liner. Fan housing maintenance has not been reduced. Additional mist eliminators were installed to reduce acid rain but the gas velocity was too great destroying the mist eliminator. The reheater is still not working well and the stack liner is being replaced.

Analysis of the FGD availability data in Table 3-4 and Figures 3-3 through 3-8 leads to several conclusions. No correlation between FGD availability and the size of the generating unit, the type of FGD process, the size of the FGD modules, or the ability to bypass was observed. Three systems examined in this study which have a large number of modules and/or a spare module (La Cygne No. 1, Sherburne County No. 1, and Bruce Mansfield No. 1) all have reasonably high modular availabilities. Application on a peaking or intermediate unit rather than base load allows maintenance to be performed on a more routine basis, and, therefore, enhances reliable operation. Since FGD units

[a]The FGD unit was to have 6 total modules with 1 being a spare. However, all 6 modules are required for satisfactory operation at full load. Another module is therefore being added to serve as a spare.

have operated successfully on low sulfur coal (e.g. Sherburne County No. 1) and high sulfur coal (e.g. La Cygne), the proper design and operation of the system were determined to be more important than the sulfur content of the coal. Historically, inclusion of spare modules and an open water balance without recycle are additional factors that have contributed to more reliable operation. The establishment of a separate operating and maintenance crew that is specifically trained to work with the FGD unit is a final important factor in reliable operation. All of these factors are important considerations in any analysis of system availability.

3.4 Effect of Flue Gas Desulfurization Availability on an Individual Utility Generating Station

Application of a flue gas desulfurization system to an electric utility generating station will have a direct effect on an individual generating station since the availability of the FGD unit has a direct impact on the ability of the station to meet demands for power. The individual utility generating station case for this study was assumed to be a base loaded station operating at or near full capacity. Base loading means that a unit is generally run at a constant or nearly constant output of electric power except during times when system economics dictate reductions in load to avoid shutting other units down. In general, base load units are the most economic units on a system. Edison Electric Institute (ED-043) defines base loading as "when a unit is generally run at or near rated output."

One way to estimate the effect of FGD on a utility generating unit is to take the product of the average estimated FGD unit availability and the average generating unit availability. This product is the resultant estimated average plant availability including the FGD system. The FGD unit availability is the availability of the entire FGD unit and is the probability that the FGD unit will operate a certain percentage of the time at a specific fraction of full capacity. In other words, an FGD unit availability is associated directly with some specific level of operation of the FGD unit and, therefore, some specific level of operation of the generating station to which the FGD unit is connected. This method of analysis does not consider partial outages or individual module failures.

Based on the data in Table 3-2 in Section 3.2.1, mature coal-fired units have an average operating availability of about 75 percent. This means that on the average the generating station would be capable of operation at its rated output 75 percent of the time.

A parametric study of the effect of FGD unit availability on an individual utility generating station was performed. Generating unit availability was assumed to be 75 percent while FGD unit availability was varied from 0 to 100 percent. The results of this parametric study are shown in Figure 3-9. As can be seen, the FGD unit availability has a dramatic effect on generating station availability and, therefore, on the ability of the generating station to respond to demands for power. It follows, then, that the results of an assessment of FGD impact rest heavily on the FGD unit's availability.

From the presentation and discussion of FGD operating experience in Section 3.2.2, an FGD modular availability in the 70 to 90 percent range was chosen for a mature FGD system in this study. The FGD unit availability at full capacity can be calculated using the modular availability, the number of modules in the FGD unit, and the number of modules required for operation at full capacity. Assume a five module FGD unit with identical

