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Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plants and Other Existing Stationary Facilities

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PREFACE

Part I provides guidance on identifying those sources to be analyzed for BART, assessing the anticipated improvement in visibility, conducting an engineering analysis, and establishing emission limitations for BART. Part II contains an explicit discussion of the engineering analysis required by Part I. Part II is primarily for the analysis of fossil fuel-fired power plants with a generating capacity in excess of 750 MW. The procedures outlined in Part I, however, may be used for other existing stationary facilities as well.

PART I

GUIDELINE FOR DETERMINING

BEST AVAILABLE RETROFIT TECHNOLOGY

PART I. GUIDELINE FOR DETERMINING BEST AVAILABLE RETROFIT TECHNOLOGY

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PART I. GUIDELINE FOR DETERMINING BEST AVAILABLE RETROFIT TECHNOLOGY

1.0 INTRODUCTION

Section 169A of the Clean Air Act, as amended in 1977, calls for the protection of visibility in mandatory Class I Federal areas where visibility is an important value.* Section 169A specifically requires affected States to remedy existing visibility impairment, in part, through installation of Best Available Retrofit Technology (BART) for certain existing stationary facilities.

EPA has promulgated regulations to be codified at 40 CFR 51.300 et seq that implement §169A. BART determinations must be performed on a case-by-case basis considering such factors as the energy, environmental, and economic impacts of alternative control systems. This document provides guidance on identifying those sources to be analyzed for BART, assessing the anticipated improvement in visibility, conducting an engineering analysis of available control systems, and establishing emission limitations for BART. The States must determine emission limitations for fossil fuel-fired power plants with a total generating capacity in excess of 750 megawatts pursuant to this guideline, which reflects EPA's conclusion that the controls needed to meet the new source performance standard (NSPS) for power plants (40 CFR Part 60, Subpart Da) are generally available to these sources. The procedures outlined herein are also appropriate for any other existing major stationary source.

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*These areas are listed in 40 CFR Part 81, Subpart D. From this point forward, they will be referred to as mandatory Class I Federal areas.

1.1 BACKGROUND

Congress was concerned with the impairment of visibility in the nation's parks and wilderness areas, but it realized remedying existing impairment in these areas could not be reasonably accomplished overnight. In order to assure that BART requirements will not be unduly burdensome or costly, several provisions were included in Section 169A. These are:

(1) BART may not be required by the Administrator for existing stationary facilities which have been in operation for more than fifteen years as of August 7, 1977 unless the source was reconstructed after August 7, 1962.

(2) BART for fossil-fuel fired power plants with a generating capacity in excess of 750 megawatts must be determined pursuant to EPA guidelines.

(3) The Administrator may exempt from BART requirements those sources he determines do not cause or contribute to significant visibility impairment in a Class I area. This exemption may not apply to fossil-fuel fired power plants 750 megawatts or greater unless it is demonstrated to the Administrator that the facility is located at such a distance from a Class I area as not to cause or contribute to significant visibility impairment in any such area. Any exemption from BART will be effective only upon concurrence by the appropriate Federal Land Manager.

(4) In determining BART for any existing stationary facility, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any existing pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement in visibility anticipated to result from application of controls shall be considered.

1.1.1. Pollutants of Concern

Visibility impairment is caused by the scattering and absorption of light by suspended particles and gases. NO_2 is a light-absorbing gas and generally causes reddish or yellow-brown atmospheric discoloration because it absorbs light at the blue end of the spectrum. Primary particulates and secondary aerosols, formed from emissions of SO_2 and NO_x, scatter light away from and into an observer's line of sight causing a reduction in visual range and atmospheric discoloration. These three pollutants (primary particulates, NO_x, and SO_2) have been identified as the primary contributors to visibility impairment. Detailed background information can be found in "Protecting Visibility: An EPA Report to Congress."*

1.1.2 Phased Program

EPA has established a phased approach to visibility impairment. Phase I focuses on controlling those sources which can currently be identified as causing visibility impairment. Phase I visibility impairment primarily includes visible plumes emitted from stacks, and single source haze. Smoke, dust, or colored gas plumes obscure the sky or horizon. Single source haze causes a general whitening of the atmosphere and reduction of clarity of terrain features. Both forms of impairment when "reasonably attributed" to a source must be regulated under Phase I. As our scientific and technical understanding of source/impairment relationships improves, future regulations will address more complex forms of visibility impairment such as regional haze and urban plumes.

*This report is available through the National Technical Information Service, 5258 Port Royal, Springfield, Virginia 22161.

This guideline is directed toward Phase I analyses. Although the number and kind of sources and the type of pollutants included in future BART analyses may expand, the procedures outlined herein are unlikely to change substantially. In performing BART analyses the State should be cognizant of possible future requirements which could be imposed on sources as a result of later phases of the program. For example, a major power plant may have a coherent plume caused by primary particulate emissions which must be analyzed under Phase I, and also contribute to regional haze through emissions of sulfur dioxide which will be addressed in later phases. Under Phase I, the source would be analyzed for BART with respect to TSP because it causes visibility impairment in the form of a distinct plume. However, since the source may also contribute to a regional haze, the State would be well advised to also analyze control systems for SO_2 to determine if a single system could more efficiently control both pollutants than two separate systems and to evaluate whether alternative TSP control systems would be compatible with future application of control systems designed to control a different pollutant (e.g. SO_2). The State is not required to impose SO_2 controls in this situation. However, EPA intends at present that physical constraints, incompatible particulate control, etc. resulting from limitations on Phase I requirements will not serve as justification for not imposing SO_2 controls under Phase II.

PROCEDURES FOR IDENTIFYING SOURCES FOR BART ANALYSIS

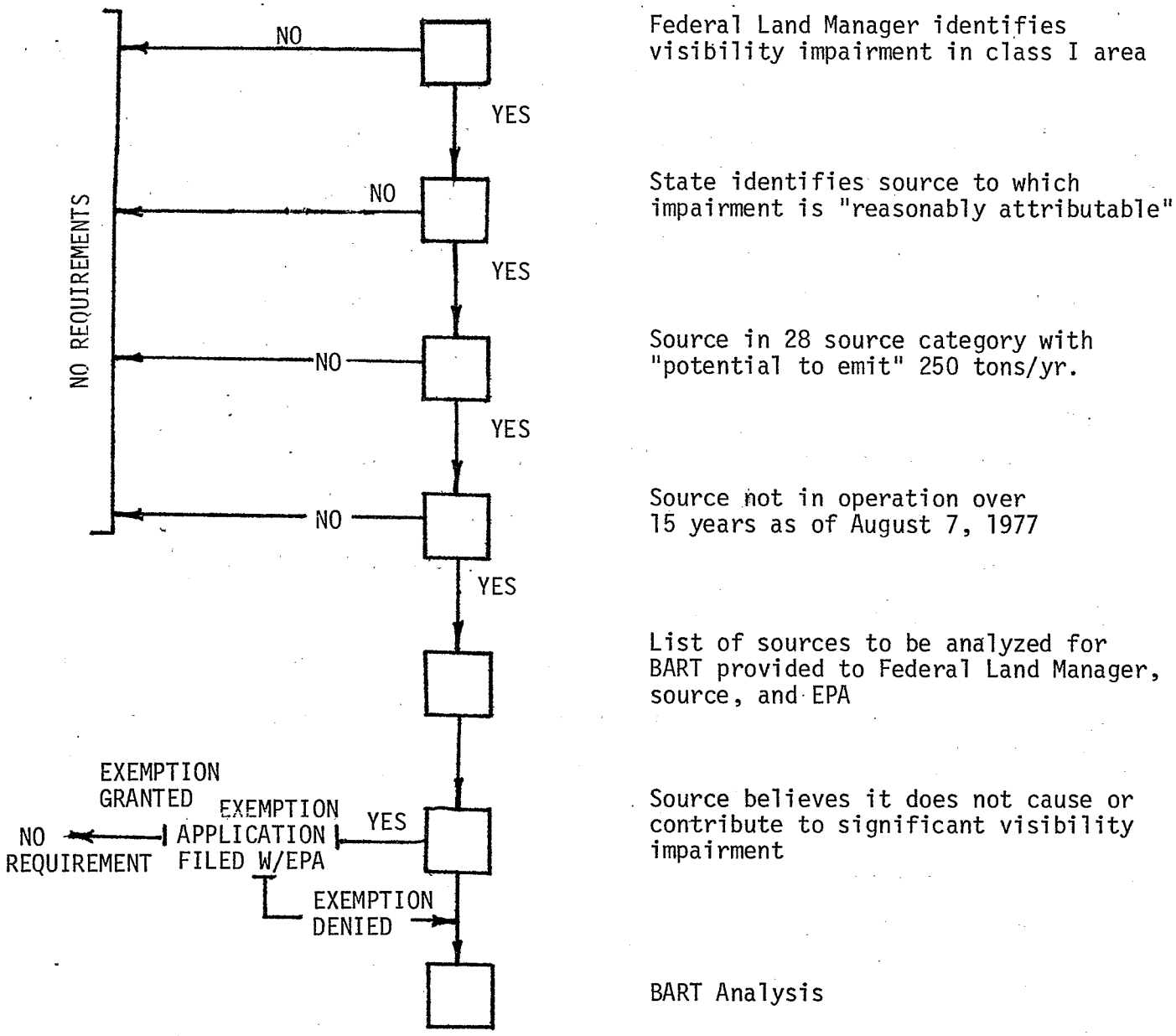

Figure 1

1.2 IDENTIFICATION OF A SOURCE IMPAIRING VISIBILITY

See Figure 1.

If a Federal Land Manager identifies visibility impairment in a Class I area, the State must first determine, if possible, by visual observation or any other monitoring technique it deems appropriate, the existing stationary facility to which the impairment is reasonably attributable. In other words, for the purposes of Phase I of the visibility program, States need only identify impairment that can be physically traced to a source.

States can use visual observation (either ground-based or with an aircraft) or any other technique it deems appropriate to determine which source causes the visibility impairment. An "Interim Guidance for Visibility Monitoring", * is available and describes current monitoring methods. It is available through the National Technical Information Service. Once the impact of the existing stationary facility on visibility is identified as being reasonably attributable to that source, the State must conduct an analysis to determine BART for that particular existing stationary facility.

The Act limits the requirement for the installation of BART to those existing stationary facilities which started operation after August 6, 1962, and were existence as of August 7, 1977. An existing stationary facility is any source which meets these requirements, is listed in Table 1, and has a potential to emit 250 tons per year, or more, of any air pollutant causing or contributing to visibility impairment.

A source which believes it does not cause or contribute to <u>significant</u> visibility impairment in a Class I area may apply for an exemption from BART. The exemption application must be submitted to the Administrator

*"Interim Guidance for Visibility Monitoring," U.S. Environmental Protection Agency EPA-450/2-80-082

TABLE 1

"EXISTING STATIONARY FACILITY"

fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,
coal cleaning plants (thermal dryers),
kraft pulp mills,
Portland cement plants,
primary zinc smelters,
iron and steel mill plants,
primary aluminum ore reduction plants,
primary copper smelters,
municipal incinerators capable of charging more than 250 tons of refuse per day,
hydrofluoric, sulfuric, and nitric acid plants,
petroleum refineries,
lime plants,
phosphate rock processing plants,
coke oven batteries,
sulfur recovery plants,
carbon black plants (furnace process),
primary lead smelters,
fuel conversion plants,
sintering plants,
secondary metal production facilities,
chemical process plants,
fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
taconite ore processing facilities,
glass fiber processing plants,
charcoal production facilities

PROCEDURES FOR BART ANALYSIS

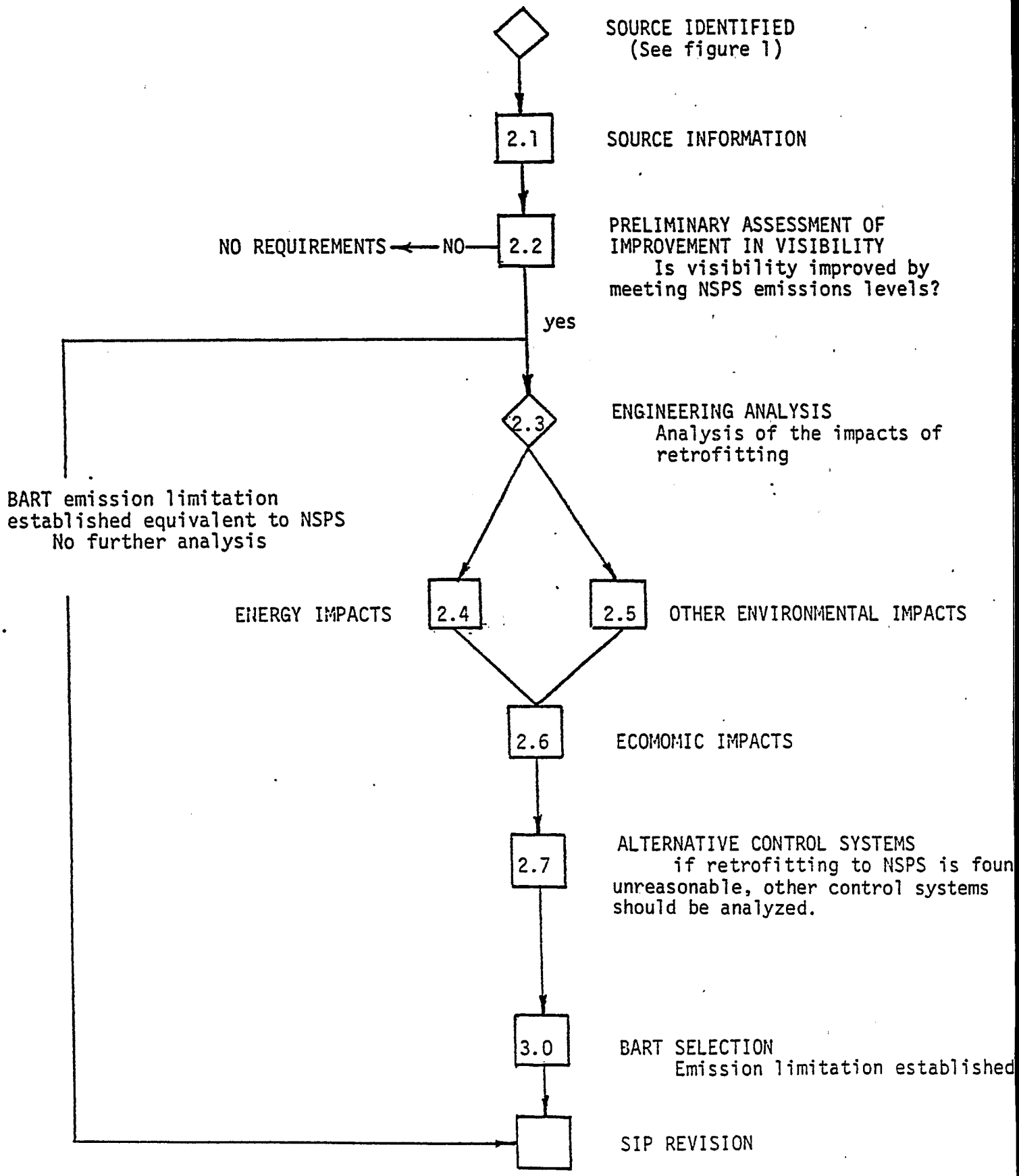

Figure 2

according to procedures outlined in 40 CFR 51.303. The Administrator, after appropriate public review, will grant or deny the exemption. Any exemption is only effective upon concurrence by the Federal Land Manager.

2.0 VISIBILITY IMPACT ANALYSIS

See Figure 2.

Upon identifying the existing stationary facility to which the visibility impairment is reasonably attributable, a BART analysis for the pollutant(s) causing the impairment must be performed. A visibility impact analysis is the first step necessary to determine if visibility is anticipated to improve from the imposition of retrofit controls. The following sections discuss how this is accomplished.

2.1 PROCEDURES

2.1.1 Source Information

In order to conduct a visibility analysis the following data are needed.

1. Plant size, capacity, mode of operation
2. Emission rates (actual and potential) for nitrogen oxides (NO_x), particulates, and sulfur dioxide (SO_x), (grams per second)
3. Remaining useful life of any existing pollution control systems
4. Remaining useful life of any specific units within the plant
5. Remaining plant life
6. Stack diameters (meters)
7. Stack heights (meters)
8. Actual gas velocity (meters per second)
9. Stack temperature (degrees Kelvin)

The above data should be obtained from the plant and should be confirmed by other data available to the State from in-house, Federal, and local agency records. Data for full load conditions should be used for preliminary visibility impact analysis. For visibility impact analyses in conjunction with evaluation of BART alternatives, variations in emission rates with changes in production may be considered if reliable data are available. Other parameters which may also be useful are opacity measurements and particle size distribution of emissions.

2.1.2 Emission Rate Estimates

A representation of current, actual emission rates, i.e., emission rates with any existing control systems, is necessary so that the expected improvement in visibility can be estimated. These emission rates can be obtained from various places such as the source itself, other control agencies, in-house data, or new emission test data. They should represent actual emissions and not estimates based upon theoretical control efficiencies.

This data should be thoroughly analyzed for its accuracy based on present plant conditions. If the emission rates do not seem appropriate in light of the observed visibility impacts, the State should require additional emission tests, and/or calculate a current emission rate considering present plant processes, air pollution control systems currently in use, and current fuel input. The differing emission rates should then be compared and, using good engineering judgment, the one which most accurately represents the current emission rate of the source should be used.

2.2 PRELIMINARY ASSESSMENT OF IMPROVEMENT IN VISIBILITY

After all appropriate data are collected and emission rates established, the amount of improvement in visibility expected from retrofitting must be assessed. This is accomplished by comparing the existing visibility (based on existing emissions) with the visibility anticipated from imposition of the maximum achievable control. Maximum achievable control is generally represented by New Source Performance Standards as published in 40 CFR Part 60, applicable to the source under analysis. If the visibility impact analysis shows visibility improves a perceptible amount under this level of control,* the BART analysis then begins to consider alternative retrofit control schemes for the source. If, after comparison of the visibility at existing and maximum achievable control levels, no perceptible improvement is expected, the analysis need not continue. Additionally, if the State chooses to impose a BART emission limitation equivalent to the NSPS the analysis need not continue.

Both analytical techniques and empirical methods may be used to estimate the degree in improvement in visibility anticipated from control of certain pollutants. Analytical techniques which assess visibility at various emission levels are now being refined by the Agency. Two guideline documents, "Workbook for Estimating Visibility Impairment" and "User's Manual for the Plume Visibility Model (PLUVUE)," discuss a useful analytical technique to aid in assessing improvements in visibility at various control levels. These documents have undergone public review and are available through NTIS. Although this technique has yet to be fully validated, preliminary results using data from EPA's VISTTA program are promising, and the Agency believes this to be a valuable

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*Preliminary studies indicate a change in contrast in the range of 0.01 to 0.04 is capable of being perceived by a human observer. [See Protecting Visibility: An EPA Report to Congress.]

part of the decision-making process. Use of these two guideline documents is not, however, required. States which in their discretion use the guidelines should not consider any results obtained exclusively, but should consider this information together with all other available information in making a regulatory decision.

Empirical methods, i.e. comparison photographic techniques, can also provide valuable input into the sum of information on which to base a BART decision. A discussion of this technique follows.

2.2.1. Primary Particulates

Primary particulates are one of the major causes of visibility impairment generally observed in the form of a distinct plume. The visibility impairment caused by a primary particulate plume is usually localized and can generally be traced back, by visual observation or monitoring, to its source. The improvement anticipated from controlling primary particulate emissions is (1) the plume disappears, (2) the effect becomes even more localized, (3) the effect is reduced perceptibly or (4) the frequency of the impairment decreases so as to improve visibility. A common sense approach using comparison photographic techniques could adequately demonstrate the impact of controlling emissions for the purposes of Phase I BART determinations. These photographic techniques would involve comparing the effects caused by a well controlled source versus those caused by the source under consideration. This comparison would be of similar sources of equivalent size under similar meteorological and geographical conditions. For example, if a similar source has applied a certain primary particulate control and its plume disappeared, or the impairment was reduced, the source could be used as an example of the

amount of improvement expected by application of that control technology. For a more specific discussion of the proper use of photographs, see Section 3.3.3 of the "Interim Guidance for Visibility Monitoring."

A more precise analysis of the effects of particulate matter on visibility is accomplished through the use of mathematical and other analytical techniques. The State may use these techniques at their discretion. However, the Agency is not requiring their use. The workbook and User's Manual referenced in the previous section describe these techniques.

2.2.2 Oxides of Nitrogen

Another major component of visibility impairment is NO_2. Gaseous NO_2 absorbs blue light creating a reddish or yellowish-brown plume. NO_x can also act as a precursor of light scattering aerosols. As with primary particulate plumes, the NO_x plume is usually localized and can generally be traced back, by visual observations or monitoring, to its source.

Current techniques for reducing NO_x emissions may show some improvement in visibility, but evidence shows such techniques generally do not reduce emissions sufficiently to render the plume unobservable or provide substantial improvement in visibility. New, more effective control techniques, at present available only under limited circumstances, should become available within the next few years. Section 51.302 of the regulations requires States to reanalyze any pollutant (such as NO_x) that has not previously been controlled by BART when the Administrator determines that new, more effective control technology is available.

As with particulate matter, a precise analysis of the effects of NO_x is accomplished with the analytical techniques mentioned previously.

2.2.3 Sulfur Dioxide

Sulfur dioxide does not directly affect visibility, but is a precursor of light scattering aerosols. These fine particles, (sulfates) by scattering light in the observer - target path, reduce the contrast and, therefore the clarity and detail, between the target and its background. This general reduction in contrast caused by sulfate aerosols is most often associated with regional haze, which will be dealt with under Phase II, but sulfates can and do contribute to visible plumes and single source haze. If the visibility impairment is "reasonably attributable" to the source, as may be the case in isolated, rural environments, the source should be required to implement BART to reduce SO_2 emissions where improvement in visibility is anticipated. However, since SO_2 is most often a contributor to regional haze, an existing major facility that emits SO_2 will generally not be subject to BART for that pollutant for the first phase of the visibility program.

Analytical techniques are needed, but not required, for a precise analysis of SO_2 and its effects on visibility. The Workbook and User's Manual referenced previously provides information on this.

2.2.4 Other Factors To Be Considered

Frequency, duration, and time of occurrence refer to how often an impairment impacts a class I area, how long this impairment lasts, and when the impairment occurs. Relative improvement such as the model predicts will not always present all the benefits that can be obtained. For example, the model may show an overall improvement in sky-plume contrast of 10 percent from worst case impairment, but this may be sufficient to reduce the frequency of the impairment so that its impact

is substantially reduced during period of maximum visitor use. Oftentimes, a reduction in frequency and duration will provide a maximum benefit for a minimum control effort. Thus, the temporal extent of the impairment is of great importance and should be considered when assessing anticipated improvements in visibility.

2.3 ENGINEERING ANALYSIS

If visibility is expected to improve as a result of the imposition of controls, available retrofit control systems should be analyzed so that an emission limitation representing BART can be established. BART determinations must be based on the cost of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, any existing air pollution control technology in use at the source, the remaining useful life of the source, and the degree of improvement reasonably anticipated to result from the use of such technology.

A general discussion of the economic, energy, and nonair environmental impacts which should be considered is found in the following sections. For the engineering analysis required by this part, information specific to coal fired power plants is found in Part II. Part II provides information on selecting alternative retrofit systems, and assessing the economic, energy, and environmental impacts of retrofit alternatives.

2.4 ENERGY IMPACT

Energy impacts should address energy use associated with the control system under investigation and the direct effects of such energy use on the facility and the community. Some specific considerations for energy impacts are presented below.

2.4.1 Energy Consumption

The amount, type (e.g., electric, coal, natural gas), and source of energy required by the control system under consideration should be identified and compared. In analyzing for energy consumption, comparisons can be made in terms of energy consumption per unit of pollution removed (for example, Btu/ton particulate removed).

2.4.2 Impact on Scarce Fuels

The type and amount of scarce fuels (e.g., natural gas, distillate oil) which are required to comply with the control requirement should be identified and compared. The designation of a scarce fuel may vary from area to area, but in general a scarce fuel is one which is in short supply locally and can better be used for alternative purposes, or one which may not be reasonably available to the source either at present or in the future.

2.4.3 Impact on Locally Available Coal

A control system which requires the use of a fuel other than locally or regionally available coal should be discouraged if such a requirement causes significant local economic disruption or unemployment.

2.5 ENVIRONMENTAL IMPACT

The net environmental impact associated with the emission control system should be determined. Both beneficial impacts (e.g., reduced emissions attributed to a control system) and adverse impacts (e.g. exacerbation of another pollution problem through use of a control system) should be discussed and quantified. Indirect environmental

impacts (such as pollution impacts at an off-site plant which manufactures chemicals for use in pollution control equipment) normally need not be considered. Some specific considerations are presented below.

2.5.1 Air Pollution Impact

The impact of air pollutants emitted from a gas stream or a fugitive emission source can be assessed in terms of either quantity of emissions, modeled effects on air quality, or both. If application of a control system directly removes or releases other air pollutants (or precursors to other air pollutants), then the pollutants affected and the impact of these emission changes should be identified. The analysis can consider any pollutant affecting air quality including pollutants which are not currently regulated under the Act, but which may be of special concern regionally or locally.

2.5.2 Water Impact

Relative quantities of water used and water pollutants produced and discharged as a result of use of the emission control system should be identified. Where possible, the analysis should assess their effect on such local surface water quality parameters as pH, turbidity, dissolved oxygen, salinity, toxic chemical levels and any other important considerations, such as water supply, as well as on groundwater. The analysis should consider whether applicable water quality standards are met and the availability and effectiveness of various techniques to reduce potential adverse effects.

2.5.3 Solid Waste Disposal Impact

The quality and quantity of solid waste (e.g., sludges, solids) that must be stored and disposed of or recycled as the result of the application of an alternative emission control system, if considered, should be

compared with the quality and quantity of wastes created if the emission control system proposed as BART is used. The composition and various other characteristics of the solid waste (such as permeability, water retention, rewatering of dried material, compression strength, leachability of dissolved ions, bulk density, ability to support vegetation growth and hazardous characteristics) which are significant with regard to potential surface water pollution or transport into and contamination of sub-surface waters or aquifers should be considered. The relative effectiveness, hazard and opportunity for solid waste management options, such as sanitary landfill, incineration, and recycling, should be identified and discussed.

2.5.4 Irreversible or Irretrievable Commitment of Resources

The BART decision may consider the extent to which the emission control system may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the system may result in irreversible or irretrievable commitment of resources (for example, use of the scarce water resources).

2.6 ECONOMIC ANALYSIS

This analysis should address the economic impacts associated with installing and operating control systems under consideration for BART. Costs associated with New Source Performance Standards can be found in the NSPS Background Information Documents. Other economic impacts which should be considered follow.

2.6.1 Direct Costs

The direct cost for a control method should be presented. Investment costs, operations and maintenance costs and annualized costs should be presented separately. Costs should be itemized and explained. Credit

for tax incentives should be included along with credits for product recovery costs and by-product sales generated from the use of control systems. The lifetime of the investment should be so stated. The costs of air treatment, water treatment, and solid waste disposal should be presented separately. When considering the addition of control equipment to that already in place, the cost of incremental control should be analyzed. Additionally, the expected useful life of any existing control equipment should be evaluated on the basis of its expected retirement/ replacement schedule.

As a guide in determining when control costs become excessive, comparisons can be made in terms of certain cost effectiveness ratios. Such ratios may include the following:

- ratio of total control costs to total investment costs
- cost per unit of pollution removed (for example, dollars/ton)
- unit production costs (for example, mill/kw-hr, dollars/ton).

In some cases, the unit of production output may be difficult to determine, as in the case of a plant producing many different products. In such cases, unit production costs can be expressed as cost per dollar of total sales.

The remaining useful life of the source will have an effect on the amortized cost of the anticipated control equipment and, as such, should be given strong consideration in determining BART.

2.6.2 Capital Availability

Capital availability addresses the difficulty that some sources may face in financing alternative control systems. Proof of such claims should be fully documented.

2.6.3 Local Economic Impacts

Local economic impacts address the economic feasibility of BART requirements and the impact on production decisions of the firm in response to the level of control. For example, BART could alter the economics of the plant to the point where the decision would be made to cancel expansion of a facility, to reduce the scale of operation, or to change the production mix. The local employment effects, including number of jobs, dollars paid in salaries, and changes in employee skill levels required should be evaluated. The guideline does not imply that the BART decision should force a plant to the brink of shutdown. The BART decision must be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts.

2.7 CONSIDERING ALTERNATIVE CONTROL SYSTEMS

As previously stated, for fossil fuel fired power plants with a generating capacity in excess of 750 megawatts, the Agency believes that the NSPS level of control can be met with technology that is generally available to these sources, and that this level of control generally represents the best these sources can install as BART.

In determining BART, and for inclusion in its SIP, the State must explain in detail how it weighed the various BART factors required by the Act (§169A(g)(2)), the regulations (§51.301(c)), and this guideline. This explanation must demonstrate that the emission limitation chosen (if one other than the NSPS) reflects a reasonable balance of the various BART factors. This explanation must set forth the visibility, energy, economic, and other impacts associated with application of an NSPS level of control, and compare those impacts to alternative levels of control

including the level of control selected by the State as BART. Because EPA believes that NSPS control generally represents the best these sources can install as BART, if the State sets for a pollutant emitted by a fossil fuel fired power plant with a generating capacity in excess of 750 megawatts a BART emission limitation equivalent to the NSPS level of control, this detailed demonstration will not be required for the purposes of EPA review.

3.0 BART SELECTION

An emission limitation that is BART must be established for each source. This along with all evidence as to why this emission limit was chosen is incorporated into the SIP submitted to EPA for approval. It is suggested that if a range of alternative control systems were examined, the State arrange these alternatives into an array. This array would include a description of each alternative considered, the cost of the alternative, the improvement in visibility obtained, and any economic, energy, on nonair environmental factors which affect the selection. This array would provide a logical sequence by which the BART emission limitation was set. The State must also present the logic network used in its final decision making process.

PART II

RETROFIT GUIDELINES FOR

COAL-FIRED POWER PLANTS

This report has been reviewed by the Office of Air Quality Planning and Standards, Office of Air, Noise, and Radiation, Environmental Protection Agency, and approved for publication. Mention of company or product names does not constitute endorsement by EPA. Copies are available free of charge to Federal employees, current contractors and grantees, and non-profit organizations - as supplies permit - from the Library Services Office, MD-35, Environmental Protection Agency, Research Triangle Park, NC 27711; or may be obtained, for a fee, from the National Technical Information Service, 5285 Port Royal Road, Springfeild, VA 22161.

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PART II

SECTION 1

BACKGROUND INFORMATION

1.1 INTRODUCTION

This part of the proposed BART guideline is for use in assessing the effectiveness of retrofit control techniques and for estimating cost. They are flexible with respect to specifying control systems for implementation of BART.

1.2 RELATION TO PART I

Part I provides guidance on identifying those sources to be analyzed for BART, assessing the anticipated improvement in visibility, conducting an engineering analysis, and establishing emission limitations for BART. Part II, as discussed below, contains an explicit discussion of the engineering analysis required by Part I. Part I is general guidance and is appropriate for the analysis of all existing major stationary source categories.

This Part II provides specific engineering information on coal-fired power plants having an operating capacity in excess of 750 megawatts. It provides information for selecting alternative retrofit systems, and assessing the economic, energy, and environmental impacts of retrofit alternatives. Although this part is specifically for coal-fired power plants, much of the engineering information and procedures may be helpful when analyzing sources in other source categories.

1.3 UTILIZATION OF PART II

1.3.1 Purpose

The guidelines in this document specify the emission levels, emission reduction potential, and costs corresponding to each of the retrofit systems discussed. By judicious application of these data to any plant situation, an estimate of cost and effectiveness of a control may be made for that plant. The guidelines are not intended to provide comprehensive cost estimates for retrofitting coal-fired steam generators. Comprehensive cost estimates require extensive engineering studies such as the preparation of specifications, bid criteria, equipment layouts, and detailed drawings. Because the funds needed for these types of studies are usually beyond the budgets of most air pollution control agencies, the broad cost estimating techniques of this document are recommended. The cost estimating data and procedures of this document will generally yield reasonable cost. Should one suspect that the cost estimates of this document would lead to a false conclusion on the cost feasibility of retrofitting certain control systems, the more comprehensive cost (and more costly) estimating techniques previously described should be used. Although the precision of the cost estimates can be improved by more costly studies, the accuracy of conclusions on the effectiveness of the various systems for reducing emissions would generally not be significantly improved by further study.

This document was prepared recognizing that there are techniques other than those used as the basis for this document that are as effective as those used for the cost estimates. Consequently, the owner of a coal-fired steam generator should be allowed to select other techniques as long as such alternate systems perform at a level of effectiveness required by the BART determination.

1.3.2 Data, Assumptions, and Technical Approach

This study resulted from the need to understand the basis and methods of retrofit cost analysis that would cause emission reduction of nitrogen oxides, particulate, and sulfur oxides. The cost modules developed have been based on the emission levels found in EPA background documentation (1, 2, 3, and 4,). These levels are 210 and 260 nanograms per joule heat input (0.5 lbs/10^6 Btu and 0.6x lb/10^6 Btu) for NO_x from subbituminous and bituminous coal respectively; 13 ng/J heat input (0.03 lbs/10^6 Btu) for particulate emissions; and 90% removal of the sulfur oxides from the power plant flue gas. These three pollutants are of prime visibility concern although emissions from large, coal-fired, steam generators also include carbon monoxide, halogens, trace metals, and hydrocarbons (including polycyclic organic matter). As stated in Part 1, it is doubtful that either NO_x or SO_x control will be required in Phase 1 of the visibility program. However, when this report was begun it was felt that control systems for all of the major visibility impairing pollutants should be investigated. All of that information is presented here for reference and future use. The process and cost data were obtained primarily from background information for new source performance standards and from Pullman Kellogg in-house work (1,2,3,4, and 5). The data needed for establishing process requirements to retrofit the example power plants were obtained from information furnished by the power plants, from visual inspection of the plant sites during plant visits, and from yearly reports prepared by the utilities (FPC Form 67).

The methods considered for control of emissions are: boiler modifications for reduction of nitrogen oxide emissions; particulate control using baghouses and/or electrostatic precipitators (hot or cold side); and flue gas desulfurization by either wet or semi-dry scrubbing.

The scope of work was directed to designs for retrofitting power plants with 750 MW, or larger, total plant capacity. However, some of the designs can be applied to much smaller plants. The costs developed here incorporate the variations involved in attaining the plant capacity; therefore, the study accomodates retrofitting most power plants with emission controls.

1.3.3 Content and Limitations

The general content and the costs in this report describe the method and choice of individual retrofit for emission controls. The document also develops a method for determining total retrofit investment and annual operating costs. The content has been developed for engineering personnel use such that the States and Federal government can make best available retrofit technology decisions. It is also intended for use by those interested industry personnel involved in environmental control. The appendices provide examples of retrofit costs and plant layout requirements for three power plants. Reduction in nitrogen oxide formation is achieved by boiler modification only; no other control alternatives have been selected. Particulate emissions control is limited to baghouses and electrostatic precipitators (hot and cold side). The flue gas desulfurization systems are designed for wet or dry scrubbing.

1.3.4 Method of Use

Methods for developing cost data are described in Section 3. The technique for using these cost modules to determine the total retrofit costs for a power plant is described in Section 4. Examples are presented in the Appendices.

1.4 REFERENCES

1. EPA, "Electric Utility Steam Generating Units, Background Information for Proposed NO_x Emission Standards." EPA-450/2-78-005a, July 1978.
2. EPA, "Electric Utility Steam Generating Units, Background Information for Proposed Particulate Matter Emission Standards." EPA-450/2-78-006a, July 1978.
3. EPA, "Electric Utility Steam Generating Units, Background Information for Proposed SO_2 Emission Standards." EPA-450/2-78-007a, August 1978
4. EPA, "Electric Utility Steam Generating Units, Background Information for Proposed SO_2 Emission Standards Supplement." EPA-450/2-78-007a-1, Aug 1979
5. Final report, "Retrofit Guidelines for Coal-Fired Power Plants," Pullman Kellogg Division of Pullman Incorporated, EPA Contract No. 68-02-2619, Work Assignment 13, September 1979

SECTION 2
RETROFIT EMISSION CONTROL TECHNIQUES

2.1 GENERAL

The retrofitting technques for NO_x, SO_2, and particulate emissions considered in this document are based only on commercially available methods for reducing these pollutants. For NO_x, the emission reduction techniques considered include staged combustion (overfire air and/or curtain air) and low NO_x burners. The particulate collection studies examined ESP's (cold or hot side) and baghouses (fabric filters).

The maximum control effectiveness of the systems discussed in this document is as follows:

NO_x

Subbituminous coal	210 nanograms per joule ($0.5\ lb/10^6$ Btu)
Bituminous coal	260 nanograms per joule ($0.6\ lb/10^6$ Btu)

<u>Particulates</u>	
Fabric Filters and Electrostatic Precipitators	13 nanograms per joule ($0.03\ lb/10^6$ Btu)
Scrubbers	21 nanograms per joule ($0.05\ lb/10^6$ Btu)
<u>SO_2</u>	
Wet scrubbers	90 percent removal of the SO_2
Dry scrubbers	70 percent removal of the SO_2

As discussed in Section 2.2 and Section 3, it may not always be possible to attain these NO_x levels for all retrofit situations. The EPA position on the operating effectiveness of particulate and SO_2 retrofit control systems is discussed in Appendices D and E of these guidelines.

Control of SO_2 emissions included studies of both wet and semi-dry scrubbing. The costs developed for the wet scrubbing system include cases that use lime or limestone, Wellman Lord, Mag-ox, or double alkali scrubbing. The semi-dry scrubbing (lime) uses the Joy-Niro process. This process uses a spray dryer followed by a baghouse for particulate collection.

The control systems outlined above are discussed in detail in the following sections.

2.2 NO_x EMISSION CONTROL TECHNIQUES

Section 2.2 discusses the technical aspects of retrofitting to reduce NO_x emissions from coal-fired steam generators. There are several expert and excellent documents in the public domain which discuss the various aspects of control systems for reducing NO_x emissions. Some of these discussions were submitted as comments to the proposed visibility regulations. This guideline was not designed to eliminate the consideration of any other information available to the State. The State should use such information at its discretion, with sound engineering judgment.

There are two distinct mechanisms for forming NO_x; one is fixation of elemental nitrogen from the air, and the other results from chemically combined nitrogen taken from fuel, in this case, coal. Fixation of the nitrogen in air can be limited by reducing the level of thermal excitation caused by flame temperature. The principal methods for reducing thermal excitation are: (a) flue gas recirculation, (b) staged combustion, (c) water or steam injection, (d) reduced air preheat, and (e) reduced heat-release rate.

Formation of NO_x by oxidizing the nitrogen in coal constitutes as much as 80 to 90 percent of the total NO_x emissions from pulverized-coal-fired boilers. By limiting the combustion air supplied at or near the burners and by directing air to limit high temperature mixing of volatilized coal, nitrogen, and air, nitrogen oxide formation from coal nitrogen can be retarded. As the fuel-rich mixture cools by radiating heat to the surrounding colder surfaces, the mixture flows into the air rich zone and completes combustion at lower temperatures - temperatures which are less favorable for developing NO_x. This method, one of several used to reduce NO_x emissions, is called staged combustion. There are several NO_x control techniques discussed in this document common to all four boiler manufacturers including:

- Low excess air,
- Staged combustion,
- Low NO_x burners,
- Flue gas recirculation,
- Burners out-of-service,
- Flue gas treatment,
- Derating,
- Reduced air preheat.

The sections that follow discuss these techniques and their potential adverse side effects. For new steam generators, NO_x emissions from burning Western subbituminous coals can be reduced to a level of 210 nanograms per joule heat input (0.5 lb/10^6 Btu) and emissions from burning bitumious coals can be reduced to 260 nanograms per joule (0.6 lb/10^6 Btu) without significant adverse side effects (1). NO_x control for new boilers has to be accomplished by custom design for the steam generator in order to minimize adverse side effects while limiting NO_x emissions.

For existing steam generators, it is not possible to change the shape or size of the combustion chamber substantially without replacing the steam generator. The state of the art for reduction of NO_x by combustion modification is not developed to the extent that the effectiveness of applying known control techniques to existing steam generators can be predicted accurately. In addition, it is not possible to predict the combustion conditions where adverse side effects will become intolerable for existing units. Consequently, reducing NO_x emissions from existing steam generators involves trial and error as well as application of sound engineering principles. Western subbituminous coals have less tendency to cause tube wastage and slagging than some high sulfur Eastern bituminous coals. Therefore, the probability of success in reducing NO_x emission by applying combustion modification techniques is greater for Western coal. Both Combustion Engineering (C-E) and Babcock and Wilcox (B&W) steam generators have been retrofitted to reduce NO_x emissions to levels less than 210 nanograms per joule (0.5 lb/10^6 Btu) without significant adverse side effects (1).

2.2.1 Low Excess Air

About 10 to 20% excess air is needed in addition to the theoretically required air to assure efficient, stable operation of the boiler. This amount of excess air is needed to cover the normal ± 3 percent fluctuations in required combustion air, to aid soot burnout, to increase convective heat transfer, to harden the slag, and to minimize tube wastage (corrosion). After accommodating the air requirements established by these operating conditions, if excess air can be reduced, then NO_x is reduced either because less oxygen is available during volatilization, or thermal NO_x is retarded by low, oxygen radical concentrations. However, under ideal conditions, well mixed, adiabatic combustion systems respond adversely to lower excess air, because higher NO_x emissions result from higher adiabatic flame temperatures. For pulverized-coal-fired plants, the reduction in NO_x emissions may be as much as 20% when applying the low-excess-air control method. When this method is applied, tight control of individual burners must be made with respect to fuel/air ratio. Although utility boiler systems usually show NO_x reductions with low excess air, the effectiveness of reduced excess air varies for individual boilers and there are some associated problems which are discussed in the following sub-sections.

2.2.1.1 Tube Wastage.- Operation in an environment with too low excess air produces a fuel rich reducing atmosphere which may accelerate the corrosion of the furnace tubes. Therefore, there is a lower limit for reduction of excess air below which potential adverse side effects begin to accelerate (1).

2.2.1.2 Slagging.- Potentially, low excess air can accelerate slagging (1). The molten component of the ash becomes slag in the reducing atmosphere created by low excess air.

2.2.1.3 Increased ash combustibles and CO content.- Low excess air operation can have an adverse effect on particulate loading if there is an increase in unburned carbon in the ash. Any increase in particulate loading is accompanied by changes in particulate characteristics such as size distribution, and ash resistivity which can affect the collection efficiency of ESP's. The increase in unburned carbon may also result in energy losses in the boiler. Opacity may be increased because of the increase in particulate loading which causes overloading of ESP's. Low excess air can also increase the CO emissions (1).

2.2.1.4 Reduced steam superheat.- When the amount of excess air is reduced, the flue gas mass flowrate decreases. This causes a decrease in the heat transfer rate and may lead to a decrease in the superheated steam temperature. A difference of up to 28°C (50°F) in the superheat and reheat steam temperature may occur. Also, the reduced superheat temperature may require existing old plants to reduce capacity as much as 30% of their rated power output (1).

2.2.1.5 Reduced boiler efficiency.- Low excess air may not reduce the boiler efficiency because the energy loss due to the increase in unburned carbon and CO may be offset by the decrease in energy loss to the stack resulting from a lower flue gas temperature. Efficiency may be improved in cases where CO and ash combustibles are not increased significantly because combustion control settings are tuned more finely (1).

2.2.1.6 Flame Stability.- Flame stability can be affected by reducing excess air. Flameouts and pulsations not only disrupt electric power generation but also cause potential safety hazards. Consequently, for all steam generators, there are low excess air conditions that are intolerable.

2.2.2 Staged Combustion

Staged combustion can be accomplished in three ways. One method is by maldistributing air (over-fire air), another method is by maldistributing fuel (burner-out-of-service), and the third method involves special burner design. A typical utility boiler operates with an array of burners, each of which operates at the percentage of excess air specified for the boiler. The flame characteristics differ with the individual boiler manufacturer's design. Staged combustion is accomplished by redistributing the air flow such that a cooler secondary combustion zone is encountered by the fuel-rich combustion gases after they leave the flame basket. Staged combustion has two effects on NO_x production;

- Fuel NO_x is reduced because less oxygen is available during volatilization.
- Thermal NO_x is reduced because the flame temperature does not reach as high a peak as when all the heat release occurs in one stage.

The extent of staged air can be conveinently indexed by the fraction of stoichiometrically-required air remaining at the burner flame baskets. For example, suppose a six-level burner boiler operating with 15% excess air has five operating burner levels with air supplied to six levels. Then one-sixth of the air supply is staged, leaving the burners operating at 96% (115 x 5/6) of the required stoichiometric air. This type of staged combustion has shown reductions of NO_x production by as much as 20 to 40% for pulverized-coal-fired utility boilers (1). Staged combustion by special burners produces a lazy, fuel-rich flame surrounded by an air envelope. Limited tests indicate that this type of burner can reduce NOx

emissions by as much as 50%. Potential adverse side effects of staged combustion are much the same as those discussed in Section 2.2.1.

2.2.3 Low NO_x Burners

Low NO_x burners are designed to reduce NO_x emission levels either alone or in combination with the use of overfire air ports. With the low NO_x burner designs, it is possible to eliminate or alleviate the potential problem that creates reducing atmosphere pockets, and the tube wastage associated with reducing atmospheres should be far less serious. Low NO_x burners are designed to reduce highly turbulent mixing between the secondary and primary air streams. Because of low turbulence intensity, the flame length in low NO_x burners will be longer than the flames of normal high turbulence burners, and these increased flame lengths must be evaluated by the manufacturer when retrofitting a boiler. Potential adverse side effects are much the same as those discussed in Section 2.2.1.