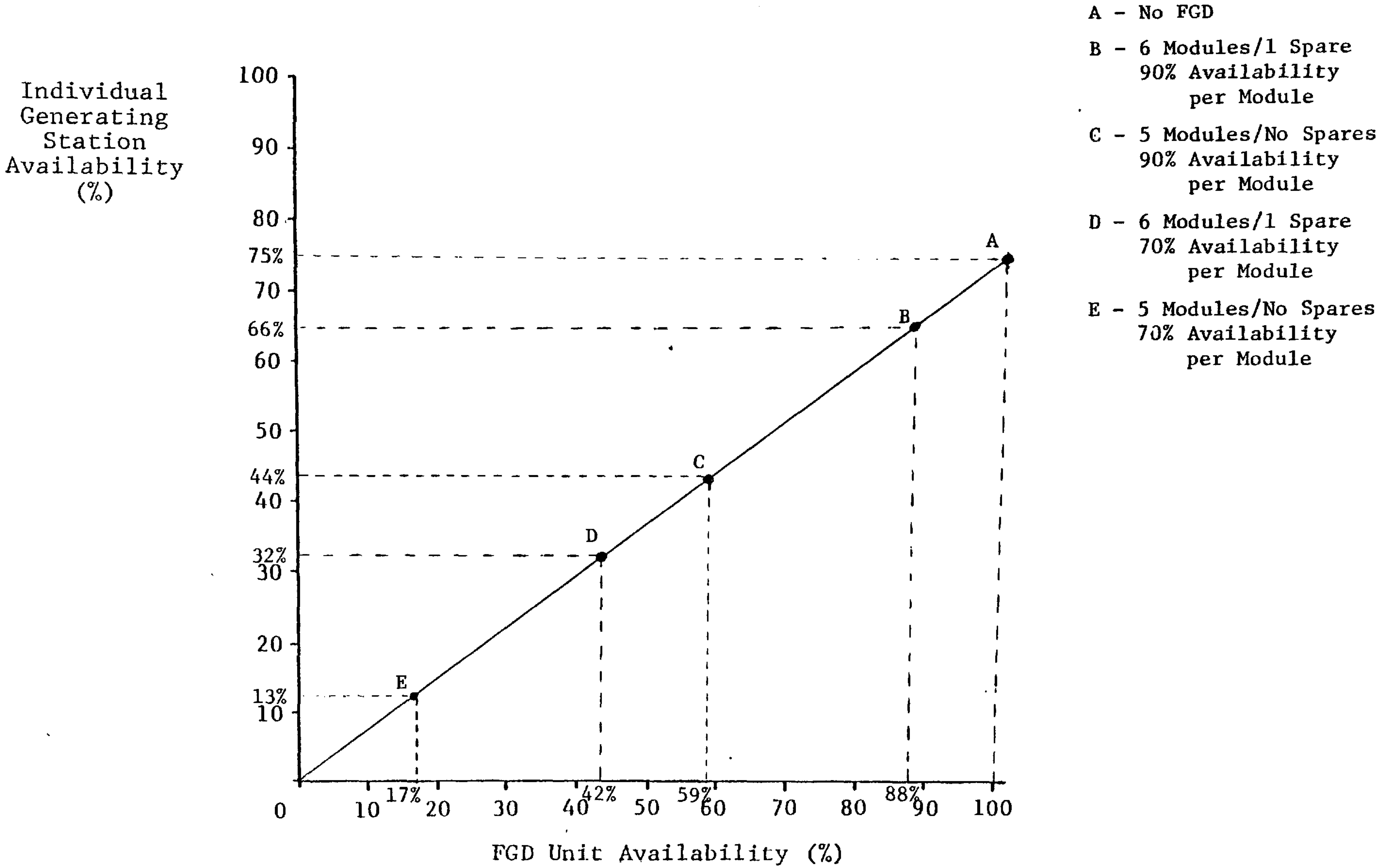

Figure 3-9. Effect of flue gas desulfurization unit availability on individual generating station availability at maximum load.

modules and no spares. With a 70 percent modular availability, the FGD unit availability at full capacity would be 17 percent. With a 90 percent modular availability, the FGD unit availability at full capacity would be 59 percent. The resultant plant availability for an individual generating station with an FGD system would then range from about 13 to 44 percent. These availabilities correspond to a significant reduction in the amount of time a station could operate at its rated output unless the station were allowed by bypass the FGD unit. For the 13 percent plant availability (70 percent FGD availability), a reduction of about 62 percent results. With a plant availability of 44 percent (90 percent FGD availability), the reduction is about 31 percent.

As a result, the ability of an individual generating station to meet consumer demands would be reduced by 31 to 62 percent due to the use of an FGD unit. This comparison is relative to a coal-fired unit with an availability of 75 percent. Since the unit considered in this section operates at rated output, the 31 to 62 percent reduction in availability would have to be offset in some manner. One solution would be to build additional generating capacity that can supply the power that is no longer generated by the individual station due to the application of the FGD unit. Another alternative is the sparing of selected FGD equipment and/or modules.

Assume a spare module is added to the FGD unit such that five of the six modules can treat the flue gas generated at full capacity operation of the boiler. The spare module results in a full capacity availability of 42 percent for the unit with a modular availability of 70 percent. The unit with a 90 percent modular availability has a full capacity availability of 88 percent with a spare module. The resultant plant availability for an individual station with an FGD unit would then range from about 32 to 66 percent. The use of a spare module, therefore, improves the availability of the unit dramatically. Unit availability improves still more with each spare module added but the economics become less favorable with each spare added. A preliminary examination of the impact of a spare module was completed for the individual utility generating station case. This examination is presented in Appendix B.

Previously, the discussion has been limited to operation of the utility generating station at full capacity. During periods of reduced load on the generating station an FGD module might be down but the FGD unit could possibly still treat all of the flue gas. For this reason, the availability of the unit for a range of boiler loads including partial outages and the load duration curve for the system are both important considerations. However, a comprehensive incorporation of this factor into this study was beyond the constraints of this study. The effect of a load duration curve was considered in a rudimentary manner in this study. A method which could be used to incorporate a load duration curve is also presented in Appendix B.

3.5 Effect of Flue Gas Desulfurization Availability on Generating Systems

This study considers the effect of FGD on the nine NERC regions and on the nation as a whole. The approach to this examination is the same as that used for an individual utility generating station in the preceding section. For the generating systems, however, the FGD units will only affect the new coal-fired capacity that comes under EPA's New Source Performance Standards. As previously stated, all of this new coal-fired capacity is assumed to use flue gas desulfurization as the method of SO_2 control. Therefore, the effect of FGD on each system is proportional to the new coal-fired steam turbine generating capacity in that system.

A parametric study of the effect of FGD availability on 10 utility systems was performed for the year 1985. FGD unit availability was varied from 0 to 100 percent. The effect of this availability on the new coal-fired capacity then determined the overall effect on the system. The new coal-fired capacity was represented as a single generating plant with one FGD unit composed of one module. FGD unit availabilities of 70, 80, and 90 percent are emphasized in estimating the impact of FGD availability on electric generation.

The effect of flue gas desulfurization on a utility system was estimated as shown below:

$$\% \text{ Capacity With FGD} = (100\% \text{ Capacity Without FGD}) - (\% \text{ New Coal}) \times (1\text{-FGD Availability})$$

The system is assumed to be at 100 percent capacity prior to application of FGD. The reduction in capacity due to the use of FGD was approximated as the product of the fraction of new coal capacity in a system and the reduction in availability of this new coal capacity due to FGD. The fraction of new coal represents coal-fired plants coming on line between 1976 and 1985.

For example, in 1985 System 4 has 14.5 percent new coal capacity (Table 3-1). If an FGD availability of 80 percent is assumed, the effect of FGD is estimated by

$$100\% - (14.5\%)(1-.8) =$$
$$100\% - (14.5\%)(.2) =$$
$$100\% - 2.9\% = 97.1\%$$

Therefore, the estimated effect of the use of FGD is a reduction of generating capacity to 97.1 percent of the capacity without FGD. The impact of FGD on each system examined using the method above is shown in Table 3-15 for 1985. Projections were not carried beyond 1985 because data for the systems examined was not readily available beyond 1985. Additional follow-on work will be done to carry the projections through 1998 and to also consider other factors such as load demand curves.

The effect of FGD varies from system to system depending on the amount of new coal capacity and the FGD availability that is assumed. System 2 shows the greatest impact while System 3 is the least affected. The percent new coal for each system is shown in Table 3-16.

The effect of FGD availability on a generating system is observed to be less dramatic than for an individual station. This would be expected due to the diluting effect of power generation with fuels other than coal or with coal units that do not have FGD systems for SO_2 control. For a single new coal station the entire station was affected by FGD availability. Conversely, only the new coal capacity of a generating system is affected by FGD.