2.2.4 Flue Gas Recirculation

The flue-gas recirculation method of NO_x control operates by recirculating flue gas to the windbox which reduces the formation of thermal NO_x by lowering flame temperature and oxygen concentration at the burners. This technique has been tried on an experimental basis and has been found to be relatively ineffective in coal-fired units. Also, the flyash problems in the recirculation systems have not been solved sufficiently to warrant a conclusion that the technique has been demonstrated effectively (1).

2.2.5 Burners Out-Of-Service

This method of NO_x control is accomplished by shutting off the pulverizers supplying the upper level burners. The technique can be accomplished only if the remaining pulverizers have enough spare capacity to supply the total amount of coal required. Often, application of the technique increases the minimum excess air requirements of the boiler, and this may result in efficiency loss in the boiler. Boiler derating may be required when fans are already operating near their maximum capacity. Also intolerable superheat conditions may occur because of a resultant shift of the high temperature zone towards the superheater. The technique could be useful, however, for both owners and regulatory agencies, in helping to determine what adverse side effects might ensue from equipping a unit for overfire air while avoiding the need for costly modifications.

2.2.6 Flue Gas Treatment

The flue gas treatment method of NO_x control has been applied to oil and gas-fired units in Japan. EPA is investigating the Japanese technology for potential application to the U.S., coal-fired situation. At present, this technology is not sufficiently demonstrated on coal-fired units to be considered here (1).

2.2.7 Derating

Derating operates by causing a reduction in the volume of flue gas which produces a reduction of NO_x, both in concentration and mass flow rate. Also, reducing the heat release rate reduces combustion gas temperatures more rapidly, thereby reducing the rate of formation of NO_x from the reactions between the nitrogen in the combustion air and oxygen.

NO_x control by derating older units will be more difficult because of smaller combustion chamber design practiced by boiler manufactures prior to 1971. The older units, with a smaller firebox, have higher heat release rates when compared to the units designed after 1971, which have a 15 to 50% increase in combustion chamber size.

Usually derating is an undesirable NO_x control technique. However, at times, it might develop that derating would be a preferable alternative for utility owners who otherwise would have to make costly steam generator modifications.

2.2.8 Reduced Air Preheat

Reduced air preheat to control NO_x emission is a nonviable method because of the need for a hot air supply to the pulverizer to heat the coal. The method causes losses in boiler efficiency because of heat losses attributable to increased stack gas temperature.

2.3 PARTICULATE EMISSION CONTROL

2.3.1 Electrostatic Precipitators (ESP)

Electrostatic precipitators function by charging and collecting particles on collection electrodes, and by disposing of the collected ash. Primary electric power supply is usually 240 or 480 volts of alternating current. Transformer-rectifier sets are used to convert the current from alternating to direct and to step up the secondary voltage. High efficiency ESP systems are equipped with power controls which regulate power at the optimum levels for particulate collection. Secondary voltages range from

10,000 to 40,000 volts, depending upon the particulate and gas characteristics. Rapping systems dislodge the collected ash. These systems are equipped with controls which permit adjustment of both the frequency and intensity of rapping. High efficiency ESP systems are equipped with multiple hoppers and baffles to minimize the tendency for gases to bypass the electrical field (sneakage). ESP systems are capable of reducing particulate emissions to levels as low as 13 nanograms per joule heat input (0.03 lb/10^6 Btu) (2).

Performance of an ESP is affected by the following factors (2):

- Coal ash characteristics - size distribution of particulates, compositions such as sulfur content, etc.
- ESP size - collection area and flow, cross-sectional area for flue gas
- Grounded collection surface spacing
- Power control design
- Gas flow distribution
- Rapping control design
- Flyash handling system design
- Thermal expansion design
- Discharge electrode failure
- Maintenance practices
- Gas conditioning

2.3.2 Baghouses

Baghouses used for particulate emissions control are effective to the extent of 13 ng/J heat input (0.03 lbs/10^6 Btu) (2) for best-controlled sources. Pressure drop data show a range of less than 1.25 kilopascals (5" H_2O) to 2.5 kilopascals (10" H_2O),

all at full load. Air-to-cloth ratios corresponding to these pressure drops range from 0.58 to 0.91 actual cubic meters per minute per square meter (1.9 to 3.0 ACFM/Ft^2). Data show that an air-to- cloth ratio of 0.61 actual cubic meters per minute per square meter (2 ACFM/Ft^2) is a conservative criterion for sizing a baghouse for a coal-fired steam generator with pressure drops of less than 1.25 kolopascals (5"H_2O) at full load gas volumes. Although it is not demonstrated on large sized electric utility steam generators, it is possible that precharging the particulates before entry into the bags would permit the use of much smaller baghouses with air to cloth ratios of as much as 1.2 actual cubic meters per minute per square meter (4 ACFM/Ft^2)[A]. The life of a bag is estimated to be at least 2 years if pressure drops are less than 1.25 kilopascals (5"H_2O).

The key factors which affect baghouse performance are (2);

- o Bag material,
- o Bag construction,
- o Bag treatment,
- o Baghouse size,
- o Configuration of baghouse and its control,
- o Techniques of cleaning,
- o Construction of tube sheet,
- o Process characteristics,
- o Maintenance practices.

2.3.3 Flyash Scrubbers

In common practice, using scrubbers to control particulates from coal-fired power plants is done only in conjunction with FGD systems. The FGD system can be designed either for simultaneous removal of SO_2 and particulates (Kellogg-Weir scrubbers, TCA scrubbers, etc.) or for separate particulate and sulfur dioxide removal (venturi-spray tower combination). Scrubbers are capable of reducing particulate emissions to levels as low as 21 nanograms per joule heat input (0.05 lb/10^6 Btu) (2).

A great variety of scrubber types and configurations exist. Some of the most widely used scrubbers are venturi, spray tower, orifice impingement, and self-induced spray. The basic principle of scrubber operation involves confronting particulates with impact targets which can be either wetted surfaces or, and most frequently, individual droplets.

The efficiency of a wet scrubber is a function of a number of variables including particle characteristics (diameter, density, viscosity) between the particle and the scrubbing slurry droplet. To obtain efficient particulate removal, the system is designed for an optimum combination of these parameters. This combination is achieved by using a high liquid to gas ratio (L/G) of scrubbing slurry to gas stream, and by providing a high degree of atomization for the scrubbing liquid. The choice of particulate collector must take into account the particle size distribution, the required collection efficiency, and the overall energy consumption (as measured by the pressure drop across the system).

2.3.4 Effect of Acid Mist on Particulate Emissions

Particulate emissions from coal can be affected by acid mist concentrations. Reference 2 shows FGD units on well-controlled coal-fired power plants do not increase particulate emissions through sulfuric acid formation and interaction.

2.4 EMISSION CONTROL OF SULFUR OXIDES

2.4.1 General

The combustion products of the coal-fired, power-generation station contain sulfur dioxide. There are several sulfur removal alternatives. These alternates can be grouped into these three principal categories:

- Desulfurization of coal prior to combustion - either by chemical or physical cleaning.
- Desulfurization of coal during combustion - fluidized bed combustion.
- Flue gas desulfurization.

For this project only flue gas desulfurization will be considered as a means for controlling emissions of sulfur oxides to the atmosphere.

There are several types of FGD processes that are commercially available now, and they are grouped into two major categories that are based on the product resulting from the process:

- Throwaway processes where all waste streams are discarded.
- Regenerable processes where the waste stream is treated for regeneration of the sorbent and recovery of sulfur compounds such as sulfur, sulfuric acid, and concentrated H_2S.

Both processes treat the flue gases using either wet, semi-dry, or dry desulfurization modes. Since dry processes, such as dry scrubbers using boiler injection with limestone, are not within the scope of this study, they will not be considered further. The wet and semi-dry processes are accomplished using either slurry or clear liquor, and these are further divided by the type of alkali used for the scrubbing solution.

Figure 2-1 illustrates the general classification of these FGD processes. This figure also indicates the nine most highly developed processes at the extreme right.

2.4.2 Description of Selected Wet and Semi-Dry Scrubbing Systems

2.4.2.1 SO_2 control by wet scrubbing.- Wet scrubbing processes have gone through extensive research, development, and full scale demonstration work. The available data indicate that wet scrubbing will remove both SO_2 and particulates. Usually, the flyash is collected upstream of the FGD unit to minimize the volume of sludge and to prevent erosion of the desulfurization equipment. The flue gas from the boiler, after going through fly ash removal (ESP, or baghouse), enters the scrubber where the SO_2 is removed by the scrubbing liquor (either slurry or clear). The cleaned gas then passes through an entrainment separator to remove entrained slurry droplets or fine particulate matter in the gas. Since the scrubbed gas has been cooled and has had its

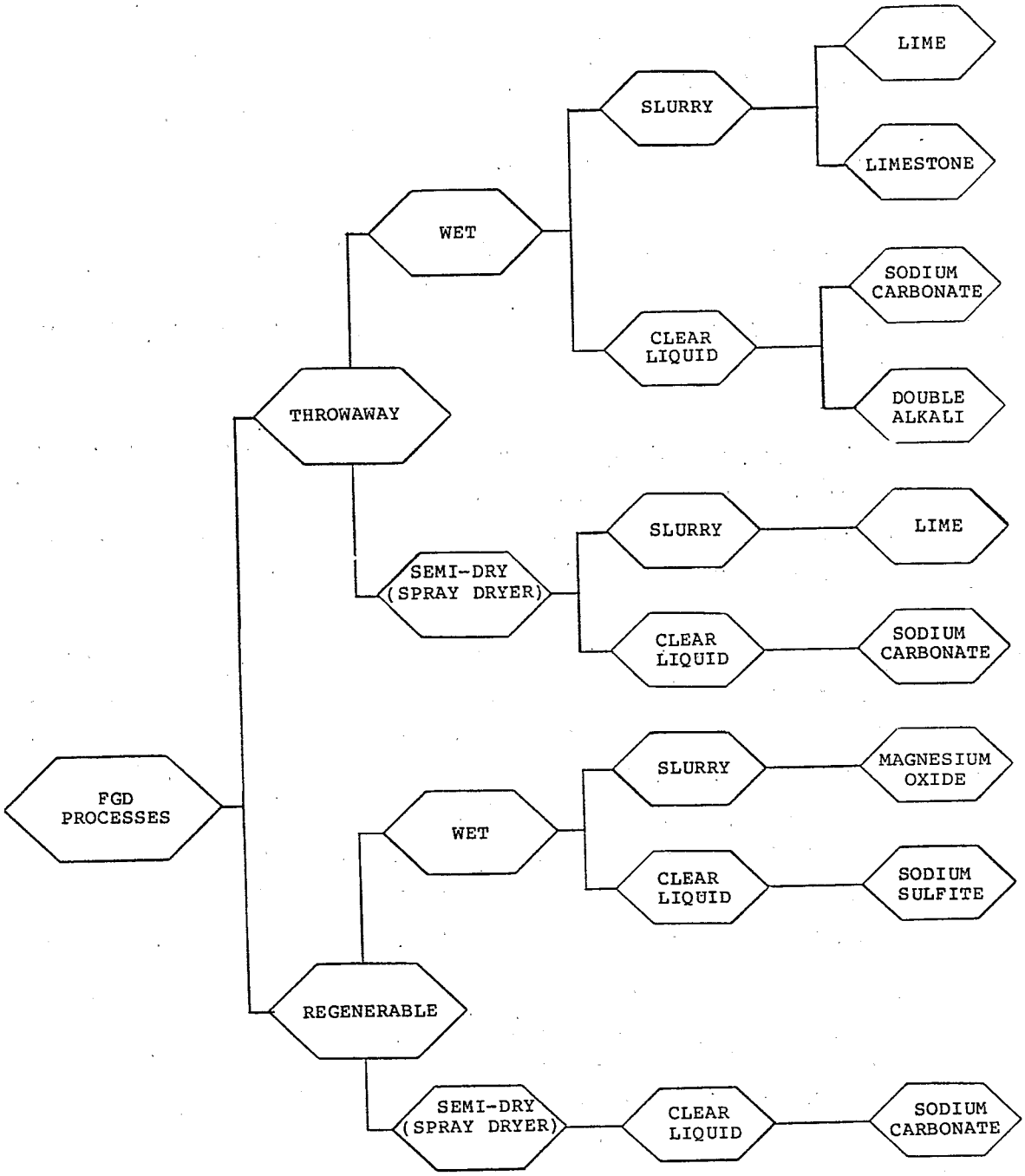

Figure 2-1.- Most highly developed flue gas desulfurization processes.

moisture content increased by the scrubbing liquor, it is often reheated before it enters the stack. Reheat minimizes condensation and corrosion of the equipment downstream of the scrubber (ductwork, fans), and it also helps to avoid plume formation at the stack exit. The product sludge is either discarded (throwaway) or processed further (regenerable).

The types of process equipment and operating parameters vary widely for these systems. The principal differences are in the following equipment and chemicals:

- Scrubbing equipment - The several successful systems already used include packed tower, horizontal spray towers, vertical spray towers, tray columns, and venturi scrubbers.

- Types of alkali - For throwaway systems, the types of scrubbing media that have been used are either a slurry (lime, limestone, or alkaline fly ash) or a clear liquid (sodium carbonate, double alkali, lime chloride and dilute acids). Regenerable systems use clear liquids mostly (sodium sulfate, ammonia, citrated potassium trisulfate). The alkali, magnesium oxide, has been used as a scrubbing slurry also.

- Process Design Parameters - Parameters such as liquid- to-gas ratio (L/G), gas velocity, scrubbing medium, flow configuration (counter, cross or cocurrent), and pressure drop for the entire scrubbing system vary considerably for the FGD processes. These variables have a large effect on the FGD system operating costs.

A. Wet scrubbing throwaway processes

In the throwaway processes, the product sulfur removed is waste. Usually the waste stream is a sludge containing sulfur compounds, unreacted alkali, fly ash, and water. Table 2-1 shows some of the commercially available FGD processes. Further discussion is limited to wet lime/limestone processes.

Wet lime/limestone processes

Wet lime and limestone systems make up a large portion of the operating FGD scrubbers. Since commercial installations have been operating for several years, the overall operability and reliability of both systems has been proven. The basic process is fairly simple and very few process steps are involved. In the first step, hot gases are quenched to saturation temperature and passed along to the scrubbers where a lime or limestone slurry contacts the gases for SO_2 removal. The cleaned gases are reheated and discharged to the atmosphere.

The lime/limestone scrubbing slurry is prepared using slakers (lime) or ball mills (limestone). The scrubbing slurry is collected in a tank and recirculated to the scrubber. A purge stream containing the net make of sulfite-sulfate can be oxidized further by air or oxygen prior to entering the thickener for separation of the suspended solids. Thickened slurry containing 20 to 40 percent solids can be sent directly to a disposal pond or it can be filtered. Filters are used for further reduction of sludge volume by increasing the solids content to about 70 wt%. Clear liquid is returned to the system.

TABLE 2-1.- CHARACTERISTICS OF COMMERCIAL THROWAWAY FGD PROCESSES

PROCESS	PRIMARY REMOVAL AGENT	FORM OF PRINCIPAL SULFUR PRODUCT	OPERATIONAL MODE
Wet Lime/Limestone	Lime or Limestone	$CaSO_3$, $CaSO_4$	Wet
Alkaline Fly Ash	Alkaline Fly Ash	$CaSO_3$	Wet
Sodium Carbonate	Sodium Carbonate	Na_2SO_3	Wet
Double Alkali	Sodium Hydroxide	$CaSO_4$	Wet
Dilute Sulfuric Acid/Gypsum	Sulfuric Acid	$CaSO_4$	Wet

The process has the following characteristics:

- One of the lowest capital costs, as specific economic studies have shown (3).
- Lime/limestone processes are not adversely affected by fly ash in the system. They can remove both SO_2 and particulates.
- SO_2 removal efficiencies are generally high - greater than 90% (4,5).
- Reserves of lime/limestone are abundant in the U.S.
- Some of these processes, if not designed properly, have problems with plugging, scaling and corrosion .
- Large liquid-to-gas ratio or substantial gas pressure drop occurs in some processes.
- The large quantity of waste requires a large, lined, disposal pond.

Figure 2-2 illustrates a typical process flow diagram for lime/limestone scrubbing.

2.4.2.2 SO_2 control by semi-dry scrubbing.- The concept of semi-dry scrubbing for removal of sulfur dioxide from flue gases is relatively new to the electric power industry. As of late 1979 no commercial scale, semi-dry scrubbing sytems were in operation. However, several semi-dry scrubbing units are currently on order for installation at coal-fired power plants in the United States.

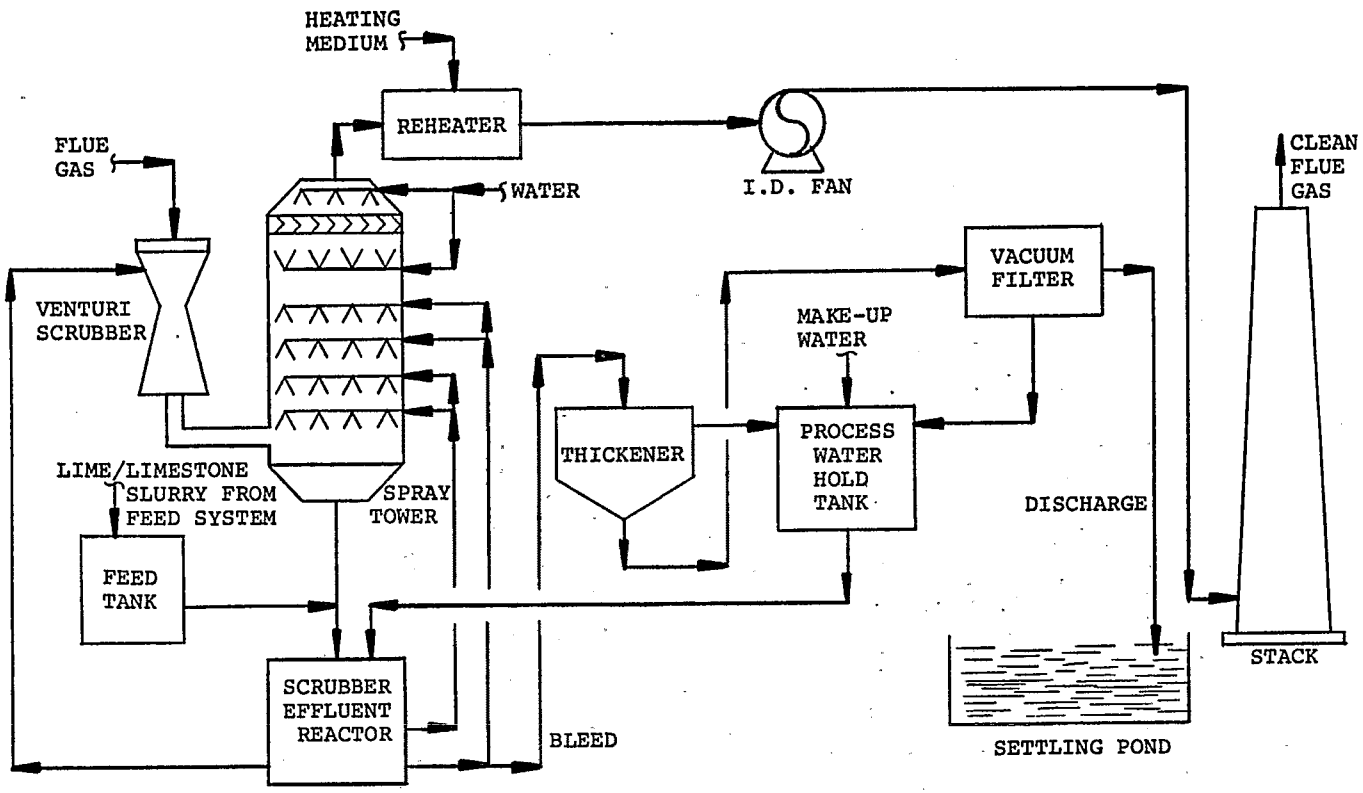

Figure 2-2.- Typical process flow diagram for lime/limestone scrubbing.

Semi-dry FGD systems achieve SO_2 and particulate removal by using the combination of a spray dryer followed by a conventional particulate control device. Figure 2-3 illustrates the general process flow scheme for semi-dry scrubbing with lime. Sulfur dioxide removal takes place in the spray dryer, where the flue gas that enters flows through a finely atomized spray of alkali scrubbing solution. This solution uses either a sodium based (soda ash) or calcium based (lime) type of alkali. The SO_2 alkali reaction takes place between the gas and liquid droplets and/or between the gas and entrained particulates (6,7). At the same time, the water in the scrubbing slurry droplets evaporates due to the thermal energy provided from the incoming flue gas. The treated flue gas leaves the spray dryer at a temperature of about 28°C (50°F) above its dew-point or about 77°C (170°F). This temperature can be controlled by properly selecting the liquid-to-gas ratio at about 0.4×10^{-4} M^3/SM^3, (0.3 Gal/MSCF). The reaction product is a relatively dry, powder mixture of sulfite, sulfates, and unreacted alkali. Collection of the reaction products containing sulfur and particulates is accomplished by using either an ESP or a fabric filter (baghouse). The fabric filter also serves for additional SO_2 removal by reaction between the gas and unused sorbent. Spent sorbent is usually discarded.

Operating experience with spray dryers on utility boilers has been limited to pilot-scale test programs (8,9). Test results in these programs have indicated SO_2 removals between 50 and 90% with lime alkali at stoichometric ratios (SR) of 0.8 to 2.0. (SR = moles lime/mole SO_2 entering). Process evaluations also indicate that semi-dry processing is economically attractive only in applications with moderate SO_2

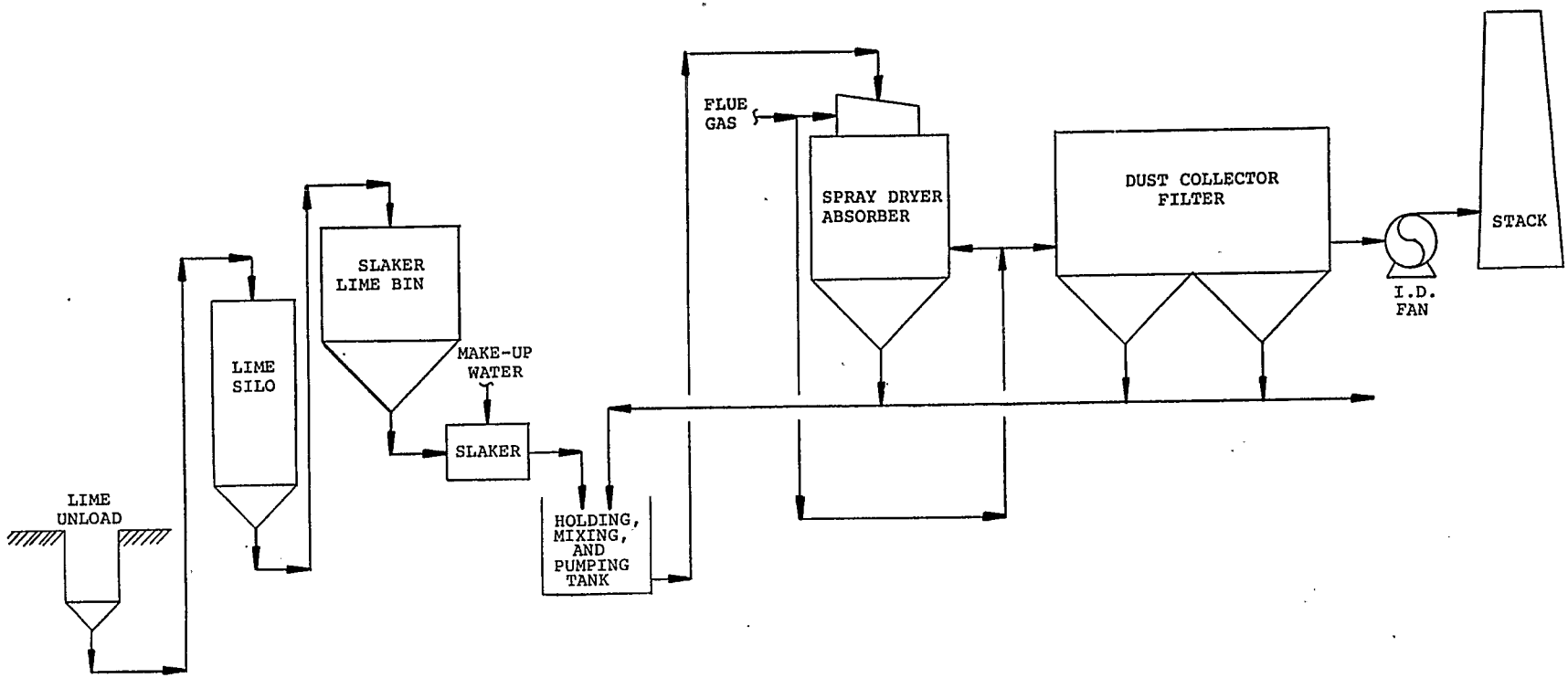

Figure 2-3.- General process flow diagram for semi-dry SO_2 scrubbing with lime.

removal requirements (approximately 70% max.) and with coals of low to medium sulfur content. Some of the characteristics of semi-dry scrubbing include:

- Dry powdered waste - no sludge
- High turndown capabilities
- No wet-dry interfaces
- No plugging or fouling problems
- Low pressure drop
- Power consumption about 50% of most wet-scrubber consumption
- High reliability
- No corrosion problems
- No reheat requirements

The projected advantages of the semi-dry scrubbing system and the positive results of pilot scale testing have prompted utilities to give serious consideration to spray drying as a means of SO_2 emission control.

There are several commercially available semi-dry processes (6) such as those offered by Wheelabrator-Frye/Rockwell International; Joy Manufacturing Company's Western Precipitation Division in conjunction with Niro atomizer; Babcock & Wilcox; and Carborundum. Of these four processes only Wheelabrator-Frye/Rockwell has both regenerable and throwaway processes. The other three are offered only as throwaway processes. Characteristics of some of the semi-dry scrubbing units currently on order are listed in Table 2-2.

TABLE 2-2.- SEMI-DRY SCRUBBING SYSTEMS; CHARACTERISTICS OF SOME OF THE SYSTEMS PRESENTLY UNDER CONSTRUCTION

Utility Station	Coal Characteristics %S	%Ash	Btu/Lb	Boiler Rating, MW	Reagent	Design SO_2 Removal	Vendor
1) Otter Tail Power, Coyote #1	.9	6.5	7,050	400	Soda Ash	50	Wheelabrator-Frye/Rockwell International
2) Basin Electric Laramie River #1	.8	7.0	8,100	550	Lime	90	Babcock & Wilcox
3) Basic Electric Antelope Valley #1	.7	8.0	6,600	455	Lime	78	Joy/Niro

A. Semi-Dry SO_2 Scrubbing Throwaway Processes

1. Wheelabrator-Frye/Rockwell International

The Wheelabrator system (spray dryer/baghouse) when operating in an open loop is offered as a throwaway process. The spray dryer is equipped with a multiple atomizer and a roof dispenser. The alkaline scrubbing slurry is a sodium carbonate solution. The Coyote Station located near Beulah, North Dakota (10) has this semi-dry FGD system scheduled for commercial operation in 1981. This system will serve a 410 MW lignite-fired unit. The process flow diagram is shown in Figure 2-4.

2. Joy/Niro

The alkaline scrubbing slurry uses either soda ash or lime as alkali. The spray-dryer design uses a single atomizer and compound gas dispenser to achieve adequate gas mixing. Joy/Niro system (spray dryer/baghouse) has developed a recirculation system in which lime slurry is mixed with recirculated fly ash and spent reagent, for reinjection into the spray-dryer (patent pending) the process flow diagram is shown in Figure 2-5. The semi-dry FGD system using a lime scrubbing slurry is being installed at the Antelope Station Unit 1, a (440 MW gross capacity). It is scheduled for commercial operation in 1982.

3. Babcock & Wilcox

This system (spray dryer/ESP) consists of a horizontal reactor using a "Y" jet dual fluid atomizer followed directly by an electrostatic precipitator. The system uses a lime scrubbing slurry. The Laramie River Station

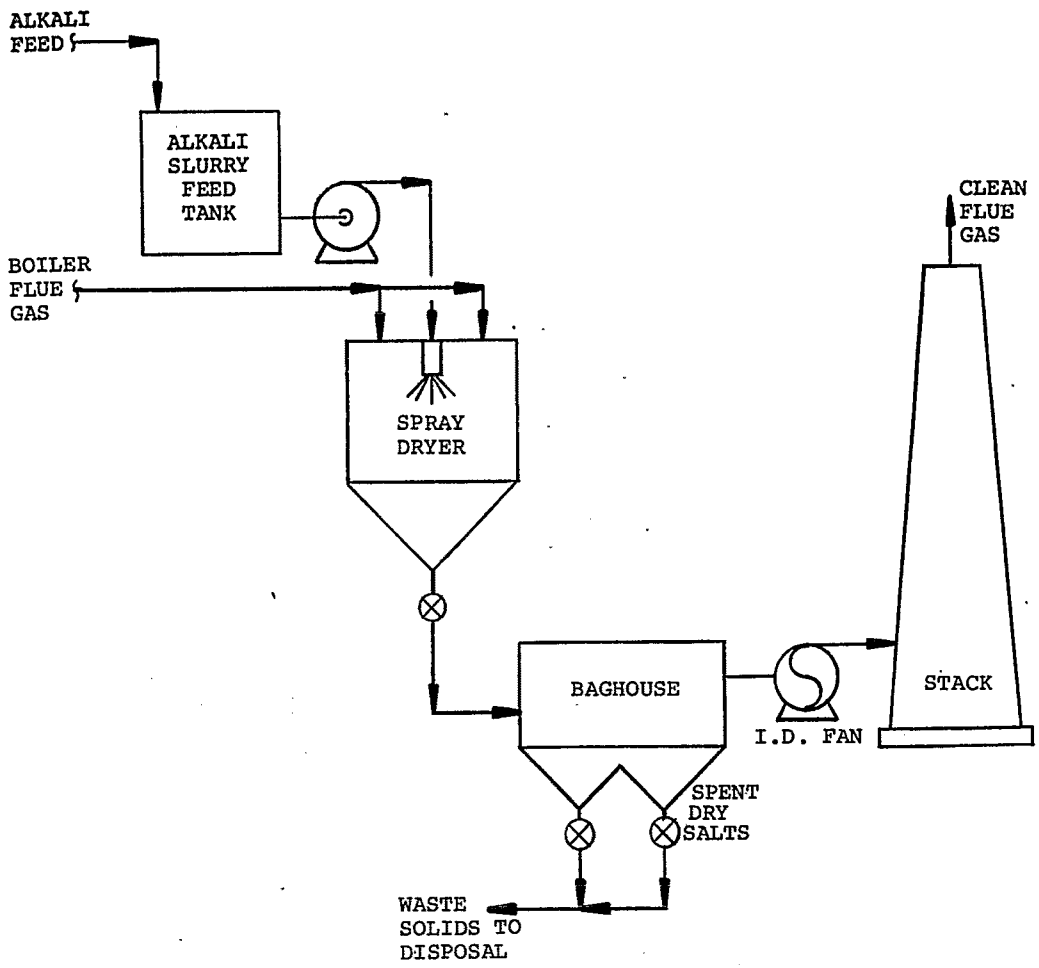

Figure 2-4.- Semi-dry scrubbing system - Wheelabrator-Frye/Rockwell International.

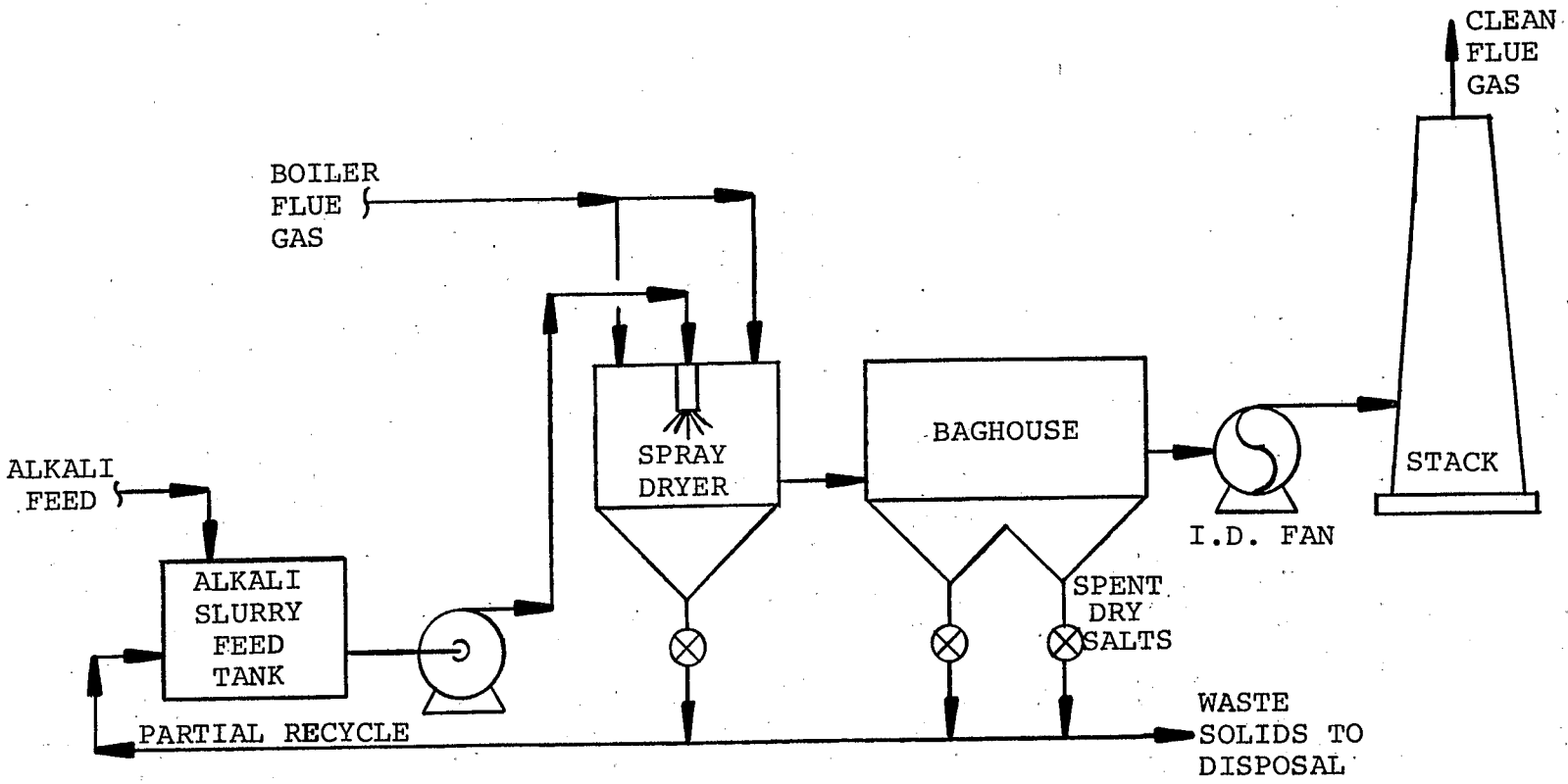

Figure 2-5.- Semi-dry scrubbing system - Joy-Niro.

Unit 3, whose gross capacity is 575 MW, is installing this system (6). Commercial operation should start in April 1982. The process flow diagram is shown in Figure 2-6.

4. Carborundum

A De Laval spray dryer in combination with a baghouse is used for this system (6). A test program using the process is underway presently at the pilot plant located at Leland Olds Station, Unit 1. The test program includes uses of either dual, fluid-spray nozzles or a rotary atomizer. No commercial operation plant is scheduled.

2.5 EMISSION MONITORING

In order to assure that the lowest NO_x, particulate, and SO_2 emission levels are achieved in a boiler system, emission monitoring systems must be used. Currently no continuous monitoring systems have been developed for measuring mass particulate emissions. However, a variety of instruments are available for measuring, indicating, and recording opacity. These instruments as well as methods and critera for evaluating performance are given in Reference 11.

Monitoring SO_2 and NO_x emissions in units of mass per unit heat input involves integrating the output of SO_2 and NO_x sensors with the output of CO_2 or O_2 sensors. Various SO_2, NO_x, CO_2, and O_2 sensing instruments, that are suitable for this purpose, are described in Reference 11. Reference 11 also discusses how the various outputs are integrated to furnish continuous indications and records of SO_2 and NO_x emission levels. In addition, the reference describes the methods and criteria for evaluating the performance of SO_2 and NO_x emission monitoring systems.

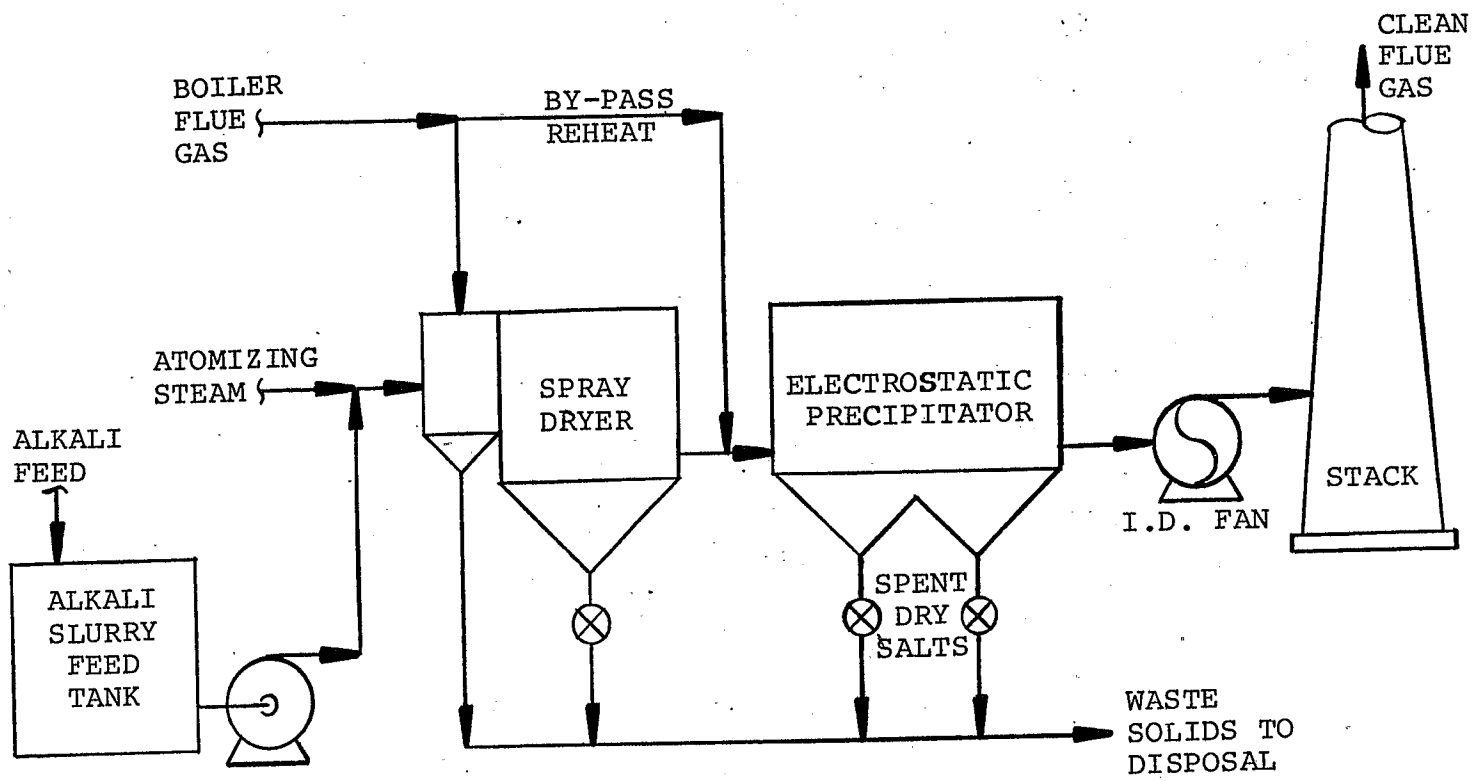

Figure 2-6.- Semi-dry scrubbing system - Babcock & Wilcox.

2.6 REFERENCES

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SECTION 3
RETROFIT DESIGN AND COSTS

3.1 GENERAL

The key pieces of equipment used to retrofit pulverized-coal-fired, steam generators for NO_x reduction and for control of SO_2 and particulates are fixed in operational design. The functional design for sizing to meet emission level requirements reduce relatively easily to physical layout considerations and mathematical analysis. Using the retrofit technology outlined in Section 2, this section presents the guidelines for determining retrofit costs. It also presents the equations for prorating to other design conditions. This is the basis for estimating costs for any desired retrofit situation. A typical schedule for retrofitting these plants concludes the discussion.

3.1.1 Emissions

The cost modules for NO_x reduction are based on the best available technology associated with boiler modifications to reduce NO_x formation. This document presents costs based on these modifications. Emission levels of 210 ng/J heat input (0.5 lb/106 Btu) for subbituminous coal and 260 nanograms per joule

heat input (0.6 lbs/10^6 Btu) for bituminous coal are the basis of the modification costs.[1] Actual implementation of the modifications discussed previously may not permit this emission level to be reached, but it presents the best potential for NO_x emission reductions.

The costs for SO_2 control are based on achieving SO_2 reductions in the flue gas of up to 90%.[2] For particulate control, the cost modules are based on achieving emission levels of 13 ng/J heat input (0.03 lb/106 Btu).[3]

3.1.2 Basis of Costs

The costs of an emission control systems are estimated as capital costs and annualized cost. The capital cost represents the initial investment necessary to install and commission the system. All costs are based on 3rd-quarter 1979 dollars. Annualized costs represent the cost of operating and maintaining the system and the charges needed to recover the capital investment, which are referred to as fixed costs. The cost of land for sludge disposal is not included in this study. Land used for sludge disposal is considered to have zero value once sludge disposal at that site has ceased.

Capital costs consist of direct and indirect costs incurred up to the tie-in and startup of the retrofit. Direct costs include the costs of various items of equipment and the labor and material (construction costs including field overhead) required for installing these items and interconnecting the systems. Indirect costs

include such items as freight, procurement, and allocated costs associated with the purchase and installation of the control equipment.

3.1.2.1 Direct costs.[4] - The purchased cost of the equipment and the cost of installing it are considered direct costs. The cost of an equipment item is the purchase price paid to the equipment supplier on a free-on-board (f.o.b.) basis; this does not include the freight charges. Installation costs cover the interconnection of the system, which involves piping, electrical, and the other work needed to commission it such as the cost of securing permits and the cost of insurance for the equipment and personnel on site. The costs of foundations, supporting structures, enclosures, ducting, control panels, instrumentation, insulation, painting, and similar items are attributed to installation. Costs including site development, relocation or alteration of existing facilities, administrative facilities, construction of access roads and walkways, and establishing rail, barge, or truck facilities have not been included in developing the retrofit costs except as noted; they must be determined on an individual basis for a specific plant.

3.1.2.2 Indirect costs.[4]- The indirect costs include freight from point of origin and indirect capital costs. The indirect capital costs consist of several cost items which are calculated as percentages of the total installed cost (TIC), the direct costs as noted above. The indirect capital costs include the following items:

A. Interest - Interest covers costs accrued on borrowed capital during construction. (About 10% of the TIC.)

B. Engineering costs - These costs include administrative, process, project, and general costs; design and related functions for specifications; bid analysis; special studies; cost analysis; accounting; reports; procurement; travel expenses; living expenses; expediting; inspection; safety; communications; modeling, pilot plant studies; royalty payments during construction; training of plant personnel; field engineering; safety engineering; and consultant services. (About 10% of the TIC.)

C. Taxes - Include sales, franchise, property, and excise taxes. (About 1.4% of the TIC.)

D. Allowance for shakedown - Includes costs associated with system startup. (About 5% of the TIC.)

E. Spare parts - Represent costs of items stocked in an effort to achieve 100 percent process availability; such items include pumps, valves, controls, special piping and fittings, instruments, spray nozzles, and similar equipment not included in base cost modules. (About 0.5% of the TIC.)

F. Contingency costs - Includes costs resulting from malfunctions, equipment design alternations, and similar unforeseen sources. (About 20% of the TIC).

G. Contractors fee and expenses - Includes costs for field labor payroll, supervision field office, administrative personnel, construction offices, temporary roadways, railroad trackage, maintenance and welding shops, parking lot, communications, temporary piping, electrical, sanitary facilities, rental equipment, unloading and storage of materials,

travel expenses, permits, licenses, taxes, insurance, overhead, legal liabilities, field testing of equipment, and labor relations. Contractor fees and expenses are about 5% of the TIC. The indirect cost for a given estimate is about 58.6% of the TIC. Indirect costs have been added to all costs presented in this document.

3.2 RETROFITTING TO REDUCE NO_x EMISSIONS

The effectiveness of applying currently available retrofit control for NO_x emissions to new coal-fired power plants is 210 ng/J heat input (0.5 lbs/10^6 Btu) for subbituminous coal and 260 ng/J heat input (0.6 lbs/10^6 Btu) for bituminous coal.[1] However, these levels may not always be achievable for existing units as a result of intolerable adverse side effects. For new units adverse side effects can be avoided by proper original design, but with existing units it is more difficult to apply the techniques while avoiding effects are discussed in Section 2.2.

Expert advice from steam generator manufacturers and/or combustion engineers is recommended in conjunction with decision making on best available retrofit technology for NO_x control.

3.2.1 Retrofit Techniques for NO_x Control

3.2.1.1 Plant data requirements.- When considering retrofitting a particular boiler for NO_x control in a plant, the following information related to existing boiler design and operation should be gathered:

- Type of boiler (single-wall, opposed-wall, tangential, or arch-fired)
- Manufacturer of the boiler
- Type of existing burners (arrangment, burner type, and burner capacity)
- Existing NO_x control and monitoring equipment
- Drawings of burner arrangement,
- Existing NO_x emissions level and State NO_x emissions limit

3.2.1.2 Design parameters.- There are several key elements involved in retrofitting steam generators for NO_x control. Each element is addressed separately in the following paragraphs to clarify its importance.

A. Type of boiler - Steam generator designs vary between manufacturers. Also individual manufacturers may offer more than one type of design, and they change their designs over the years to accomodate changed fuels, design improvements, and government regulations. Consequently, retrofit designs for coal-fired steam generators have to be customized for the needs of each unit.

B. Overfire air - Overfire air may range from 15 to 30% of the total air. The suggested value depends on the manufacturer and type of boiler. Overfire air is effective for Foster Wheeler, Riley Stoker, and C-E boilers and is one of the key elements for NO_x control in these units. B&W (5) does not recommend overfire air. When applying overfire air, ports must be cut in the firebox, and the wall tubes have to be modified to make space for the air port and tilt mechanism. Additional windbox modifications for connecting the duct to the overfire air ports and the individual air control dampers are required to complete the overfire air port retrofit. The overfire air jet velocity used is 61 M/sec (200 feet per second), to provide sufficient jet penetration depth.

C. Curtain air ports - Curtain air ports are applied only to the Foster Wheeler and Riley Stoker boilers. The main objective in using curtain air ports is to minimize slagging and tube wastage problems. The same air jet velocity, 61 M/sec (200 feet per second) used for overfire air is used in sizing the curtain air ports. The addition of ducts and individual air-flow control dampers is needed in addition to the wall tube modifications and firebox wall cutting. Curtain air ports are designed and installed in a manner to surround the bottom, the right and the left sides of the entire burners. Overfire air ports occupy the top row of burners. The amount of curtain air used is 10% of the total air and this is distributed equally among all curtain air ports. Again, the application and effectiveness of using curtain air ports are dependent on the type and year of manufacture of the boilers.

D. Low NO_x burners - B&W low NO_x burners have been tested and can be applied to existing units. Foster Wheeler data on low NO_x burners indicate, it may not always be effective or possible to apply low NO_x burners to existing old units. When retrofitting existing plants with low NO_x burners, rearrangement of the burners in the firebox wall might be necessary. This modification involves several operations including:

- modification of the membrane tubes to accomodate the low NO_x burners
- modification of the membrane tubes to close the holes where the original burners existed
- re-piping the coal feed lines from the pulverizer

- modification of the windbox to add a compartment for better control of air/fuel ratios

- tuneup or retrofitting the NO_x emission monitoring system.

E. Combustion air control

- Babcock & Wilcox uses a compartmentalized windbox to provide secondary air flow metering and flow control for each pulverizer. The result is a rigid coal/air ratio control to each burner group and flexibility to operate with lower total excess air while maintaining an oxidizing atmosphere around each burner. The Dual Register burner and the compartmentalized windbox are coupled together for this system. Excess air in the system ranges from 15 to 20%.

- C-E boilers use twenty percent excess air. The air/fuel ratio is kept slightly above stoichiometric at the burners. Twenty percent of the total air is used as overfire air.

- Twenty percent excess air is used for Foster Wheeler boilers. The percentage of overfire air is 30% and curtain air is 10% of the total air.

- Twenty percent excess air is used for R-S boilers. Overfire air is 30% and curtain air is 10% of the total air.

3.2.1.3 Retrofit calculation procedures. -

A. Dual Register Burners for Babcock & Wilcox Steam Generators - As mentioned in the previous sections, for the B&W boilers, the Dual Register burners coupled with modified windbox compartments is the technique recommended for NO_x control. The existing cell burner, and each coal nozzle must be replaced by an individual dual register burner. The dual register burners have a rating equal approximately that of a coal nozzle or one-third of that of a cell burner, and therefore, the total number of the Dual Register burners installed will be three times that of the cell burners.

B. Sizing of Overfire Air (OFA) Ports & Curtain Air (CA) Ports - The burner arrangement dictates the number and location of overfire air ports and curtain air ports. For this study C-E, F-W, and Riley Stoker boilers are retrofitted with overfire-air ports, but only F-W and Riley Stoker boilers will be retrofitted with curtain air ports. The location of the overfire air ports is, in principle, always at the top of each topmost burner of each vrtical burner column, for all three boilers. (see Figure 3-1) In the figure, (A) is an example of the normal location of the OFA port in a C-E boiler. where the firbox structure does not allow the OFA ports to be located directly on top of burners, the OFA port is offset but near the burner top. C-E has retrofitted OFA ports in a manner similar to (b) for NO_x control tests at Alabama Power Company's, Barry Unit 2 (6).

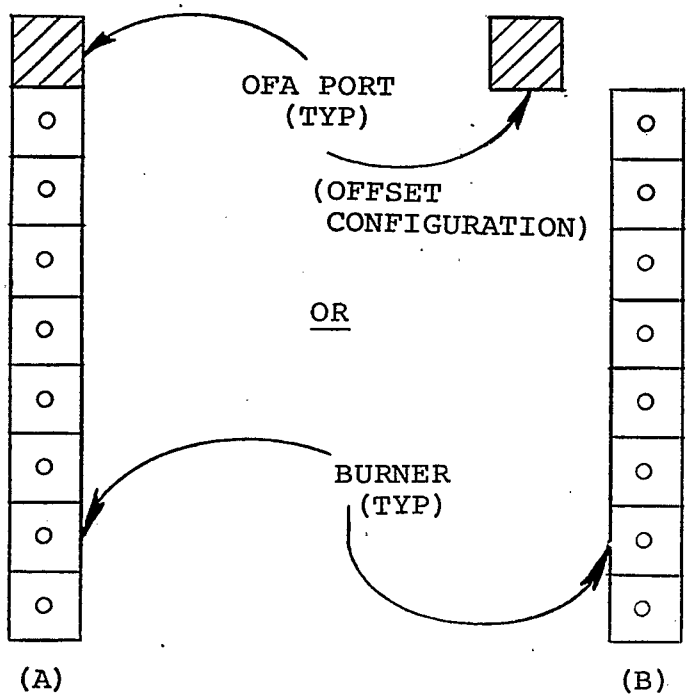

Figure 3-1.- Location of overfire air ports for C-E boilers.

Figure 3-2 shows the arrangement of the curtain air ports for the Foster Wheeler and Riley Stoker boilers.

From Figure 3-2, you can see that the number of OFA ports is equal to the number of burner columns, N, and the number of curtain air ports is (N + 2M) where M = number of burners per column. The size of each OFA port is based on the overfire air required at an inlet velocity of 61 M/sec (200 Ft/sec).

In order to minimize the number of wall tubes which will be affected and to minimize impairment of the firebox wall in retrofitting OFA ports, a 2:1 ratio of height and width is used.

3.2.2 Retrofit Costs for NO_x Control

The following sections provide guidelines for estimating the costs of retorfitting for NO_x control. These cost estimates should be supplemented whenever possible by consultation with boiler manufacturers and/or other experts on boiler modifications.

3.2.2.1 Burner module cost.-

A. Retrofit Capital Cost -

The low NO_x burner module costs for B&W retrofit are given in Table 3-1. A boiler manufacturer's fee of $60,000 for an engineering analysis of the firebox should be added to the total retrofit cost for the boiler once the burner module costs are determined.

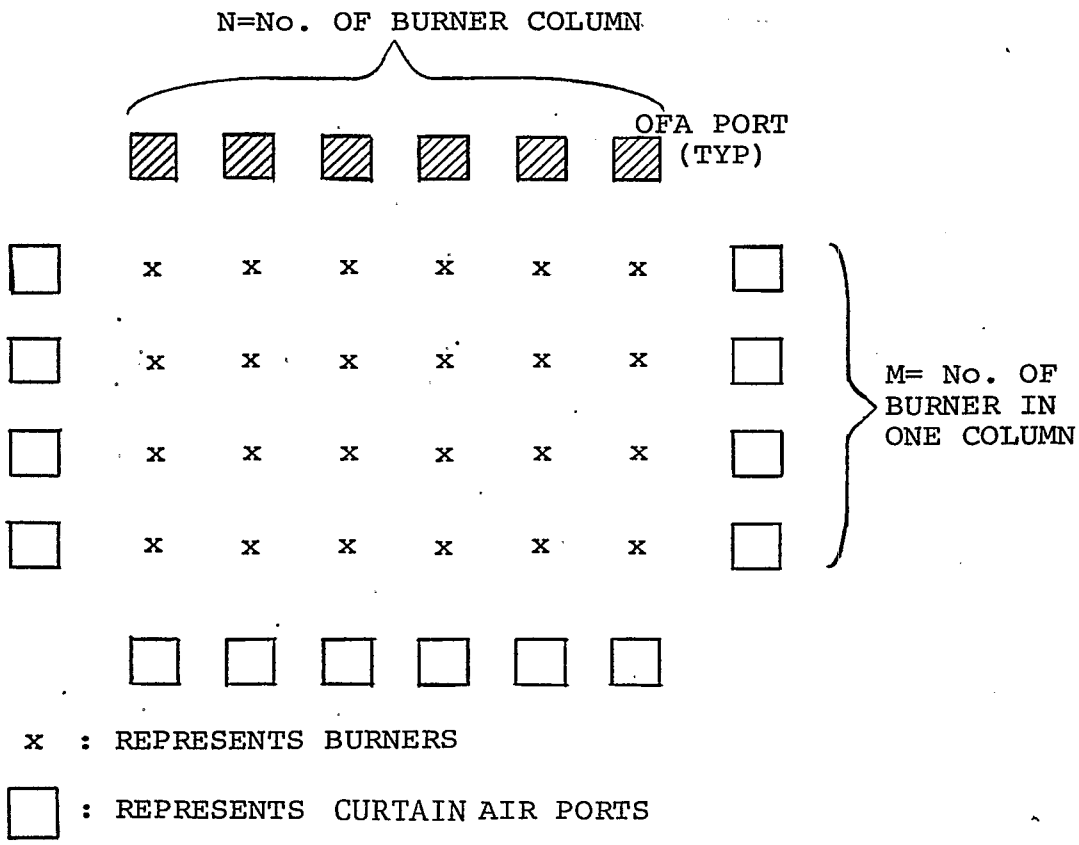

Figure 3-2- Arrangement of curtain air ports for F-W and R-S boilers.

TABLE 3-1.- B&W LOW NO_x BURNER COSTS

Burner[a] (MW=3.5)	$ 61,800
Piping	1,000
Instruments	8,000
Insulation, paint	100
Freight	4,100
Construction Cost	59,000
Total Installed Cost	134,000
Indirect Capital Cost[b]	79,000
Total Module Cost Per Burner	$213,000

B. Annual Costs -

Annual costs for B&W low NO_x burner retrofit systems should be estimated at 17.2 percent of the total capital cost. No allowance should be made for maintenance because maintenance costs for the new burners should be much the same as maintenance costs for the old style burners. No allowance is made for additional operation labor or energy costs.

3.2.2.2 Overfire air ports.-

A. Retrofit Capital Cost -

The cost of an overfire air port for C-E, FW, and R-S retrofits includes port and membrane wall tubes modifications, port tilt mechanism, air flow controls, windbox and ducts additions, and the boiler manufacturer's engineering analysis of the firebox. A boiler manufacturer's fee of $60,000 for an engineering analysis of the firebox should be added to the total retrofit cost for the boiler once the burner module costs are determined. The module cost of an overfire air port is given in Table 3-2.

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[a]Burner cost based on Dual Register burner, three burners required for each cell burner replaced

[b]See Section 3.1.2 for definition of indirect capital costs

TABLE 3-2.- OVERFIRE-AIR PORT COSTS

Port fabrication	$ 12,500
Duct work and windbox modification	4,500
Instruments and controls	6,500
Freight	1,500
Subcontract	4,500
Construction Cost	56,000
Total Installed Cost	85,500
Indirect Capital Cost[a]	50,100
Total Module Cost Per Port	$135,600

B. Annual Costs -

Annual costs for overfire and curtain air ports should be estimated at 22.2 percent of total capital costs. This allows 17.2 percent for amoritization and 5.0 percent for maintenance and supplies.

3.2.2.3 Curtain Air Ports.-

A. Retrofit Capital Cost -

Cost of a curtain air port is taken as 63% of an OFA port or $ 85,000/port. The boiler manufacturer's engineering analysis should be included in the OFA ports costs as given in Section 3.2.2.2

B. Annual Costs -

See Section 3.2.2.2 B

3.2.2.4 Combustion air fan.- No costs for additional combustion air fans are estimated for special burner, overfire air, and curtain air modules.

[a]See Section 3.1.2 for definition of indirect capital costs

3.3 RETROFITTING DUCTWORK AND STACKS

For most existing power plants, there will not be enough space to locate retrofit systems between the steam generator and the existing stack. Although it might be possible to remove existing air pollution control systems to make room for the retrofit system between the steam generator and the stack, this would usually make it necessary to shut down the steam generator for more than one year while the retrofit system is being installed. Consequently, retrofitting will usually involve installing the retrofit system beyond the existing stack. This will increase the length of duct work required to retrofit an air pollution control system to an existing steam generator and stack.

The additional length of ductwork required for retrofitting is the length of ductwork needed to connect the retrofit system to the existing ductwork near the stack and the length of ductwork needed to return the cleaned gases from the retrofit system to the existing stack. Otherwise the lengths of ductwork needed for a new or a retrofit air pollution control system are much the same.

Analysis of the costs of ductwork for retrofit situations indicates that 15 percent of the total capital costs of a new air pollution control system is a liberal allowance for the additional cost of ductwork for a retrofit system.[13,14] In special cases where space limitations make it necessary to locate the retrofit air pollution control system remote from the existing stack, it may be less costly to erect a new stack in conjunction with the retrofit system thereby decreasing the length of ductwork needed to connect the retrofit system to the stack. Table 3-3 shows estimated capital costs of new stacks.[15]

The diameter of stack needed should be estimated using a gas volume of 3760 actual cubic feet per minute per gross megawatt of steam generator capacity and a linear gas velocity at the outlet of 65 feet per second.

In cases where SO_2 control systems are to be retrofitted it may be necessary to reline or to replace the existing stack to provide for corrosion resistance. These costs are not included in the cost estimates of this document.

TABLE 3-3. Values of A and B for Estimating the Cost[15] of Utility Boiler Stacks

Inside Stack Diameter at Outlet Feet	A	B
15	0.185	2.625
20	0.393	2.535
30	2.184	2.330
40	4.377	2.262

Where $Y = AH^b$

Y = Capital cost (direct and indirect) third quarter 1979 dollars

H - Stack height - feet (range between 250 and 1200 feet)

Costs include - concrete shell, foundations, and steel liner

Designed for -

Windload - 40 pounds per square foot

soil bearing - 4500 pounds per square foot

seismic conditions - Zone 1 (minor risk)

3.4 RETROFITTING TO CONTROL PARTICULATE EMISSIONS

3.4.1 General

Electrostatic precipitators and baghouses are most commonly used for high efficiency removal of particulates from the combustion gases of coal-fired steam generators. When flue gas desulfurization systems are required, particulate scrubbing is often incorporated into the air pollution control system, although, of course, scrubbing can be used for particulates in systems when sulfur is not a problem.

When an ESP is installed before the air preheater, it is called a hot-side ESP. When it is installed between the air preheaters and stack, it is called a cold-side ESP.

Baghouses for high efficiency particulate control have become more widespread recently, especially when the coal ash is difficult to collect with an ESP. Baghouses are located downstream of the air preheater.

There are other particulate collectors such as cyclones and settling chambers, but they are not efficient enough to reduce particulate emissions to the levels required by current new source performance standards.

The three alternatives to be explored for this particulate emissions control retrofit study are:

- Upgrading either cold-side or hot-side EPS systems
- Installing baghouses
- Installing scrubbers in conjunction with flue gas desulfurization while retaining the existing particulate controls.

Various levels of particulate emission control can be achieved by retrofitting ESP's based on various specific collection areas. The efficiency achieved by baghouses has been demonstrated to control particulate emissions to levels less than 13 nanograms/joule (0.03 lb/106 Btu) with an air to cloth ratio of 0.61 actual cubic meters per minute per square meter (2 ACFM/ft2) and with pressure drops of less than 1.25 kilopascals (5 in. H_2O) in the filter at the full-load gas volume.[3]

The EPA position on aspects involved with the operating effectiveness of the electrostatic precipitator and baghouse systems of this document are discussed in Appendix E of these guidelines.

Unlike techniques for NO_x emission reduction, the principal systems for particulate emissions control - ESP's and baghouses, can be applied to all four manufacturer's boilers. Key elements in retrofitting an existing plant for particulate emissions control include the following items:

- The total collection area and arrangement of the existing particulates collection equipment (ESP's or baghouses) must be known.
- The available plant space for retrofitting ESP's, or baghouses, or scrubbers must be established and must be determined to be adequate. Unlike NO_x emission reduction retrofits, the retrofitting for particulate emissions requires significant additional plant space. Relocation of existing equipment, and addition of flue gas ducts and fans may be involved. The existing plot plan affects the retrofit cost because the choice of arrangement for the retrofitted equipment is very much

dictated by it. Detailed information about the avilability of additional space is a vital element for an economic retrofit.

- Flue gas flow rate and its temperatures in and out of the air preheater and out of the economizer must be known. These data govern the size of the retrofitted system.

3.4.2 Electrostatic Precipitator Design

The design of a new ESP system should be based on the performance data of the existing ESP system firing the same coal whenever possible. In case there are no such data available, coal ash analysis provides valuable data for selecting the size and type of ESP required to achieve the desired efficiency. Ash resistivity is a major factor affecting the size of an ESP system. The resistivity of ash entering the air preheater is much less when it is at temperatures of 316 to 482°C (600 to 900°F) compared to its resistivity at the air preheater outlet where the temperature is about 149°C (300°F). Therefore, with high resistivity ash coal, it is easier to collect on the hot side than on the cold side. The following factors must be taken into account in deciding whether a hot-side or a cold-side ESP system is to be used (3):

- Space available for the retrofit system
- Temperature-resistivity characteristics of the fly ash
- Specific collection area requirements
- Differences in gas volume caused by temperature differences
- Differences in gas volume caused by air leakage into the air preheater
- Differences in construction requirements caused by temperature differences

Analysis of the data on ESP's in Reference 3 shows that ESP systems can limit particulate emissions from steam generators to levels less than 13 nanograms per joule (0.03 lbs/10^6 Btu). The size of the system required to meet a given emission level depends upon ash characteristics and the level of control required.

The factors that have been discussed dictate that the features in the following list need to be included in ESP retrofit systems for control of particulate emissions from large steam generators.

- Either a cold-side system or a hot-side system is chosen and the choice depends on circumstances such as the additional space required and available, and the possibility for installing the ductwork on either the entrance side or the downstream side of the air preheater.
- Sufficient electrical sectionalization should be included in the ESP system to ensure that adequate collecting surface area will be available should a breakdown occur in one of the sections.
- Automatic power controls should be provided as well as instrumentation showing; 1) primary voltage, 2) primary current, 3) secondary voltage, 4) secondary current, 5) spark rate for each individual section.
- Insulation should be sufficient to minimize temperature drops which would cause acid attack.
- Enough flue-gas-flow, cross-sectional area should be included to ensure maintaining the system in the high collection efficiency range.
- Provisions should be made for good flue gas velocity distribution in the gas passages, even at partial loading.
- Sectionalization of the rapping system for difficult dust should be about 139 square meters (1,500 ft^2) of collecting plate area per rapping section.
- Separate electrical sectionalization should be about one section for each 5 MW of gross generating capacity.

Retrofitting can achieve the following limits indicated in Table 3-4 that follows (3):

TABLE 3-4.-ESP SPECIFIC COLLECTION AREA (SCA) FOR VARIOUS COALS[a]

Coal Sulfur Content %	Emission Limit (lb/10 Btu)	ESP Type	SCA[3] Ft^2/1000 ACFM
.8	.03	Hot	650
.8	.03	Cold	1000
.8	.05	Hot	550
.8	.05	Cold	800
.8	.10	Hot	400
.8	.10	Cold	650
3.5	.03	Colda	360
3.5	.05	Colda	300
3.5	.10	Colda	240

[a]Hot side ESP's not normally used with 3.5% S coal

The following data can be used for estimating the flue gas volume once the gross MW capacity of the unit is known:

Coal Heating Value (as burned):	Variable, depending on the coal
Heat Rate:	2.924×10^3 J/KWSec (10,000 Btu/KW Hr)
"F" Factor (11):	2.64×10^{-7} Dry Standard Cubic metres per joule (9,820 SCF/10^6 Btu) at 0% excess air and 20°C (68°F)
Excess Air at Economizer:	25%
Flue Gas Temperature out of Economizer (Hot Side):	343°C (650°F)

Excess Air Out of Air Preheater:	45%
Flue Gas Temperature out of Air Preheater (Cold Side):	149°C (300°F)
Water Content of Flue Gas:	10% of dry gas volume

3.4.2.1 Hot-side precipitator.- The major problem encountered in retrofitting hot-side ESP systems to an existing plant is insufficient space for fitting the hot-side ESP between the economizer and air preheater. If there is a space problem, either the air preheater has to be moved and relocated to allow for duct work, or considerations must be given to retrofitting with cold-side ESP systems.

Duke Power Company has retrofitted both hot-and cold-side ESP systems at their utility plants (16). Duke Power's hot-side ESP retrofits to their C-E boilers was achieved without relocating the air preheaters because space was available for ducting tie-ins.

For Duke Power hot-side retrofits, the flue gas duct was partitioned into two parts at the horizontal section in front of the air preheater. Hot flue gas was guided into a new duct, stemmed from one side of the partition, and was routed to the hot-side ESP system. The return gas from the ESP system was directed into a new duct that lead back to the other partition and flowed into the air preheater.

When the existing gas passage ducting does not allow for any modification, the only alternative to retrofitting with hot-side ESP systems is to remove the air preheater and relocate it in order to provide enough space for the duct work. This installation involves shutdown time. The retrofit work must be based on individual designs for each situation.

3.4.2.2 Cold-side precipitator.- Retrofitting cold-side ESP systems to an existing plant involves connecting and adding ducting to the existing flue-gas outlet of the air preheater or the existing ESP. The exit flue-gas duct from the ESP systems is connected to the ID fan, stack, or scrubber system depending upon plant design.

3.4.2.3 Flue Gas Conditioning

The specific collecting surface area values of Table 3-4 do not reflect the possible beneficial effect of flue gas conditioning agents such as sulfur trioxide, sulfuric acid, or ammonia. Although it is possible that use of these agents would reduce the size of the ESP required to meet a given level of control, the conservative estimates of Table 3-4 should be used for cost estimating. However, if an owner elects to use flue gas conditioning to implement a best available retrofit technology decision, this should be allowed with a provision that the emission limitations of the BART decision must be met.

3.4.3 Baghouse Design

The type of baghouse considered in this retrofit study is the inside-out, multicompartment, reverse-air design. Of course other baghouse designs, such as outside-in filtration, pulse-jet cleaning, and shake cleaning can be used as alternatives.

The design criteria and design features of the baghouse systems to be used in this retrofit study are summarized in the following list:

- Air to cloth ratio is 0.61 actual cubic meters per minute per square metre (2 ACFM/Ft^2) to handle full load gas volume at pressure drops less than 2.5 kilopascals (10" H_2O)
- Reverse-air cleaning
- Multicompartment system
- Provision for isolating each compartment for cleaning or maintenance while the other compartments are on line
- Provision for automatic cleaning on a compartment by compartment basis with controls for adjusting the quantity of reverse air, the frequency of cleaning, and the duration of cleaning
- Provision for instruments indicating pressure drop and temperature in and out of the baghouse
- Adequate insulation to minimize temperature drops which would cause acid attack on the baghouse

3.4.4 Retrofit Costs For Particulate Control

3.4.4.1 Electrostatic Precipitators.- The following equation should be used to estimate the capital cost of retrofit electrostatic precipitator (ESP) systems.[3]

Cold Side ESP Systems

$$y = 3635\ (x)^{.6404}$$

Hot Side ESP Systems

$$y = 414.5\ (x)^{.8129}$$

Where:

y = total capital cost in third quarter 1979 dollars

x = square feet of collecting surface area

These costs include the direct and indirect costs of the ESP including ash removal and the additional cost of retrofit ductwork (15 percent). The costs are derived from the costs used to support the new source performance standards for new electric generating units.[3]

The total collecting surface area required can be determined using 1) the data of Table 3-4, 2) data on the size of each steam generator to be studied, 3) data on the ESP collecting surface area installed, and 4) data on the coal characteristics. With low sulfur coal more collecting surface area is usually needed than for high sulfur coal. In most cases it will not be possible to retrofit a hot side ESP. However, since some hot side ESP's have been retrofitted, cost data is included.[16] When the necessary data has been obtained from the power plant, cost estimates can be made.

Once the levels of control to be studied are selected (usually by those responsible for visibility impact analysis) the specific collecting surface areas (SCA) should be selected from Table 3-4. For cases not covered by the table or where there is doubt that the values of the table are applicable, ESP vendors should be consulted for advice or engineering judgments should be made. Total gas volume should be computed using the following estimates.

Hot Side ESP Systems

Gas volume = 4730 ACFM per megawatt at 650°F

Cold Side ESP Systems

Gas volume = 3760 ACFM per megawatt at 300°F

Although actual gas volume may be less than the foregoing values, these estimates provide a safety factor for cost estimating. These gas volume values should not be used for enforcement purposes when test data show different values.

Once the total collecting surface area requirements are estimated using the data on gas volume and collecting surface area, any installed collecting surface area should be deducted to determine retrofit requirements. The example on the Navajo plant of Appendix C shows how the foregoing technique is applied. Once the additional ESP area has been estimated the capital cost of the retrofit system should be computed using the applicable capital cost equation.

Annual costs should be estimated using the following equations:[3]

Cold Side ESP Systems - $y = 965.03\ (x)^{0.6381}$

Hot Side ESP Systems - $y = 111.54\ (x)^{.8099}$

y = annual costs - third quarter 1979 dollars per year

x = retrofit collecting surface area required - square feet

Annual costs can be estimated in units of mills per kilowatt hour by dividing the dollar values by annual power generation. In the absence of data from the plant, annual power generation should be estimated assuming the steam-electric generating system operates at 65 percent of net (not gross) generating capacity during the year. In determining net generating capacity the electric power requirements of the retrofit systems should be deducted from the net generating capacity of the plant prior to retrofitting.

ESP retrofit costs should be estimated separately for each steam generator. As previously stated, the costs include both direct and indirect costs and provide an allowance for the additional cost of retrofit ductwork. Other costs that are not included but that might be involved are discussed in Sections 4.2, 4.4, 4.5, and 4.6.

The electrical energy requirements of ESP systems are estimated to be 2.810 kilowatts per 1000 square feet of collecting surface area added.[13] This value or a value obtained by consultation with ESP vendors should be used to estimate the requirements for replacement of electric generating capacity as discussed in Section 4.4.

3.4.4.2 Baghouses. - The following equations should be used to estimate the capital cost of baghouses for any retrofit situations:[3]

$$y = 173420\ (x)^{0.8384} \text{ without booster fan}$$

or

$$y = 174987\ (x)^{0.8563} \text{ with booster fan}$$

Where:

y = capital costs - third quarter 1979 dollars

x = size of baghouse - megawatts

These equations are applicable for full or partial gas treatment. For example where a 500 megawatt unit is to be retrofitted for filtration of 70 percent of the flue gas, baghouse size would be 350 megawatts. A booster fan should be provided in cases where only a baghouse is to be retrofitted. If the baghouse is to be retrofitted in conjunction with SO_2 control, the cost of the booster fan is included in the SO_2 control cost estimate.

The baghouse capital cost equations include the direct and indirect costs of the baghouse additional retrofit ductwork, and the ash removal systems for a 2-to-1 air to cloth ratio, reverse air baghouse. The costs do not include those discussed in Section 4.2, 4.4, 4.5, and 4.6. The data needed for baghouse cost estimates are data on the size of each steam generator (gross megawatts) and the foregoing equations. The capital and annual costs are derived from the cost data used to support the new source performance standards for electric utility steam generators and include a 15 percent allowance for additional retrofit ductwork.[3] Costs should be estimated separately for each baghouse system.

Annual costs for baghouses should be estimated using the following equations:[3]

$y = 31090\ (x)^{.8494}$ without booster fan

$y = 21934\ (x)^{.9358}$ without booster fan

Where:

y = annual costs - third quarter 1979 dollars per year

and

x = baghouse capacity - megawatts

These costs can be converted to units of mills per kilowatt hour using the techniques described in Section 3.4.4.1.

The electrical energy requirements of baghouses are estimated to be 6.615 kilowatts per megawatt of baghouse capacity.[13] This value should be used to estimate the capital cost of replacing electric generating capacity as discussed in Section 4.4 and for estimating unit annual costs as discussed in Section 3.4.4.1.

Other costs that may be involved with retrofitting but not included in the foregoing cost estimates are discussed in Sections 4.2, 4.4, 4.5, and 4.6.

3.5 Retrofitting To Control SO_2 Emissions

3.5.1 Retrofit Costs For Wet SO_2 Control

Table 3-5 shows the values of A and b to be used in estimating retrofit costs for various flue gas desulfurization systems where:[2]

$$y = Ax^b$$

and

y = capital cost - third quarter 1979 dollars

x = size of system - megawatts

TABLE 3-5.- VALUES OF A AND b FOR ESTIMATING CAPITAL AND ANNUAL COSTS OF WET FLUE GAS DESULFURIZATION SYSTEMS [2]

SYSTEM	CAPITAL COSTS THIRD QUARTER 1979 DOLLARS		ANNUAL COSTS THIRD QUARTER 1979 DOLLARS PER YEAR	
	A	b	A	b
Lime FGD				
Eastern 3-5%S	1.715×10^6	0.6612	494×10^3	0.7107
Eastern 7.0%S	1.874×10^6	0.6663	528.2×10^3	0.7264
Western 0.8%S	1.450×10^6	0.6546	405×10^3	0.7052
Anthracite	166.0×10^3	1	61.62×10^3	1
Lignite	166.2×10^3	1	61.92×10^3	1
Limestone FGD				
Eastern 3.5%S	2.321×10^6	0.6375	656.4×10^3	0.6803
Eastern 7.0%S	2.373×10^6	0.6563	672.0×10^3	0.7020
Western 0.8%S	1.756×10^6	0.6455	508.3×10^3	0.6828
Mag-Ox FGD				
Eastern 3.5%S	2.708×10^6	0.6279	810.9×10^3	0.6623
Eastern 7.0%S	2.790×10^6	0.6464	811.6×10^3	0.6869
Double Alkali FGD				
Eastern 3.5%S	2.624×10^6	0.6194	712.0×10^3	0.6745
Western 7.0%S	2.791×10^6	0.6274	735.6×10^3	0.6955
Wellman Lord FGD				
Eastern 3.5%S	2.573×10^6	0.6156	784.1×10^3	0.6415
Western 7.0%S	2.542×10^6	0.6307	775.8×10^3	0.6539

The costs include the direct and indirect costs of:

- Feed storage and handling
- Scrubbing
- Plume reheat to 175°F
- Liquor treatment
- Sludge disposal
- and Booster fans

The costs include one spare scrubbing module and booster fan for each steam generator and allow 15 percent for the additional cost of retrofit ductwork. The design effectiveness of the systems shown in Table 3-5 is 90 percent removal of SO_2. The EPA position on aspects involved with the operating effectiveness of the wet SO_2 scrubbing systems of this document is discussed in Appendices D and E of these guidelines. The costs are derived from the costs used to support the new source performance standards for new steam electric generating units.[2]

The cost equations can be used for partial scrubbing cost estimates. The size of scrubbing system for partial scrubbing should be calculated by the following equation:

$$C_{SCR} = \frac{C_{SG} \times P}{0.9}$$

Where C_{SCR} = Size of scrubbing system for partial scrubbing-megawatts

C_{SG} = Size of steam generator-gross megawatts

and P = Percent SO_2 removal desired

Once the size of the scrubbing system is computed, the capital cost should be estimated using the applicable values of A and b from Table 3-5. For most cases the least costly system (usually lime scrubbing) should be selected. Data on coal characteristics and steam generator size (gross megawatts) are all that are needed to estimate retrofit costs. Costs should be estimated separately for each steam generator.

For partial scrubbing of less than 75 percent of the flue gases plume reheat is usually not necessary since the bypassed flue gas will usually heat the combined gas from the scrubber to at least the combined gas from the scrubber to at least 175°F. The capital costs estimated using Table 3-5 can be adjusted by deducting $6000 for each megawatt of scrubber capacity for cases where no plume reheat system is necessary.[13] Case 2A of Appendices A, B, and C show examples of capital and annual cost estimates for partial scrubbing.

Annual costs should be estimated using the data of Table 3-5 and the following equation:[2]

$$Y = AX^b$$

Where Y = annual scrubbing costs - Third quarter 1979 dollars per year

X = scrubber capacity - megawatts

For partial scrubbing cases that do not include a reheater $4200 per year per megawatt of scrubber capacity should be deducted from annual costs.[13] Unit annual costs can be estimated using the techniques described in Section 3.4.4.1.

Electrical energy requirements for wet scrubbing systems should be estimated as shown in Table 3-6[2]. Auxiliary boiler capacity for reheating from 125° to 175°F should be estimated at 210,000 Btu per hour heat input per megawatt of scrubber capacity.[13]

Other costs that may be involved with retrofitting but are not included in the foregoing estimates are discussed in Sections 4.2, 4.3, 4.4, 4.5, and 4.6.

3.5.2 Retrofit Costs for Lime Dry SO_2 Control

The total indirect and direct capital cost of lime dry scrubbing systems should be estimated at 125 third quarter 1979 dollars per kilowatt of scrubber capaticy.[17] These costs include:

- Feed Storage and Handling
- Dry Scrubbing
- Sludge Disposal
- Booster Fans
- and Retrofit Ductwork

The design effectiveness of the system is 70 percent removal of SO_2. The costs include 15 percent allowance for the additional cost of retrofit ductwork.

TABLE 3-6. ELECTRICAL ENERGY REQUIREMENTS FOR WET FLUE GAS DESULFURIZATION[2]

System	Electrical Energy Required Percent of Scrubber Capacity (Gross Megawatts)
Lime Scrubbing	
0 - 3.5 percent sulfur	3.5
7.0 percent sulfur	3.5
Limestone Scrubbing	
0 - 3.5 percent sulfur	3.5
7.0 percent sulfur	4.3
Double Alkali Scrubbing	
0 - 3.5 percent sulfur	3.1
7.0 percent sulfur	3.1
Magnesium Oxide Scrubbing	
0 - 3.5 percent sulfur	5.9
7.0 percent sulfur	9.4
Wellman Lord Scrubbing	
0 - 3.5 percent sulfur	13.3
7.0 percent sulfur	25.9

The annual costs of dry scrubbing are estimated at 41,500 third quarter 1979 dollars per year for each megawatt of scrubbing system capacity.[13]

Electrical energy requirements for dry scrubbing should be estimated at 16.9 kilowatts per megawatt of scrubber capacity.[13]

Annual costs can be converted to unit annual costs using the techniques described in Section 3.4.4.1. Other costs involved with retrofitting but are not included in the foregoing estimates are discussed in Sections 4.2, 4.4, 4.5, and 4.6.

3.5.3 Makeup Water Requirements

For some cases, especially for power plants located in arid Western areas, makeup water supply can be a problem. Water requirements for wet scrubbing systems are estimated to be 1 gallon per minute per megawatt.[13] Water requirements for dry scrubbing are estimated to be 0.8 gallons per minute per megawatt.[13] In cases where water supply is limited, use of other water sources such as cooling tower blowdown should be considered.

3.6 LAND AREA REQUIREMENTS

Additional space is needed for retrofit air pollution control systems except for NO_x steam generator modifications where the necessary hardware can be fitted within existing structures. In most cases it will be necessary to locate retrofit particulate and SO_2 emission control systems on the other side of the existing stack from the steam generator. Although it might be possible to locate part of the retrofit systems between the stack and the steam generator by removing existing air pollution control systems, usually this is not a viable option since removing existing equipment would involve extended, costly shutdown of the steam generator.

For electrostatic precipitators a minimum of 12.5 square feet of space is needed for each 1000 square feet of collecting surface area added.[13] Minimum baghouse space requirements should be estimated at 37 square feet per megawatt of baghouse capacity.[13] These space requirements are for a 2 to 1 air to cloth ratio baghouse and do not include space for ash

storage or disposal.

Table 3-7 shows space requirements for wet lime, wet limestone, and dry lime scrubbing systems.[13] These estimates include space for feed storage and handling, scrubbers, and liquor treatment but do not include space for sludge disposal. Table 3-8 shows values for estimating SO_2 sludge generation.[13] A 50 percent solids content should be used for all cases except for low sulfur Western coals or for Eastern coal cases where a special oxidation system is to be installed. For those cases 70 percent solids content should be used. Sludge volumes can be converted to area by assuming a pond depth and life. A pond depth of 50 feet and a life of 20 years should be used except for site specific situations where other values are a more logical choice.

The foregoing values should be used to identify potential space problems involved with retrofitting. If space problems are identified, more comprehensive studies than those of this document will be needed to indicate potential solutions.

3.7 EMISSION MONITORING COST

The retrofit cost for emissions monitoring systems (18, 19, 20) is divided into two categories:

3.7.1 Retrofit Capital Costs

Monitoring Equipment

SO_2/NO System (1/Boiler)		
Analyzer, Remote Readout & Control	=	$30,000
Installation Cost	=	22,000
Total Installed Cost	=	52,000
Indirect Capital Cost[a]	=	30,000
Field Certification Fee	=	10,000
Total SO_2/NO System:	=	92,000

[a]Refer to Section 3.2.1 for definition

TABLE 3-7. MINIMUM LAND AREA REQUIREMENTS FOR LIME AND LIMESTONE SCRUBBING SYSTEMS[13]

System	Minimum Land Area Required (Square Feet Per Megawatt Scrubber Capacity)
Wet Lime Scrubbing	
0.5 percent sulfur	80
3.5 percent sulfur	180
Wet Limestone Scrubbing	
0.5 percent sulfur	80
3.5 percent sulfur	140
Dry Lime Scrubbing (Includes Baghouse)	80

TABLE 3-8. SLUDGE GENERATION FOR LIME AND LIMESTONE SCRUBBING SYSTEMS[13]

System	Sludge Generation (Cubic Feet Per Year Per Megawatt For 1 Percent Sulfur Coal)
Wet Lime Scrubbing (50 percent solids)	6,000
Wet Lime Scrubbing (70 percent solids)	4,000
Wet Limestone Scrubbing (50 percent solids)	7,000
Wet Limestone Scrubbing (70 percent solids)	5,000
Dry Lime Scrubbing	6,000

Opacity System (1/Boiler)		
Transmissiometer, Remote Readout, Converter Unit, Air Flush Equip., and Miscellaneous	=	$15,000
Installation Cost	=	26,000
Total Installed Cost	=	14,000
Indirect Capital Cost[a]	=	24,000
Field Certification Fee	=	3,000
Total Opacity System:		$68,000
Oxygen Analyzers (2/Boiler)		
Probe, Shield, Umbilical & Controller	=	$40,000
Installation Cost	=	37,000
Total Installed Cost	=	77,000
Indirect Capital Cost [a]	=	45,000
Field Certification Fee	=	5,000
Total for Two Oxygen Analyzers:		$127,000
Strip Chart Recorders 3/Boiler)	=	$ 6,000
Installation Cost	=	6,000
Total Installed Cost	=	12,000
Indirect Capital Cost[a]	=	7,000
Total for Three Strip Chart Recorders:		$19,000
Data Processor (1/Plant)		
Processor, Software Pkg., Cabinet & Reason Code Panel	=	$50,000
Installation Cost	=	25,000
Total Installed Cost	=	75,000
Indirect Capital Cost[a]	=	44,000
Field Certification Fee	=	2,000
Total Data Proces:		$121,000

In summary, capital costs are estimated at $306,000 per steam generator plus $121,000 for a plant data processor.

[a] Refer to Section 3.2.1 for definition

3.7.2 Operating Costs

Operating Costs Plant[b]

Labor 1 man per shift with 3 shifts @ $11/MH		
Annual Labor Cost	=	$96,100
Material and Miscellaneous	=	3,900
Total	=	$100,000

3.7.3 Annual Costs

Annual costs should be estimated at 17.2 percent of capital costs plus $100,000 per year per plant as given above.

[b]Annual operating costs based on 365 days per year and 24 hours per day.

3.8 TIME REQUIREMENTS FOR RETROFITTING

Figure 3-3 presents a typical engineering, procurement and construction schedule for retrofitting a large power plant for NO_x, particulate, and SO_2 control. The elapsed time from contract award to plant operation is 60 months. The engineering time span is 26 months, and procurement is 36 months. Purchasing is completed when the final purchase order is released; however, inspection, expediting, and traffic are involved until the last of the materials are delivered. The construction span is 33 months. This span allows four months for tie-in to the existing equipment, and it is based on staggering the shutdown of the units. No special unit shutdowns would be required; normal plant shutdowns would be utilized to tie into the existing equipment. The time periods shown in Figure 3-3 can vary considerably if other factors such as economic, political, or international situations become involved.

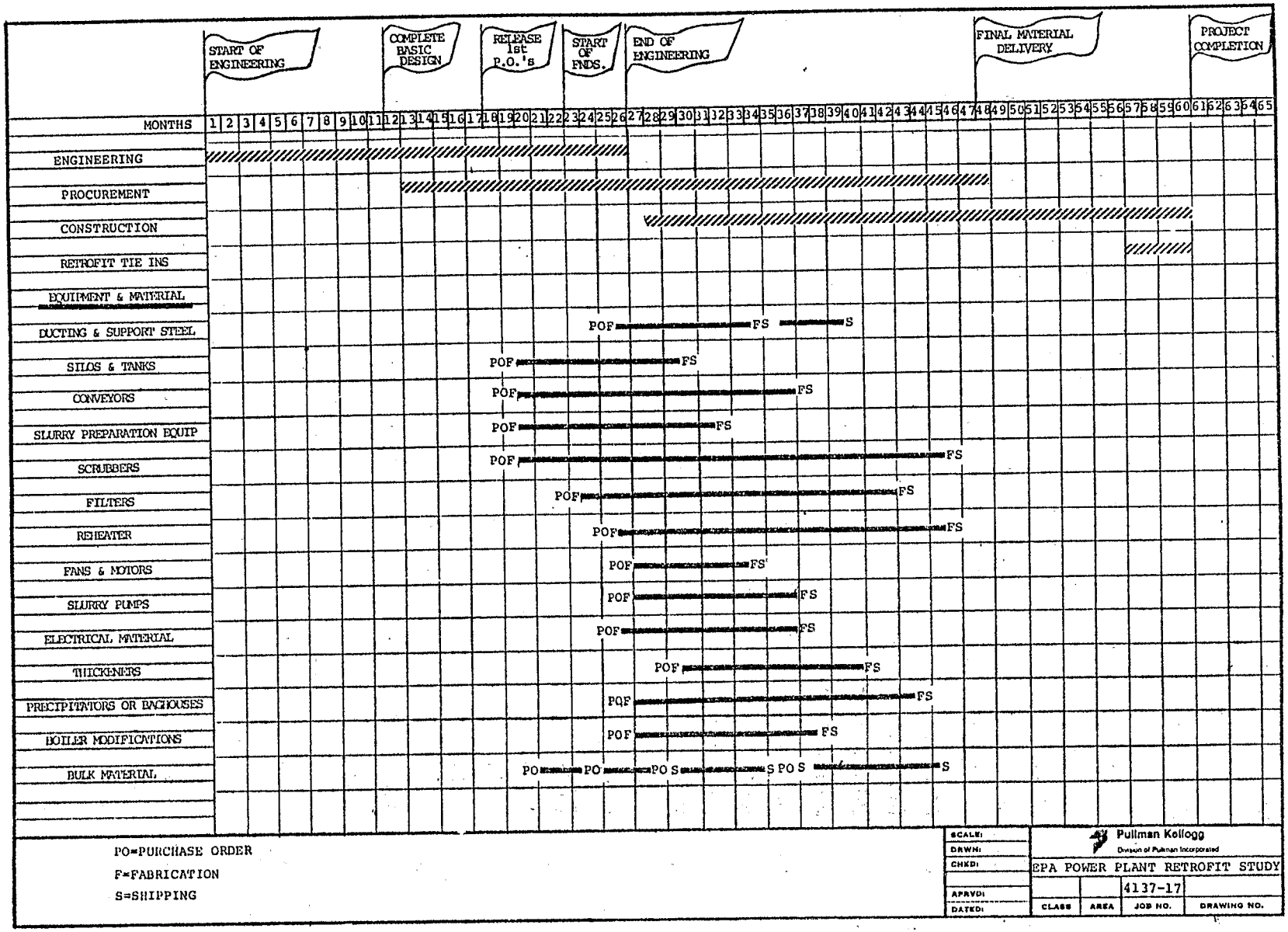

Figure 3-3 Typical schedule for retrofitting large power plants.

3.9 REFERENCES

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18. Letter from K.A. Kedtke, Leon Siegler, Inc., to N. Master, Pullman Kellogg, Budgetary Quote, June 29, 1979.
19. Letter from R.F. Crowthen, Dynatron, Inc., to N. Master, Pullman Kellogg, Budgetary Quote, June 26, 1979.
20. Letter from L.N. Roten, Thermo Electron to Dr. K. Hsiao, Pullman Kellogg, Budgetary Quote, June 25, 1979.

SECTION 4

TECHNIQUES FOR ESTIMATING TOTAL RETROFIT COSTS FOR EMISSION CONTROL

4.1 GENERAL

The cost of a power plant retrofit is estimated in terms of capital cost and annualized cost (1). Capital cost represents the initial investment necessary to install and commission the retrofit, and the capital costs consist of the direct and indirect costs that are defined in Section 3.2.1. Annualized costs are composed of direct and fixed charges. Working capital, that is the money required to operate the plant after completion of the retrofit, should also be included in the retrofit cost. Specific cost estimating examples are given in Appendices A, B, and C.