Table 3-15. ESTIMATED EFFECT OF FLUE GAS DESULFURIZATION UNIT AVAILABILITY ON 1985 SYSTEMS[a]

System	FGD Unit Availability (%)[b]		
	70	80	90
1	94	96	98
2	90	93	96
3	99	99+	99+
4	95	97	99
5	91	94	97
6	99	99+	99+
7	97	98	99
8	91	94	97
9	96	97	98
10	95	97	98+

[a]Effect is determined by the ratio of system generating capability with FGD units over system generating capability without FGD units expressed as a percentage.

[b]One FGD unit composed of one module on a single generating station representing all new coal capacity.

TABLE 3-16. NEW COAL GENERATING CAPACITY IN EACH SYSTEM - 1985[a]

System	% of 1985 Total Capacity
1	18.4
2	33.6
3	3.5
4	14.5
5	29.2
6	4.4
7	11.7
8	30.0
9	13.5
10	16.0

[a]Fraction of 1985 total capacity represented by coal-fired units coming on-line between 1976 and 1985.

The significance of the 1985 impacts shown in Table 3-15 is difficult to put into perspective until a comparison is made with consumer demand. The National Electric Reliability Council (NERC) has projected the 1985 summer total resources and peak loads in megawatts for the systems examined in this study (NA-325). The summer peak demand as a fraction of the total summer resources for each system is presented in Table 3-17.

TABLE 3-17. SUMMER PEAK LOADS - 1985 PROJECTIONS BY NERC

System	Summer Peak Load (%)[a]
1	89
2	82
3	78
4	85
5	80
6	71
7	85
8	88
9	76
10 (Nation)	81

[a]Expressed as a percentage of the total summer resources (MW) projected for 1985 by NERC.

Source: NA-325

Each of the cases presented for 1985 in Table 3-15 can potentially meet the highest summer peak load projected by the NERC for 1985 (Table 3-17). However, it is critical to understand that the primary reason consumer demand can be met in these 1985 example systems is the excess capability above peak loads that is built into the utility systems. The maximum summer peak load projected for 1985 is not greater than 89 percent of total resources due to the presence of excess capacity. Table 3-17 indicates that the excess capability above the peak load varies from 11 to 24 percent. The utility industry is required to maintain these types of excess capabilities to insure their ability to meet consumer demand, to allow for growth of demand, and to provide emergency power if a generating unit or units, a transmission line, or an interconnection should fail.

To maintain this generating capability above maximum demand, a general reduction in generating capability that occurs for any reason including the application of FGD must be offset. The effect of the reduction in generating capability due to FGD unit availability was estimated assuming that reductions would be offset by the addition of more generating capacity.

It is important to note that the data in Table 3-15 are for 1985. Because lead times for construction of new coal generating units range from 7 to 10 years, 1985 is probably the first year that the effects of the NSPS would be seen. Because of the projected rapid growth in requirements for new coal units brought on by the energy crisis, it is important to estimate the effects of a revised NSPS in years beyond 1985. The amount of new coal generating capability beyond 1985 that would be subject to any revised new source performance standards has been estimated as 133,800 Mw in 1988 and 386,800 Mw in 1998 (WO-139). The 1988 estimate includes the 1980-1988 projects while the 1998 estimate includes 1980-1998. The additional generating capacity required to offset the reduction in generating capability caused by FGD is thus expected to increase significantly between 1985 and 2000 due to this threefold increase in new coal capacity. Consequently, the effects of FGD on reliability will probably increase in magnitude in the future. Rough estimates of this effect, obtained by analyzing all new coal as a single unit with a single scrubber unit composed of one module, are given in Table 3-18. Average FGD availabilities of 70, 80, and 90 percent were assumed. These additional generating requirements are estimates for the entire United States. They cannot be apportioned or extrapolated to any specific generating system.

TABLE 3-18. ESTIMATE OF MEGAWATTS OF ADDITIONAL GENERATING CAPACITY REQUIRED TO OFFSET THE EFFECT OF FGD IN 1988 AND 1998

Year	FGD Availability[a]		
	70%	80%	90%
1988	40,100 Mw	26,800 Mw	13,400 Mw
1998	116,000 Mw	77,400 Mw	38,700 Mw

[a]One FGD unit composed of one module on a single generating unit representing all new coal capacity.

4.0 IMPROVEMENTS TO FLUE GAS DESULFURIZATION AVAILABILITY

Solutions to some of the problems encountered by lime/limestone FGD systems have been found. The system components which are subject to high failure rates have also been identified. Methods to overcome these high failure rates such as sparing or maintenance have subsequently been examined. Certain measures that have resulted or can result in high levels of system availability have also been defined by the FGD industry. A discussion of each system operating experience as to problems and solutions follows in Section 4.1. Component failures are then examined in Section 4.2. Finally, measures to improve availability are presented in Section 4.3.

4.1 Operating Experience for Existing Systems

The problems which have been encountered and solved at seven existing FGD systems were documented. The applicability of the solutions at one site to other sites was also examined. The seven systems surveyed were Will County No. 1, La Cygne No. 1, Phillips, Cholla No. 1, Green River, Sherburne County No. 1, and Bruce Mansfield No. 1. The operating problems, solutions or approaches to solutions, and unit maintenance are given in Table 4-1.

A similarity in the problems from system to system is observed. These problems can be generally grouped as follows: (1) erosion of pumps, seals, and control valves; (2) deposits, plugging, or scaling on scrubber internals, nozzles, strainers, mist eliminators, and in-line reheaters; (3) corrosion of fans, reheaters, ducts, and stacks; and (4) vibration and poor thermal mixing with direct-fired reheaters. Solutions