4.2 Working Capital

Working capital is the money set aside to operate the plant after completion of the retrofit. The working capital should be estimated as 25% of the total annual operating costs (direct and fixed).

4.3 Auxiliary Boiler Costs

When plume reheat is required the capital cost of an auxiliary boiler should be included in the total capital cost estimate. Section 3.5.1 describes the techniques that should be used to estimate the size of auxiliary boiler needed. The annual costs of plume reheat steam are included in the annual cost estimates of Table 3.4. Table 4-1 should be used to estimate the capital cost of auxiliary boilers.

TABLE 4-1

CAPITAL AND ANNUAL COSTS (2) FOR AUXILIARY[2] BOILERS GREATER THAN 250 x 10^6 Btu/Hr HEAT INPUT

Capital Cost (a)

	$/$10^6$ Btu/Hr Heat input capacity
Boiler	33,150
Pollution Control (b)	4,735
total	37,885

Annual Boiler Costs (a)

	$/$10^6$ Btu/heat input (a)
Boiler Fixed Costs	1.00
Pollution Control Fixed Costs (b)	0.14
Boiler O & M	1.43
Pollution Control O & M(b)	0.43
total	3.00(a)

Steam Costs (a)

	$/$10^6$ Btu of steam (c)
Boiler Less Fuel Cost	3.75
Fuel Cost (d)	0.63
total	4.38 (a)

(a) Third quarter 1979 dollars

(b) Includes systems for 90 percent SO_2 removal and particulate emission reduction to 0.03 lb/10^6 Btu

(c) Assumes 80 percent boiler efficiency

(d) Assumes \$0.50/10^6 Btu fuel cost for Western power plants. This value should be adjusted for fuel costs for plant studied.

4.4 Electrical Energy Penalty

The total capital cost of a retrofit system includes the capital cost of replacing the generating capacity lost because of the electric power requirements of the retrofit systems. This capital cost is $1,046 for each kilowat of capacity required by the retrofit systems.[1,3,4]

Sections 3.4 and 3.5 describe the techniques to be used for estimating retrofit electric power requirements for particulate and SO_2 control.

4.5 Other Costs Not Estimated

There are other capital and annualized costs involved in conjunction with retrofits that are not estimated in this document. This section identifies these cost elements and provides guidance on factoring these costs into decision making on best available retrofit technology (BART) determinations.

Other potential costs that are not included in the estimates of this document are identified as follows:

1. Cost of land
2. Cost of relocating facilities to make room for the retrofit systems
3. Cost of altering existing facilities to accommodate the retrofit systems
4. Cost of providing additional facilities for additional employees such as offices, locker rooms, etc.

5. Cost of downtime for installing retrofits
6. Cost of stacks

The cost estimates of this document provide ample allowances for grading, excavating, piling, and for temporary construction facilities, etc.

In some cases, additional land may need to be purchased to make up for the space needed for retrofit systems. Since the cost of this land can usually be recovered when the land is no longer needed, it is not included as a capital cost. It is recognized, however, that necessary funds would have to be made available for such land purchases and that annual costs would result. In the case of land for sludge disposal, it is assumed that once the land is used, it would not be possible to reclaim the land for any useful purpose. More study is needed to show that land used for sludge disposal can be reclaimed for future use.

Since most power plants have not been designed for future large retrofit systems, it is likely that most retrofit cases will involve relocation of some facilities such as shops, offices, or coal storage and handling systems. These capital costs will also cause an increase in annual costs.

Types of alterations that might be required to accommodate retrofit systems are the cost of relining stacks to compensate for more corrosive gas conditions or for reinforcing existing ductwork to compensate for changed flue gas pressure conditions, or costs for major changes to structures to accommodate NO_x combustion modifications. The costs of nominal alterations in conjunction

with NO_x combustion modifications is included in the cost estimates of this document. Based on boiler manufacturer's advice, it may also be necessary to modify boiler pressure parts to control steam conditions to specifications. These costs are site-specific and are not estimated in this document.

The cost of downtime is also significant. The costs of this document assume that no additional downtime is required for retrofitting. The way downtime is avoided is by making all necessary changes to the existing system and by tieing in the retrofit systems during normal outages or during unscheduled outages attributable to factors other than retrofitting. As shown by Figure 3-8, these types of changes can be made during a 5-year period. If downtime is necessary, the following factors should be taken into account in assessing costs.

1. The cost of purchased power. Usually purchased power costs more than the cost of generating power within the system. However, at times the added cost of purchased power is reduced if the purchasing power system sells a like amount at the same price in conjunction with an exchange agreement.

2. The cost of power generation and distribution. Even if it is not necessary to purchase power from another system, downtime can involve significant additional costs. Downtime may make it necessary for a power system to generate power at a less efficient plant or at a plant firing more costly fuel. Power transmission losses also need to be considered. For the plants of Appendices A, B, and C, it is most likely that any downtime that would make it necessary to generate power elsewhere would involve significant additional fuel costs.

3. Loss of Productivity. When a steam generator is down, some labor, supplies, and services costs continue. Although these costs are small in comparison to other downtime costs, they should be considered in sufficient depth to classify them in their proper perspective.

Another cost that is not estimated in this document is the cost of transporting sludge from the liquor treatment system to the disposal site. This cost is estimated at $2 per ton per mile. Such costs are not estimated because it is not certain how far the sludge would have to be transported.

4.6 Cost of Derating

As discussed in Section 2-2.7, derating is usually an undesirable technique for reducing emissions. This is because there are usually more cost effective methods available. The costs of derating are very variable and are site specific. Consequently, no generalizations can be made on costs except to identify the potential cost elements.

For cases where electrical energy demand is increasing (this is almost always the situation) the generating capacity lost because of derating must be replaced. The cost of replacing generating capacity is given in Section 4.4 For cases where generating capacity is limited as compared with power system electrical demand, derating costs can be the same as the costs for downtime discussed in Section 4.5. For the most costly case it might be necessary to purchase power from another power system for several years until the power generating capacity lost by derating is replaced. However in most cases derating costs would not be this severe. For actual cases, additional studies are necessary to estiamte the costs of derating.

4.7 Escalation

The costs of this document are based on September 1979 dollars. Section 3.8 presents data on schedules for retrofitting which can be used in conjunction with economic data not given in this document to estimate the effect of escalation on capital costs.

4.7 REFERENCES

1. Wright, J., "Cost Analysis of Lime Based Flue Gas Desulfurization Systems for New 500 MW Utility Boilers", PEDCo Contract No. 68-02-2842, Assignment 25, January 1979.
2. Impact Analysis of Selected Control Levels for New Industrial Boilers, Preliminary Draft, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina June 1980.
3. EPA, "Electric Utility Steam Generating Units - Background Information for Proposed SO_2 Emission Standards". EPA-450/2-78-007a, August 1978.
4. EPA, "Electric Utility Steam Generating Units - Background Information for Proposed Particulate Matter, Emission Standards". EPA-450/2-78-006a, July 1978.

APPENDIX A

EXAMPLES FOR RETROFITTING THE FOUR CORNERS POWER STATION

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SECTION A-1
GENERAL

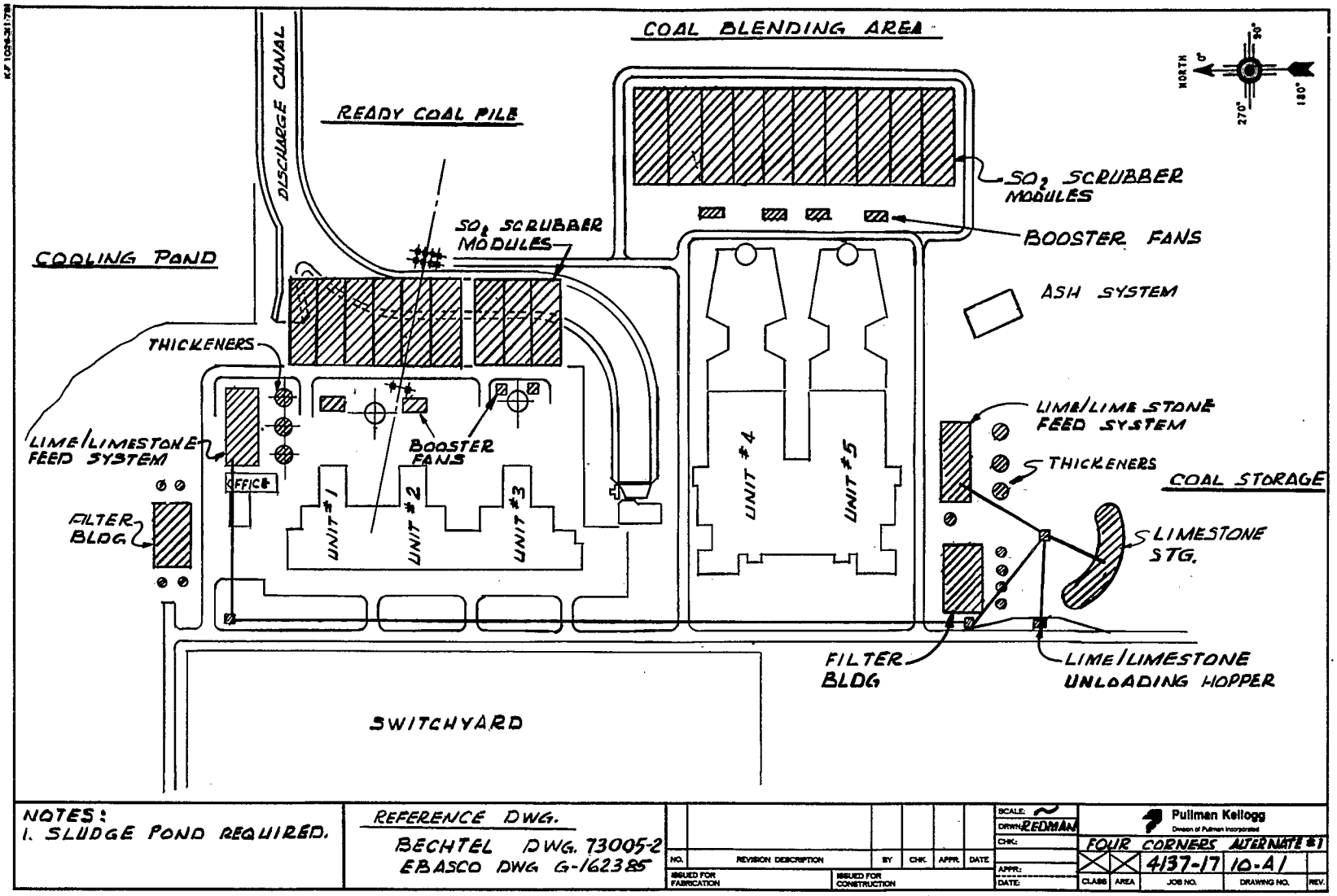
A-1.1 RETROFIT ALTERNATIVES

Four alternatives for retrofitting each boiler at the Four Corners Power Plant were considered in this appendix to demonstrate the use of the techniques described in Section 3 of the report. All alternatives include maximum NO_x control and the installation of opacity, SO_2, NO_x emission monitoring systems. Since some of the aspects of these alternatives differ for the boilers to which they apply, they have been grouped by unit numbers for the discussion. Alternatives for the Unit 1,2, and 3 boilers are as follows:

Alternative 1 - Add wet SO_2 scrubbing to each unit to achieve 90% SO_2 removal. The existing venturi scrubbers are retained to control particulate emissions to a level of 21 ng/J heat input (0.05 lbs/10^6 Btu). Figures A-1 and A-2 show the general arrangement plot plans with the addition of the SO_2 scrubbing modules.

Alternative 2 - Remove the existing venturi particulate scrubbers and add wet SO_2 scrubbing to achieve 90% SO_2 removal for each unit. Also, add high-efficiency, cold-side electrostatic precipitators (ESP's) for control of particulate emissions to a level of 13 ng/J heat input (0.03 lbs/10^6 Btu). Figures A-3 and A-4 show the general arrangement plot plan with the added SO_2 scrubbing modules and cold-side ESP's.

Alternative 2a - The retrofit for particulate removal in Alternative 2a is to the same emission level as for Alternative 2, but baghouses have been used for cost comparisons with Alternative 3. The wet SO_2 scrubbing



NOTES:
1. SLUDGE POND REQUIRED.

REFERENCE DWG.
BECHTEL DWG. 73005-2
EBASCO DWG G-162385

NO.	REVISION DESCRIPTION	BY	CHK.	APPR.	DATE
ISSUED FOR FABRICATION		ISSUED FOR CONSTRUCTION			

SCALE: ~
DRWN: REDMAN
CHK:
APPR:
DATE:

Pullman Kellogg
Division of Pullman Incorporated

FOUR CORNERS ALTERNATE #1

CLASS	AREA	JOB NO.	DRAWING NO.	REV.
		4137-17	10-A1	

Figure A-1.- Addition of wet SO_2 scrubbing modules.

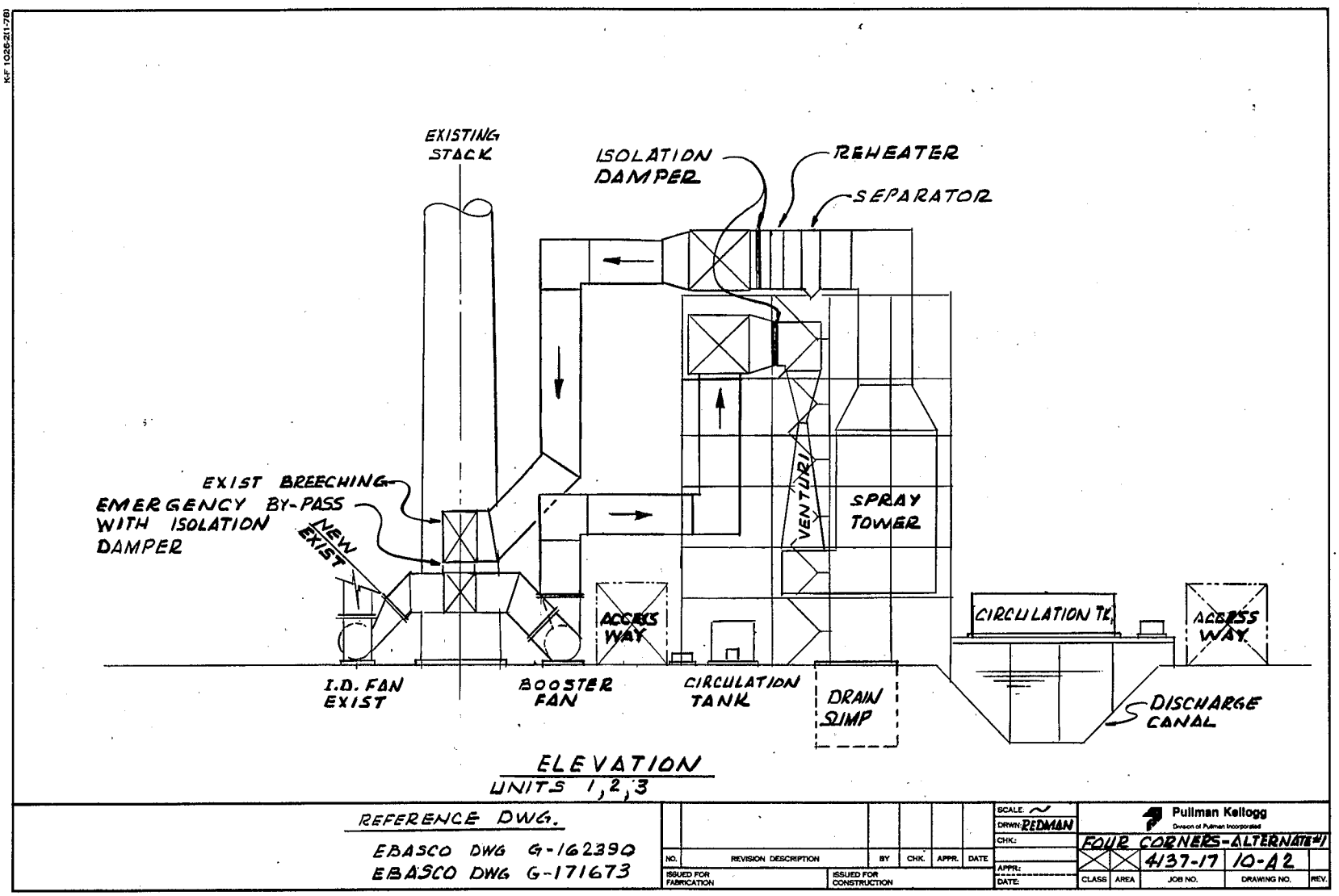


Figure A-2.- Arrangement of wet SO_2 scrubbing modules for Units 1, 2, and 3.

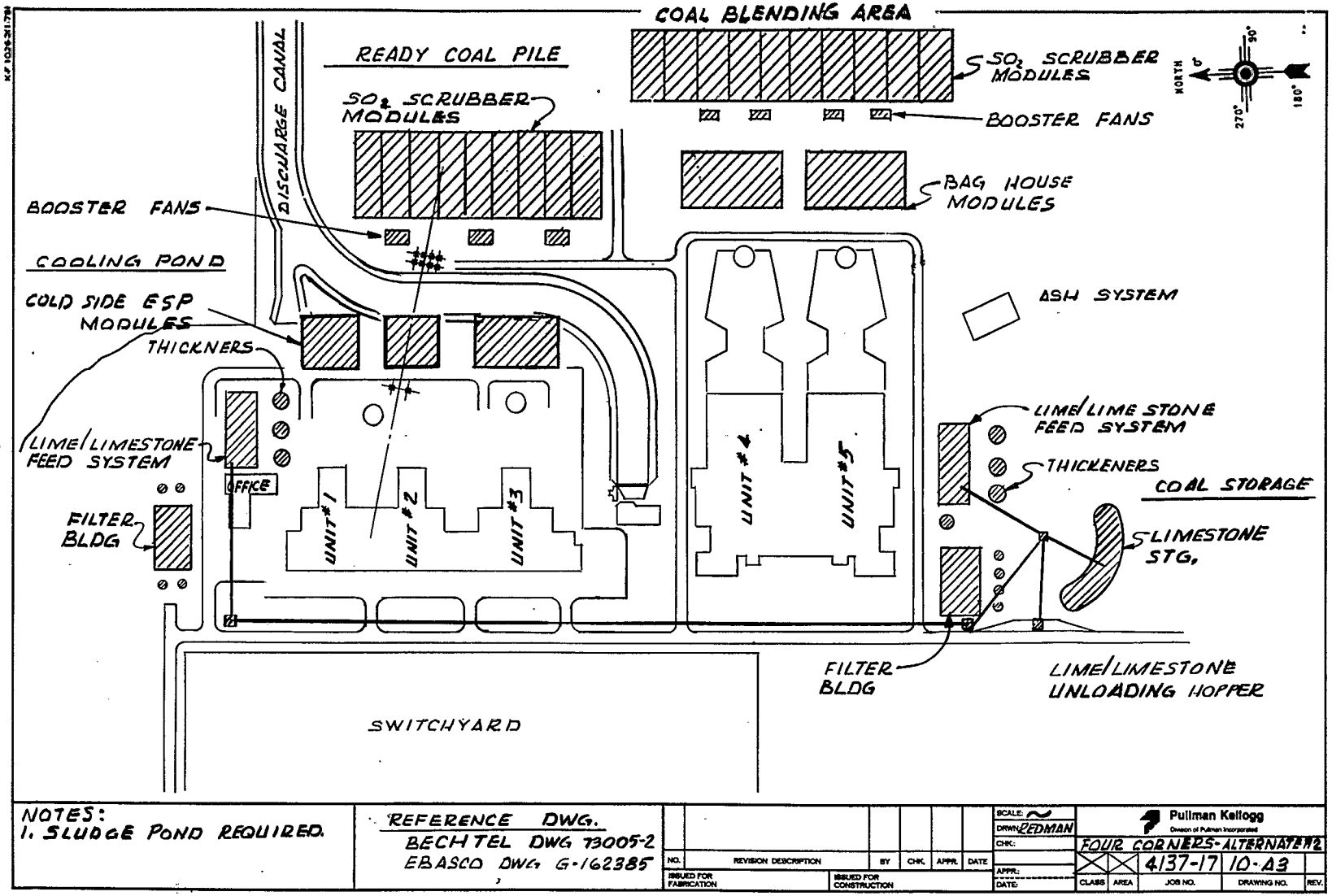


Figure A-3.- Addition of wet SO_2 scrubbing and particulate emission control modules.

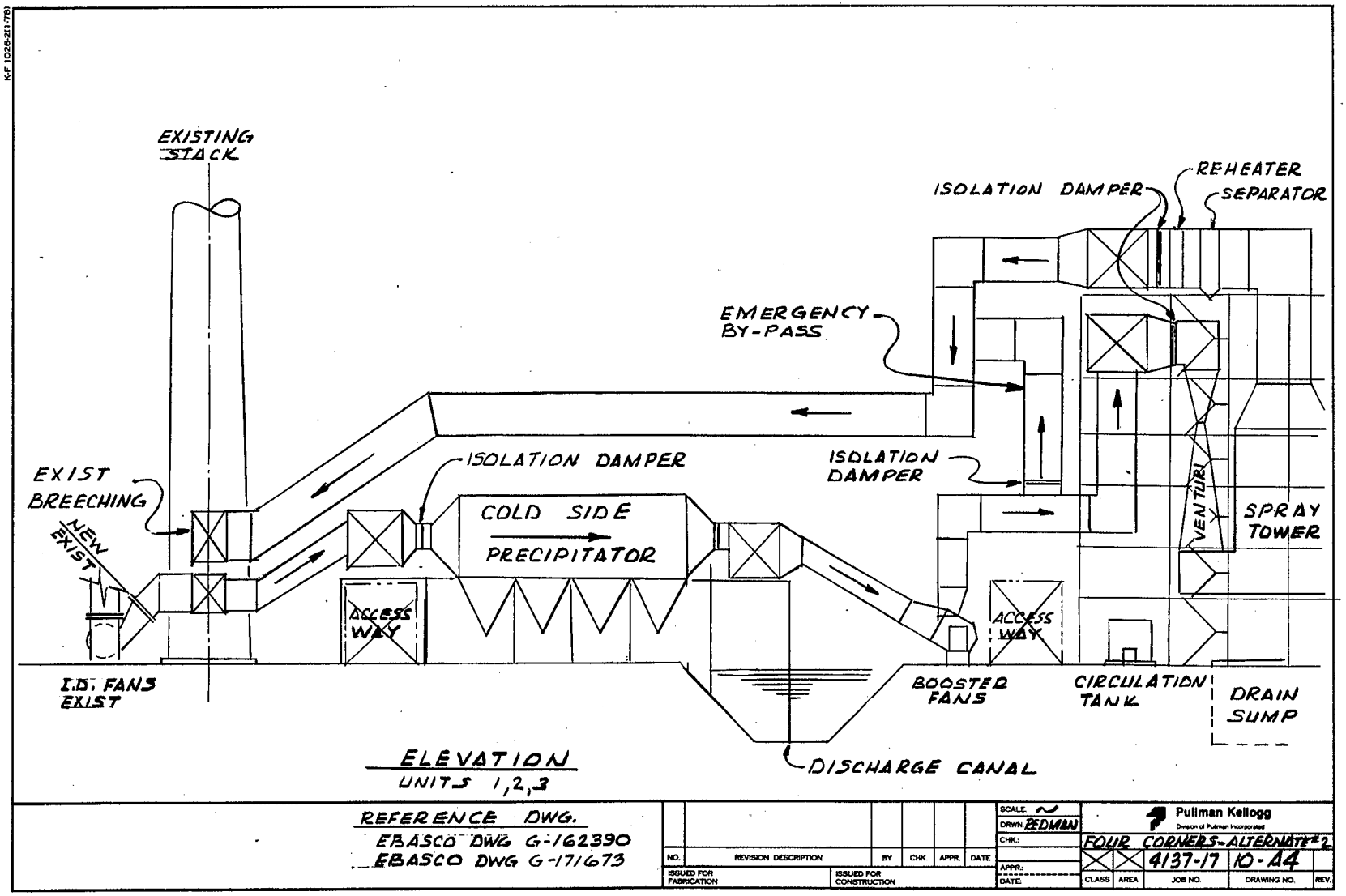


Figure A-4.- Arrangement of cold side ESP's and wet SO_2 scrubbing modules for Units 1, 2, and 3.

in this case is based on 70% SO_2 removal for cost comparison with semi-dry scrubbing of Alternative 3.

Alternative 3 - The existing venturi particulate scrubbers are removed in this case and semi-dry (spray drying) SO_2 scrubbing is added for 70% SO_2 removal. Baghouses are used as dry collectors, for control of particulate emissions to a level of 13 ng/J heat input (0.03 lbs/10^6 Btu). Figures A-5 and A-6 show the general arrangement using the dry scrubbing/baghouse modules.

The three alternatives considered as examples for retrofitting the Units 4 and 5 boilers are:

Alternative 1 - Add wet SO_2 scrubbing to achieve 90% SO_2 removal and retain the existing ESP and particulate removal for control to an emission level of 21 ng/J heat input (0.05 lb/10^6 Btu). Figures A-1 and A-7 show the general arrangement of the plant with the added SO_2 scrubbing modules.

Alternative 2 - This option adds baghouses plus wet SO_2 scrubbing for 90% SO_2 removal, and it retains the existing ESP's and particulate removal for control to an emission level of 13 ng/J heat input (0.03 lbs/10^6 Btu). Figures A-3 and A-8 show the plant's general arrangement with the added SO_2 scrubbing modules and baghouses.

Alternative 2a - Alternative 2a includes the same retrofit for particulate removal emission levels as Alternative 2, but baghouses have been used for cost comparison with Alternative 3. The SO_2 scrubbing is based on 70% SO_2 removal for cost comparison with semi-dry scrubbing in Alternative 3.

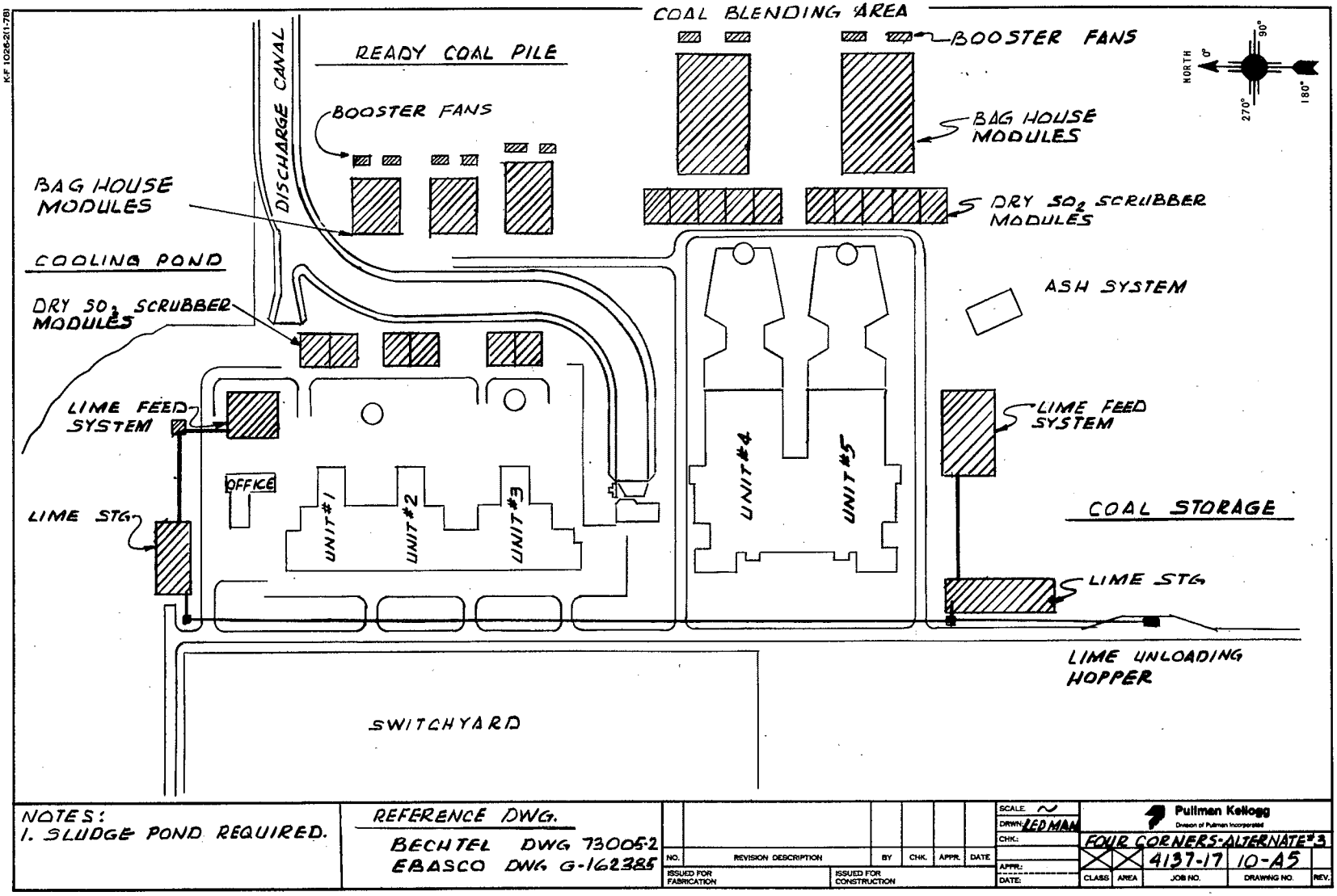


Figure A-5.- Addition of dry SO_2 scrubbing modules with baghouses.

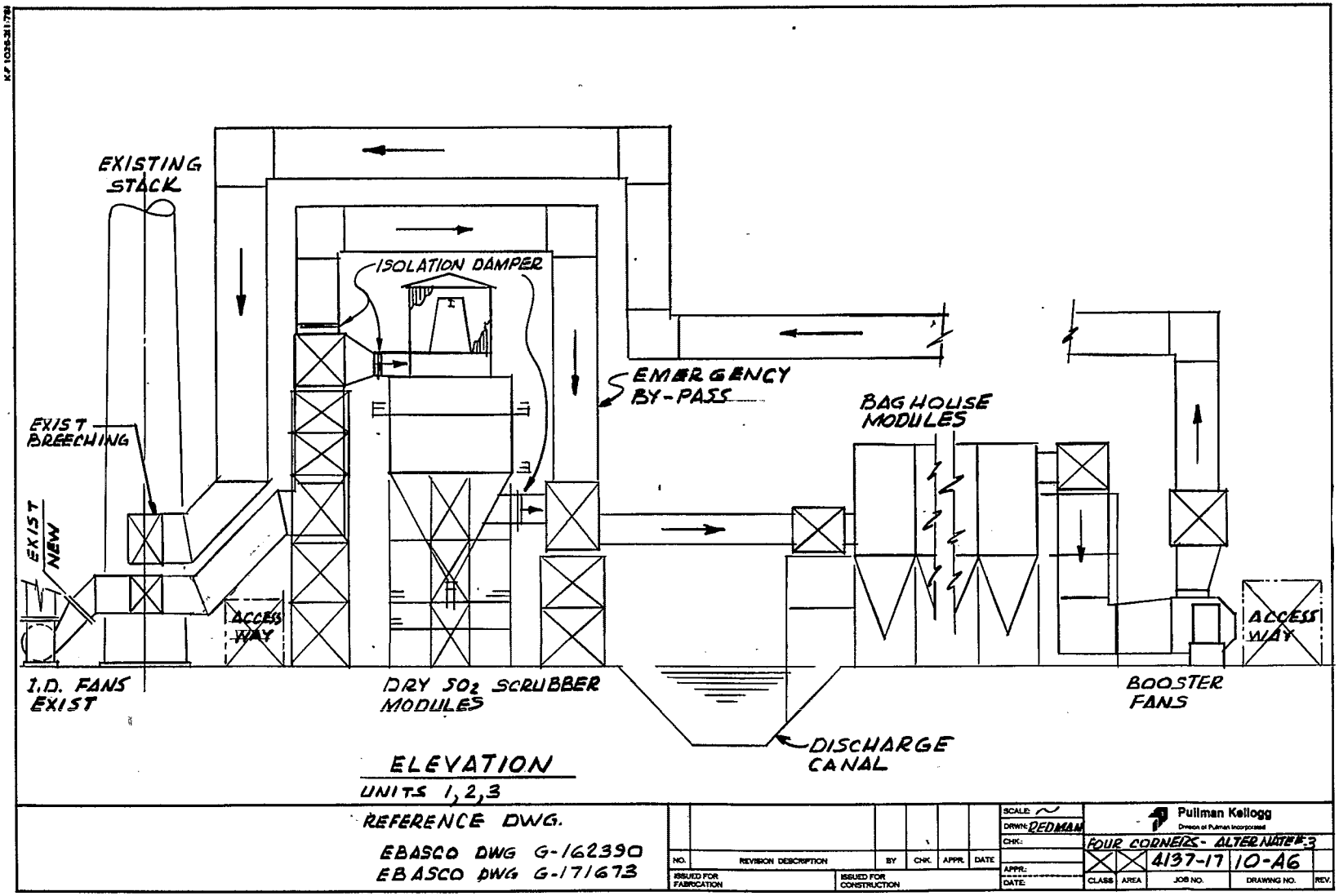


Figure A-6.- Arrangement of dry SO_2 scrubbing and baghouse modules for Units 1, 2, and 3.

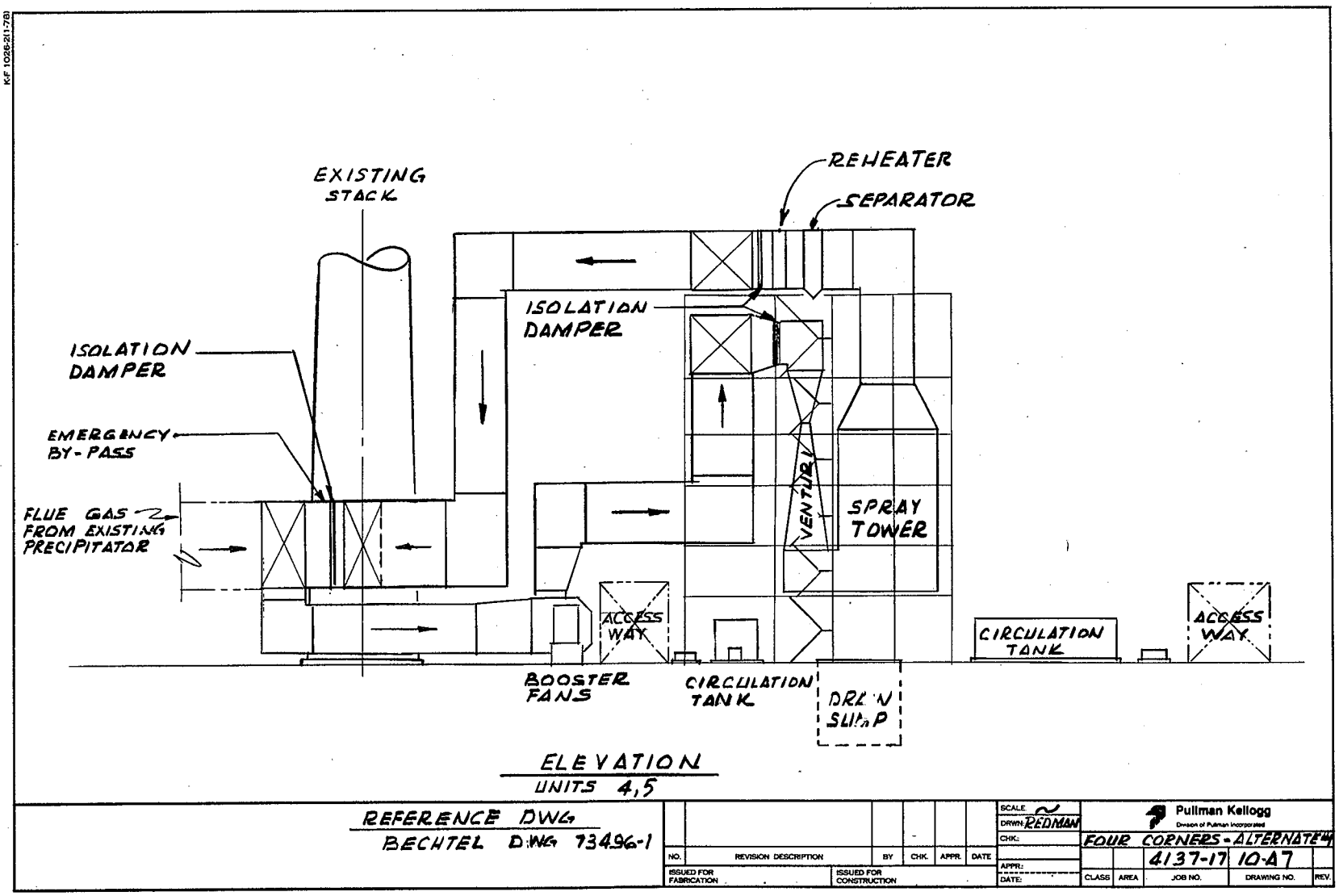


Figure A-7.- Arrangement of wet SO_2 scrubbing modules for Units 4 and 5.

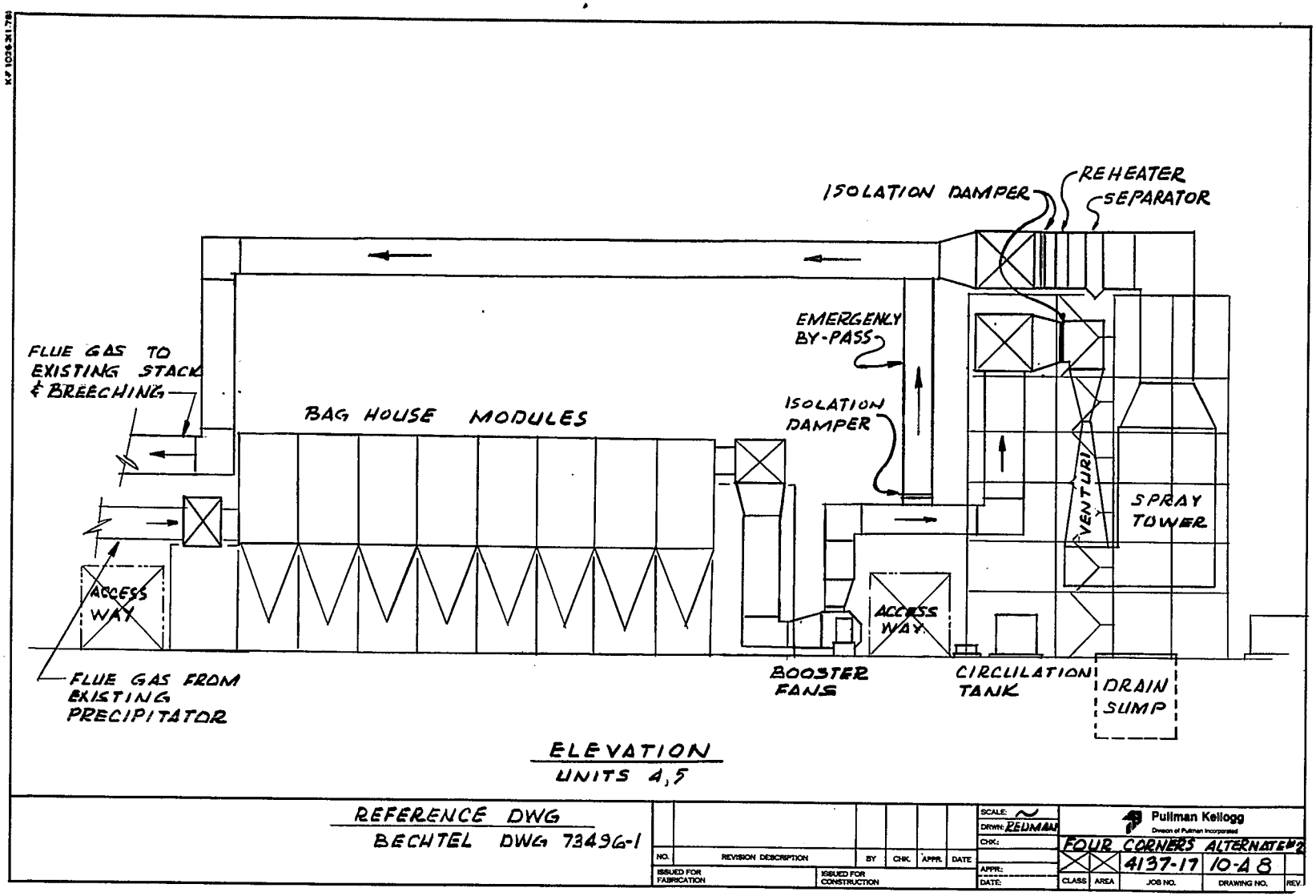


Figure A-8.- Arrangement of baghouse and wet SO_2 scrubbing modules for Units 4 and 5.

Alternative 3 - Dry SO_2 scrubbing (spray drying) is added for 70% SO_2 removal. Baghouses are used for dry collectors and, combined with the existing ESP's, provide for particulate removal to a level of 13 ng/J heat input (0.03 lbs/10^6 Btu). Figures A-5 and A-9 show the general arrangement with the added dry scrubbing modules. Section A-6 describes the techniques used for estimating costs.

A-1.2 PLANT CHARACTERISTICS

The characteristics of the plant site, existing equipment, and the space requirements for the retrofit example are shown in the following list (1):

A. The station is located on a 1000 acre tract of land.

B. Particulate removal for Units 1,2, and 3 is accomplished using two venturi scrubbers per unit.

C. Units 4 and 5 have cold side precipitators for particulate removal.

D. Each boiler for Units 1,2 and 3 is provided with two, forced draft (FD); three, primary-air (PA); and two, induced-draft (ID) fans.

E. Each boiler for Units 4 and 5 is provided with four, forced-draft (FD) and two primary-air (PA) fans.

F. The number of SO_2 scrubbing modules is based on the total calculated flue gas rate from each boiler.

G. One SO_2 scrubbing module is provided as a common spare for each group of modules per boiler.

H. One flue gas reheater is required per wet SO_2 scrubbing module for 90% SO_2 removal.

I. One flue gas booster fan is required per scrubbing module.

J. The individual scrubbing modules are provided with dampers. This provision allows the individual modules to be isolated for maintenance.

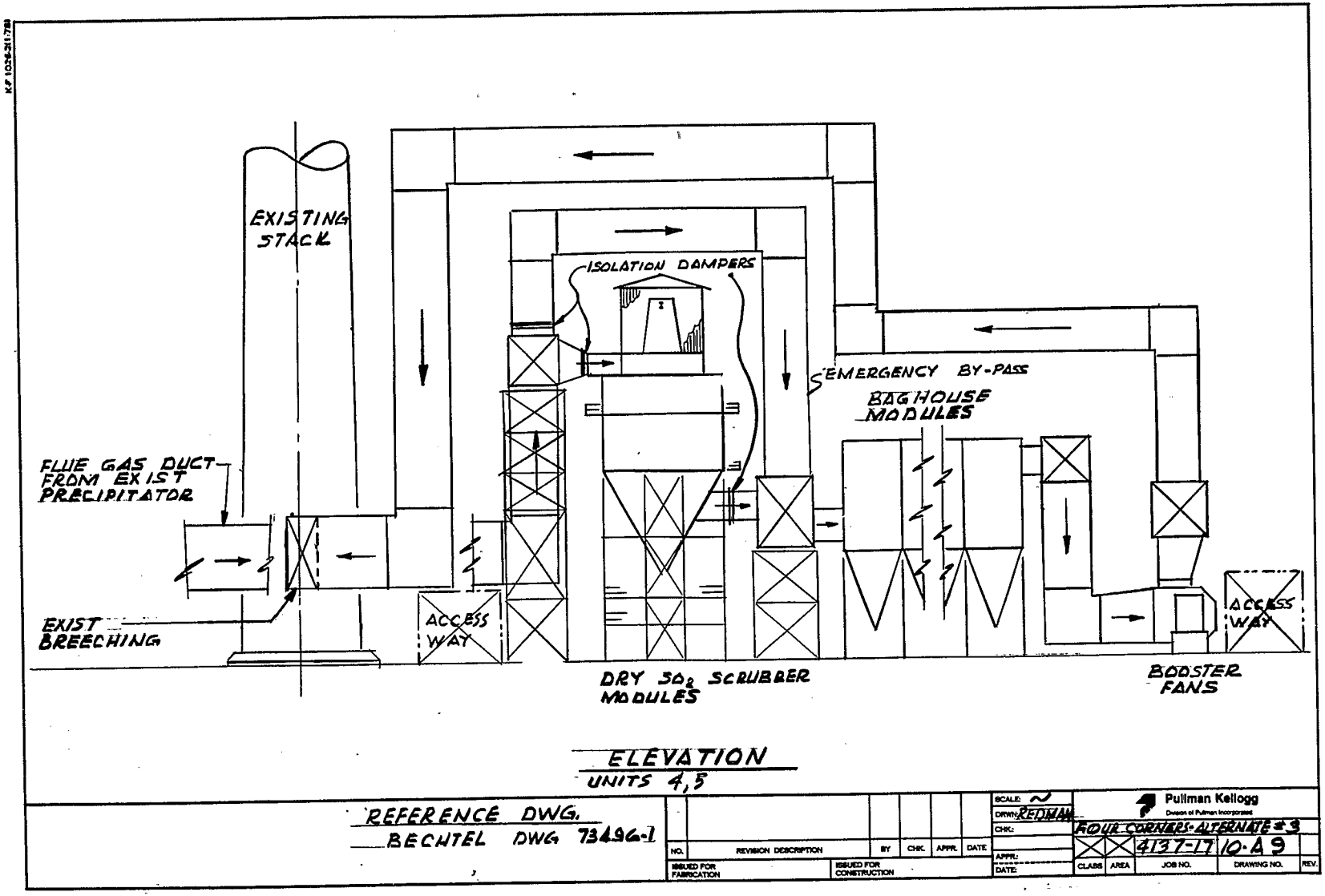


Figure A-9.- Arrangement of semi-dry SO_2 scrubbing (spray-dryer) and baghouse modules for Units 4 and 5.