TABLE 4-1. SUMMARY OF PROBLEMS, SOLUTIONS, AND MAINTENANCE AT EXISTING FGD SYSTEMS

Unit	Operating Problems	Solutions	Unit Maintenance	References
Will County No. 1 (Commonwealth Edison)	Plugging and scaling in demister and occasionally the reheater.	Convert to more open design mist eliminator. Change constant demister underspray to fresh water and install intermittent overspray.	Repacking pumps, plugged slurry feed lines, wash reheater down every 2-3 months, wash fans when unit is down, repair corrosion areas.	RO-243 IS-021 PE-259 CO-596 CH-393 RO-314 RE-263
	Corrosion and erosion of reheater tubes.	Improved mist elimination. Repair in tubes.		
	Vibration of and deposition on reheater tubes.	Baffles and rebracing stopped vibration. Improved 2-stage demister reduced deposition.		
	Limestone blinding.	Remove scrubber from service.		
	Erosion and plugging of spray nozzles.	Change nozzles.		
	Internal and external buildup of deposits on venturi nozzles.	Clean nozzles.		
	Fan vibrations.	Clean and rebalance fans.		
	Operation with high S coal resulted in high slurry carryover, demister plugging, reheater coil fouling and leaks, massive absorber scale, fan rotor scale.			
La Cygne No. 1 (Kansas City Power & Light)	Corrosion of reheat tubes.	Replace some tubes with resistant materials and remove some tubes. Inject hot air from combustion air preheater at reheater inlet. Results in 70 MW derating of boiler due to limiting fan capacity.	Clean one module each night on a rotating basis. Cleaning requires 3 men 10-12 hours for each module. Areas requiring attention: reheater pluggage, demister pluggage, venturi well and nozzle deposits, sump accumulation. Fans are shut down 4-10 hours every 4-5 days. Scrubber operating and maintenance force: 33 operating, 16 maintenance, 2 administrative. Total-51.	CH-393 CO-596 RO-243 RO-314 PE-259 MC-293 MC-289 MC-295
	Deposits on induced draft fan blades.	Shut down fan for high pressure washing.		
	Corrosion of induced draft fans.	Test coatings and corrosion resistant metals.		
	Corrosion of duct works after ID fans.	Replace expansion joints and some duct panels.		
	Erosion in Venturi nozzles.	Install hydroclone in slurry recycle line.		
	Corrosion of carbon steel lances for demister underwash.			
	Rubber lining flaking off recycle slurry system.			
	Hard scale, especially in absorber trays.	Closely control pH to reduce scale.		
	Deposits in reheaters, demisters, sumps, venturi walls, nozzles, strainers.	Large maintenance crew.		
	Sludge deposits in elevated duct work between fans and stack.			
	Instability of I.D. fans develops at full power and trips boiler safety controls.	Derate plant to avoid activation of safety controls.		
	Erosion and corrosion of mist eliminators.	Replace with thick, corrosion resistant, reinforced plastic assemblies.		
	Corrosion of stack inner structure due to acid condensation.	Coat stack with resistant material.		

TABLE 4-1 (Continued). SUMMARY OF PROBLEMS, SOLUTIONS, AND MAINTENANCE AT EXISTING FGD SYSTEMS

Unit	Operating Problems	Solutions	Unit Maintenance	References
Phillips (Duquesne Light)	Solids buildup on induced draft fans.	Reduced by redesign of spray washers.	General operation has one of four trains out continually for repairs, cleaning, and preventive maintenance.	RO-243 KN-039 CO-596 CH-393 RO-314 PE-107 PE-265 PE-266 PE-267
	Corrosion resistant coatings on fans broke off causing fan imbalance.	Adherent coatings have not been found.		
	Acid condensation near the base of the brick-lined stack penetrated the mortar.	Mortar in the brick-lining was repaired.		
	Corrosion and erosion at the fan welds.	Automatic washing is not solution. Use resistant materials.		
	Erosion of slurry recirculation pump impellers. Pump seals also erode.	Alternate designs and materials were tested. Not solution as yet.	Every 3,000-5,000 service hours shut a train down for one month inspection, cleaning, and repairs. Every 6 months isolate a thickener for inspection, cleaning, and repairs. 8 maintenance and 13 operators full-time. Also average 7.7 men per day from craft union.	
	Solids buildup in scrubber loop have prevented closed loop operation.	Blowdown a bleed stream until solution is found.		
	Rubber-lined plug-type bleed valves eroded.	Replace with pinch-type valves.		
	Solids deposition in scrubber restricts gas flow.	Vessel must be completely cleaned about every 1400 service hours. Cleaning requires 1400-1700 man-hours. One boiler was routed through the scrubber bypass to prevent loss of boiler capacity (Aug 75-Jan 77).		
	In-line fuel-oil reheater is not operational. Corrosion in burner and chamber. Poor thermal mixing resulted in hot spots in ducts downstream of reheater.	Operating solutions have not been successful.		
Cholla No. 1 (Arizona Public Service)	Corrosion of reheater tubes and duct expansion joints due to acid runoff from duct walls.	Insulate ducts and replace expansion joints with rubberized fabric type. Install baffle to divert condensed acid from tubes.	Required for nozzles, scale removal, valve wear, pump packing, pump impellers, process liners, reheater, and mist eliminators. Jan-Aug 1973 averaged 30 man-hours/day. Represents about 40% of total utility maintenance. Repair linings and coatings in localized area. Six full-time maintenance personnel.	RO-243 MU-074 PE-259 CO-596 CH-393 RO-314 HE-258
	Impeller corrosion on pumps.	Rebuild pumps.		
	Plugging of packed tower and mist eliminators when system is brought down.	Water wash on shut down.		
	Vibration of reheater tubes.	Partially damp with baffles.		
	Scaling and plugging first stage demister.	Redesign demister.		
	Plug nozzles.	Increase liquor velocity - not totally eliminate problem.		
	Solids buildup in pump seal water.	Reverse packing gland position.		
	Plugged process lines.	Modify piping layout.		
	Erosion in pumps.	Rebuild pumps.		
	Corrosion in mist eliminators and in duct work.	Line with resistant material.		

TABLE 4-1 (Continued). SUMMARY OF PROBLEMS, SOLUTIONS, AND MAINTENANCE AT EXISTING FGD SYSTEMS

Unit	Operating Problems	Solutions	Unit Maintenance	References
Green River (Kentucky Utilities)	Failure of recycle, pumps and feed tank agitator.	Repair.	Areas requiring attention: recycle pumps, pond pumps, contactor bed, demisters, agitators. Maintenance represents about 25% of total scrubber operating costs. Work force includes 4 operators and 1 instrument man. Utility maintenance crews are presently used but scrubber maintenance personnel may be added in the future.	PE-259 AN-184 SI-174
	Frozen lines.	Thaw and repair.		
	Deposition in pumps and tanks.	Clean out pumps and tanks.		
	Failure of rubber-lined pump impellers.	Replace with unlined impellers.		
	Vibration in ID booster fan.	Repair.		
	Deterioration of stack liner.	Repair and replace liner.		
	Plugging of contactor bed.	Wash out manually when unit is down.		
	Failure of gland packing in slurry recycle pumps.			
Sherburne County No. 1 (Northern States Power Co.)	Slurry bypassing strainers ahead of recycle pumps and plugging nozzles.	Possible solution is replacement with perforated plate and soot blower. Presently clean nozzles during maintenance.	Two modules are checked and cleaned each night. Areas requiring attention: nozzles, venturi, marble bed, demisters, reheater, valves, pumps. Each module requires 2-8 hours for maintenance. Maintenance crews-12 men: 6 days/week for #1 and 2. A crew of 35 is required to maintain scrubber operations for Sherco #1 and #2.	PE-259 RO-243 KR-115 KR-116
	Soot blower not operating properly.			
	Erosion of spray nozzles.	Replace with ceramic nozzles.		
	Erosion of sidewalls of reaction tank.	Use stainless steel wear-plate as temporary solution.		
	Erosion of valves.			
	Mud/scale in marble bed.	Breakup and wash manually.		
	Deposition of soft solids in mist eliminators and reheater.			
	External corrosion of reheater tubes.	Modifications have been attempted to resolve stress problem.		
	Instrumentation problems.	Two technicians to maintain instruments.		
	Failure of rubber lining. Subsequent plugging of downstream nozzles and headers.	Remove rubber lining. Carbon steel has now failed from erosion.		
	Wear and sealing problems with spray water pump.	Evaluate new materials for pump internals and rubber-lined pump.		
Bruce Mansfield No. 1 (Pennsylvania Power Co.)	Inadequate mist elimination.	Attempt to increase capacity with little success.	Not available.	WO-130
	Demister plugging.			
	Vibration in reheater.			
	Corrosion of rubber-lined booster fan linings.	Repair rubber linings.		
	Erosion of first stage venturi lining followed by corrosion.	Install wear plates.		
	Bubbling of stack lining resulting in corrosion of metal beneath.	Repair lining.		
	Plugging of strainers.			
	Erosion of control valves.			
	Erosion of pumps.	Test materials of construction.		

are also often similar and, therefore, often applicable from one system to the other. However, any application must be examined on a case-by-case basis. Resistant materials or coatings have generally been used in attempts to overcome erosion and corrosion problems. Careful control of the scrubber operation and the prevention of solids entrainment in the gas have been partially successful in preventing deposits buildup, plugging, or scale. The use of large operating and maintenance crews in addition to control of the chemistry appears to be the most dependable solution to plugging and scaling at this time, however. This approach also applies to erosion and corrosion problems in some instances. Workable solutions for the direct-fired reheater problems have not been reported.

4.2 Flue Gas Desulfurization Component Failures

The system components with high failure rates were found to be primarily the same items identified in the previous section on operating problems. These items include the slurry pumps, pump gland water system, nozzles, control valves, fans, mist eliminators, and reheaters.

The slurry pumps, gland water system, and control valves can be readily spared in any system to a sufficient degree that the effect of high failure rates for these items can be reduced. On the other hand, the nozzles, fans, mist eliminators, and reheaters are unique to each module and, therefore, cannot be readily spared within a module. As a result, the only way these items can be spared is to spare the entire module. This is much more expensive than the internal sparing of pumps, gland water systems, or control valves. Nevertheless, the costs can be justified if sparing a module can significantly reduce the effect of the high failure rates of these components.

Rotating maintenance, such as that performed at La Cygne and Sherburne County, can also significantly reduce the failure rates of these components. Frequent inspection and maintenance by a crew associated exclusively with the FGD system has proven very successful at both La Cygne and Sherburne County. Use of a separate crew trained to operate the FGD system and an instrumentation maintenance crew can also help to reduce failure rates in general.

4.3 Measures to Improve Flue Gas Desulfurization Availability

Various measures have been or can be used to maintain high levels of FGD availability. These measures can be grouped into maintenance methods, operating techniques, and design concepts. These three types of measures are defined and assessed in this section.

Maintenance Methods

The extensive maintenance programs applied at La Cygne and Sherburne County have successfully maintained a high system availability. The important factors in these maintenance programs are: (1) taking one or more modules off-line each night for inspection and cleaning, (2) use of a separate maintenance crew trained to work on the FGD system, and (3) a general dedication to gaining a better understanding of the system and how to maintain it better.

The areas or components in the system that should be given the most attention vary somewhat depending on the design. For most systems they will include the nozzles, headers, strainers, scrubber internals, pump packing and impellers, mist eliminators, fans downstream of the scrubber, reheaters, agitators, valves, and slurry lines.

Operating Techniques

There are several operating techniques that have been or can be used to contribute to maintaining a high FGD system availability. Over and underspray of mist eliminators (demisters) removes deposits from the mist eliminators. Open loop oepration of the demister wash cycle is more effective than the use of only recycle water. Fresh water is used to dilute the recycle water to reduce the potential for scale formation on the demister. Increased utilization of the lime or limestone also improves demister operation by reducing the quantity of calcium ion entrained in the gas which in turn reduces the scaling potential.

Operating with an open loop water balance has also benefited FGD systems. The discharge of water from the system reduces the chloride and dissolved solids concentrations in the process water. The chlorides promote corrosion while the dissolved solids enhance the potential for scaling and plugging. However, discharged water quality considerations must be considered. Operating the system subsaturated with respect to sulfates also reduces sulfate scaling potential.

Automatic pH and process control result in more stable operation and tend to prevent major failures such as massive scaling. On-site routine chemical monitoring of relative saturations of sulfite and sulfate can aid in the detection of scaling conditions.

Finally, a staff of operators and technicians to work with the FGD system on a daily basis is very important. As in the maintenance area, the quality of the operating crew can significantly affect availability.

<u>Design Concepts</u>

Each of the FGD systems examined in this study differs somewhat in design concept. Some of the concepts that have been or potentially can be successful in enhancing availability are: (1) dry particulate removal before the FGD system with an electrostatic precipitator (ESP), (2) dry flue gas booster fan between the ESP and scrubber rather than a wet fan after the scrubber, (3) adequate redundancy of pumps, valves, lime/limestone feed systems, packing gland water systems, etc., (4) spray tower scrubber configuration, (5) adequate instrumentation for pH, SO_2, additive use, etc. with automatic controls, (6) indirect reheat of flue gas, and (7) adequate particle dropout area to reduce solids carryover to the mist eliminators.