K. Retrofit equipment tie-in to the power plant is based on completion during a normal power plant maintenance turn-around of 3 to 6 weeks.

L. An emergency bypass is provided around each SO_2 scrubbing system to allow emergency operation of the boiler in the event of a major FGD malfunction. Bypassing of the particulate control equipment is not provided.

A-1.3 EXISTING FACILITY RELOCATIONS

Major revamp work that would be required to install the equipment needed for SO_2 and particulate control includes relocation of some existing buildings and/or systems. The requirements for the alternatives being considered are:

Alternative 1 - The following equipment relocation would be necessary to allow for the space requirements of the wet SO_2 scrubbing systems.

A. For Units 1,2, and 3, relocation of all buildings situated east and north of the unit is necessary.

B. For Units 1,2, and 3, the scrubbers are located on structures built over the cooling water discharge canal.

C. For Units 4 and 5, no major equipment relocation is required.

Alternative 2 - All equipment relocation considerations of alternative 1 also apply to this alternative. In addition the following items must be relocated.

A. For Units 1,2, and 3, relocation is needed for the ready to use coal pile and some of the coal conveying equipment.

B. For Units 4 and 5, relocation of the blend coal pile is required, to provide space for installing the baghouses.

Alternative 3 - Equipment relocation requirements of Alternative 1 also apply to this alternative. In addition, the following items must be relocated.

A. For Units 1,2, and 3, relocation of the ready to use coal pile and some of the coal conveying equipment is required.
B. For Units 4 and 5, relocation of the blend coal pile is required, to provide space for installing the baghouses and booster fans.

A-1.4 FLUE GAS DUCTING REQUIREMENTS

Bypass duct and dampers are provided to enable the flue gas to bypass the SO_2 scrubbing system completely under emergency conditions. For all five units, the bypass duct is upstream of the SO_2 scrubbing system. Emergency bypassing of particulate control equipment is not considered. Bypass duct locations for the three alternatives are indicated below:

Alternative 1

Units 1,2 and 3.- The bypass duct is taken from the plenum located between the ID fan and the booster fan. Figure A-2 indicates this relationship.

Units 4 and 5.- The bypass duct is taken from the inlet duct just between the existing ESP and the booster fan. See Figure A-7 for a graphic indication of this ducting.

Alternative 2

Units 1,2 and 3.- Bypass duct is taken from the plenum located between the scrubber and the booster fan. Figure A-4 shows the elevation view for the cold side ESP and SO_2 scrubbing modules.

Units 4 and 5.- Bypass duct is taken after the baghouse, just before the scrubber. Figure A-8 shows the elevation view for the baghouse and SO_2 scrubbing modules.

Alternative 2a

The bypass duct is the same as for Alternative 2. This duct can also be used during normal operation to divert about 22% of the total flue gas that does not require treatment, since the module removes 90% SO_2, and this alternate requires only 70% SO_2 removal. The bypass duct also provides the flue gas requirements for reheat.

Alternative 3

The bypass duct is taken just ahead of the spray dryer, and it ties into the duct to the baghouses. This location of the emergency bypass permits operation of the baghouse for particulate control when a spray dryer is out of service. Figure A-6 and A-9 show the elevation views for the dry scrubbing and baghouse modules, and they indicate this relationship.

SECTION A-2
BACKGROUND DATA

A-2.1 PLANT DESCRIPTION (1,2)

The Four Corners Power Plant consists of five thermoelectric generation units that develop a total plant capacity of 2085 MW(net) and 2181 MW(gross). The capacity for each boiler is:

Unit No.	1	2	3	4	5
Gross MW	190	190	245	778	778
Net MW	175	175	225	755	755

Units 1, 2, and 3 are owned and operated by Arizona Public Service (APS). Units 4 and 5 are jointly owned by six electric utilities and operated by APS. The participating utilities are Southern California Edison Co., 48%; APS 15%; Public Service of New Mexico 13%; Salt River Project 10%; Tucson Gas and Electric Co., 7%; and El Paso Electric Co., 7%.

All five units are pulverized-coal-fired, dry-bottom boilers, where about 20% of the ash in the coal is retained as bottom ash. The remaining ash is entrained in the flue gas and is collected by using either a Venturi Wet Scrubber System or an Electrostatic Precipitator (ESP). There are four flue gas stacks. Units 1 and 2 are served by a common stack that is 250 feet high and has an 18.5-foot I.D. The stack for Unit 3 is also 250 ft high, but it has a 15-foot I.D. The two stacks for Units 4 and 5 are 300 feet high and have 28.5-foot I.D's.

Units 1 and 2 each have two, horizontal-shaft regenerative, Ljungstrom air preheaters. Unit 3 has the same preheaters as Units 1 and 2 but with vertical shafts. Units 4 and 5 each have two, horizontal-shaft, regenerative, Ljungstrom air preheaters, and they each have a tubular air preheater.

The bottom ash is conveyed hydraulically to dewatering bins and then trucked either to the ash disposal pond (bottom ash from Units 1, 2, and 3) or to the coal mine (bottom ash from Units 4 and 5). The water after separation (decanted water) is returned to Morgan Lake.

Two, 100-foot I.D. thickeners serve Units 1, 2, and 3 for clarifying spent ash liquor. The solids concentration of the thickener underflow is about 40 wt%. The plant has a brine concentrator to treat the water from the ash pond.

Circulating, cooling-water discharge canal is located between Units 3 and 4. The Instrument and Plant Air Compressor Building is located between Units 2 and 3. Units 4 and 5 have nine coal mills per unit, plus a spare one. Units 1, 2, and 3 have three coal mills per unit, working at full capacity, and they have no spares. Figure A-10 shows a general plot plan arrangement for the Four Corners power station.

A-2.2 STEAM GENERATOR DESCRIPTION

Units 1 and 2 have a total generating capacity of 350 MW (net) and 380 MW (gross). Each unit consists of a balanced-draft, Riley-Stoker (R-S), 175 MW (net), 190 MW (gross) boiler. Both units went into operation in 1963.

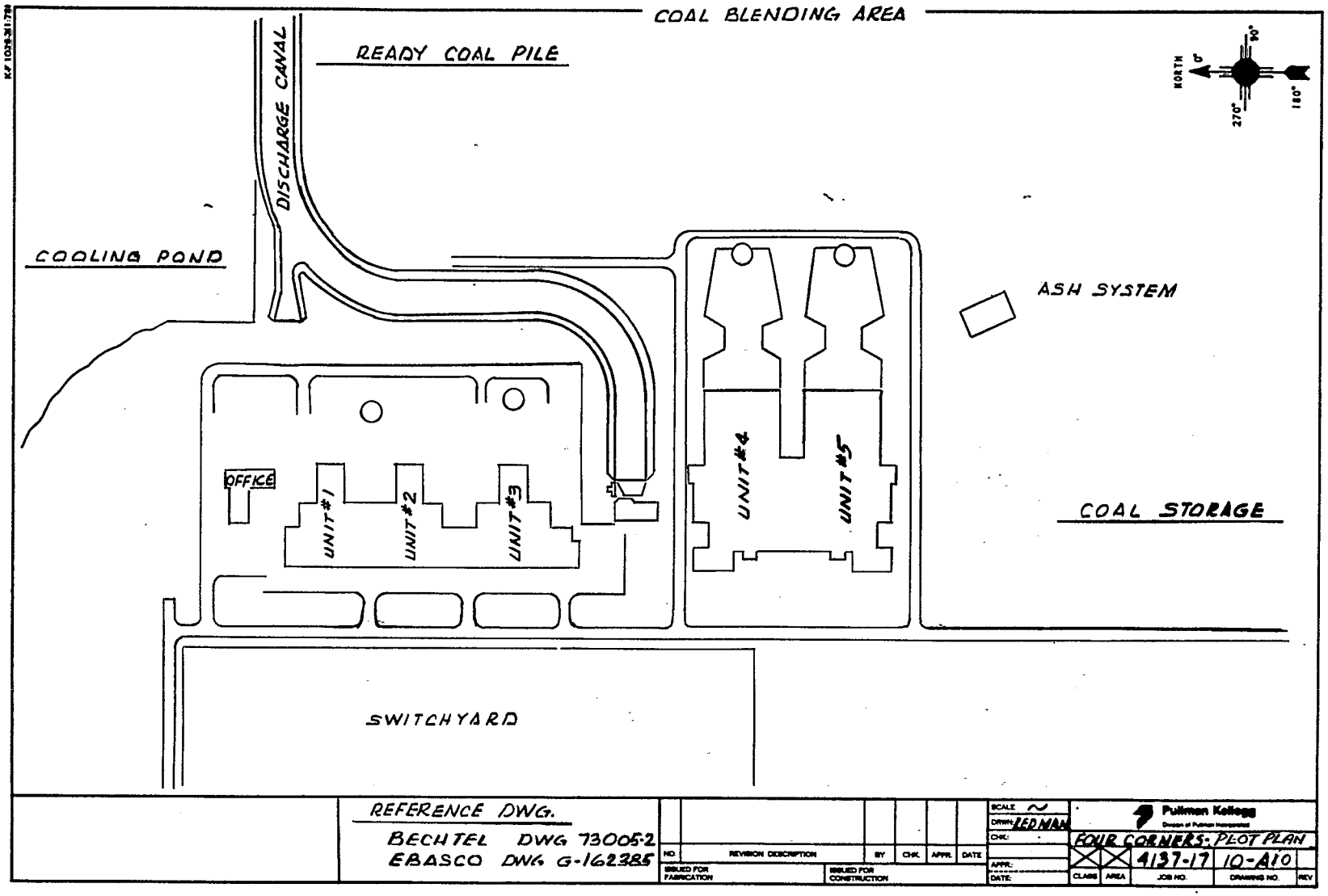


Figure A-10.- General plot plan of the Four Corners power station.

Unit 3 uses a balanced-draft, Foster-Wheeler (F-W), 225 MW (net), 245 MW (gross) boiler. Unit 3 started operating in 1964.

Units 4 and 5 have a total generating capacity of 1510 MW (net) and 1556 MW (gross). Each unit consists of a pressurized, Babcock & Wilcox (B&W), 755 MW (net), 778 MW (gross) boiler. Unit 4 was started in 1969 and Unit 5 in 1970. Fireboxes for the five boilers were designed prior to 1970.

For Units 1,2, and 3, there are two forced-draft (FD), three primary-air (PA) and two induced-draft (ID) fans per unit. Units 4 and 5 have four FD and two PA fans per unit. Paddle-type fans are used for the units.

A-2.3 EXISTING NO_x CONTROL

There are five boilers at the Four Corners Station. Units 1 and 2 use Riley Stoker boilers that are of the horizontal, single-wall-fired type. The burners are arranged in six vertical columns with three burners on each column. Retrofit work has been performed for NO_x reduction through burner modifications. The retrofit work was developed, and installed by APS using a KVB spoiler design (3). There are no data avaialble to show the effectiveness and results of the retrofit. Unit 3 has a Foster Wheeler, horizontal, single-wall-fired boiler. The burners are arranged in four vertical columns with five burners in each column. Plant data show that no retrofit work for NO_x reduction purposes has been done on Unit 3. Units 4 and 5 are B & W boilers of the opposed-wall-fired type. The burners on each unit are arranged in six vertical columns on each opposite wall.

The burners are the B & W's, high-intensity-cell, turbulence burners. All burners are contained in a single windbox. Units 4 and 5 were installed originally with flue-gas (FG) recirculation systems; however, the FG recirculation system has been taken out because of severe mechanical difficulties associated with the fans.

A-2.4 EXISTING PARTICULATE CONTROL (2)

Boilers 1, 2, and 3 each use two venturi, wet-scrubber systems for collecting flyash from the flue gas. The venturi scrubber systems remove about 98% of the flyash from the flue gas. Boilers 4 and 5 each are equipped with two cold-side ESP's manufactured by Research Cottrell. These ESP's collect about 97% of the flyash from the flue gas. The total existing ESP collection area per boiler is 373,000 ft^2.

A-2.5 EXISTING SO_2 CONTROL

SO_2 emission control is accomplished by using low sulfur subbituminous coal as fuel.

SECTION A-3
PLANT SURVEY FORM

A-3.1 COMPANY AND PLANT INFORMATION (1,2)

1. Company Name: Arizona Public Service Company
2. Main Office: P.O. Box 21666, Phoenix Arizona 85036
3. Plant Manager: Mr. B.E. Haelbig
4. Plant Name: Four Corners Power Plant
5. Plant Location: Fruitland, San Juan County, New Mexico
6. Person to Contact For Further Information: Mr. J. Weiss
7. Position: Senior Environmental Eng. Special Projects
8. Telephone Number: (602) 271-2292
9. Date Information Gathered: May 8 - May 10, 1979
10. Participants In Meeting — Affiliation

Participants In Meeting	Affiliation
D. Campbell	APS/Acting Manager of Eng. Four Corners Plant
J. Weiss	APS/Senior Environmental Eng. Special Projects
N. Gonzalez	Pullman Kellogg
R. Redman	Pullman Kellogg
R. Roberts	Pullman Kellogg

A-3.2 PLANT DATA (APPLIES TO ALL BOILERS AT THE PLANT)

	BOILER NO.				
	1	2	3	4	5
Capacity, MW, Net,	175	175	225	755	755
Service (Base,Peak)	BASE	BASE	BASE	BASE	BASE
FGD System Used?	NO	NO	NO	NO	NO

A-3.3 BOILER DATA

1. Maximum Continuous Heat Input (MM Btu/Hr):

Unit 1 or 2	Unit 3	Unit 4 or 5
1760	2230	7040 (assuming 755 MW net peak)

2. Maximum Continuous Generating Capacity:

Unit	1	2	3	4	5
Gross(MW)	190	190	245	778	778
Net (MW)	175	175	225	755	755

2a. Maximum Heat Input (MM Btu/Hr):

Unit 1 or 2	Unit 3	Unit 4 or 5
1006 Btu/K WHR	2230	7460 (assuming 800 MW net peak)

3. Flue Gas Temperature to Stack: 120°F(Units 1,2,3); 220°F(Units 4,5)

4. Maximum Continuous Flue Gas Rate to Stack:

Unit 1 or 2	640,000 ACFM at 120°F
Unit 3	800,000 ACFM at 120°F
Unit 4 or 5	3,000,000 ACFM at 220°F

These values are typical continuous flue gas flows at full load. Flows can vary ± 10%, depending on excess air, coal composition, and water injection rate.

5. Flue Gas Analysis:

Flue Gas Component	Units 1-2-3	Units 4-5
$\%O_2$	4.3 - 7.0	3.8 - 5.7
$\%CO_2$	12 - 14.8	13.6 - 15.3
$\%N_2$ (and inerts)	80.6 - 81.5	80.6 - 81.5

6. Flue Gas Recirculation For NO_x Control[a]:

7. Boiler Manufacturer: R-S (Units 1,2); FW (3); B&W (4,5)

8. Years Boilers Placed In Service: 1963 (1,2); 1964 (3)
1969 (4); 1970 (5)

9. Boiler Service (Base Load, Peak, etc.): Base

9a. Wet Bottom ___-___ Dry Bottom _X_

Units:	1/2	3	4	5
10. Stack Height Above Grade (Ft):	250	250	300	300
10a. Stack Diameter[b] (Ft):	17.7	14	28.5	28.5

10b. Velocity Of Gas (Exit):

	Stack 1-2	Stack 3	Stack 4	Stack 5
Flue Gas Velocity (fps) Leaving Stack At Full Load (Net)	43-86 (175-350 MW)	87 (225 MW)	78 (755 MW)	78 (755 MW)

10c. Exit Gas Temperature (°F):

115-122	122-130	205-245	205-245

10d. Number Of Liners/Boiler: 1 for each stack

---

[a]FG recirculation originally installed for units 4 & 5. Later was taken out due to severe mechanical difficulties.

[b]Stack diameter at top. For units 1,2, and 3 includes liner.

11. Boiler Operations (Hours/Year-1978):

Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
6994	7933	7296	5300	4874

11a. Boiler Operations (Hours/Year @ full load): N/A

12. Boiler Capacity Factor[a]: (1978):

Units				
1	2	3	4	5
67.60	83.87	72.55	49.62	48.35

13. Boiler Operating Pressure (psig):

Units		
1 & 2	3	4 & 5
1925	2125	3590

14. Boiler Superheat Heat Temperature (°F):

1005	1005	1000

14a. Boiler Reheat Temperature (°F):

1005	1005	1000

14b. Economizer B.F.W. Outlet Temperature (°F):

510	560	650

15. Ratio Of Fly Ash/Bottom Ash = 80/20

---

[a] Defined as:

$$\frac{\text{KWH GENERATED IN YEAR}}{\text{(Net) Max Cont. Generating Capacity in KW x 8760 HR/YR}}$$

16. Burners:

	Units 1&2	Units 3	Units 4&5
Type	Flair	Flair	Cell
Manufacturer	APS/ Design	Foster/ Wheeler	Babcock & Wilcox
No.Per Unit	18	18	18 cells/ 54 burner nozzles
Coal (#/Hr/ Burner)	10,280	14,450	50,000
Primary Air (% of Total)	15%	10%	N/A
Secondary Air (% of Total)	85%	90%	N/A
Total Excess Air (%)	20%	20%	18%

17. Fans (FD & ID):

Forced Draft (FD)			
Type	Air Foil	Air Foil	Air Foil
Manufacturer	Green Fuel Economizer Co.	Westinghouse/ Sturtevant	Westinghouse/ Sturtevant
Induced Draft (ID)			
Type	Paddle Wheel	Paddle Wheel	N/A
Manufacturer	American Std.	American Std.	N/A
Primary Air (PA)			
Type	Radial	Radial	Air Foil
Manufacturer	Buffalo Forge Company	Westinghouse/ Sturtevant	Clarage Fan
No. Per Unit			
F.D.	2	2	4
I.D.	2	2	N/A
P.A.	3	3	2

	Units		
	1&2	3	4&5
Rating (CFM each)			
F.D.	258,000	292,000	535,000
I.D.	387,000	435,000	N/A
P.A.	68,250	75,920 (calc.)	218,000
Differential Pressure (inches of water)			
F.D.	11.6	10.25	23.7
I.D.	16.0	12.04	N/A
P.A.	24.5	24.5 (approx)	37

18. Windbox:

Compartment	Single	Single	Single
Controlled	Register	Register	Register
Mode of control	Manual	Manual	Manual

19. Steam Temperature Control (Superheated & Reheated):

Attemporator			
Cap. lb/hr	73,000	40,000	225,000

20. Pressure Profile Throughout The Unit:

Units 1-2-3	Unit 4-5
Balanced Draft	Pressurized

21. Air Preheater:

	Units 1&2	Units 3	Units 4&5
Type	Ljungstrom Horizontal	Ljungstrom Vertical	Ljungstrom/ Tubular/Horiz.
No. Per Unit	2	2	2/1
Flue gas ΔT[e]	434°F	418°F	414°F
Air ΔT[e]	562°F	516°F	485°F
Design flow:			
Gas Mlb/Hr	1,790	2,285	7,100
Air Mlb/Hr	1,462	1,980	6,290
Design ΔP (in. of H_2O)	3.40	2.70	3.2
Flue gas inlet Temp °F	720	720	655
Air preheater outlet temp.	642°F	596°F	565°F
Flue gas pre-outlet temp.	286°F	302°F	241°F

22. Number Of Sections Of Air Ducts:

2	2	2

22a. Size Of Air Ducts:

Each of the air ducts on Units 1 and 2 has a cross sectional area equal to approximately 120 square feet. Each of the air ducts on Unit 3 has a cross sectional area equal to approximately 191.8 square feet. Unit 4&5 not available.

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[e] These figures correspond to normal operating conditions at rated full load.

23. Number Of Flue Gas Ducts:

Units		
1&2	3	4&5
2	2	2

23a. Size Of Flue Gas Ducts:

Each of the flue gas ducts on Units 1 and 2 has a cross sectional area equal to approximately 132 square feet. Each of the flue gas ducts on Unit 3 has a cross sectional area equal to approximately 186.4 square feet. Unit 4&5 not available.

A-3.4 FUEL DATA

1. Coal Analysis (as received) (%):

	Max.	Min.	Avg.
S	---	---	0.7
Ash	---	---	22

2. Total Ultimate Analysis (Wt%)

Component	Average
Ash	22
S	.7
Moisture	10.8
Oxygen	10.4
Hydrogen	3.76
Nitrogen	0.84
Carbon	51.4
Btu/lb	8800

A-3.5 ATMOSPHERIC EMISSIONS

1. Applicable Emission Regulations:

	Particulates		SO_2	NO_x
a) Current requirements	(1,2,3)	0.05	-	0.7
	(4,5)	0.50		FED
Maximum allowable emissions Lb/MM Btu input to boiler				
b) Future requirements	For Dec.1982		0.53	0.5
	(4,5)	0.05		

2. Plant Program For Particulates:

Units 1,2 and 3 have a total of six Chemico venturi wet scrubbers, each scrubber module handling 400,000 - 500,000 ACFM @ 340°F.

Units 4 and 5 have Research Cottrell electrostatic precipitators. The flue gas flow from Unit 4 or 5 to the corresponding precipitator is 3.1×10^6 ACFM @ 250°F.

3. Plant Program For SO_2 Reduction: Use of low sulfur coal

4. Plant Program For NO_x Reduction: Modified burners in Units 1 & 2. (KVB NO_x spoilers installed).

A-3.6 PARTICULATE REMOVAL

1. Type

	Units 1-2-3	Units 4-5
Type	Venturi Wet Scrubber	E.S.P.
Manufacturer	Chemico	Research Cottrell
Efficiency % design/actual	99.6/99.6	97/97
Specific collection area	N/A	138 Ft^2/1000
Total collection[a] area	N/A	373,000 Ft^2/BLR

Design basis, sulfur of fuel: 0.7%
Emission rate Lb/MM Btu (under normal operation conditions):

Unit	1 or 2	3	4 or 5
SO_2	0.9-1.5	0.9-1.5	1.4-1.9
NO_x	0.58-0.7	0.8-1.4	0.7-1.1
Total particulates	0.02-0.05	0.02-0.05	0.25-0.5

2. Solids Collection System:

Present operating condition:[b]
At maximum capacity: Yes X No

---

[a] For each boiler there are two cold side ESP's with each having 16 electrical sections for a total of 32 electrical sections per boiler.

[b] Bottom ash is hydraulic conveyed to dewatering bins & then trucked to coal mine (for units 4&5). The dewatered bottom ash is trucked to ash disposal pond and used to sand blast. Fly ash is pneumatically conveyed and sent to storage silo and then trucked to the coal mines.

The inlet fly ash loading range is 12-20 lb/10^6 Btu
The inlet bottom ash loading range is 3-5 lb/10^6 Btu

The inlet flue gas temperature is 280-350°F for Units 1-2-3, and 230-280°F for Units 4-5.

A-3.7 SCRUBBER TRAIN SPECIFICATIONS (for venturi scrubbers)

1. Scrubber:

Type	Chemco wet venturi
Liquid/gas ratio	16.9 gpm/1000 ACFM (Units 1,2 and 3)
Gas velocity	Information not available (Varies to maintain pressure differential.
Materials of construction	Top gas inlet - unlined carbon steel wetted center; 316 stainless steel high gas velocity throat; 316 stainless steel intermediate plumb carbon steel lined with polyester glass reinforced resin. All other scrubber shell sections and supports are coated with polyester glass resin. Internal mist eliminators are of polypropylene glass reinforced.

Internals:

Type	Internal mist eliminator
No. of stages	6 pass arrangement

Type and size of packing material: Slats and spacers in a 30' OD x 13' ID and 34' OD x 15' ID

Packing thickness per stage: 2 9/16"

Material of construction:

Packing - polypropylene glass reinforced
Supports - 316 stainless steel/fiberglass

2. Clean Water Tray (at top of scrubber): N/A

3. Mist Eliminator (M.E.)

Type	Baffle
No. of passes	6
Space between vanes	3"
Angle of vanes	55°
Size of M.E.	2'3 3/8"
Distance between top of liquid inlet and bottom of M.E.	78' (Units 1&2) 85' (Unit 3)
Position	Vertical gas flow Horizontal blade eliminators
Materials	Polypropylene Fiberglass reinforced
Method of cleaning	Annual overhaul and periodic sprays

A-3.8 CALCINING AND/OR SLAKING FACILITIES

One lime slaker, having an average on-line capacity of 0.42 tons per hour, serves the scrubber systems on Units 1-2-3.

1. Source Of Water For Slurry Make-up Or Slaking Tank:

   Morgan Lake is the source of make-up water to the slaking tank.

A-3.9 DISPOSAL OF SPENT LIQUOR

1. Transporting:

   Fly ash from Units 1-2-3 is slurried from the thickener to the ash ponds at the rate of 18 tons/hr for Unit 1 and 2 and 20 tons/hr for Unit 3.

   Fly ash from Units 4-5 is trucked to the Navajo Mine pit at the rate of 71 tons/hr for each unit.

   There is no scrubber sludge to dispose of.

2. Oxidizer:

   This section is not applicable to the systems at the Four Corners Power Plant.

Source of water and pressure:	Morgan Lake @ 60-80 PSI
Flow rate during cleaning:	Not available
Frequency and duration of cleaning:	Not available

4. Reheater:

Type: Steam coils SS-316-L Units 1-2-3 (No longer in operation)

5. Scrubber Pressure Drop Data (inches of water):

	Units 1-2-3
Particulate scrubber	25" W.G.
Mist eliminator	2" W.G.
Reheater	Removed
Ductwork	Not available
Total FGD system	Not applicable
Total part system	28" W.G.

6. Fresh Water Make-up Flow Rates:

The Four Corners Power Plant has no SO_2 scrubbers, but it does have particulate scrubbers on Units 1-2-3. Units 4 and 5 have no scrubbers. Steam and cooling water blowdown are not available as make-up to the scrubber systems on Units 1-2-3. Morgan Lake provides the make-up water for the particulate scrubbing systems on Units 1-2-3.

7. Bypass System: None

3. Clarifiers (thickeners):

Number: 2
Dimensions: 100 Ft. I.D.
Concentration of solids in underflow: 40 wt% solids
Amount of flocculant: None

4. Rotary Vacuum Filter: N/A

5. Sludge Fixation: N/A

A-3.10 COST DATA

The original estimated cost for the installation of particulate scrubbers on Units 1-2-3 was $6,900,000. The final installed cost, including the costs of replacement of the recycle pump and installation of the lime feed system was $27,780,000. The operating and maintenance costs during the year of 1978 for the scrubbers on Units 1-2-3 were:

Operation of the facilities		$ 250,000
Flyash & sulfur sludge removal		954,000
Replacement power costs		2,649,000
	Operations Total	$3,853,000
Maintenance		2,798,000
	Total	$6,651,000

A-3.11 MAJOR PROBLEM AREAS: (Corrosion, Plugging, etc.)

1. SO_2 Scrubber, Circulation Tank, Pumps, and Nozzles - Problem/Solution:

   Corrosion problems were experienced with the stainless steel linings, and erosion problems occurred with the coating used in the scrubber. Also, corrosion and erosion problems were encountered with the pumps related to the scrubbers. Initial operation of the scrubbers resulted in severe pluggage which was reduced by the addition of lime to control the pH. Pluggage of nozzles within the system is still a problem with small chunks flaking off within the scurbber system and being recycled to the nozzles. The system does not have SO_2 removal capabilities at this time, and no circulation tank is being used.

2. Mist Eliminator - Problem/Solution:

   The original mist eliminators were constructed from a polyethylene material and were very flammable. As a result of repairs in the scrubber areas, there were two serious fires that resulted in extended down time to repair damage. Mist modules have since been changed to a fiberglass material that is less flammable. Another problem related to the mist eliminators was fouling, that required more water to keep the modules clean than the design called for. This problem has been alleviated by the addition of lime for pH control.

3. Reheater - Problem/Solution:

   The reheaters for these units were a 316L stainless steel which was found to be very sensitive to the acid mist in the flue gases. After a few months of use, the

reheaters were no longer servicable and have since been removed from service. Revoval of the reheaters caused serious stack deterioration problems resulting in the necessity to replace the stack liners.

4. Venturi Scrubber, Circulation Tanks and Pumps - Problem/Solution:

Shortly after startup, the scrubber venturi and recycle pumps had a serious erosion-corrosion problem and required redesigning. The venturi of the scrubber was modified to include acid brick to prevent erosion-corrosion in the throat area. The recycle pumps were replaced with a rubber lined pump to improve the reliability of the pump system.

5. I.D. Booster Fan and Ductwork - Problem/Solution:

The original ID fans were a 316 stainless steel. Due to vibration problems these failed and had to be replaced with inconel fans. Since that time, the only problem has been the erosion on the blades due to ash carryover from the venturi scrubber. The duct from the ID fans to the stack was originally lines with 316L stainless steel and was plug welded to a carbon steel sheel. This arrangement resulted in deterioration and failure of the stainless steel in the area of the welds. This lining has since been replaced with a fiberglass lining and is repaired on an annual basis.

6. Limestone Milling System or Lime Slaking - Problem/Solution:

The present system is a quick lime system with a batch slaking process and problems in this area relate to the size of the slaking unit and the relatively short

slaking period required to fill the batch tanks. This short time does not permit continuous operation of the slaking unit at designed temperatures which has caused some carryover of lime into the grits system. Scaling of the system continues to be a problem in the lime slaker area due to the hard water that is being used for this process.

7. Sludge Treatment and Disposal - Problem/Solution:

This item is not applicable to the scrubbing system at the Four Corners Power Plant. However, the following comments apply to fly ash disposal from the scrubber systems.

Flyash from the scrubber operation is settled in thickeners and pumped to settling ponds for dewatering. This has been a relatively reliable system. The principal problem has been chips from the scrubber operation causing plugging or fouling of the underflow removal piping. On occasion, this has resulted in the failure of the thickener rakes and a subsequent outage of the thickener for clean out and repair.

8. Description of scrubber control methods under fluctuating load.

Scrubber control consists of adding lime and recirculating slurries until the specified pH limits and percents of solids are obtained. Frequent scaling of the pH probes which are located in the scrubber recycle slurries have occured. Good pH control is essential for scale-free operation, especially when the scrubber liquids are recycled.

A-3.12 METHODS OF MEASURING EMISSIONS

EPA methods 6,7 and 5 respectively, are used to measure SO_2, NO_x and particulate emissions.

SECTION A-4
RETROFIT DESCRIPTION

A-4.1 NO_x EMISSION CONTROL

Table A-1 develops details of the retrofit examples investigated for NO_x reduction to boilers 1,2,3,4 and 5.

Figure A-11 shows the arrangement of the burners, the overfire air (OFA) ports, and the curtain air (C.A.) ports for the Number 1 and 2 boilers. Figure A-12 shows the arrangement of the burners, the OFA ports, and the curtain air ports for the Number 3 boiler.

Figure A-13 indicates the burner arrangement and windbox compartment modifications for Boilers 4 and 5 after being retrofitted. Eighteen sets of cell burners are in use, and each cell burner has three cone nozzles. The number of sets of cell burners is different on each wall. One wall has 8 sets of burners, and the opposite wall has 10 sets. Assuming each cone nozzle is equivalent to an individual, dual-register burner, 54 sets of dual register burners would be required for a retrofit. It may be necessary to provide a total rearrangement of burners to accomodate the different flame characteristics of the B&W, dual-register burner. The windbox is compartmented horizontally as part of the retrofit. A vertical partition at the middle of each compartmented windbox facilitates air distribution. secondary air control dampers are provided at both ends of each compartmented windbox.

TABLE A-1.- RETROFIT FOR NO_x REDUCTION

Units	#1 & #2	#3	#4 & #5
Boiler MW (MW/Boiler Gross)	190	245	778
Boiler Manufacturer	Riley Stoker	Foster Wheeler	B & W
Burners: Type Arrangement	Single-Wall Firing	Single-Wall Firing	Opposed-Wall Firing
No. Burners/Vertical Column	3	5	
No. of Burner Columns	6	4	54 Burner Nozzles
Theoretical Air SCFM/Boiler	338,362	423,807	1,320,980
Excess Air %	20	20	20
Air Temp. At Preheater Outlet (°F)	642	596	565
TYPE OF RETROFIT			
1. Overfire Air (OFA)	Yes	Yes	N/A
% of OFA to Total Air	30	30	"
Total OFA ACFM	254,233	305,140	"
No. of OFA Ports	6	5	"
Size of OFA Port	H 32" X W 16"	H 40" X W 18"	
Air ACFM/OFA Port	42,380	61,030	"
2. Curtain Air (C.A.)	Yes	Yes	"
% of C.A. to Total Air	10	10	"
Total C.A. ACFM	84,744	101,714	"
No. of C.A. Port	12	15	"
Size of C.A. Port	9 1/4" X 9 1/4"	9" X 9"	"
Air ACFM/C.A. Port	7,060	6,781	"
3. Low NO_x Burners	No	Yes	Dual Register Burner
4. Compartmented Windbox	N/A	N/A	Yes

TABLE A-1.- RETROFIT FOR NO_x REDUCTION (Continued)

Units	#1 & #2	#3	#4 & #5
ASSOCIATED MODIFICATION WORK NEEDED:			
Cutting of OFA Port	Yes	Yes	N/A
Cutting of C.A. Port	Yes	Yes	N/A
Removing & Modification of Membrane Wall Tubes[a] (Approximate No. of Tubes)	120	120	Yes[a]
Windbox Modification	No	No	Yes
Duct Connection (Addition)	Yes	Yes	Yes
OFA Tilt Drive Mechanism	Yes	Yes	N/A
Control To Each OFA & C.A. Port	Yes	Yes	N/A

[a] Firebox wall and membrane wall might need modification to install low NO_x burners.

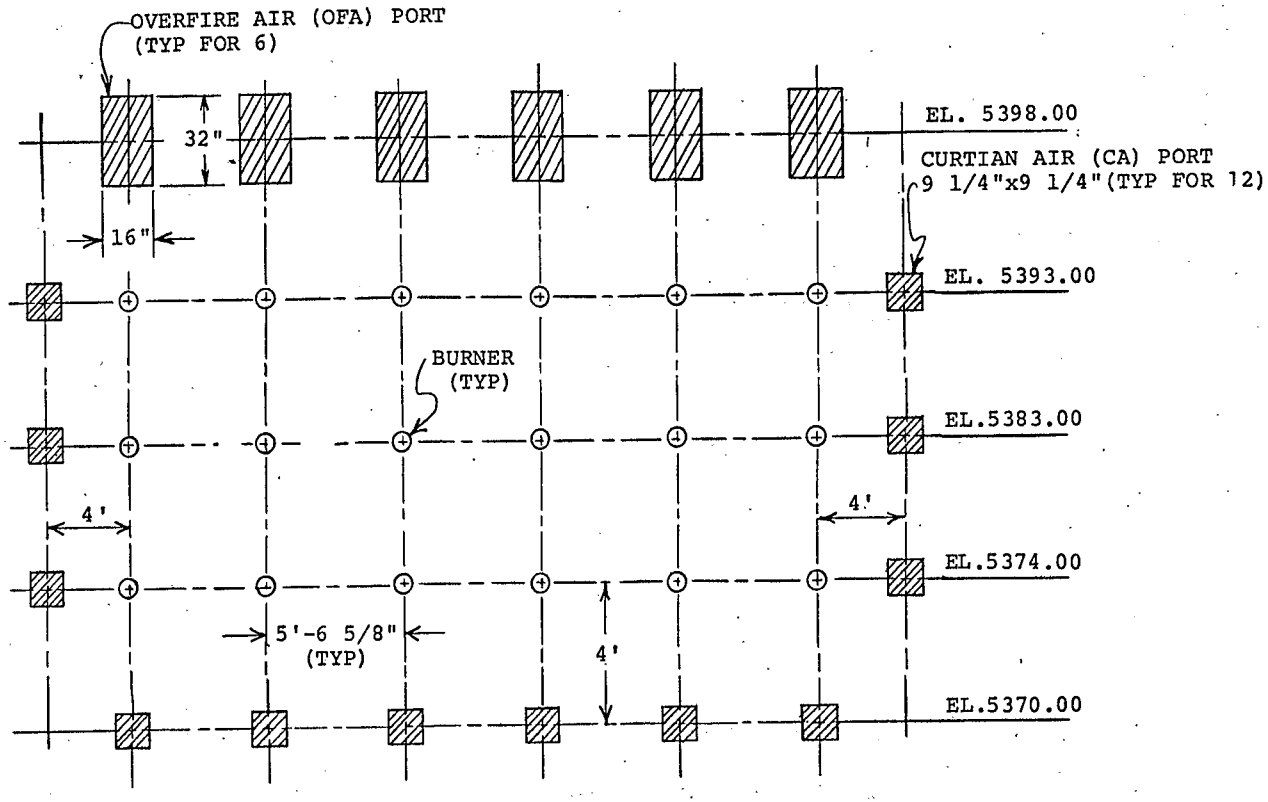

Figure A-11.- Retrofit arrangement of OFA and CA ports for Units 1 and 2 - Riley-Stoker boilers.

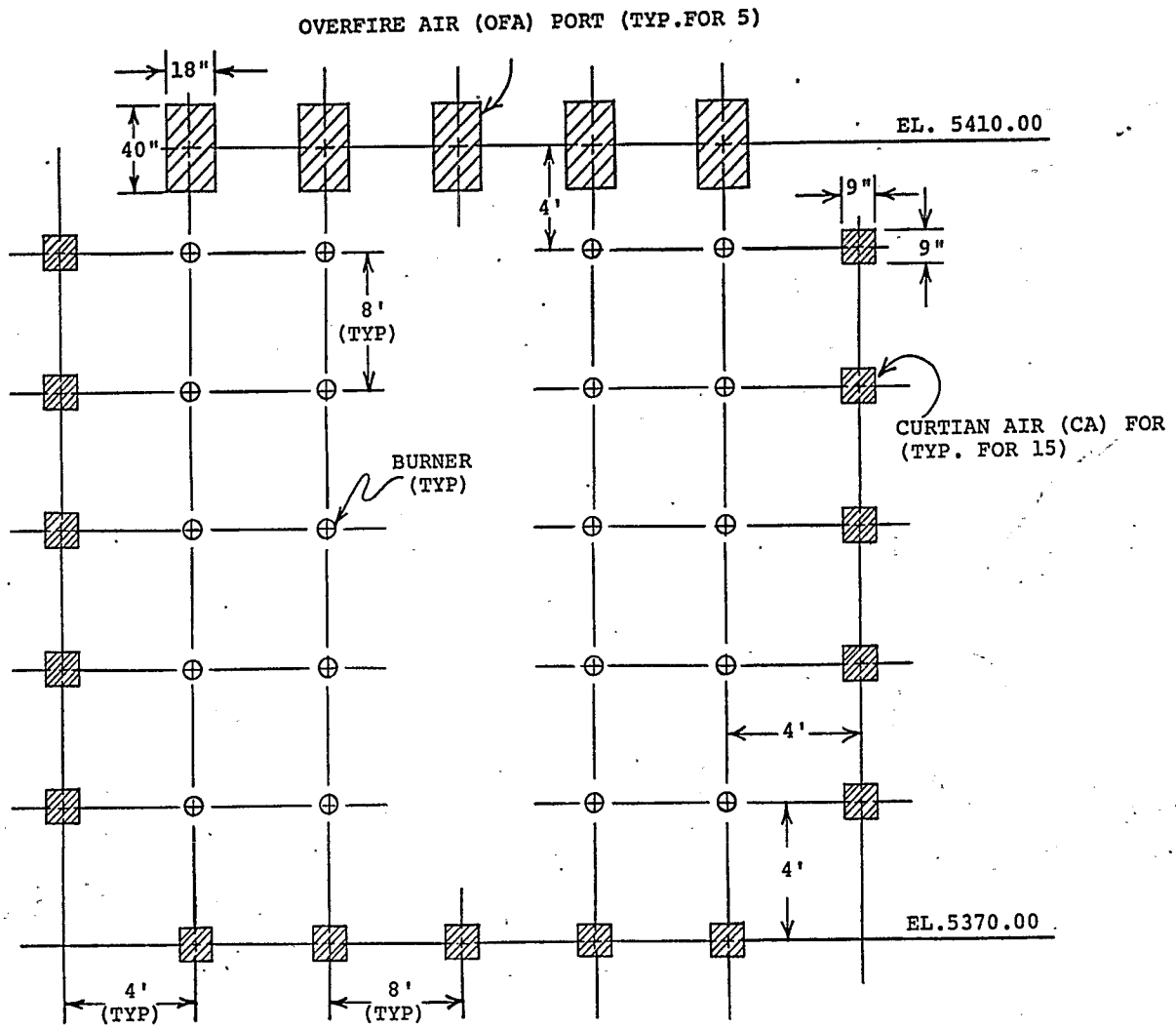

Figure A-12.- Retrofit arrangement of OFA and CA ports for Unit 3 - Foster Wheeler boiler.

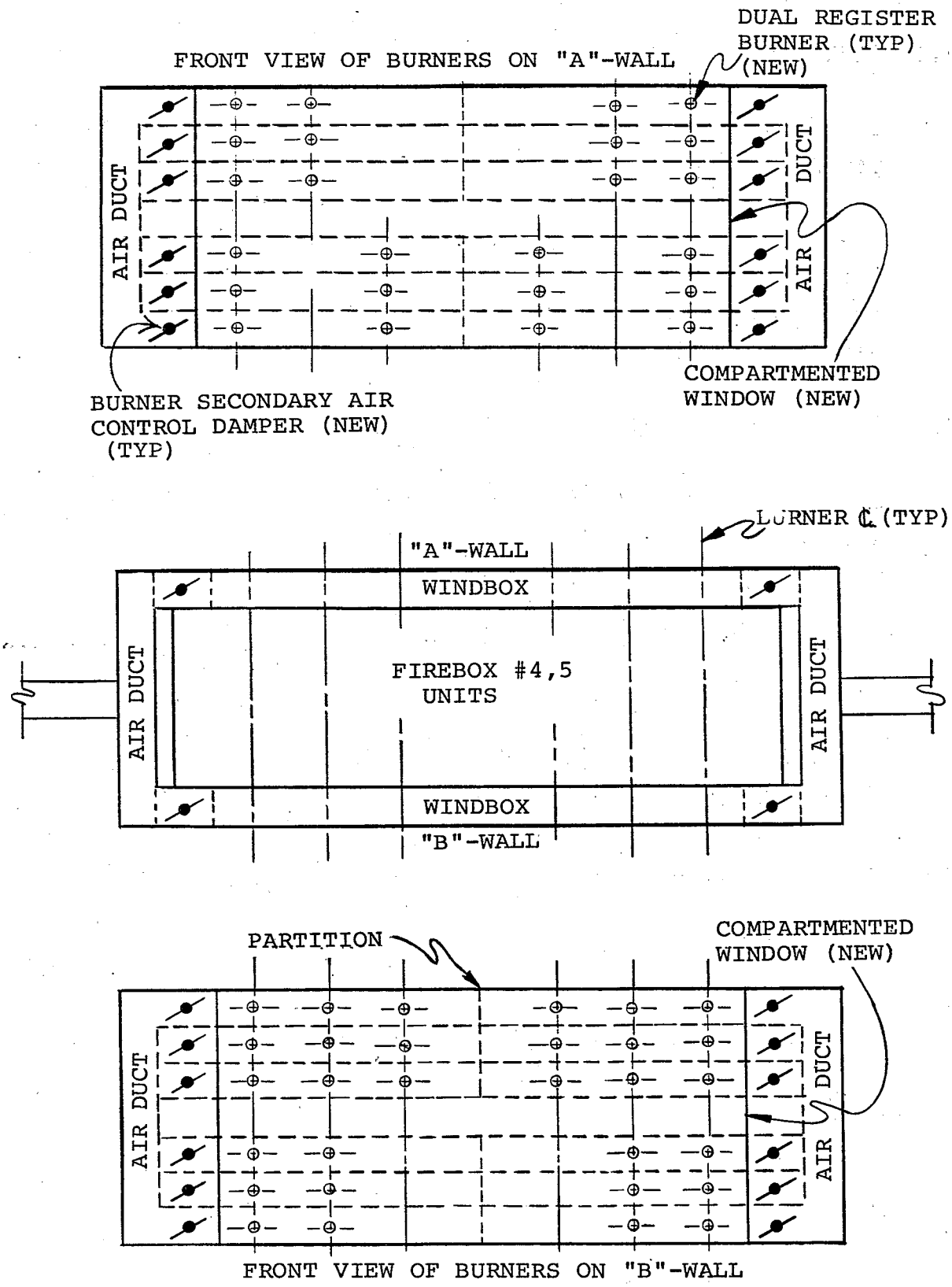

Figure A-13.- Retrofit of Units 4 and 5 with 54 sets of Dual Register (B&W) burners and compartmentized windbox.

A-4.2 PARTICULATE EMISSION CONTROL

The related data and the calculated results for particulate emission control retrofit work for Units 1 & 2 are shown in Table A-2. Unit 3 data are shown in Table A-3, and Table A-4 has the information for Units 4 and 5. For Units 1,2 & 3, hot side ESP retrofitting was not considered due to space limitations and relocation requirements for the air preheaters.

A-4.3 SO_2 EMISSION CONTROL

System requirements are based on 90% SO_2 removal for wet scrubbing and 70% SO_2 removal for dry scrubbing with 0.7 percent sulfur coal.

Sizes have been selected based on meeting SO_2 removal requirements.

To evaluate the dry scrubbing systems, the corresponding number of wet scrubber modules that would produce a 70%, SO_2 removal has been used. Also, the flue gas rate to be bypassed given in the table is the appropriate rate to produce the effectively 70%, SO_2 removal when using a 90%, wet SO_2 removal system.

TABLE A-2.- RETROFIT DATA FOR ELECTROSTATIC PRECIPITATORS AND BAGHOUSES - UNITS 1 AND 2

Power Plant:	Four Corners
Boiler No.	#1 & #2
Gross MW/Boiler:	190
Flue Gas (ACFM/Boiler @ 2610 SCFM/MW @ 68°F):	
300°F	713,800
68°F (SCFM)	495,900
170°F[a]	623,400
125°F[b]	576,100

Per Boiler	Cold Side ESP	Baghouse Wet Scrubbing	Baghouse Dry Scrubbing
Total Req'd Particulate Collection Area (FT^2)	713,800	356,900	311,700
Existing Collection Area (FT^2)	0	0	0
Collection Area to be Added (FT^2)	713,800	356,900	311,700
No. of ESP Trains	2		
No. of ESP Modules/Train	11		
Total No. of Modules to be Added	22	20	17
Total Area Added (F+2)	712,800	369,460	314,000
ESP Electrical Sectionalizing			
Total No. of Electrical Sections Required Per 5 MW	38		
Existing Electrical Sections	0		
No. of Elec. Sec/New Module	2		
Total No. of Elec. Sections Added	44		
Total	44		
MW/Section	4.32		

[a]Includes water from dry scrubbing

[b]Includes 13.3 percent water from wet scrubbing

TABLE A-3.- RETROFIT DATA FOR ELECTROSTATIC PRECIPITATORS AND BAGHOUSES - UNIT 3

Power Plant:	Four Corners
Boiler No.	#3
Gross MW/Boiler:	245
Flue Gas (ACFM/Boiler):	
300°F	920,400
68°F (SCFM)	639,450
170°F[a]	803,800
125°F[b]	742,900

Per Boiler	Cold Side ESP	Baghouse Wet Scrubbing	Baghouse Dry Scrubbing
Total Req'd Particulate Collection Area (FT^2)	920,400	460,200	402,000
Existing Collection Area (FT^2)	0	0	0
Collection Area to be Added (FT^2)	920,400	460,200	402,000
No. of ESP Trains	3		
No. of ESP Modules/Train	10		
Total No. of Modules to be Added	30	25	22
Total Area Added (F + 2)	972,000	461,800	406,400
ESP Electrical Sectionalizing			
Total No. of Electrical Sections Required Per 5 MW	50		
Existing Electrical Sections	0		
No. of Elec. Sec/New Module	2		
Total No. of Elec. Sections Added	60		
Total	60		
MW/Section	4.13		

[a]Includes water from dry scrubbing

[b]Includes 13.3 percent water from wet scrubbing

TABLE A-4.- RETROFIT DATA FOR ELECTROSTATIC PRECIPITATORS AND BAGHOUSES - UNITS 4 AND 5

Power Plant:	Four Corners
Boiler No.	#4 & #5
Gross MW/Boiler:	778
Flue Gas (ACFM/Boiler):	
300°F	2,923,000
68°F (SCFM)	2,031,000
170°F[a]	2,553,000
125°F[b]	2,359,000

Per Boiler	Cold Side ESP	Baghouse Wet Scrubbing	Baghouse Dry Scrubbing
Total Req'd Particulate Collection Area (FT^2)	2,923,000	1,461,500	1,276,500
Existing Collection Area (FT^2)	373,000	0	0
Collection Area to be Added (FT^2)	2,550,000	1,461,500	1,276,500
No. of ESP Trains	8		
No. of ESP Modules/Train	10		
Total No. of Modules to be Added	80	80	70
Total Area Added (F+2)	2,592,000	1,477,800	1,293,000
ESP Electrical Sectionalizing			
Total No. of Electrical Sections Required Per 5 MW	155		
Existing Electrical Sections	32		
No. of Elec. Sec/New Module	2		
Total No. of Elec. Sections Added	160		
Total	192		
MW/Section	4.03		

[a]Includes water from dry scrubbing

[b]Includes 13.3 percent water from wet scrubbing

SECTION A-5
RETROFIT COSTS

Retrofit capital and annualized costs for the alternatives discussed in Section A-1 are included in this section. The total required plant investment costs given for each alternative do not include the costs of removing and/or relocating any existing equipment that may be associated with the particular retrofit alternative. The cost for land required for sludge disposal (from SO_2 removal) and the associated sludge transportion to the disposal site are not included in the retrofit plant investment or annualized operating costs. Also, the following cost items are realized but not included in the total retrofit capital and annualized costs:

(1) Site preparation
(2) Cost of down-time
(3) Additional stack lining if flue gas desulfurization is installed
(4) Costs for removing ventiru scrubbers on Units 1, 2, and 3

Working capital, the money required to operate the new equipment associated with the retrofit, has been calculated for each retrofit alternative.

TABLE A-5. CAPITAL INVESTMENT COSTS FOR RETROFITTING THE FOUR CORNERS POWER PLANT - MILLIONS OF THIRD QUARTER 1979 DOLLARS (a)

Cost Item	Alternative 1	2	2a	3
1. NOx Control	28.93	28.93	28.93	28.93
2. Particulate control	0.00	156.80	137.71	(b)
3. SO_2 control	369.47	369.47	303.25	272.63(b)
4. Emission Monitoring	1.65	1.65	1.65	1.65
5. Auxiliary Boiler	17.35	17.35	0	0
6. Replacement of Power Generating Capacity	79.85	97.52	77.19	38.54
7. Working Capital	36.64	45.25	35.75	24.04
total	533.89(c)	716.97(c)	584.48(c)	365.79(c)
Dollars per Kilowatt Gross Generating Capacity	245	329	268	168

(a) Includes direct and indirect costs

(b) Costs of particulate and SO_2 control are combined

(c) See Section 4.5 for other costs not estimated

TABLE A-6 ANNUAL COSTS FOR RETROFITTING THE FOUR CORNERS POWER PLANT - MILLIONS OF THIRD QUARTER 1979 DOLLARS PER YEAR (a)

Cost Item	Alternative 1	2	2a	3
1. NOx Control	5.265	5.265	5.265	5.265
2. Particulate Control	0	34.418	26.439	(b)
3. SO_2 Control	140.924	140.924	110.912	90.510(b)
4. Emission Monitoring	.384	.384	.384	.384
total	146.573(c)	180.991(c)	143.000(c)	95.159(c)
Mills per kilowatt hour of net power generation (current net less retrofit power requirements at 65 percent of maximum net load)	12.2	15.2	11.9	7.9

(a) Includes fixed capital charges

(b) Costs of particulate and SO_2 control are combined

(c) See Section 4.5 for other costs not estimated

SECTION A-6
REFERENCES

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2. Letters from C.D. Jarman, Arizona Public Service to N. Master, Pullman Kellogg, 5 July 1979
3. Meeting notes - N. Gonzalez/N. Master, Pullman Kellogg - meeting with J. Weiss, et al, Arizona Public Service and S. Cuffe/J. Copeland, EPA, Phoenix, Arizona, 17 July 1979
4. Letters from J.C. Evans, Snell & Wilmer to N. Master, Pullman Kellogg, 1 June and 9 August 1979
5. Drawings received from APS:
   Bechtel DWG 73005-2, Plot Plan, Rev 2, 2-20-70
   Ebasco DWG G-162385, Plot Plan, Rev 3-A, 9-17-63
   Ebasco DWG G-162390, General Arrangement Section A-A, Rev 5, 11-13-62
   Ebasco DWT G-171673, General Arrangement Section A-A, Rev 4, 3-6-64
   Bechtel DWG 73496-1, General Arrangement Section, Rev 1, 2-14-68

APPENDIX B

EXAMPLES OF RETROFITTING THE MOHAVE POWER STATION

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SECTION B-1
GENERAL

B-1.1 RETROFIT ALTERNATIVES

The four alternative examples considered in this appendix follow. All alternatives include maximum NO_x control and the installation of emission monitoring systems for opacity, SO_2, and NO_x.

Alternative 1 - Add wet scrubbing to achieve 90% SO_2 removal and retain the existing ESP's for particulate emissions control to a level of 21 ng/J heat input (0.05 lb/10^6 Btu). Figure B-1 shows the general arrangement of the plant with the addition of the wet SO_2 scrubbing modules.

Alternative 2 - This option adds baghouses plus wet SO_2 scrubbing for 90% SO_2 removal, and it keeps the existing ESP's for control of particulate emissions to a level of 13 ng/J heat input (0.03 lbs/10^6 Btu). Figure B-2 shows the plant's general arrangement with the added SO_2 scrubbing modules and baghouse modules.

Alternative 2a - The retrofit for particulate control in Alternative 2a is the same as for Alternative 2, using baghouses for cost comparison with Alternative 3. The wet SO_2 scrubbing in this case is based on 70% SO_2 removal for cost comparison with semi-dry scrubbing in Alternative 3.

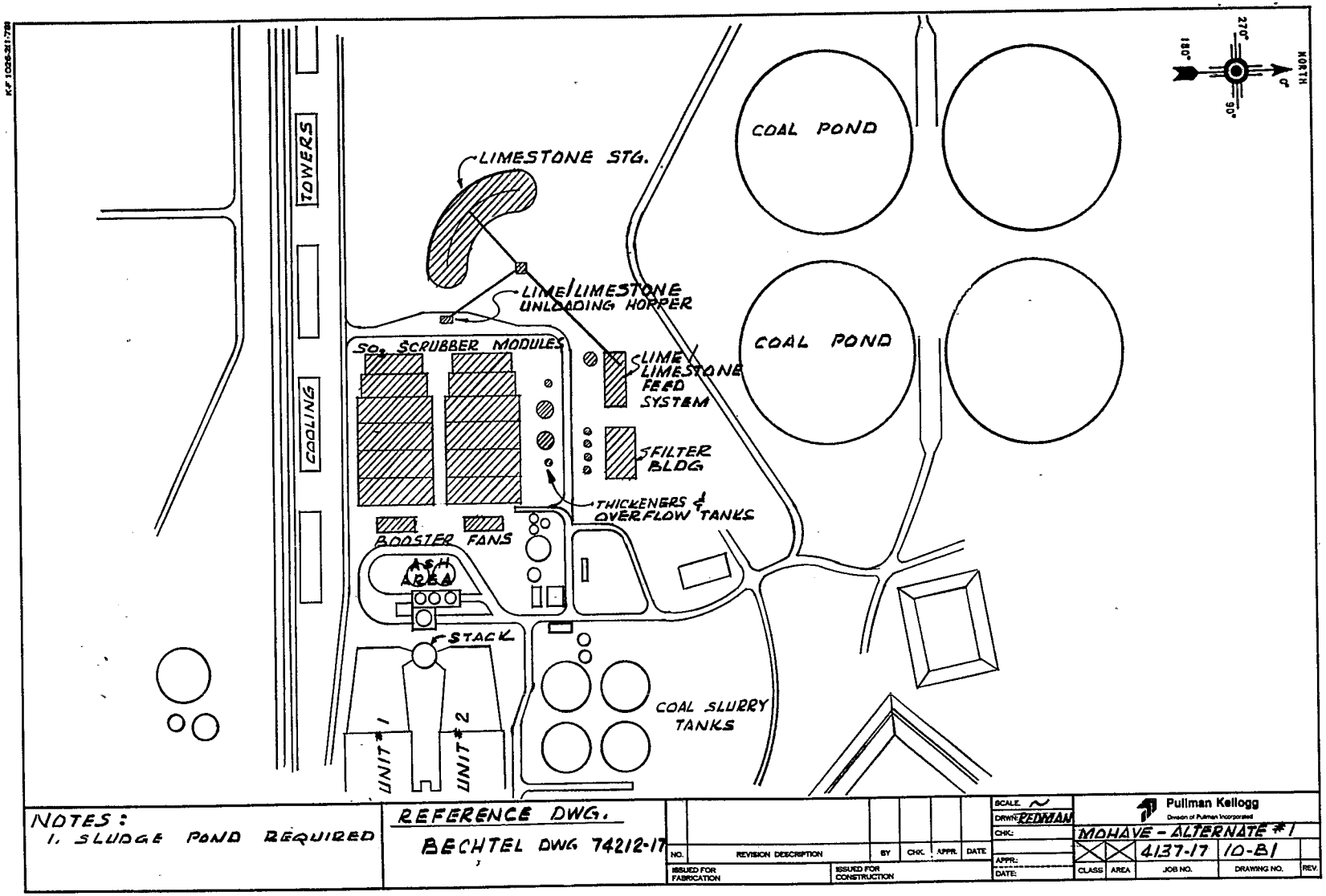


Figure B-1.- Addition of wet SO_2 scrubbing modules.

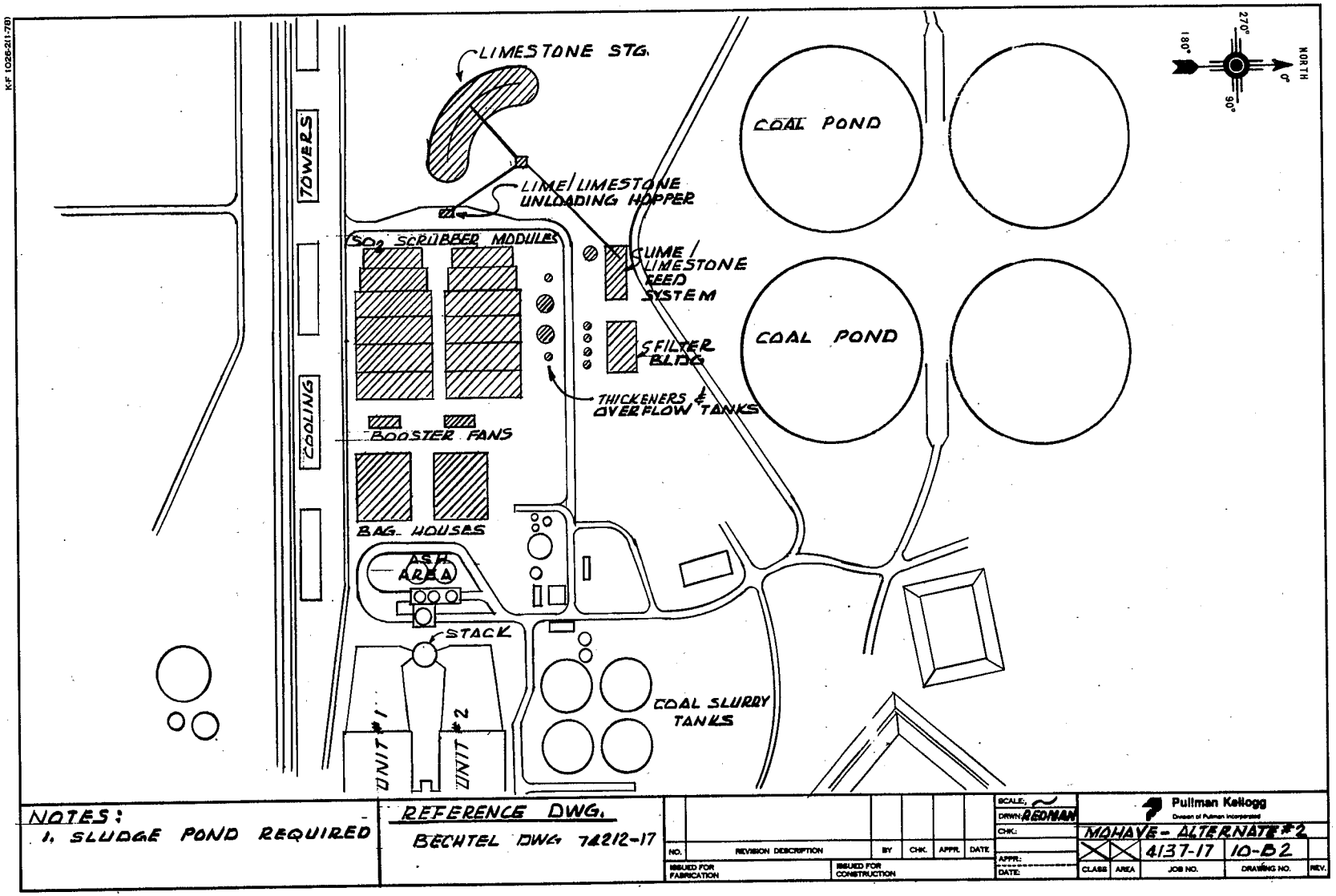


Figure B-2.- Addition of baghouses and wet SO_2 scrubbing modules.

Alternative 3 - Semi-dry SO_2 scrubbing (spray drying) for 70% SO_2 removal is used in this case. Also baghouses are used as dry collectors with the existing ESP's for control of particulate emissions to a level of 13 ng/J heat input (0.03 lbs/10^6 Btu). Figure B-3 shows this general arrangement with the addition of the SO_2 scrubbing modules and baghouses.

B-1.2 PLANT CHARACTERISTICS

Major revamp work required to install the SO_2 and particulate control equipment does not involve relocation of existing equipment. Characteristics of the plant site, existing equipment, and space requirements for each retrofit example are shown in the following list (1).

A. The existing electrostatic precipitators are located downstream of the air preheater (cold side).
B. Each of the two boilers has two primary-air (PA) fans and two forced-draft (FD) fans.
C. The number of SO_2 scrubbing modules used is based on the total calculated flue-gas rate from each boiler.
D. One SO_2 scrubbing module per boiler is provided as a spare.
E. One flue-gas reheater is required for each wet SO2 scrubbing module for 90% SO_2 removal.
F. One flue-gas, booster fan is required for each scrubbing module.
G. The individual scrubbing modules are provided with dampers. This provision allows the individual modules to be isolated for maintenance.
H. Tie-in of retrofit equipment to the power plant is based on completion during normal power plant maintenance turn-arounds of 3 to 6 weeks.

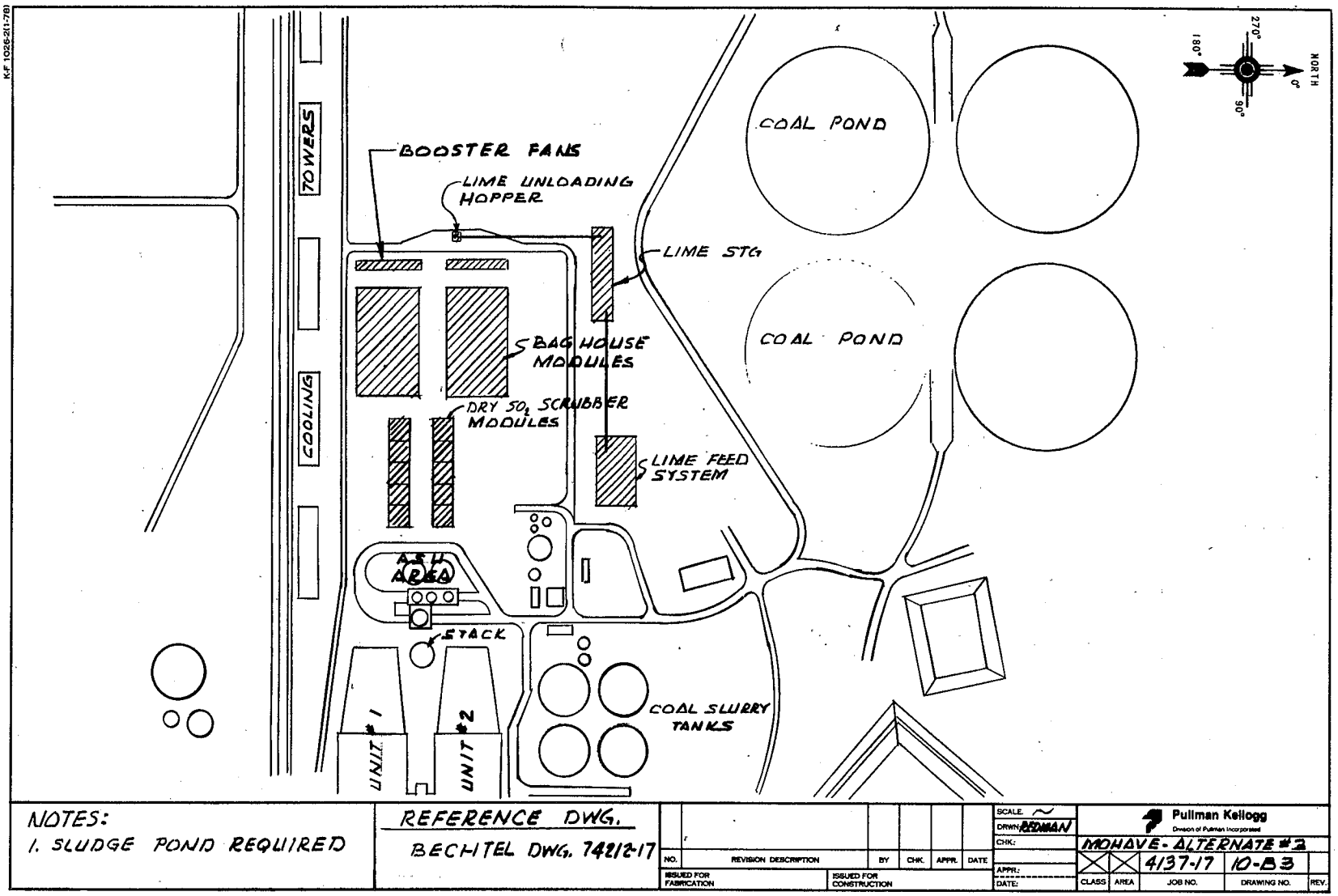


Figure B-3.- Addition of dry SO_2 scrubbing modules with baghouses.

I. Tie-ins to the existing stack are the basis for the retrofit examples and are realized to be extremely difficult. Addition of a new stack is a possible alternative but was not considered for estimating the costs for retrofitting the plant.

J. An emergency bypass is provided around each SO_2 scrubbing system to allow operation of the boiler in the event of a major FGD malfunction. Bypassing of the particulate control equipment is not provided.

B-1.3 FLUE GAS DUCTING REQUIREMENTS FOR RETROFITTING

Bypass duct and dampers are provided to enable the flue gas to completely bypass the SO_2 scrubbing system. Bypass duct locations for the three alternatives are indicated below:

Alternative 1 - The emergency bypass duct is located adjacent to the stack upstream of the wet SO_2 scrubbing module booster fans. Figure B-4 shows the additional ducting requirements for the retrofit. Figure B-5 shows the elevational view for the SO_2 scrubbing module.

Alternative 2 - The emergency bypass duct is taken after the baghouse, just before the scrubber modules as shown in Figure B-6. Figure B-7 shows the elevation view for the SO_2 scrubbing and baghouse modules.

Alternative 2a - The bypass duct is the same as used in Alternative 2. This duct can also be used during normal operation to divert about 22.2% of the total flue gas that does not need to be treated, since the module remove 90% SO_2 and this alternate requires only 70% overall SO_2 removal. The bypass duct also provides the flue gas requirements for reheat.

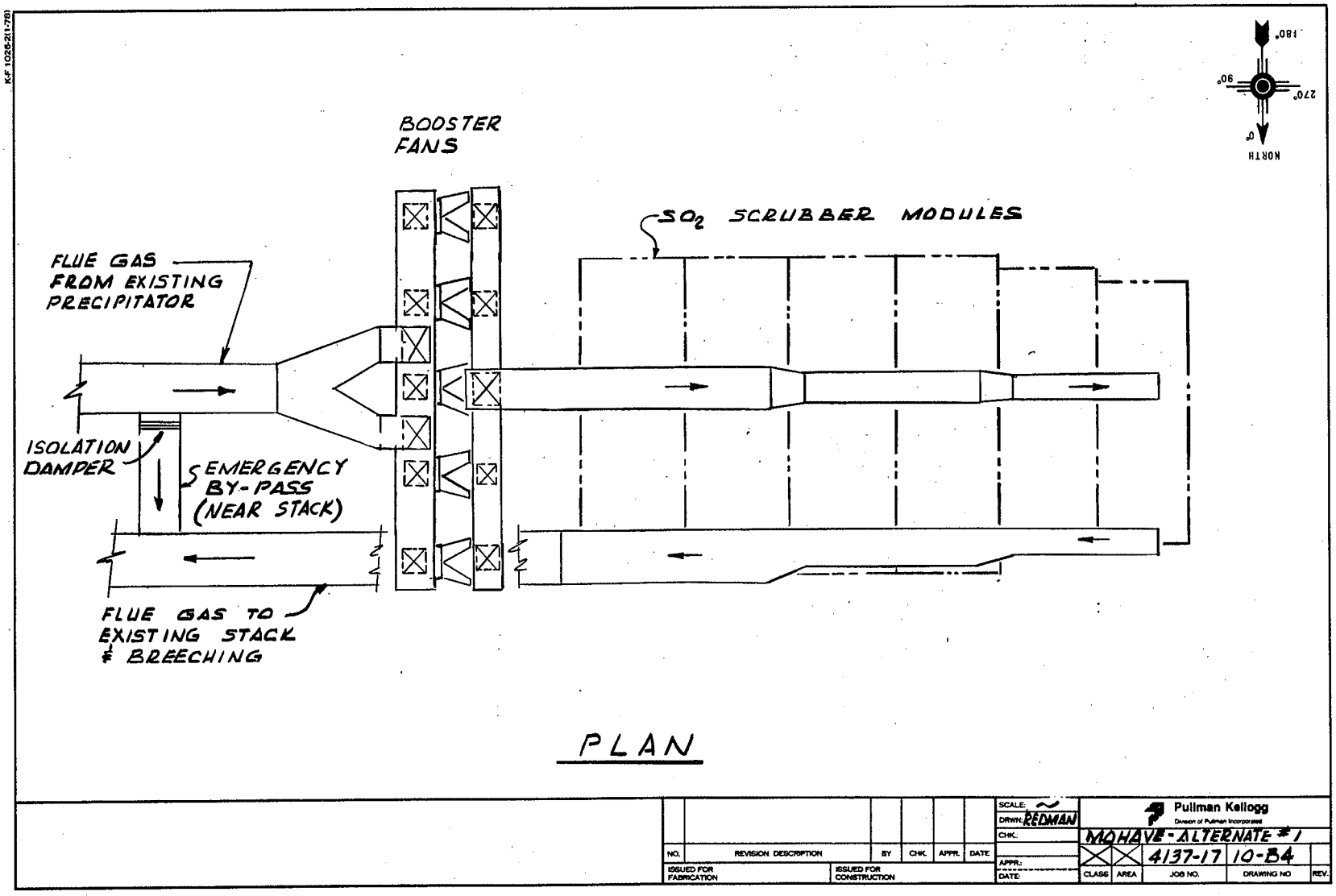


Figure B-4.- Plan arrangement of wet SO_2 scrubbing modules.

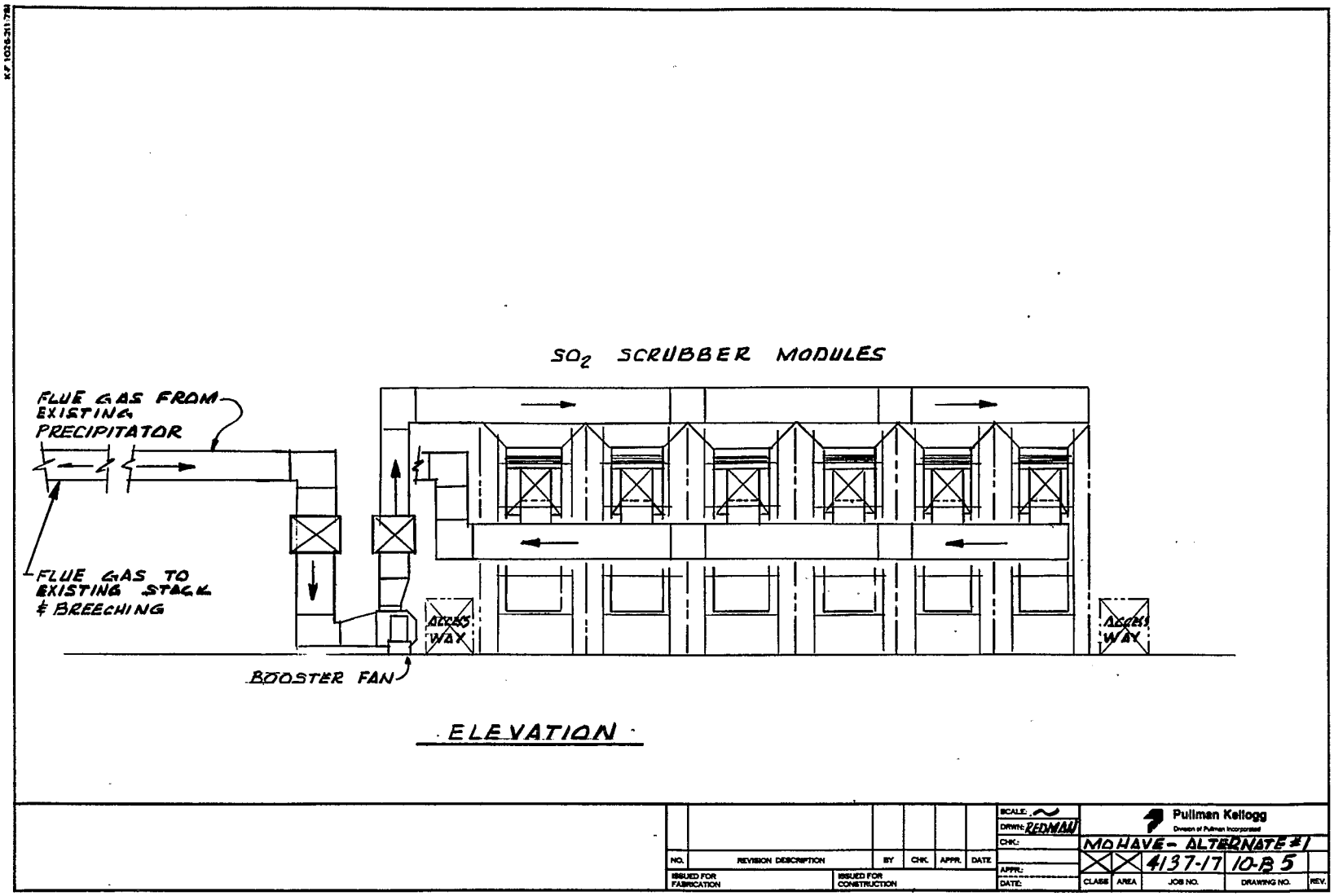


Figure B-5.- Elevation arrangement of wet SO_2 scrubbing modules.

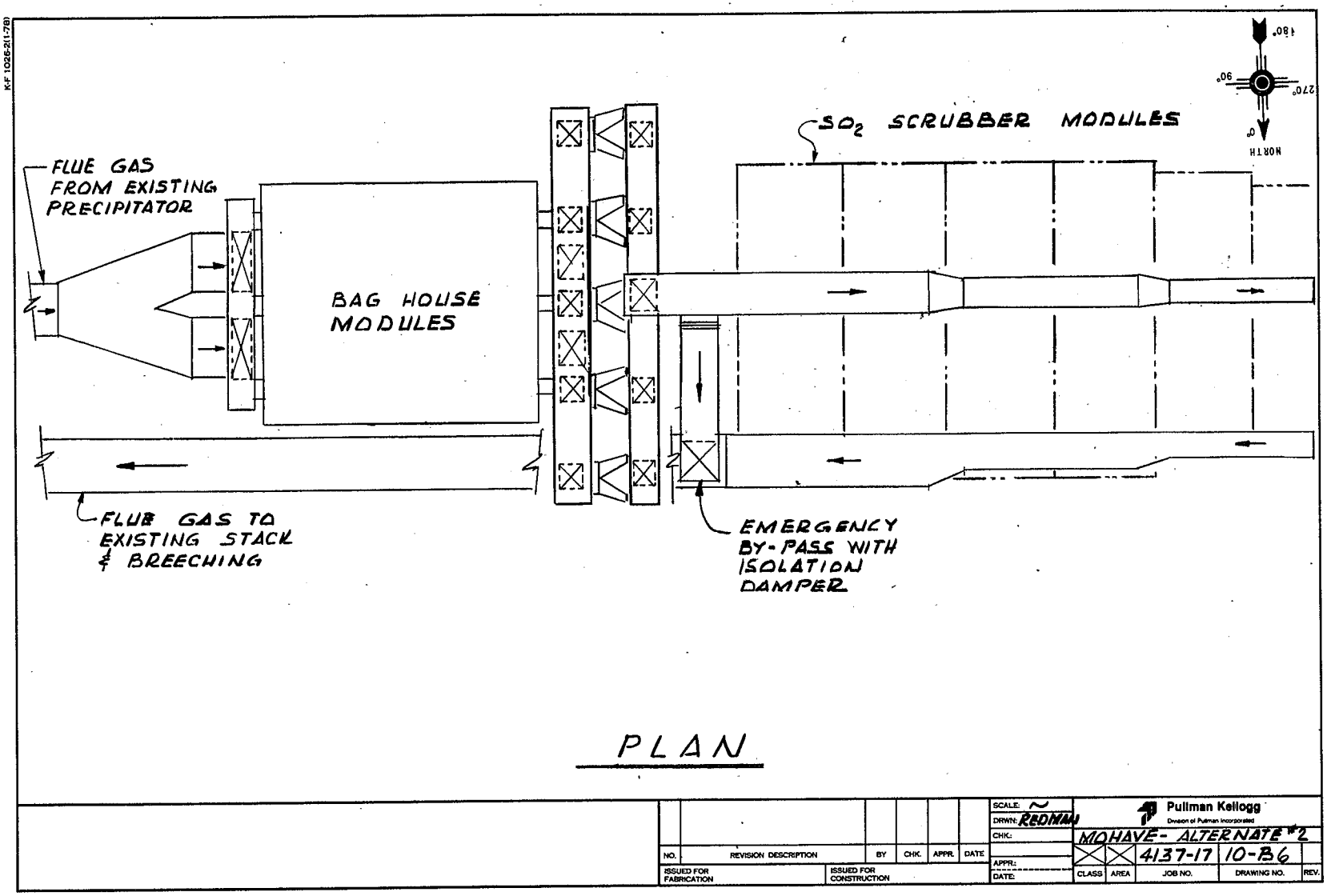


Figure B-6.- Arrangement of ducting for baghouses and wet SO_2 scrubbing systems.

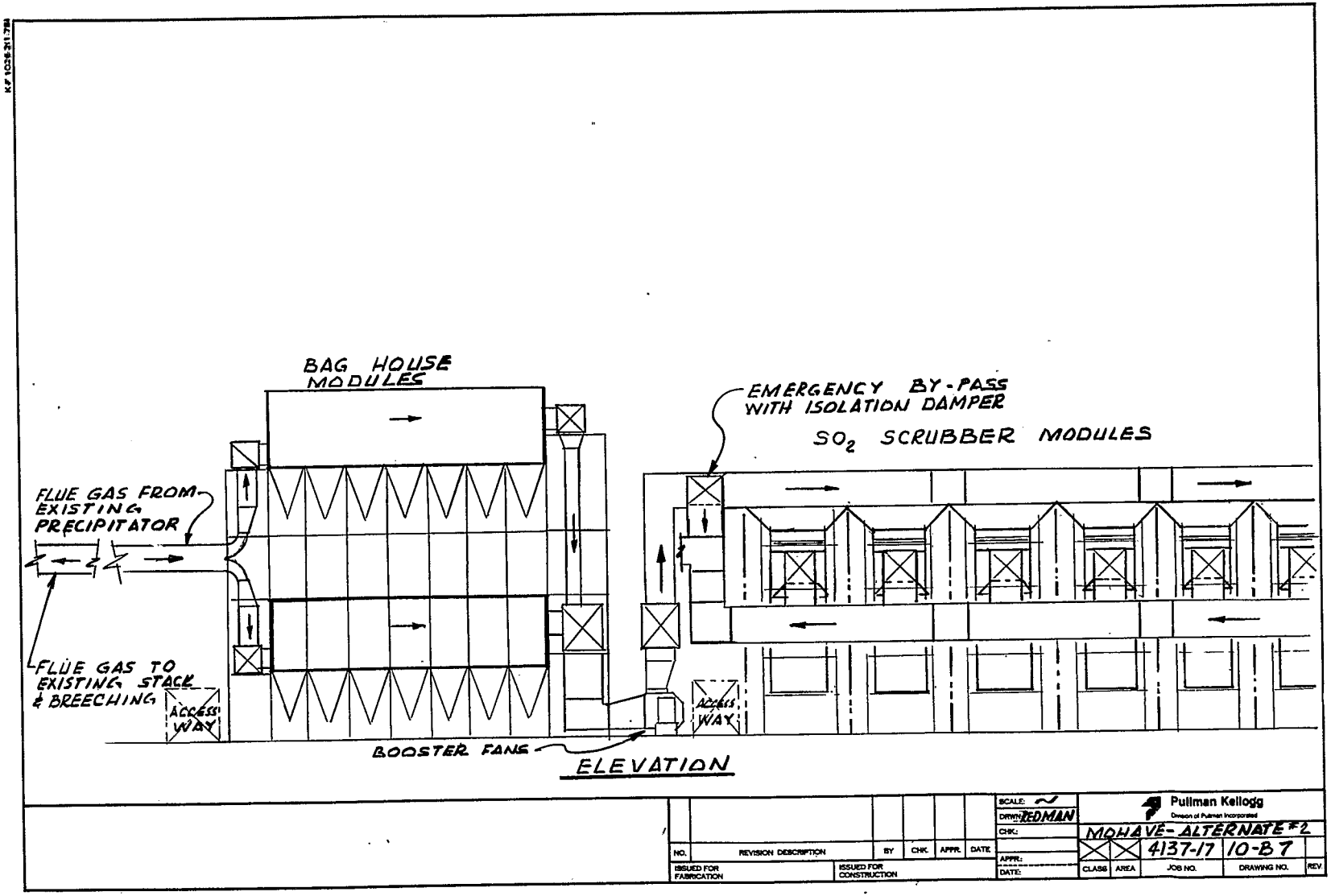


Figure B-7.- Arrangement of wet SO_2 scrubbing and baghouse modules.

Alternative 3 - The bypass duct is taken ahead of the spray dryer and tied into the duct going to the baghouses. This location of the emergency bypass permits operation of the baghouse for particulate control when a spray dryer is out of service. Figure B-8 shows the elevation view for the dry-scrubbing and baghouse modules.

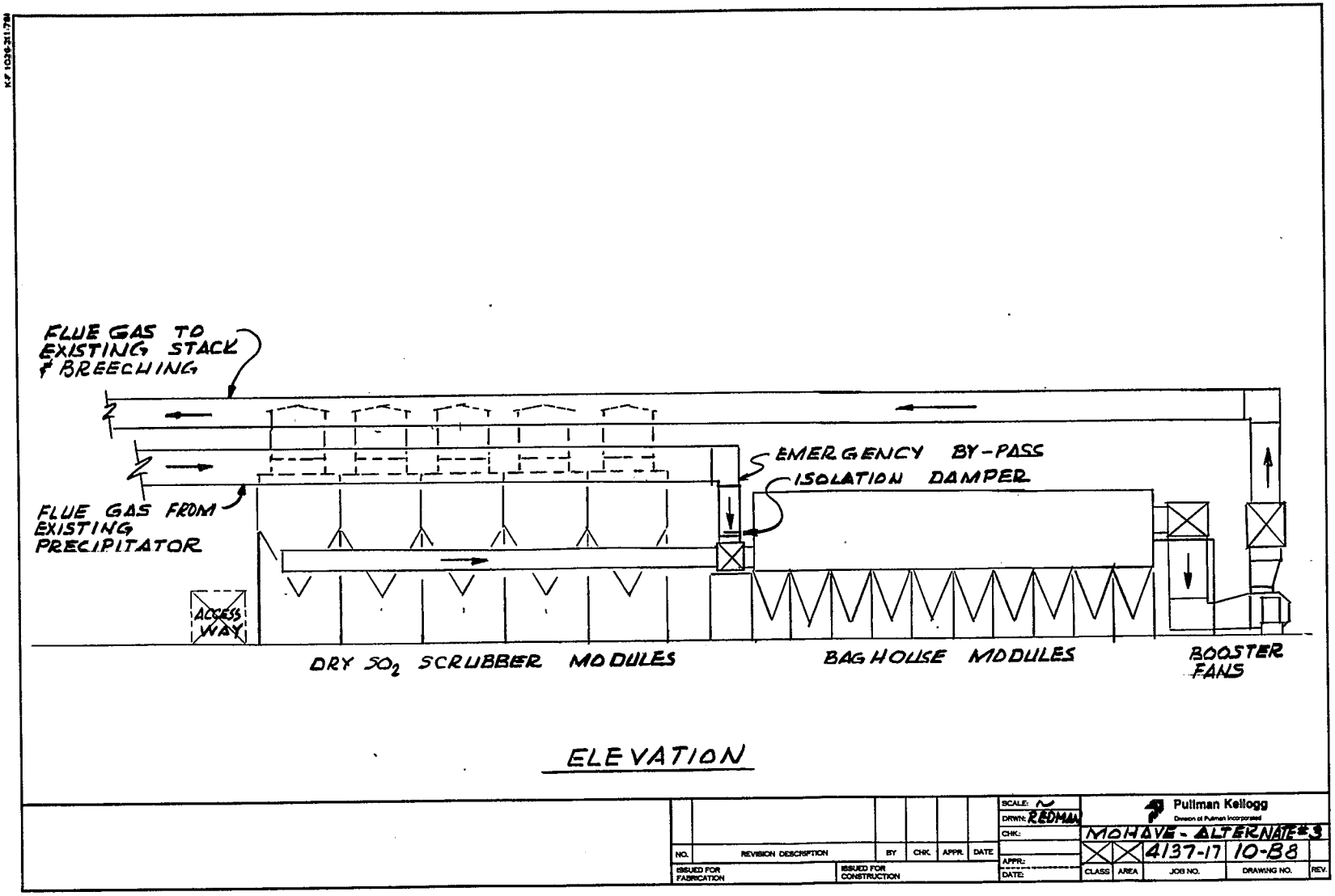


Figure B-8.- Arrangement of dry SO_2 scrubbing and baghouse modules.

SECTION B-2
BACKGROUND DATA

B-2.1 PLANT DESCRIPTION (1,2)

The Mohave Generating Station is owned jointly by Southern California Edison, (56%), The Los Angeles Department of Water and Power, (20%), Nevada Power Company, (14%), and the Salt River Project, (10%). It is operated by Southern California Edison (SCE).

Total plant capacity is 1580 MW(net) and 1640 MW(gross). It consists of two, 790 MW(net), 820 MW(gross), forced-draft, pressurized-firebox, pulverized-coal-fired, steam generators. The two, Combustion Engineering (CE) boilers are equipped with tilting tangential burners. Each boiler has 8 burner sets, and each burner set has 10 burner nozzles. There are, therefore, 80 burners per boiler. The coal feed rate per boiler is approximately 856,000 lbs/hr.

Pulverized subbituminous coal slurry is dewatered in centrifuges before the coal is fed into the burners.

The flue gas duct runs vertically down from the rear side of each boiler, and it turns 90° to the horizontal. The duct is then branched into two ducts, each connected to an electrostatic precipitator. Ducts from each precipitator combine into one duct and are connected to one side of the single 500 ft. stack.

Bottom ash from the boiler bottoms is mixed with water and is transferred, as slurry, to three settling tanks. The ratio of fly ash to bottom ash is 70/30. The water overflow from each tank is stored in a fourth tank for further settling of the ash, and then it is recycled to complete the "closed-loop" slurry loop. The flyash from the precipitators is pneumatically transported to a dry ash storage bin.

The ash disposal site is sized for 30 years of disposal capacity.

The flyash and the closed-loop, wet-ash, collecting systems are currently operating at full capacity. Therefore, the capacity of each collecting system has to be increased for any increase in the amount of collected particulates that occurs as a result of retrofitting. Figure B-9 shows the general plot plan arrangement for the Mohave power station.

B-2.2 STEAM GENERATOR DESCRIPTION

Each boiler uses a forced draft system, and the firebox is operated at 21" H_2O, positive pressure. Any further increase in the firebox pressure to compensate for pressure drop with the additional emission control equipment may result in problems of flue gas leakage. Therefore, the addition of induced draft (ID) fans have been considered for the retrofit examples. The existing boiler design does not allow for the use of new FD fans as an alternative to the addition of the ID fans. Each boiler has two primary air fans (PA) and two forced-draft fans (FD) operating in parallel.