Dry particulate removal overcomes the erosion and corrosion problems of wet particulate removal. A dry fan that is upstream of the scrubber is not subject to the deposits, erosion, and corrosion that a wet fan encounters. The wet fan is moving a wet gas that: (1) has entrained solids that will stick to the fans, and (2) contains acid that can condense on the fan or be picked up by deposits on the fan. An example is Bruce Mansfield. Units No. 1 and No. 2 have wet particulate removal and wet fans. The problems associated with No. 1 were presented in Section 4.1. Unit No. 3 will have an ESP and a dry fan.

A spray tower scrubber is another concept being considered. Spray towers can reduce the erosion and plugging problems associated with some other types of contactors. Bruce

Mansfield and Sherburne County are examples. Bruce Mansfield No. 1 and No. 2 have two-stage venturis. No. 3 will have a horizontal spray tower. Sherburne County No. 1 and No. 2, which use a marble bed contactor, is examining substitution of a spray tower for the marble bed.

Automatic controls are being installed by Sherburne County No. 1 and No. 2 and by Phillips to improve operation of these systems. Phillips is also installing a redundant lime feed system.

Indirect reheat is more reliable than other types of reheat. Indirect reheat is accomplished by heating air by steam or hot water heat transfer, direct combustion, etc. outside the flue gas duct and, then, combining this hot air with the flue gas in the duct. Indirect reheat avoids the placement of a heat exchanger in the flue gas stream or firing a direct combustion unit in the duct.

An adequate particle dropout area before the mist eliminator reduces the carryover of large particles to the mist eliminators by the flue gas. The distance between the top of the contacting zone and the mist eliminator and the velocity of the gas are two factors that affect the dropout area. A turn in the duct between the scrubber and the mist eliminator also reduces the quantity of particles in the gas.

APPENDIX A

RELIABILITY/AVAILABILITY
DEFINITIONS USED BY EEI AND PEDCo

DEFINITIONS USED BY EDISON ELECTRIC INSTITUTE (ED-043)

A. EQUIPMENT DEFINITIONS

1.	Non-header Unit	Unit in which a single boiler is connected solely and independently to a given turbine-generator.
2.	Header Unit	Unit in which the turbine-generator is not solely and independently connected to single boiler.
3.	Major Equipment	Major group of equipment within a unit, such as: boiler, reactor, generator, steam turbine, condenser.
4.	Component	Part within a "major equipment" group, such as: superheater tube, governor, buckets, boiler feed pump.
5.	Maximum Dependable Capacity (MDC)	The dependable main-unit capacity winter or summer, whichever is smaller.

B. OPERATION AND OUTAGE DEFINITIONS

1.	Available	The status of a unit or major piece of equipment which is capable of service, whether or not it is actually in service.
2.	Base Loading	When a unit is generally run at or near rated output.
3.	Cranking Loading	When a unit is generally shut down on standby for auxiliary power during emergency.
4.	Cycling Loading	When a unit is generally run but at a load which varies widely with system demand.
5.	Economy Outage	(See Reserve Shutdown)
6.	Forced Outage	The occurrence of a component failure or other condition which requires that the unit be removed from service immediately or up to and including the very next weekend.

7.	Forced Partial Outage	The occurrence of a component failure or other condition which requires that the load on the unit be reduced 2% or more immediately or up to and including the very next weekend.
8.	Maintenance Outage	The removal of a unit from service to perform work on specific components which could have been postponed past the very next weekend. This is work done to prevent a potential forced outage and which could not be postponed from season to season.
9.	Non-curtailing Equipment Outage	The removal of a specific component from service for repair, which causes no reduction in unit load or a reduction of less than 2%.
10.	Non-operating Equipment Test	A scheduled test or required operation of a back-up system which is not normally operating.
11.	Outage Cause	A component failure, preventive maintenance, or other condition which requires that the unit or a component be taken out of service or run at reduced capacity.
12.	Peaking Loading	When a unit is generally shut down and is run only during high demand periods.
13.	Planned Outage	The removal of a unit from service for inspection and/or general overhaul of one or more major equipment groups. This is work which is usually scheduled well in advance (e.g., annual boiler overhaul, five-year turbine overhaul).
14.	Reserve Shutdown	The removal of a unit from service for economy or similar reasons. This status continues as long as the unit is out but available for operation.

15. Scheduled Partial Outage — The occurrence of a component failure or other condition which requires that the load on the unit be reduced 2% or more but where this reduction could be postponed past the very next weekend.

16. Unavailable — The status of any major piece of equipment which renders it inoperable because of the failure of a component, work being performed or other adverse condition.

C. TIME DEFINITIONS

1. Available Hours (AH) — The time in hours during which a unit or major equipment is available; SH + RSH.

2. Demand Period — The time interval each day which is the period of maximum demand on a particular system.

3. Economy Outage Hours (See Reserve Shutdown Hours) (TEOH) — The theoretical value of Economy Outage Hours (TEOH) is the difference between Available Hours and Service Hours. If the TEOH differs by less than 1% with the Economy Outage Hours reported at the end of the year, they are considered equal and flagged with Code 1. If the difference is more than 1%, but less than 10%, they are flagged with Code 3; but the reported Economy Outage Hours are still used. However, if the difference is greater than 10%, the calculated value TEOH is used, and Code 2 is a flag that Economy Outage Hours have been derived.

4. Forced Outage Hours (FOH) — The time in hours during which a unit or major equipment was unavailable due to a Forced Outage.

5. Forced Partial Outage Hours (FPOH) — The time in hours during which a unit or major equipment is unavailable for full load due to a forced partial outage.