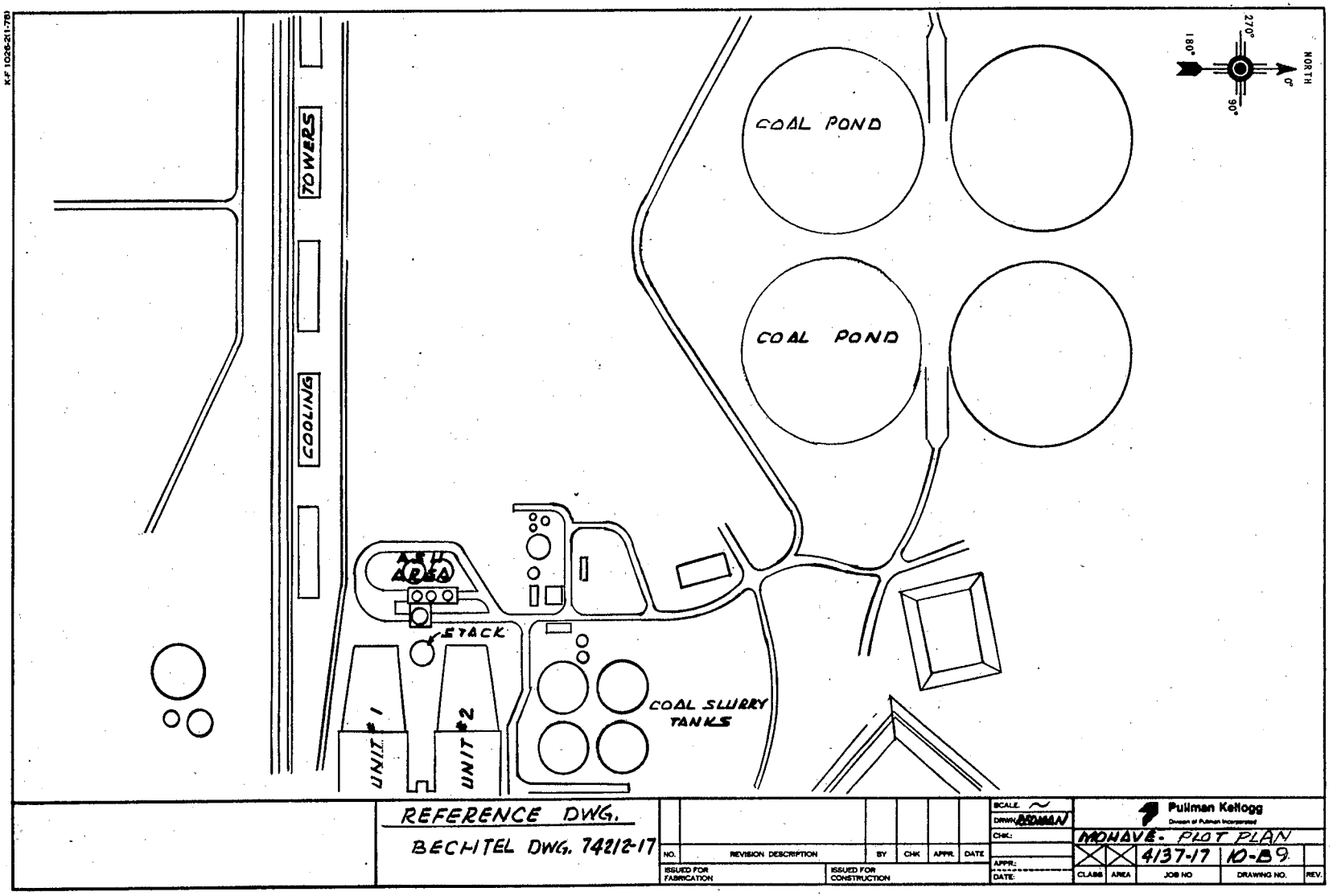


Figure B-9.- General plot plan of the Mohave power station.

The two, CE 790 MW (net) boilers are tangentially fired and twin furnace designs. Neither boiler is equipped with over fire air ports. The boilers are the dry bottom type.

Vertical-shaft, regenerative, Ljungstrom air preheaters are used. There are two air preheaters per boiler.

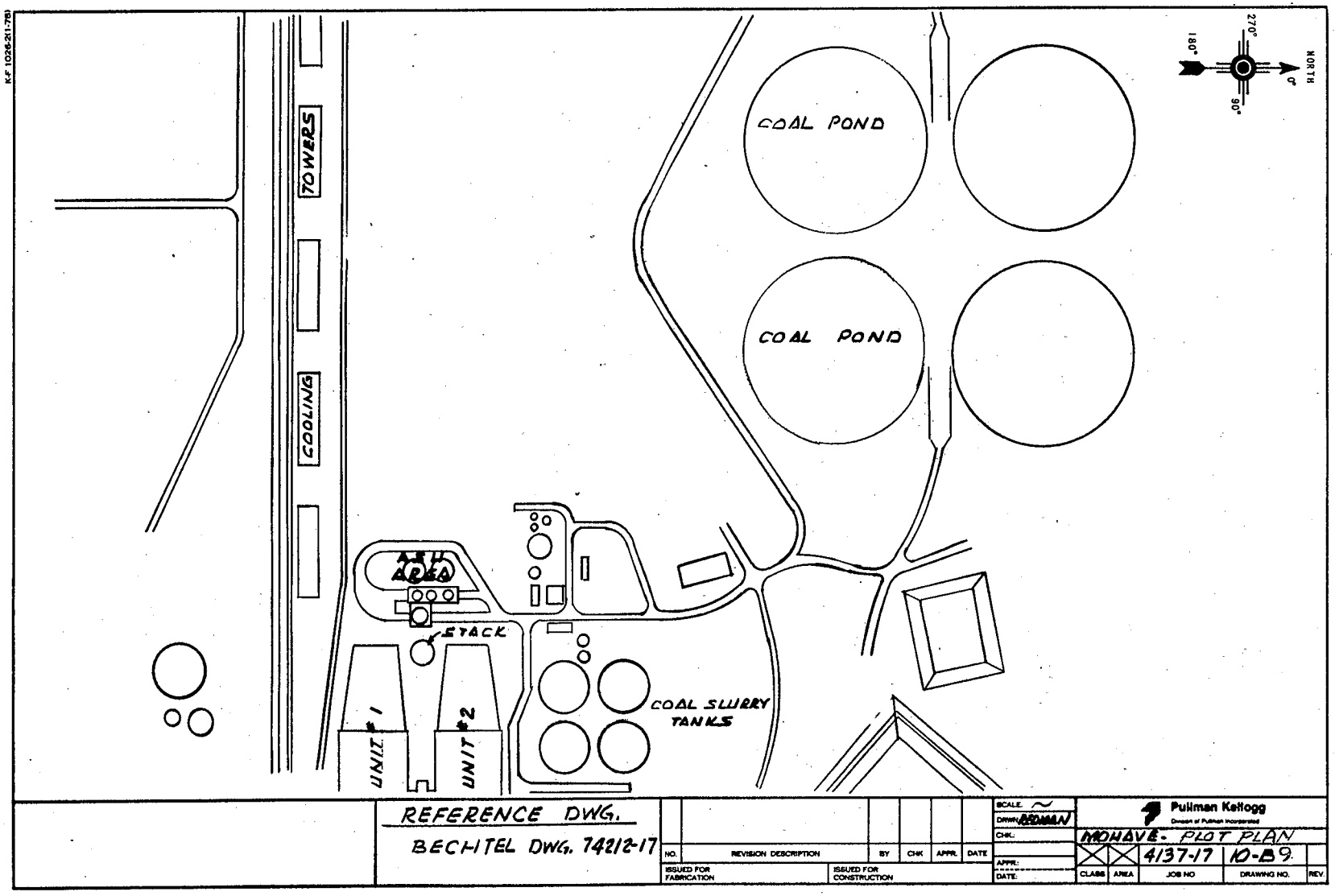
B-2.3 DESCRIPTION OF EXISTING NO_x CONTROLS (3)

Presently there are no specific controls for NO_x emission in the plant. Originally, an NO_x monitoring device was designed and installed at the plant by SCE, but it is no longer in operation because of maintenance problems. No retrofit work for NO_x reduction has ever been done.

B-2.4 DESCRIPTION OF EXISTING PARTICULATE CONTROLS (4)

The existing particulate controls consist of two sets per boiler of cold side, Research-Cottrell, Inc., electrostatic precipitators. The manufacturer's guarantee was 97.9% removal efficiency, at 2,300,000 ACFM per boiler, with flue gas temperature at 268°F, and with coal sulfur contents over 0.3 wt%. Expected performance was 98.6% under similar conditions.

Installation of the cold side ESP's was completed in 1970 and they have a life expectancy of 35 years. Two sets of ESP's are operated in parallel for each boiler. Each precipitator unit is enclosed in a 3/16" thick steel shell and is segmented into four mechanical units. Each precipitator is equipped with sixteen ash hoppers. Each mechanically segmented unit has 37 flue-gas passages (38 collecting plates) that are 9-inches wide. The units are



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30-feet high and 21-feet long, and they are segmented into three sections. The inlet section is 9-feet long in the flue gas flow direction and the second and third sections are each 6-feet long. The total effective collecting plate surface area is 220,000 square feet for each precipitator.

Each precipitator has 1,036 discharge electrodes. Electrically, each unit consists of four sections in the gas flow direction, while there are only three mechanical. The high voltage, uni-directional, power supply for the discharge electrodes is supplied by silicon transformer-rectifier (T-R) sets. One electrical control unit is provided for each T-R set which senses spark rate, current, and voltage. The control unit maintains optimum current and voltage conditions automatically and limits the voltage and current to the T-R set rating. The collecting plates in each precipitator are cleaned of fly ash by means of 64 magnetic impulse, gravity impact rappers. The discharge electrodes of each precipitator are cleaned of fly ash by means of 32 magnetic impulse, gravity impact rappers. The precipitator control room is situated on the roof of each precipitator. Control panels for the existing precipitators occupy the entire control room, and no space is available for additional controls for additional precipitators. Fly ash from the precipitator hoppers are pneumatically transported to a dry ash storage bin. Flue-gas exit ducts from two precipitators and merge into a single duct that connects to the stack. The corresponding duct from the other boiler is connected to the other side of the stack.

B-2.5 EXISTING SO_2 CONTROL DESCRIPTION

The SO_2 emission control is the use of low sulfur subbituminous coal as fuel for the steam generators.

SECTION B-3
PLANT SURVEY FORM

B-3.1 COMPANY AND PLANT INFORMATION (1)

1. Company Name: Southern California Edison Company
2. Main Office: 2244 Walnut Grove Avenue, P.O. Box 800, Rosemead, California 91720
3. Plant Manager: Mr. R.S. Currie, Mgr. of Steam Generation
4. Plant Name: Mohave Generating Station
5. Plant Location: Clark County, Laughlin, Nevada 89046
6. Person to Contact For Further Information: Mr. Lee Brothers
7. Position: Senior Engineer
8. Telephone Number: (213) 572-1630
9. Date Information Gathered: April 23 - April 25, 1979
10. Participants in Meeting — Affiliation

Participants in Meeting	Affiliation
L. Brothers	SCE
N. Gonzalez	Pullman Kellogg
K. Hsiao	Pullman Kellogg
N. Master	Pullman Kellogg
R. Redman	Pullman Kellogg

B-3.2 PLANT DATA (APPLIES TO ALL BOILERS AT THE PLANT)

	Boiler No. 1	Boiler No. 2
Capacity, MW (net)	790	790
Service (Base,Peak)	Base	Base
FGD System Used?	No	No

B-3.3 BOILER DATA

1. Maximum Continuous Heat Input: 16,700 MM BTU/HR
   I. 8.35×10^9 BTU/HR
   II. 8.35×10^9 BTU/HR

1a. Maximum Heat Input: 16,700 MM BTU/HR

2. Maximum Continuous Generating Capacity (Gross) 820 MW
   (Net) 790 MW

3. Flue Gas Temperature: 270-300 (@ STACK) °F

4. Maximum Continuous Flue Gas Rate 4.2×10^6 ACFM @ 60°F
   I. 2.1×10^6 SCFM
   II. 2.1×10^6 SCFM

5. Flue Gas Analysis: Not Available

6. Flue Gas Recirculation
   For NO_x Control: YES_____ NO X

7. Boiler Manufacturer: C.E. (I,II)

8. Years Boilers Placed In Service: 1971 (I), 1971 (II)

9. Boiler Service (Base Load, Peak, etc.): Base

9a. Wet Bottom _____ Dry Bottom X

9b. Firing Type: PCTA

10. Stack Height Above Grade: 500 FT.

10a. Stack Diameter (ft.): 33' ID at Outlet

10b. Velocity Of Gas (Exit): 120 Ft/Sec at Full Load

10c. Exit Gas Temperature: 300°F

10d. Number of Liners/Boiler: One (One stack for two boilers)

11. Boiler Operations: Hours/Year (1977): (I) 6194, (II) 6872,

11a. Boiler Operations: Hours/Year @ Full Load: Not Available

12. Boiler Capacity Factor[a]:(I) 56.1%,(II) 66.1%

13. Boiler Operating Pressure: 3500 PSIG @ Turbine Inlet

---

[a]Defined as:

$$\frac{\text{KWH GENERATED IN YEAR}}{\text{(Net) Max Cont. Generating Capacity in KW} \times 8760 \text{ HR/YR}}$$

14. Boiler Superheat Heat Temperature: 1000 °F

14a. Boiler Reheat Temperature: 1000 °F

14b. Economizer B.F.W. Outlet Temperature: N/A °F

14c. Superheater ΔP = 200 psi

15. Ratio of Fly Ash/Bottom Ash = 70/30

16. Burners:

Type: Tilting Tangential

Manufacturer: C.E.

No. Per Unit: 80

Rating: 130.5 MM BTU/HR

Coal: 10,700 #/HR/Burner

Primary Air: 24.4 % of Total

Secondary Air: - % of Total

Tertiary Air: NONE % of Total

Total Excess Air: 15 % of Total

17. Fans [F.D. & ID]:

Type: FD, PA

Manufacturer: American Standard (FD), Westinghouse (PA)

No. Per Unit: 2-PA, 2-FD

Rating: 305,000 ACFM Each (PA), 125,000 ACFM (FD)

p: 32.5 (FD), 31.2 (PA) "H_2O

HP: FD 7000, PA 1750

18. Steam Temperature Control (Superheated & Reheated): By Burner Tilt, Attemporator Controls Superheated & Reheat Steam

Attemporator (Capacity): Not Available

19. Air Preheater:

Type: Ljungstrom Vertical Shaft, Regenerative
No.: 2/Boiler
Flue Gas ΔT: 425°F
Air ΔT 553°F (Secondary Air)/595°F (Primary Air)
Calculated Flow Rate: 4890M lbs/Hr per A.P. (Gas)
4360M lbs/Hr Air A.P. (Air)
Calculated ΔP 3.2" H_2O (Air Side)
Flue Gas Inlet Temp.: 730 °F

B-3.4 FUEL DATA

1. Coal Analysis (as received) (%):

	MAX.	MIN.	AVG.
S	----	----	0.5
Ash	----	----	1.0

2. Total Ultimate Analysis (wt%):

	As Received	Dry Basis	As Mined
S:	0.19	0.44	
Ash:	4.85	11.43	
N:	0.53	1.24	
Moisture:	57.59		12.70
C:	28.44	67.07	
O_2:	6.29	14.85	
H_2:	2.11	4.97	
HHV (BTU/LB):		12,200	12,200

B-3.5 ATMOSPHERIC EMISSIONS

1. Applicable Emission Regulations	Particulates	SO_2	NO_x
a) State of Nevada Current Requirements Max. Allowable Emissions Lb/MM Btu Input To Boiler	0.0675	0.6	NONE

2. Plant Program For Particulates: Cold Side ESP's
3. Plant Program For SO_2 Reduction: Use of Low Sulfur Coal
4. Plant Program For NO_x Reduction: No Overfire Air. Use of Tangential Burners

B-3.6 PARTICULATE REMOVAL

1. Type	Mech.	E.S.P.	FGD
Manufacturer...	-----	Research Cottrel	---
Efficiency: Design/Actual...		97.9/98.6	
Emission Rate Lb/Hr (Total)[a]		850	
Gr/SCFM...		0.24	
Lb/MM Btu...		0.05	
Specific Collection Area (ft^2/1000 ACFM) (Design/Operating):		191/143	
Total Collection Area: 440,000 Ft^2/Boiler			
Design Basis, Sulfur Content Of Fuel...		0.5 WT%	

[a]At maximum continuous load

2. Solids Collection System

Present Operating Condition: Bottom Ash Goes To Dewatering Bins and Then Trucked Away[a]
Closed Loop Bottom Ash[b]

At Maximum Capacity: YES X NO _____

Minimum Particulate Capturing Size: 1 Micron

Particulate Loading Into Collector: GR/Cu-Ft flue gas

Unburned Carbon %: N/A

B-3.7 FRESH WATER MAKE-UP FLOW RATES AND POINTS OF ADDITION

Steam Blowdown Rate[c]: None GPM

Availability of Blowdown: None GPM

C.W. Blowdown Rate[c]: N/A GPM

---

[a]Ash disposal area based on 35 years

[b]Flyash from ESP is pneumatically conveyed to storage silos, wetted down in the unloader & trucked away

[c]Available water source for future SO_2 wet scrubber

SECTION B-4
RETROFIT DESCRIPTION

B-4.1 NO_x EMISSION CONTROL

The retrofit work investigated for NO_x reduction involves installation of overfire air (OFA) ports and the associated tilt drive mechanisms, duct work, and control air dampers for each branch air duct to each OFA port. Also, a new NO_x control and monitoring instrument system would be required for each boiler unit. Based on discussions with Combustion Engineering, 20% excess air is recommended for boiler operation, and 20% of this total air is the design rate for the OFA. The air temperature at the inlet to the firebox is 635°F, and the pressure is estimated at 34.2" H_2O. The calculated required OFA per boiler is 672,540 ACFM. Using 200 feet per second for OFA jet velocity, 16 square OFA ports, each 22 1/2" x 22 1/2", are required. Two OFA ports are installed together at the top of each tangential burner set. The associated work required includes redesign of pressure ports, cutting the firebox wall, ductwork, and added air dampers. These items are shown in Table B-1. The locations of OFA ports are shown in Figure B-10.

B-4.2 PARTICULATE EMISSION CONTROL

The calculated number of modules for ESP and baghouse use, for particulate control, and the data related to these modules are shown in Table B-2.

TABLE B-1.- RETROFIT FOR NO_x REDUCTION

Units	#1 & #2
Boiler MW (MW/Boiler)	820
Boiler Manufacturer	C-E
Burners: Type	Tangential
Arrangement	
No. Burners/Vertical Column	10
No. of Burner Columns	8
Theoretical Air SCFM/Boiler	1,464,700
Excess Air %	20
Air Temp. At Preheater Outlet (°F)	635
TYPE OF RETROFIT	
1. Overfire Air (OFA)	Yes
% of OFA to Total Air	20
Total OFA ACFM	672,540
No. of OFA Ports	16
Size of OFA Port	H W 22 1/2" X 22 1/2"
Air ACFM per OFA Port	42,034
2. Curtain Air (C.A.)	N/A
% of C.A. to Total Air	"
Total C.A. ACFM	"
No. of C.A. Port	"
Size of C.A. Port	"
Air ACFM/C.A. Port	"
3. Low NO_x Burners	N/A
4. Compartmented Windbox	N/A

TABLE B-1.- RETROFIT FOR NO_x REDUCTION (Continued)

Units	#1 & #2
ASSOCIATED MODIFICATION WORK REQUIRED:	
Cutting of OFA Port	Yes
Cutting of C.A. Port	No
Removing & Modification of Membrane Wall Tubes/Boiler (Approximate No. of Tubes)	120
Windbox Modification	No
Duct Connection (Addition)	Yes
OFA Tilt Drive Mechanism	Yes
Control To Each OFA & C.A. Port	Yes

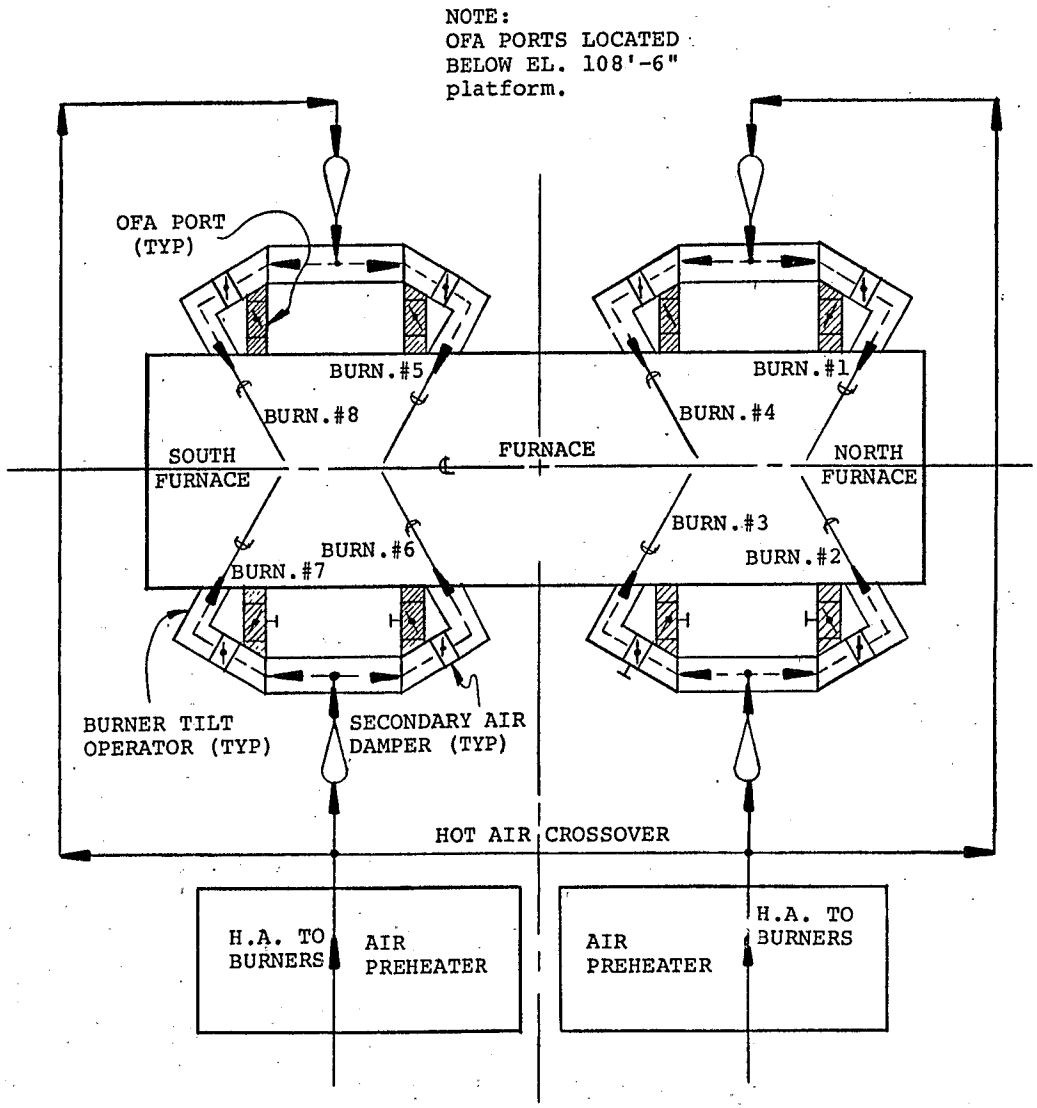

Figure B-10.- Location of OFA ports and ducts for a twin furnace Mohave boiler.

TABLE B-2.- RETROFIT DATA FOR ELECTROSTATIC PRECIPITATORS AND BAGHOUSES

Power Plant:	Mohave Power Generating Station
Boiler No.	#1 & #2
Gross MW/Boiler:	820
Flue Gas ACFM/Boiler:	
300°F	3,080,600
170°F	2,690,300[a]
125°F	2,486,300[b]
68°F	2,140,200[c]

Per Boiler	Cold Side ESP	Baghouse Wet Scrubbing	Baghouse Dry Scrubbing
Total Req'd Particulate Collection Area (FT^2)	3,080,600	1,540,300	1,345,150
Existing Collection Area (FT^2)	440,000	0	0
Collection Area to be Added (FT^2)	2,640,600	1,540,300	1,345,150
No. of ESP Trains	8	-	-
No. of ESP Modules/Train	10	-	-
Total No. of Modules to be Added	80	84	74
Total Area Added (F+2)	2,592,000	1,551,732	1,367,002

ESP Electrical Sectionalizing

Total No. of Electrical Sections Required Per 5 MW	164
Existing Electrical Sections	32
No. of Elec. Sec/New Module	2
Total No. of Elec. Sections Added	160
Total	192
MW/Section	4.27

[a] Includes water from dry scrubbing
[b] Includes water from wet scrubbing
[c] 2610 SCFM/MW @ 820 MW

SECTION B-5
RETROFIT COSTS

Retrofit capital and annualized costs are included in this section for the alternatives discussed in Section B-1. The total required plant investment costs given for each alternative do not include the costs of removing and/or relocating any existing equipment that may be associated with the particular retrofit alternative. The cost for land required for sludge disposal (from SO_2 removal) and the associated sludge transportion to the disposal site are not included in the retrofit plant investment or annualized operating costs. Also, the following cost items are realized but not included in the total retrofit capital and annualized costs:

(1) Site preparation
(2) Cost of down-time
(3) Additional stack lining, if flue gas desulfurization is installed

Working capital, the money required to operate the new equipment associated with the retrofit, has been calculated for each retrofit alternative.

TABLE B-3. CAPITAL INVESTMENT COSTS FOR RETROFITTING THE MOHAVE POWER PLANT MILLIONS OF THIRD QUARTER 1979 DOLLARS [a]

Cost Item	Alternative 1	2	2a	3
1. NO_x Control	4.54	4.54	4.54	4.54
2. Particulate Control	0	96.18	96.18	--[b]
3. SO_2 Control	234.30	234.30	191.11	205.00[b]
4. Emission Monitoring	0.73	0.73	0.73	0.73
5. Auxiliary Boiler	13.05	13.05	0	0
6. Replacement of Power Generating Capacity	60.04	71.39	58.05	28.98
7. Working Capital	23.28	27.92	22.85	17.32
TOTAL	335.94[c]	448.11[c]	373.46[c]	256.57[c]
Millions of Dollars Per Kilowatt of Gross Generating Capacity	205	273	228	156

(a) Includes direct and indirect costs.

(b) Costs for particulate and SO_2 control are combined.

(c) See Section 4.5 for other costs not estimated.

TABLE B-4. ANNUAL COSTS FOR RETROFITTING THE MOHAVE POWER PLANT - MILLIONS OF THIRD QUARTER 1979 DOLLARS PER YEAR [a]

Cost Item	Alternative 1	2	2a	3
1. NO_x Control	1.008	1.008	1.008	1.008
2. Particulate Control	0.000	18.563	18.563	- -[b]
3. SO_2 Control	91.898	91.898	71.616	68.060[b]
4. Emission Monitoring	0.226	0.226	0.226	0.226
TOTAL	93.132[c]	111.695[c]	91.413[c]	69.294[c]
Mills Per Kilowatt Hour of Net Power Generation (Current Net Less Retrofit Power Requirements at 65 Percent of Maximum Net Load)	10.3	12.5	10.1	7.5

(a) Includes fixed capital charges.

(b) Costs of Particulate and SO_2 control are combined.

(c) See Section 4.5 for other costs not estimated.

SECTION B-6

REFERENCES

1. Meeting notes - N. Gonzalez/N. Master, Pullman Kellogg - meeting with L.E. Brothers, Southern California Edison, Mohave Plant Site, 24 April 1979
2. Meeting notes - N. Gonzalez/N. Master, Pullman Kellogg - meeting with L.E. Brothers, et al, Southern California Edison and S. Cuffe/J. Copeland, EPA, 19 July 1979
3. Technical data for Mohave units 1 and 2 Electrostatic Precipitators, SCE, internal document
4. Drawing received from SCE Bechtel DWG 74212-17, Plot Plan, Rev 17, 3-19-79

APPENDIX C

EXAMPLES FOR RETROFITTING THE NAVAJO POWER STATION

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SECTION C-1
GENERAL

C-1.1 RETROFIT ALTERNATIVES

Four alternative examples for retrofitting the Navajo Power Plant were considered in this appendix to demonstrate the use of the methods developed in Section 3 of the report. Alternatives for the Units 1,2, and 3 boilers follows. Since the Navajo steam generators are designed for maximum NO_x control, no NO_x retrofitting is necessary. All alternatives include the installation of emission monitoring systems for opacity, SO_2, and NO_x.

Alternative 1 - Wet SO_2 scrubbing for 90% SO_2 removal is added to existing ESP's to provide 21 ng/J heat input (0.05 lb/10^6 Btu) particulate levels. Figure C-1 shows the plant general arrangement with the addition of the SO_2 scrubbing modules.

Alternative 2 - Alternative 2 upgrades the existing ESP collection area by adding of high-efficiency cold-side ESP's. Wet SO_2 scrubbing is also added. The resultant system provides 90% SO_2 removal and particulate emissions limitation to a leel of 13 ng/J heat input (0.03 lb/10^6 Btu). Figure C-2 shows the general arrangement when the SO_2 scrubbing and cold side ESP modules are included.

Alternative 2a - The retrofit for particulate control is the same as for Alternative 2. The wet SO_2 scrubbing is based on 70% SO_2 removal for cost comparison with semi-dry scrubbing of Alternative 3.

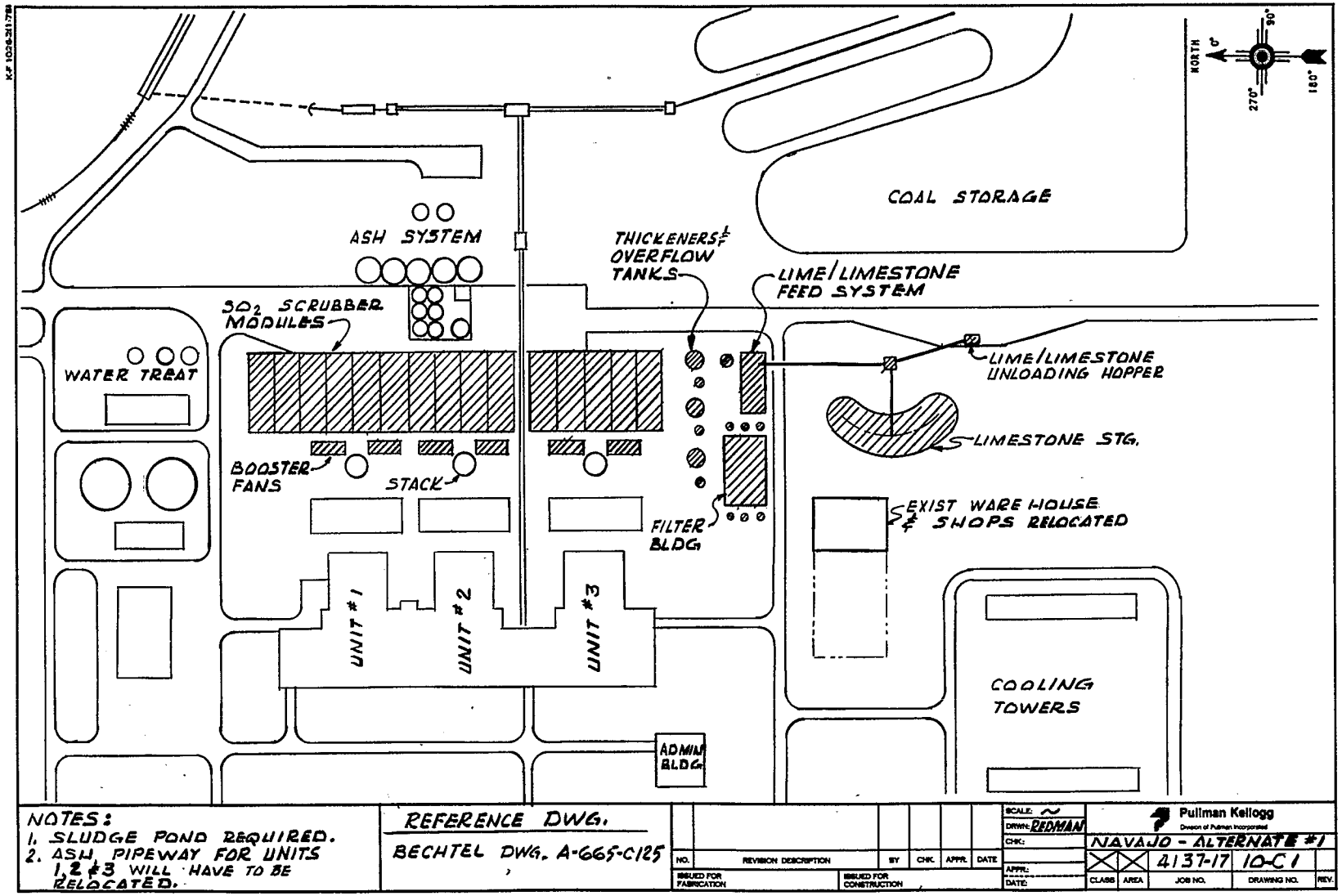

Figure C-1.- Addition of wet SO_2 scrubbing modules.

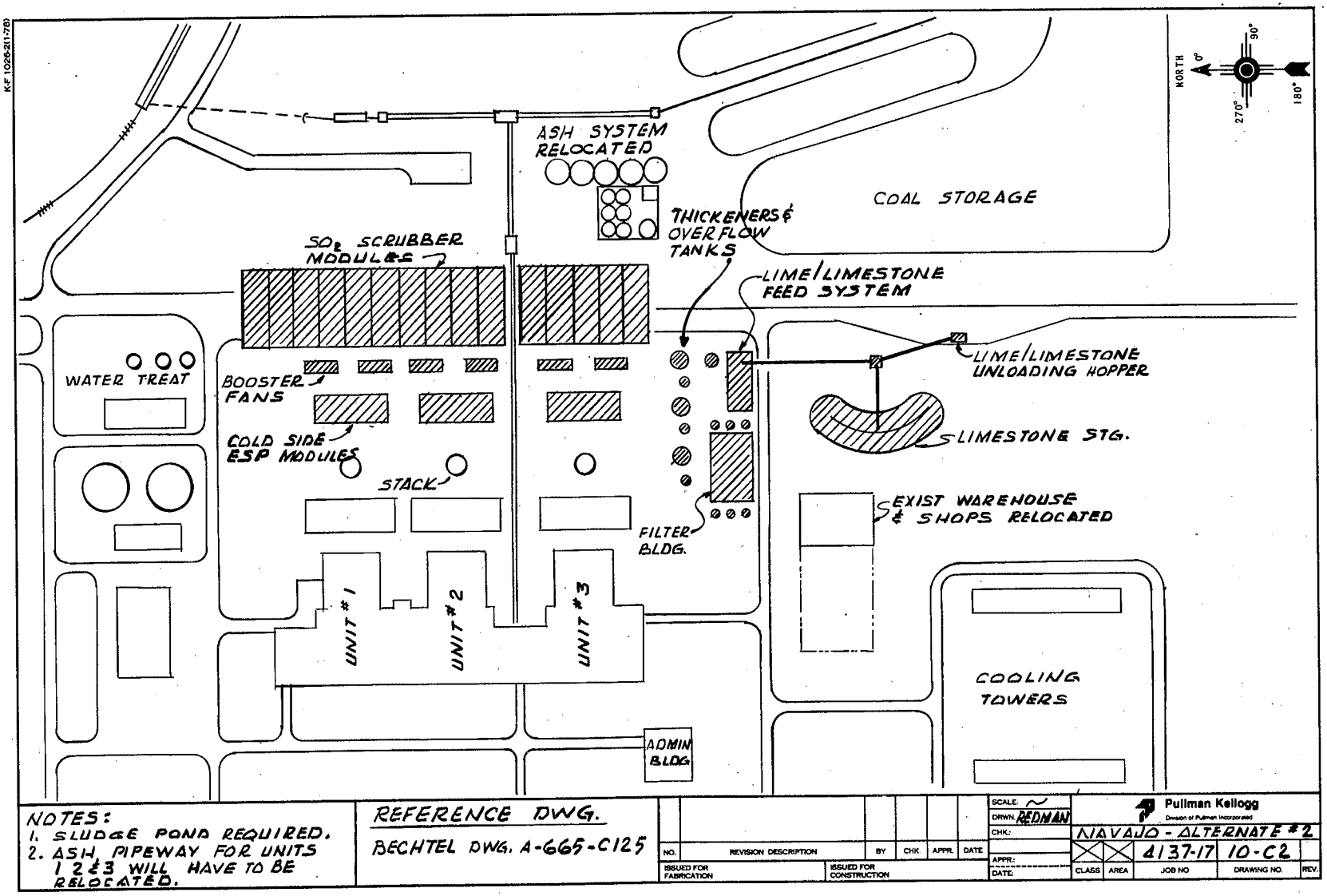

Figure C-2.- Addition of ESP's and SO_2 scrubbing modules.

Alternative 3 - Semi-dry SO_2 scrubbing (spray drying) to 70% SO_2 removal is provided for this option. By using baghouses as dry collectors with the existing ESP's. particulate emissions are controlled to a level of 0.03 lb/MM Btu. Figure C-3 shows the general arrangement plot plan with the addition of the SO_2 scrubbing modules and baghouses.

C-1.2 PLANT CHARACTERISTICS (1,2,3)

Characteristics of the plant site, existing equipment, and space requirements for retrofit are presented in the following list:

A. The Navajo Station is located on a 1021 acre tract of land.
B. Major revamp work to install the equipment for SO_2 and particulate control requires relocation of existing equipment.
C. The existing electrostatic precipitator is on the hot side of the air preheater system.
D. The existing ash disposal site is located on 765 acres about two miles east of the plant.
E. Each boiler has two primary-air (PA) fans, four forced-draft (FD) fans, and four induced-draft (I.D.) fans.
F. The number of SO_2 scrubbing modules used is based on the total calculated flue gas rate from each boiler.
G. One SO_2 scrubbing module per boiler is provided as a spare.
H. One flue gas reheater is required for each wet SO_2 scrubbing module for Alternatives 1 and 2.
I. One flue gas booster fan is provided per scrubbing module.

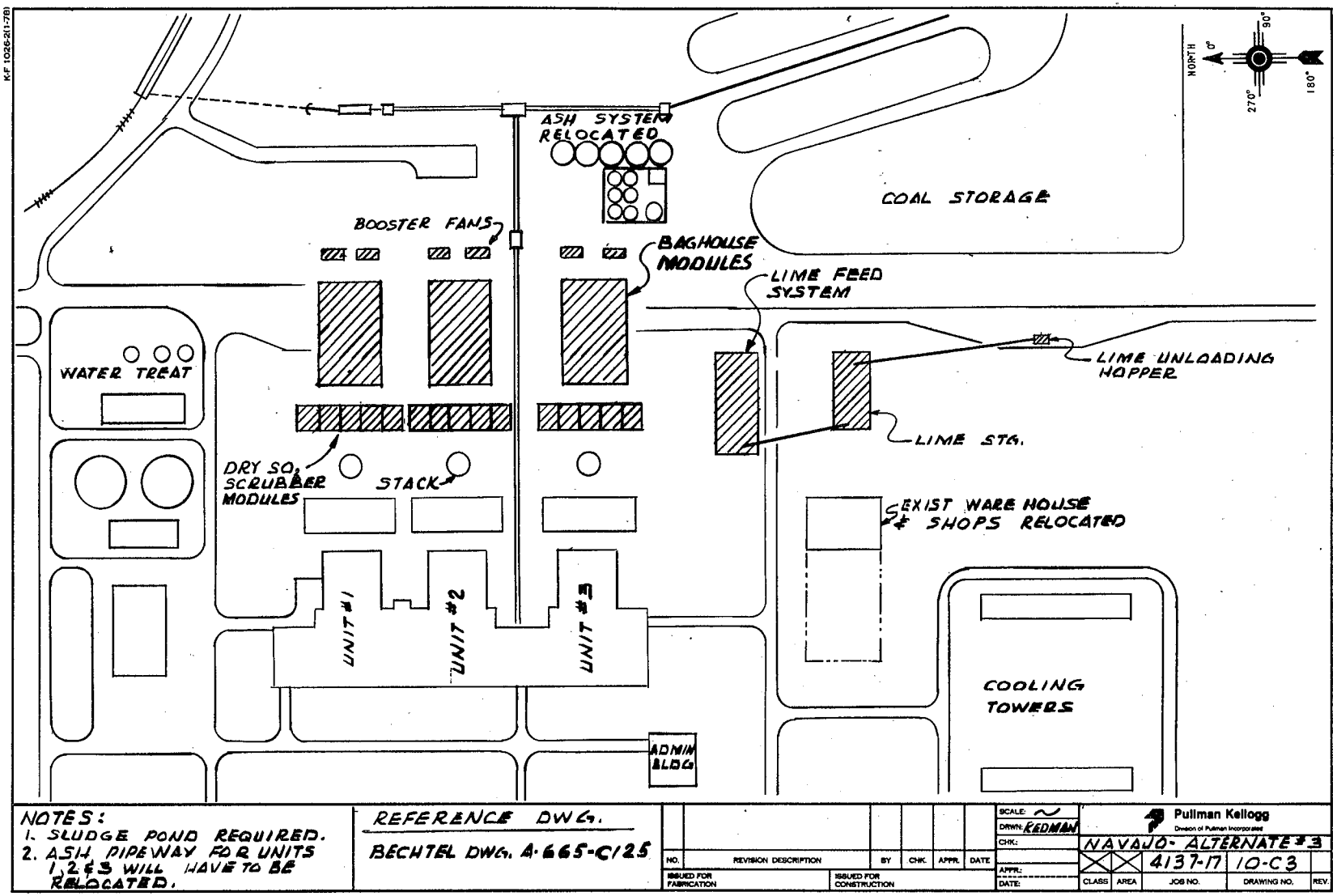

Figure C-3.- Addition of dry SO_2 scrubbing modules with baghouses.

J. The individual scrubbing modules are provided with dampers. This provision allows the individual modules to be isolated for maintenance.

K. Tie-in of retrofit equipment to the power plant is based on completion during normal power plant maintenance turn-arounds of 3 to 6 weeks.

L. An emergency bypass is provided around each SO_2 scrubbing system to allow operation of the boiler in the event of a major FGD malfunction. Bypassing of the particulate control equipment is not provided.

C-1.3 EQUIPMENT LOCATION CHANGES FOR RETROFITTING

Major revamp work to install the equipment for SO_2 and particulate control requires relocation of some existing buildings and/or systems. The requirements for the alternatives being considered are:

Alternative 1

1. Requires the relocation of the warehouse to a point some 300 yards south of the present location.

Alternatives 2 and 2a

1. Requires relocation of warehouse.

2. Requires relocation of ash settling and dewatering tanks, fly ash bins and associated auxiliary equipment now located in the ash unloading area. This would require extensive grade work to facilitate such a move. The area suggested would require an estimated 2,000,000 cubic yards of earth removal which is mostly rock. This would be in

addition to extensive modifications to the ash handling systems. It may be possible to totally redesign the ash system and avoid the excavation. The cost for work of this nature is not included in this study.

Alternative 3 -

1. Requires relocation of warehouse.

2. Requires relocation of ash unloading area, settling tanks, dewatering bins, fly ash bins and associated auxiliary equipment. This relocation has the same excavaton requirements as Alternative 2 and 2a.

No costs have been included for a sludge disposal area acquisition. This would probably require negotiations with the Navojo Tribe and could be very complicated and costly.

C-1.4 FLUE GAS DUCTING REQUIREMENTS

Bypass ducting and dampers are provided to enable the flue gas to go around the SO_2 scrubbing system. Bypass ducting is located for the three alternatives as indicated in the following paragraphs:

Alternative 1 - The bypass duct is taken from the plenum located between the ID fan and the booster fan. After bypassing the SO_2 scrubbing system, the bypass duct joins the duct to the stack. Figure C-4 shows the general arrangement of the scrubbing module and associated ducting with tie-ins to the existing breeching.

Alternative 2 - The bypass duct is taken after the cold side ESP's. Figure C-5 shows the general arrangement of the precipitators and SO_2 scrubbing modules including location of the emergency, SO_2 scrubbing system bypass.

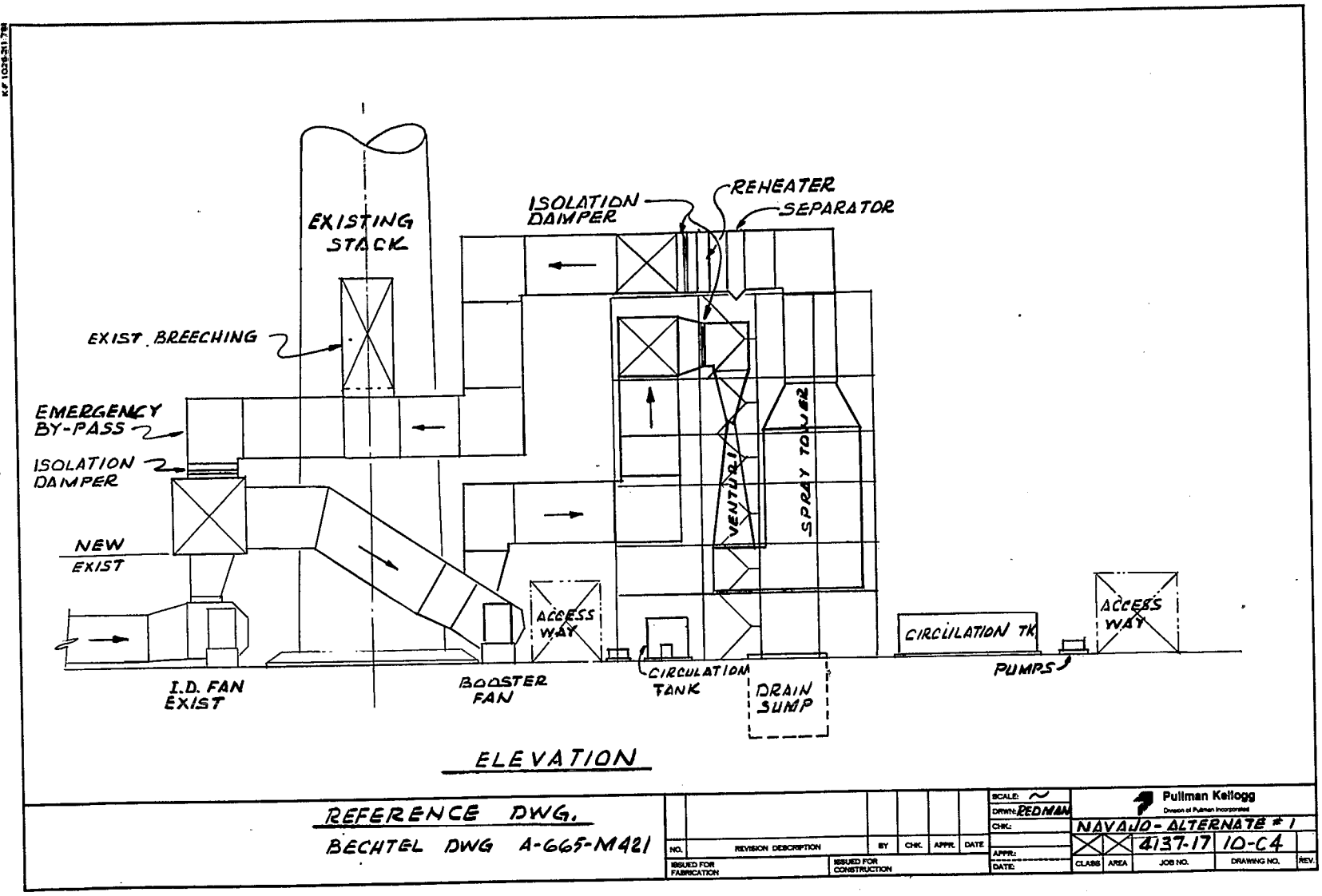

Figure C-4.- Arrangement of wet SO_2 scrubbing modules.