6.	Hours Waiting (HW)	That portion of time for any outage during which no work could be performed. This includes time for cooling down equipment and shipment of parts. This is time that could not be affected by a change in work schedule or the number of men worked.
7.	Maintenance Outage Hours (MOH)	The time in hours during which a unit or major equipment is unavailable due to a maintenance outage.
8.	Period Hours (PH)	The clock hours in the period under consideration. (Generally one year)
9.	Planned Outage Hours (POH)	The time in hours during which a unit or major equipment is unavailable due to a planned outage.
10.	Reserve Shutdown Hours (RSH)	Reserve shutdown duration in hours.
11.	Schedule Partial Outage Hours (SPOH)	The time in hours during which a unit or major equipment is unavailable for full load due to a scheduled partial outage.
12.	Service Hours (SH)	The total number of hours the unit was actually operated with breakers closed to the station bus.
13.	Unit Years (UY)	This term is the common denominator used to normalize data from units of the same type with different lengths of service. The following example contains 20 UY of experience from 4 units.

Unit	A	B	C	D	4
Years in Service	8	3	7	2	20

14.	Work (Manhours Worked) (MH)	The total number of manhours worked on or off site to accomplish repairs.

D. <u>EQUATIONS</u>

1.	Average Forced Outage Duration	(Summation of FOH)/(Number of Forced Outages)
2.	Capacity Factor	[(Total Generation in MW-Hr)/(PH x MDC)] 10
3.	Component Outage Severity Index	The average number of forced outage hours of a specific component per incident.

4.	Equivalent Forced Outage Rate (EFOR) (for each forced partial outage, an equivalent full load outage duration is calculated to include the effect of partial as well as full forced outages on the forced outage rate)	EFOR is calculated as follows: TE = FPOH (CR/CF) WHERE: TE is equivalent forced outage time CR is size of reduction or derating from full load CF is rated capacity THEN: EFOR = 100 ((TF + TES)/(TO + TF + TAS + TPS)) WHERE: TF is total full forced outage time TO is total operation time at 100% availability TAS is sum of actual forced partial outage times TES is sum of equivalent forced outage times TPS is sum of equivalent scheduled partial operating times
5.	Forced Outage Incident Rate	[(Forced Incidents)/(Forced + Maintenance + Planned Incidents)] 100
6.	Forced Outage Rate	[FOH / (SH + FOH)] 100
7.	Forced Outage Ratio	[FOH/(Total Unavailable Hours)] 100
8.	Operating Availability	[AH/PH] 100
9.	Output Factor	(Total generation in MW-Hr) x 100/ (SH x MDC)
10.	Service Factor	[SH/PH] 100

11. Relative Mechanical Availability (RMA)

Relative Mechanical Availability is a form of Operating Availability adjusted to show relative effort. The prime assumption is that most outage time is affected by work schedules and crew sizes. Relative Mechanical Availability uses an Adjusted Outage Time (AOT) based on effort. Manhours worked is a measure of effort which is reasonably independent of work schedules and crew sizes. Manhours worked (MH) divided by a standard work force (SWF) gives a derived time worked based on effort. If we assume a round-the-clock schedule, then this derived time worked is almost a derived outage time based on effort. The difference is the amount of outage time which is independent of effort called Hours Waiting (HW), See Appendix C-6. An arbitrary assumption of ten men for the standard work force gives:

$$AOT = HW + MH/10$$

Then substituting AOT for outage time in the equation for operating availability gives:

$$\begin{aligned} RMA &= [(PH-AOT)/PH] \quad 100 \\ &= [(PH-(HW + MH/10))/PH] \quad 100 \end{aligned}$$

DEFINITIONS USED BY PEDCo ENVIRONMENTAL

Boiler Capacity Factor	(kWh generation in year)/(maximum continuous generating capacity in kW x 8760 hr/yr).
Boiler Utilization Parameter	Hours boiler operated/hours in period, expressed as a percentage.
Efficiency, Particulates	Operational - The actual percentage of particulates removed by the FGD system and the particulate control devices from the untreated flue gas. All others - The design efficiency (percentage) of particulate removed by the FGD system and the particulate control devices.
SO_2	Operational - The actual percentage of SO_2 removed from the flue gas. All others - The design efficiency.
FGD Availability Factor	Hours the FGD system was available for operation (whether operated or not)/hours in period, expressed as a percentage.
FGD Reliability Factor	Hours the FGD system operated/hours FGD system was called upon to operate, expressed as a percentage.
FGD Operability Factor	Hours the FGD system was operated/boiler operating hours in period, expressed as a percentage.
FGD Utilization Factor	Hours FGD system operated/hours in period, expressed as a percentage.

APPENDIX B

INTERACTION OF SPARE MODULES AND UTILITY LOAD CURVES WITH THE ABILITY TO MEET CONSUMER DEMAND

Two aspects of the assessment of the effect of FGD availability on electric utilities have been examined in only a preliminary manner in this study. These aspects are: (1) use of spare modules in an FGD unit to improve the availability of the unit, and (2) the interaction of outage rates with the load duration curve to assess the ability to meet consumer demand. Each of these aspects will be discussed in more detail in this Appendix.

The results of the use of spare modules were determined by calculating the probability of the various numbers of modules being available for FGD units with and without a spare module. It was assumed that the demand on the utility plant was always equal to the available capacity. Also the availability of different plants and different modules is independent.

The three equations used to calculate these probabilities are:

$$P_L = A \sum_{\ell=L}^{L+K} \frac{(L+K)!}{(L+K-\ell)!\,\ell!} B^{\ell} (1-B)^{L+K-\ell} \qquad \text{(B-1)}$$

$$P_{\ell} = A \frac{(L+K)!}{(L+K-\ell)!\,\ell!} B^{\ell} (1-B)^{L+K-\ell} \quad \text{where } 1 \leq \ell < L \qquad \text{(B-2)}$$

$$P_o = 1 - \sum_{\ell=1}^{L} P_{\ell} \qquad \text{(B-3)}$$

P_L = probability that generating station with FGD can operate at full capacity

P_{ℓ} = probability that generating station with FGD can operate at ℓ/L of full capacity

P_o = probability that generating station with FGD is not available

A = availability of generating station

B = availability of each FGD module

ℓ = number of FGD modules available

L = number of FGD modules required at full capacity

K = number of spare FGD modules at full capacity

The availability for a single generating plant without FGD was assumed to be 75 percent. A five module FGD unit was selected for examination. The four cases examined were: (1) FGD modular availability of 70 percent with no spare module, (2) FGD modular availability of 70 percent with one spare module, (3) FGD modular availability of 90 percent with no spare module, and (4) FGD modular availability of 90 percent with one spare module. The results of the probability calculations are shown in Table B-1.

A spare module is particularly important at full capacity. For a 90 percent modular availability, the generating station availability increases from 44 to 66 percent due to the presence of a spare module. The impact of the spare module is lessened as the load on the FGD unit is reduced. For example, a generating station at 80 percent capacity would require four modules. The availability of the FGD unit with 90 percent modular availability increases from 69 percent to 73 percent (P_4 plus P_5) due to the spare module. This difference is obviously not as significant as for operation of the generating unit at full capacity.

Table B-1. Probability Determination for a Generating Station with FGD

	A = .75 and L = 5			
	B = .70		B = .90	
	K=0	K=1	K=0	K=1
P_5	.13	.32	.44	.66
P_4	.27	.24	.25	.07
P_3	.23	.14	.05	.01
P_2	.10	.04	.01	.01
P_1	.02	.01	.00	.00
P_0	.25	.25	.25	.25

Next, consider the interaction of the outage rate with a unit load duration curve to assess the ability to meet consumer demand. An example load duration curve is shown in Figure B-1. The load is observed to be greater than 90 percent of capacity only about 5 percent of the time. Furthermore, the load is above 80 percent of capacity about 35 percent of the time. In other words, the demand on the utility is less than or equal to 80 percent of capacity for 65 percent of the time.

Again, assume five modules must be available for operation of the generating unit at full capacity. At 80 percent of capacity, four modules would then be required. Therefore, the load can be met about 69 percent of the time with a modular availability of 90 percent and no spare module (P_4 plus P_5 in Table B-1). A spare module allows load to be met about 73 percent of the time.

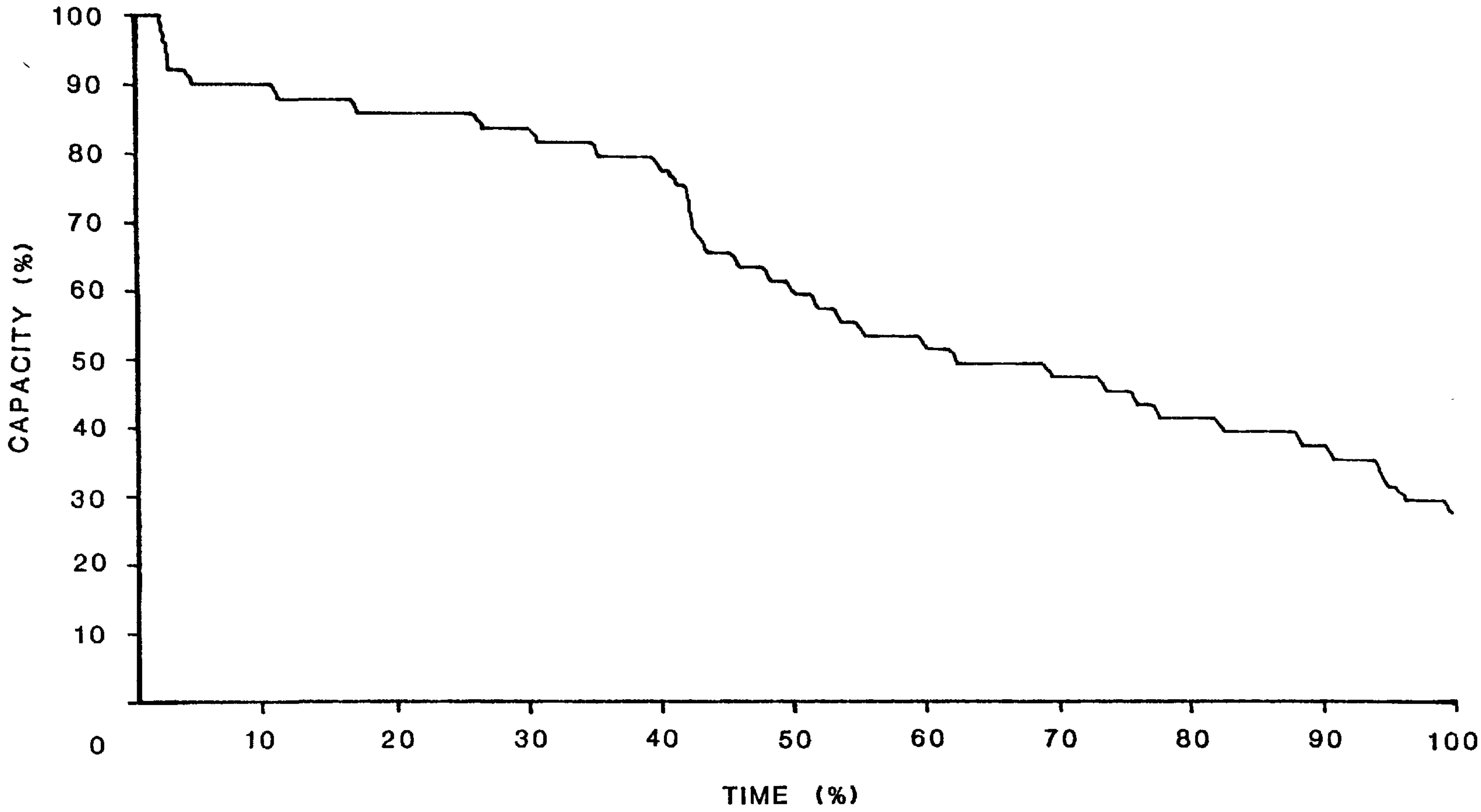

Figure B-1. Example Load Duration Curve

SOURCE: HA-697

This brief example merely serves to point out the importance of the load duration curve in any evaluation of the ability of a utility to meet consumer demand. The curve in Figure B-1 is only an example and should not be applied to any specific generating unit. Further study is necessary to apply this theory to actual systems.

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16. ABSTRACT The report gives results of an analysis of the effect of the availability of a flue gas desulfurization system on the ability of an individual power plant to generate electricity at its rated capacity. (The availability of anything is the fraction of time it is capable of service, whether or not it is actually in service.) Also analyzed are its effects on a power generating system (a group of several coal-, oil-, and gas-fired power plants plus nuclear and hydroelectric plants).

17. KEY WORDS AND DOCUMENT ANALYSIS

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

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