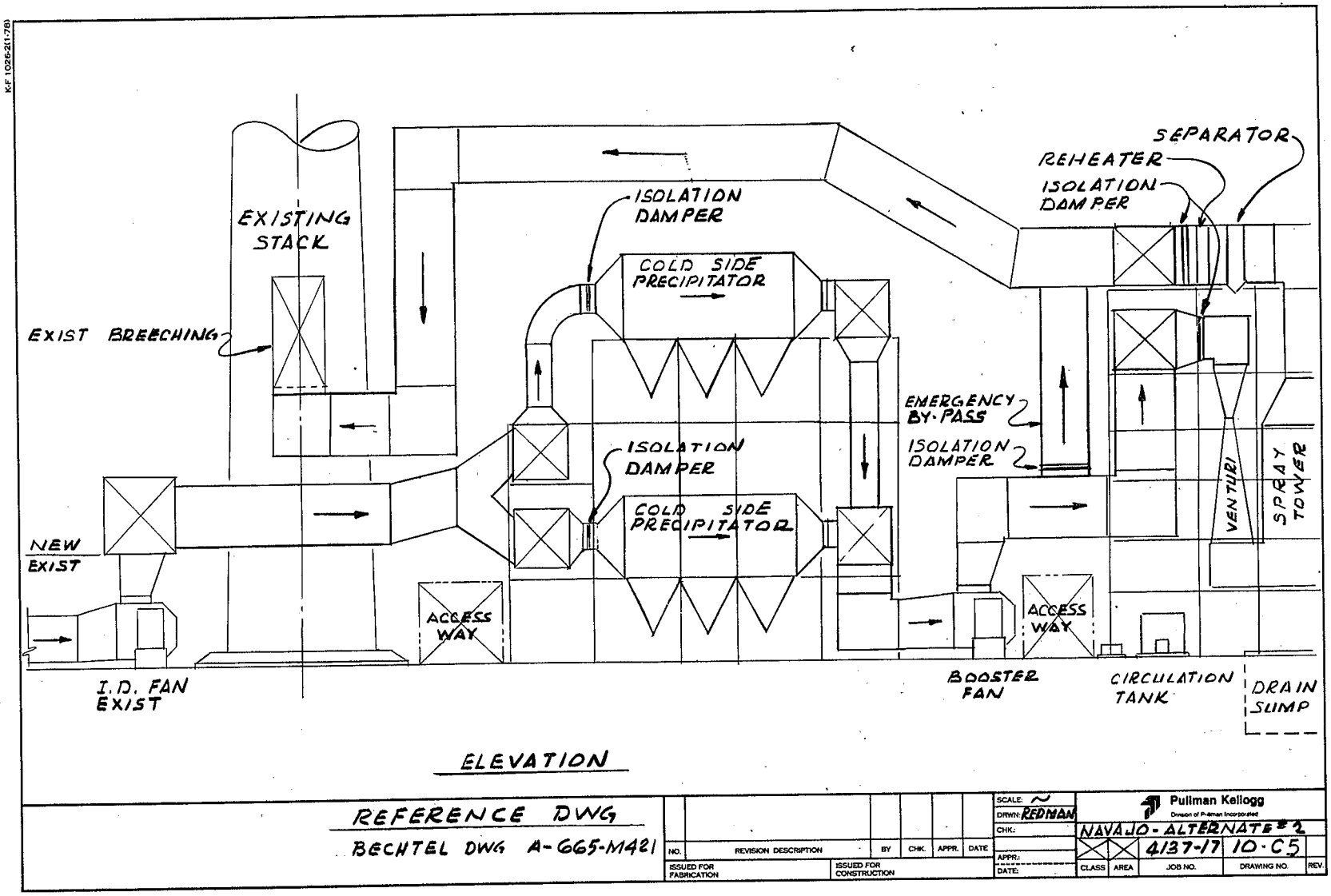

Figure C-5.- Arrangement of wet SO_2 scrubbing and ESP modules.

Alternative 2a - The bypass duct is arranged in the same manner as for Alternative 2. This duct can also be used during normal operation to divert about 22.2% of the total flue gas that does not require treatment, since the modules remove 90% SO_2 and this alternate requires only 70% SO_2 removal. The bypass duct also provides the flue gas requirements for reheat.

Alternative 3 - The bypass duct is taken ahead of the spray dryer and then ties into ducting to the baghouses. This location of the emergency bypass permits operation of the baghouses for particulate control when a spray dryer is out of service. Figure C-6 shows the general arrangement of the dry scrubbing module.

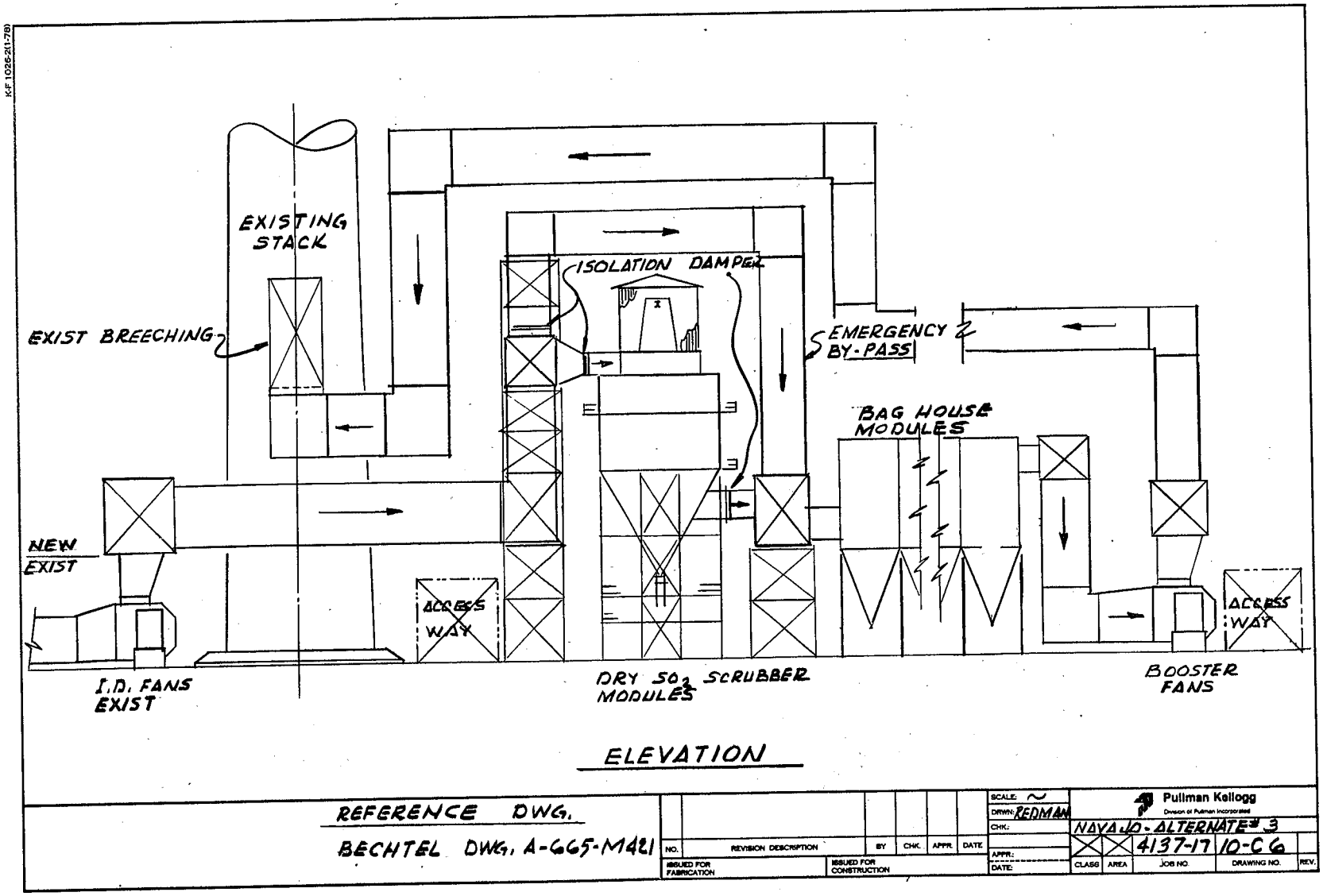

Figure C-6.- Arrangement of dry SO_2 and baghouse modules.

SECTION C-2
BACKGROUND DATA

C-2.1 PLANT DESCRIPTION (1,2)

The Navajo station is jointly owned by several governmental and private utilities. The station is operated by Salt River Project Agricultural Improvement and Power District (SRP).

Total plant capacity is 2250 MW (net) and 2415 MW (gross). The station consists of three 750 MW (net), 805 MW (gross), pulverized-coal-fired, supercritical-steam generating units manufacturered by Combustion Engineering (C.E.). The units use balanced draft systems.

A typical subbituminous coal burned at Navajo has a sulfur and ash weight percent of 0.5 and 10 to 12 respectively. The coal is mined, by Peabody Coal Company, in the Black Mesa area located in Northern Arizona. The coal feed rate to each boiler is in the range of 300-335 TPH (wet basis). The coal ash content varies with coal deliveries. At the present time ash content rejection point is 16 wt%.

Each boiler has a 775-foot high, 25-foot I.D. stack. The flue gas from each steam generator passes through a high efficiency (+99.5%) Joy-Western hot side electrostatic precipitator and is discharged to atmosphere from the stack at a velocity of about 100 ft/sec (at full load), and at a temperature of 300°F. Figure C-7 shows the general plot plan for the Navajo power station.

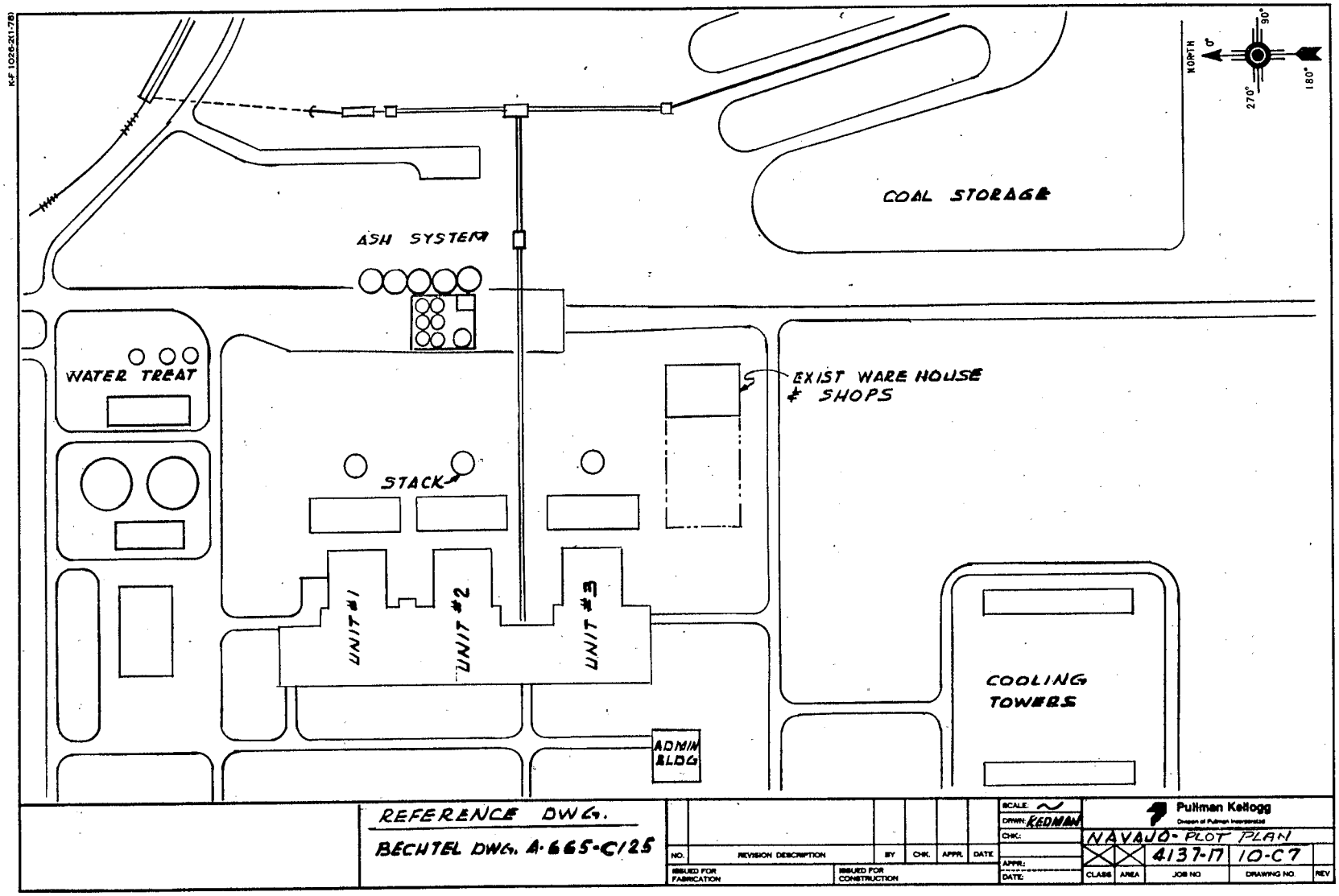

Figure C-7.- General plot plan of the Navajo power station.

C-2.2 STEAM GENERATOR DESCRIPTION (2,3)

The three Combustion Engineering boilers are equipped withr tilting tangential burners rated at 157.5 x 10^6 MM BTU/Hr/burner, and they are twin furnace designs. There are 56 burners per boiler. Each burner fires coal at a rate of 12,000 (maximum) and 11,428 (normal) lbs/hr. The total continuous heat input to the plant is 21,665.55 MM Btu/Hr with boilers I, II, III having 7,455.44, 6,789.21, and 7,420.9 MM BTU/Hr respectively. Each boiler is equipped for overfiring.

Each of the boilers has two primary-air (PA) fans, two forced-draft (FD) fans, and four induced-draft (ID) fans. The PA fans (Howden) are used for coal conveying, and they utilize about 15% of the total air. The FD and ID fans are manufacturered by Westinghouse. Each boiler has two vertical shaft, regenerative Ljungstrom air preheaters. The burner rating is 7.5 tons/hr. Each mill feeds coal to eight burners, and there are seven mills per boiler. The number of burners per boiler is 56. The coal feed rate per boiler is 300 to 335 tons per hour. The three C-E boilers are of dry bottom type with a Fly Ash/Bottom Ash ratio of 80/20. The bottom ash slurry is dewatered and is sent by truck to a disposal pond with 35 years of disposal capacity. Figure C-8 shows a schematic of the air, flue gas, and coal conveying provision for each boiler.

C-2.3 DESCRIPTION OF EXISTING NO_x CONTROLS

Presently, there are 16 overfire air ports on each boiler. The dimensions of the OFA ports is unknown. The OFA is presently set at minimum for air-flow cooling of the registers. Automatic control is available for opening the dampers. The current operation involves hand-loaded,

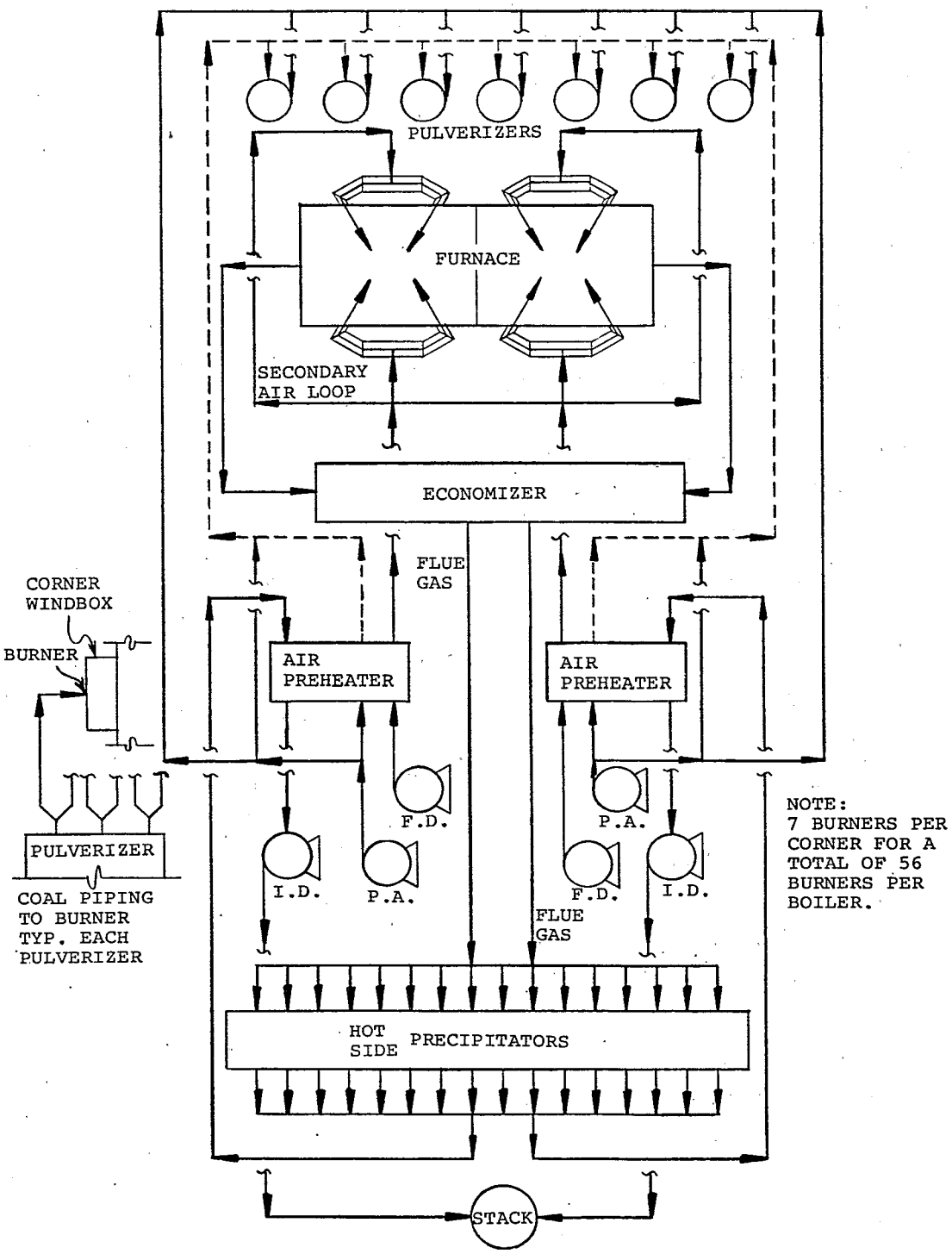

Figure C-8.- Schematic of air, flue gas, and coal conveying for the twin furnace Najavo boiler.

Bailey positioners for damper control of the OFA. Manual control is used for adjusting the tilt. One handwheel is provided for each OFA register. Tests conducted by SRP indicated no change in NO_x emission level when going from the minimum to the maximum openings of the OFA ports.

C-2.4 EXISTING PARTICULATE CONTROLS (2,3)

Each boiler is equipped with hot-side precipitators manufactured by Western Precipitators, a division of Joy Manufacturers. There are 16 mechanical flow sections, each containing 48 collection panels. There are 6 electrical sections for each mechanical section or a total of 96 electrical sections for each boiler. This is equivalent to 8.39 MW per electical section. The design efficiency of these precipitators is 99.5%. The specific collection area is 307 (design)/270 (operating) square feet per 1000 ACFM flue gas. The design basis for these ESP's is based on coal with a 0.5% (wt), sulfur content. The particulate emission rate, at maximum continuous load from these ESP's, is 468 lbs per hour per boiler, or 0.02 lbs per 10^6 Btu heat input (the designed emission rate). Total collection area per boiler is 1,209,600 ft^2. Controls for each precipitator includes the following items:

- A-C supply volt meter
- A-C current meter
- Spark rate meter
- D-C volt meter
- D-C current meter

There are 6 field monitors for each two chambers or a total of 48 monitors per boiler. Each monitor can ground out one chamber to take readings of one chamber and one field. This allows a read out of any one of the 96 fields per precipitator.

C-2.5 EXISTING SO_2 CONTROL DESCRIPTION

There are no current SO_2 emission controls except that low sulfur coal is used as fuel for the steam generators.

SECTION C-3
PLANT SURVEY FORM

C-3.1 COMPANY AND PLANT INFORMATION (1,2,3)

1. Company Name: Salt River Project
2. Main Office: P.O. Box 1980, Phoenix, Arizona 85001
3. Plant Manager: Mr. Harold Voeple
4. Plant Name: Navajo Generating Station
5. Plant Location: Page, Arizona 86040, Coconino County
6. Person To Contact For Further Information: Mr. John McNamara
7. Position: Associate General Manager-Power
8. Telephone Number: (602) 273-2851
9. Date Information Gathered: April 17 - April 20, 1979
10. Participants in Meeting — Affiliation

Participants in Meeting	Affiliation
Richard F. Durning	SRP
John R. McNamara	SRP
Donald W. Moon	SRP
Richard H. Silverman	SRP
Gregory T. Whalen	SRP
Norman Master	Pullman Kellogg
Nora Gonzalez	Pullman Kellogg
Ronnie Redman	Pullman Kellogg

C-3.2 PLANT DATA (APPLIES TO ALL BOILERS AT THE PLANT)

	BOILER NO. 1	BOILER NO. 2	BOILER NO. 3
CAPACITY, MW (NET)	750	750	750
SERVICE (BASE,PEAK)	BASE	BASE	BASE
FGD SYSTEM USED?	NO	NO	NO

C-3.3 BOILER DATA

1. Maximum Continuous Heat Input: 21,665.55 MM Btu/Hr
   I. 7,455.44 x 10^6
   II. 6,789.21 x 10^6
   III. 7,420.9 x 10^6

1a. Maximum Heat Input: 21,665.55 MM Btu/Hr

2. Maximum Continuous Generating Capacity (Gross) 805 MW
   (Net) 750 MW

3. Flue Gas Temperature: 300 (AT STACK) °F

4. Maximum Continuous Flue Gas Rate 9.34 x 10 ACFM @ 300°F

BOILER	I.	3.23 MMACFM @ 307°F
BOILER	II.	2.94 MMACFM @ 282°F
BOILER	III.	3.17 MMACFM @ 298°F

5. Flue Gas Analysis: Before Precipitator O_2 (3 - 3.5%)

6. Flue Gas Recirculation: Yes____ No X
   For NO_x Control

7. Boiler Manufacturer: C.E. (I,II,III)

8. Years Boilers Placed In Service: Initial Firing 1974 (I), 1974 (II), 1975 (III)

9. Boiler Service (Base Load, Peak, Etc.): Base Load
9a. Wet Bottom____ Dry Bottom X
9b. Firing Type PCTA

10. Stack Height above Grade: 775 ft. Per Boiler
10a. Stack Diameter (Ft.): 25' ID at Outlet
10b. Velocity Of Gas (Exit): 100-110 Ft/Sec at Full Load
10c. Exit Gas Temperature: 300°F
10d. Number Of Liners/Boiler: One (One stack per boiler)

11. Boiler Operations: Hours/Year (1978): (I) 7640, (II) 8077, (III) 7295
11a. Boiler Operations: Hours/Year @ Full Load: (I) 7640, (II) 8077, (III) 7295

12. Boiler Capacity Factor[b]: (I) 76.4%, (II) 82.1%, (III) 76.0%
13. Boiler Operating Pressure: 3800 PSIG @ Water Wall Outlets[a]

---

[a]Base Load - Operates @ 100% Capacity
[b]Defined as:

$$\frac{\text{KWH GENERATED IN YEAR}}{\text{(Net) Max Cont. Generating Capacity in KW x 8760 HR/YR}}$$

14. Boiler Superheat Heat Temperature: 1005 °F
14a. Boiler Reheat Temperature: 1002 °F
14b. Economizer B.F.W. Outlet Temperature: 631 °F @ Full Load
14c. Superheater delta P = 200 psi

15. Ratio of Fly Ash/Bottom Ash = 80/20

16. Burners [c]:

Type: Tilting Tangential
Manufacturer: Combustion Engineering (C.E.)
No. Per Unit: 56
Rating: 157.5×10^6 MM Btu/Hr
Coal: 15,000/11,428 #/Hr/Burner (Max./Normal)
7.5 T/HR/BURNER
Primary Air: 15 % of Total
Secondary Air: % of Total
Tertiary Air: None % of Total
Total Excess Air: 20 % of Total

17. Fans [F.D. & I.D.

Type: Square Cage (FD,PA,ID)
Manufacturer: Westinghouse (FD,ID), Howden (PA)
No. Per Unit: 2-PA, 4-FD, 4-ID
Rating:[d]
Regenerative Air Preheater Inlet = 10.80" H_2O
Regenerative Air Preheater Outlet = 5.50" H_2O
Windbox = 3.50" H_2O
Furnace = 0.0" H_2O
Draft At Regenerative Or Air Preheater Outlet = -14.90 H_2O

18. Windbox

Main: Equipped With Overfire Air
Branch: --
Control:--

19. Steam Temperature Control
(Superheated & Reheated)

Attemporator (Capacity): 216M lbs/hr for superheat temperature control; 4% MCR (Capacity) Feed Water To Firing Rate Ratio

---

[c] 7 Mills/Boiler 56 Burners = 300-335 TPH (Operating)
8 Burners/Mill
Each Mill 60 Tons/Hr (Design) [d]at Design Loads
[d] At design loads

20. Air Preheater

Type: Vertical Shaft, Regenerative Lungstrom
No.: 2/Unit
Flue Gas T = 398°F
Air T 507°F (Secondary)/534°F (Primary)
Design Flow Rate: 6.875M lbs/hr GAS 5,950M lbs/hr AIR
Design P 5.3" H_2O (Airside)
Flue Gas Inlet Temp.: 650 °F

C-3.4 FUEL DATA

1. Coal Analysis (as received)

	MAX.	MIN.	AVG.
S %	----	----	0.5 ----
Ash %	22	8	10

2. Total Ultimate Analysis (wt%)

S...	0.50
Ash...	10.43
N...	1.00
Moisture...	10.27
C...	61.29
O_2...	12.13
H_2...	4.37
Chlorine...	0.01
HHV (Btu/Lb)...	10,725

C-3.5 ATMOSPHERIC EMISSIONS

1. Applicable Emission Regulations

	PARTICULATES	SO	NO_x
a) Current Requirements Max. Allowable Emissions Lb/MM Btu Input To Boiler	0.1	1.0	0.7

2. Plant Program for Particulates: Hot Side ESP's

3. Plant Program For SO_2 Reduction: Use of Low Sulfur Coal

4. Plant Program For NO_x Reduction: C.E. Boiler with Tangential Firing and Overfire Capacity

C-3.6 PARTICULATE REMOVAL

1. Type

	MECH.	E.S.P.	FGD
Manufacturer...	-----	Joy Western[e,f]	------
Efficiency: Design/Actual...		99.5/98.5	
Emission Rate			
Average Lb/MM Btu...		0.06	
Specific Collection Area (ft^2/1000 ACFM) (Design/Operating):		307/270	

Total Collection Area: 1,209,600 SF

Design Basis, Sulfur Content Of Fuel... 0.5 WT% S

2. Solids Collection System:

Present Operating Condition:

[g]Bottom Ash Slurry to Dewatering Bins and Then Trucked Away To Disposal Area, Fly Ash Pneumatic Conveyed To Hopper (Truck 75 tons)

At Maximum Capacity... YES X NO
Minimum Particulate Capturing Size... 1 Micron
Unburned Carbon %: <0.03

C-3.7 FRESH WATER MAKE-UP FLOW RATES AND POINTS OF ADDITION:

Steam Blowdown Rate None GPM[h]
Availability of Blowdown None GPM
C.W. Blowdown Rate N/A GPM[h]

---

[e]At Maximum Continuous Load
[f]ESP-16 Sections (Chambers)/Unit (48 Panels/Unit), 96 Total Electrical Sections
[g]Ash Disposal Pond Based On 35 Years Life
[h]Available Water Source For Future SO_2 Wet Scrubber

SECTION C-4
RETROFIT DESCRIPTION

C-4.1 NO_x EMISSION CONTROL

The existing OFA ports require added automatic, tilt-drive mechanisms, tied to the burner tilt mechanism, for NO_x control. Twenty percent excess air is recommended with the OFA set at a flow rate of 20% of the total air. New NO_x monitoring systems will be installed for NO_x emission monitoring for each boiler.

C-4.2 PARTICULATE EMISSION CONTROL

The retrofit work to be done for particulate emission control is shown in Table C-1.

TABLE C-1.- RETROFIT DATA FOR ELECTROSTATIC PRECIPITATORS AND BAGHOUSES - UNITS 1, 2, AND 3

Power Plant:	Navajo Generating Station
Boiler No.	#1, 2 & 3
Gross MW/Boiler:	805
Flue Gas ACFM/Boiler:	
300°F	3,024,250
170°F	2,641,015
125°F	2,440,890
68°F	2,101,051

Per Boiler	Cold Side ESP	Baghouse Wet Scrubbing	Baghouse Dry Scrubbing
Total Req'd Particulate Collection Area (FT^2)	3,024,250	1,512,125	1,320,508
Existing Collection Area (FT^2)	1,209,600	0	0
Collection Area to be Added (FT^2) - Hot Side	1,814,650	1,512,125	1,320,508
No. of ESP Trains	8		
No. of ESP Modules/Train	7		
Total No. of Modules to be Added	56	82	72
Total Area Added - (F+2)	1,814,400	1,514,786	1,330,056

ESP Electrical Sectionalizing

Total No. of Electrical Sections Required Per 5 MW	161
Existing Electrical Sections	96
No. of Elec. Sec/New Module	2
Total No. of Elec. Sections Added	112
Total	208
MW/Section	3.87

SECTION C-5
RETROFIT COSTS

Retrofit capital and annualized costs are included in this section for the alternatives discussed in Section C-1. The total required plant investment costs given for each alternative do not include the costs of removing and/or relocating any existing equipment that may be associated with the particular retrofit alternative. The cost for land required for sludge disposal (from SO_2 removal) and the associated sludge transportion to the disposal site are not included in the retrofit plant investment or annualized operating costs. Also, the following cost items are realized but not included in the total retrofit capital and annualized costs:

(1) Site preparation
(2) Cost of down-time
(3) Additional stack lining, if flue gas desulfurization is installed

Working capital, the money required to operate the new equipment associated with the retrofit, has been calculated for each retrofit alternative.

TABLE C-2. - CAPITAL INVESTMENT COSTS FOR RETROFITTING THE NAVAJO POWER PLANT - MILLIONS OF THIRD QUARTER 1979 DOLLARS[a]

Cost Item	Alternative			
	1	2	2a	3
1. NO_x Control	0.00	0.00	0.00	0.00
2. Particulate Control	0.00	111.21	111.21	- -[b]
3. SO_2 Control	347.23	347.23	283.29	301.88[b]
4. Emission Monitoring	1.04	1.04	1.04	1.04
5. Auxiliary Boiler	19.21	19.21	0	0
6. Replacement of Power Generating Capacity	88.41	104.43	84.79	42.68
7. Working Capital	34.09	41.23	33.73	25.13
TOTAL	489.98[c]	624.35[c]	514.06[c]	370.73[c]
Dollars per Kilowatt of Gross Generating Capacity	203	259	213	154

(a) Includes direct and indirect costs

(b) Costs for particulate and SO_2 control are combined

(c) See Section 4.5 for other costs not estimated

TABLE C-3. ANNUAL COSTS FOR RETROFITTING THE NAVAJO POWER PLANT - MILLIONS OF THIRD QUARTER 1979 DOLLARS PER YEAR [3]

Cost Item	Alternative			
	1	2	2a	3
1. NO_x Control	0.000	0.000	0.000	0.000
2. Particulate Control	0.000	28.562	28.562	- [b]
3. SO_2 Control	136.064	136.064	106.077	100.222 [b]
4. Emission Monitoring	0.278	0.278	0.278	0.278
Total	136.342 [c]	164.904 [c]	134.917 [c]	100.500 [c]
Mills per Kilowatt hour of net generation (current net less retrofit power requirements at 65 percent of maximum net load)	10.3	12.5	10.2	7.43

(a) Includes fixed capital charges

(b) Costs of particulate and SO_2 control are combined

(c) See Section 4.5 for other costs not estimated

SECTION C-6

REFERENCES

1. Meeting notes - N. Gonzalez/N. Master, Pullman Kellogg - meeting with R.H. Silverman, et al, Salt River Project, Phoenix, Arizona, 16 April 1979
2. Meeting notes - N. Gonzalez/N. Master, Pullman Kellogg - meeting with G. Whalen, et al, Salt River Project, Page, Arizona, 17/18/19 April 1979
3. Letters from J.R. McNamara, Salt River Project to N. Master, Pullman Kellogg, 27 April, 17 May and 27 August, 1979
4. Meeting notes - N. Master/W. Talbert, Pullman Kellogg - meeting with J.O. Rich, et al, Salt River Project and J. Copeland, EPA, Phoenix, Arizona, 20 July 1979
5. Drawings received from SRP:
   Bechtel DWG A-665-C125 Site General Arrangement Plan, Rev 5, 7-8-74.
   Bechtel DWG A-665-M421 General Arrangement Section, Rev 6, 3-29-76

APPENDIX D

ANALYSIS OF FGD SYSTEM EFFICIENCY BASED ON EXISTING UTILITY BOILER DATA, PREPARED FOR EPA BY VECTOR RESEARCH, INCORPORATED

VRI-EPA7.3-FR79-1 OAQPS-78-1,VI-B-13

ANALYSIS OF FGD SYSTEM EFFICIENCY BASED ON EXISTING UTILITY BOILER DATA

R. FARRELL

T. DOYLE

N. ST.CLAIRE

NOVEMBER 1979

TECHNICAL REPORT

Prepared for
Office of Air Quality Planning and Standards
Emission Standards and Engineering Division
Environmental Protection Agency

VECTOR RESEARCH, INCORPORATED

Ann Arbor, Michigan

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1.0 INTRODUCTION AND SUMMARY

The Environmental Protection Agency (EPA) promulgated new standards of performance for electric utility steam generating units, on June 11, 1979. In addition to restricting the levels of pollutants that these units emit into the atmosphere, the standards require a 90 percent reduction in potential SO_2 emissions if they exceed 0.60 lb/million BTUs of heat input. On August 10, 1979, a petition for reconsideration of these standards was submitted to EPA by the Utility Air Regulatory Group (UARG).[1] Part of this petition requested that EPA reconsider the 90 percent removal requirement. This request was based on analyses performed by Entropy Environmentalists, Incorporated, which were documented in Appendix B of the UARG Petition entitled "A Statistical Evaluation of the EPA FGD System Data Base Included in the Subpart DA NSPS Docket". The analysis included a numerical simulation of 1,000 years of flue gas desulfurization (FGD) efficiency to examine the impact of the 90 percent efficiency standard promulgated by EPA.

Vector Research, Incorporated, (VRI) is under contract to EPA to provide statistical and analytical support to the Agency on an as needed basis. On November 1, 1979, VRI was tasked to simulate or otherwise analytically describe FGD system efficiency to permit examination of the questions raised by the Entropy findings. The primary purpose of the task was to determine the levels of system efficiency and variability in

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[1]Petition for Reconsideration, Docket Number OAQPS-78-1.

this efficiency that would be necessary to maintain at most one exceedence per year for a thirty-day rolling average on a 90 percent efficiency standard. The VRI simulation was to be based on analysis of data provided by EPA describing the efficiency of 11 flue gas desulfurization units and to additionally describe results over a wide range of facility parameters. The data analysis and simulation results were to be supplied to EPA within two weeks of initiation of the task. The authors were supported in this effort by Dr. Richard Cornell, a VRI associate, and other VRI staff.

This report presents the results of VRI's analysis activities and is organized into four chapters. This introductory chapter provides a description of the task and a summary of major results. The second chapter describes the results obtained concerning the behavior of various thirty-day averages for parametrically described FGD systems. The range of parameters used in generating these results was based in part on the statistical analysis of the data. This analysis is discussed in chapter three. The final chapter then discusses comparisons between VRI's results and those reported by Entropy Environmentalists, Incorporated.

The major conclusions of this analysis were as follows:

(1) The use of thirty-day moving averages of efficiency results in low-variability efficiency measurements at a facility, even when the daily data shows much larger variability. This results in averages which cluster much more closely around the central value of the efficiency measurements than do the daily efficiencies.

(2) Existing facilities show significant correlations in the efficiencies of sulfur removal on successive days. These autocorrelations, as well as the median levels of efficiency

and the fundamental variability of the process, influence the closeness with which thirty-day averages will remain clustered about their mean.

(3) The minimum long run average efficiency levels (described here in terms of the geometric mean) at which a facility must be operated in order that the ratio at which thirty-day rolling averages occur below 90, 89, 88, 87, 86, or 85 percent be held to one per year are shown in exhibit 1-1 for facilities with autocorrelations of 0.7 and various fundamental variability levels, some of which clearly represent good engineering and operating practice and some of which may not. Exhibit 1-2 shows similar data but for a failure rate of one failure per ten years. As the exhibits show, the rate of occurence of 30-day rolling averages below 90 percent would be above one per year for facilities wiht a 92 percent geometric mean efficiency and daily variaility anywhere from 0.20 to 0.60. These facilities would, however, have rates below one per year if the threshold were 89 percent and the daily variability were no greater than 0.26, or if the threshold were 88 percent and the daily variability was no greater than 0.32, or if the threshold were 87 percent and the daily variability was no greater than 0.38, or if the threshold were 86 percent and the daily variability was no greater than 0.43, or if the threshold were 85 percent and the daily variability was no greater than 0.48.

EXHIBIT 1-1: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER YEAR

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0068)	92.2	91.4	90.6	89.8	89.0	88.2
.21	(.0071)	92.3	91.5	90.7	89.9	89.2	88.4
.22	(.0075)	92.3	91.6	90.8	90.1	89.3	88.5
.23	(.0079)	92.4	91.7	90.9	90.2	89.4	88.7
.24	(.0082)	92.5	91.8	91.1	90.3	89.6	88.8
.25	(.0086)	92.6	91.9	91.2	90.4	89.7	89.0
.26	(.0090)	92.7	92.0	91.3	90.6	89.8	89.1
.27	(.0093)	92.8	92.1	91.4	90.7	90.0	89.3
.28	(.0097)	92.9	92.2	91.5	90.8	90.1	89.4
.29	(.0101)	93.0	92.3	91.6	90.9	90.2	89.5
.30	(.0105)	93.1	92.4	91.7	91.1	90.4	89.7
.31	(.0109)	93.2	92.5	91.9	91.2	90.5	89.8
.32	(.0112)	93.3	92.6	92.0	91.3	90.6	90.0
.33	(.0116)	93.4	92.7	92.1	91.4	90.8	90.1
.34	(.0120)	93.5	92.8	92.2	91.5	90.9	90.2
.35	(.0124)	93.6	92.9	92.3	91.6	91.0	90.4
.36	(.0128)	93.7	93.0	92.4	91.8	91.1	90.5
.37	(.0133)	93.8	93.1	92.5	91.9	91.3	90.6
.38	(.0137)	93.8	93.2	92.6	92.0	91.4	90.8
.39	(.0141)	93.9	93.3	92.7	92.1	91.5	90.9
.40	(.0145)	94.0	93.4	92.8	92.2	91.6	91.0
.41	(.0150)	94.1	93.5	92.9	92.3	91.7	91.2
.42	(.0154)	94.2	93.6	93.0	92.4	91 9	91.3
.43	(.0158)	94.3	93.7	93.1	92.6	92.0	91.4
.44	(.0163)	94.4	93.8	93.2	92.7	92.1	91 5
.45	(.0167)	94.4	93.9	93.3	92.8	92.2	91.7
.46	(.0172)	94.5	94.0	93.4	92 9	92.3	91.8
.47	(.0177)	94.6	94.1	93.5	93.0	92.5	91.9
.48	(.0182)	94.7	94.2	93.6	93.1	92.6	92.0
.49	(.0186)	94.8	94.2	93.7	93.2	92.7	92.2
.50	(.0191)	94.9	94.3	93.8	93.3	92.8	92.3
.51	(.0196)	94.9	94.4	93.9	93.4	92.9	92.4
.52	(.0201)	95.0	94.5	94.0	93.5	93.0	92.5
.53	(.0206)	95.1	94.6	94.1	93.6	93.1	92.6
.54	(.0212)	95.2	94.7	94.2	93.7	93.2	92.7
.55	(.0217)	95.2	94.8	94.3	93.8	93.3	92.9
.56	(.0222)	95.3	94.9	94.4	93.9	93.4	93.0
.57	(.0228)	95.4	94.9	94.5	94.0	93.6	93.1
.58	(.0233)	95.5	95.0	94.6	94.1	93.7	93.2
.59	(.0239)	95.5	95.1	94.7	94.2	93.8	93.3
.60	(.0245)	95.6	95.2	94.7	94.3	93.9	93.4

Facility autocorrelation = 0.7

[1]In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 1-2: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER TEN YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0068)	92.6	91.8	91.1	90.3	89.6	88.8
.21	(.0071)	92.7	91.9	91.2	90.5	89.7	89.0
.22	(.0075)	92.8	92.1	91.3	90.6	89.9	89.2
.23	(.0079)	92.9	92.2	91.5	90.8	90.1	89.3
.24	(.0082)	93.0	92.3	91.6	90.9	90.2	89.5
.25	(.0086)	93.1	92.4	91.7	91.0	90.4	89.7
.26	(.0090)	93.2	92.5	91.9	91.2	90.5	89.8
.27	(.0093)	93.3	92.7	92.0	91.3	90.7	90.0
.28	(.0097)	93.4	92.8	92.1	91.5	90.8	90.1
.29	(.0101)	93.5	92.9	92.2	91.6	90.9	90.3
.30	(.0105)	93.6	93.0	92.4	91.7	91.1	90.5
.31	(.0109)	93.7	93.1	92.5	91.9	91.2	90.6
.32	(.0112)	93.8	93.2	92.6	92.0	91.4	90.8
.33	(.0116)	93.9	93.3	92.7	92.1	91.5	90.9
.34	(.0120)	94.0	93.4	92.8	92.2	91.6	91.1
.35	(.0124)	94.1	93.5	93.0	92.4	91.8	91.2
.36	(.0128)	94.2	93.6	93.1	92.5	91.9	91.3
.37	(.0133)	94.3	93.8	93.2	92.6	92.0	91.5
.38	(.0137)	94.4	93.9	93.3	92.7	92.2	91.6
.39	(.0141)	94.5	94.0	93.4	92.9	92.3	91.8
.40	(.0145)	94.6	94.1	93.5	93.0	92.4	91.9
.41	(.0150)	94.7	94.2	93.6	93.1	92.6	92.0
.42	(.0154)	94.8	94.3	93.7	93.2	92.7	92.2
.43	(.0158)	94.9	94.4	93.8	93.3	92.8	92.3
.44	(.0163)	95.0	94.4	93.9	93.4	92.9	92.4
.45	(.0167)	95.0	94.5	94.0	93.5	93.1	92.6
.46	(.0172)	95.1	94.6	94.1	93.7	93.2	92.7
.47	(.0177)	95.2	94.7	94.2	93.8	93.3	92.8
.48	(.0182)	95.3	94.8	94.3	93.9	93.4	92.9
.49	(.0186)	95.4	94.9	94.4	94.0	93.5	93.1
.50	(.0191)	95.5	95.0	94.5	94.1	93.6	93.2
.51	(.0196)	95.5	95.1	94.6	94.2	93.7	93.3
.52	(.0201)	95.6	95.2	94.7	94.3	93.9	93.4
.53	(.0206)	95.7	95.3	94.8	94.4	94.0	93.5
.54	(.0212)	95.8	95.3	94.9	94.5	94.1	93.7
.55	(.0217)	95.8	95.4	95.0	94.6	94.2	93.8
.56	(.0222)	95.9	95.5	95.1	94.7	94.3	93.9
.57	(.0228)	96.0	95.6	95.2	94.8	94.4	94.0
.58	(.0233)	96.1	95.7	95.3	94.9	94.5	94.1
.59	(.0239)	96.1	95.8	95.4	95.0	94.6	94.2
.60	(.0245)	96.2	95.8	95.5	95.1	94.7	94.3

Facility autocorrelation = 0.7

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

The rates would be below one occurence per ten years for combinations of thresholds and daily variabilities as follows:

Threshold	Daily Variability
89%	no greater than 0.21
88%	no greater than 0.27
87%	no greater than 0.32
86%	no greater than 0.37
85%	no greater than 0.41

Data for auto correlations other than 0.7 can be found in the body of the report.

(4) There is very little change in these estimates of minimum efficiencies when the assumptions concerning the type of statistical distribution used to represent the efficiency data are varied. Both normal and lognormal distributions provide reasonable fits to the existing daily efficiency data, with the lognormal probably slightly better than the normal. (Because the lognormal distribution appears to fit the data better than the normal, it has been used in generating exhibits 1-1 and 1-2, and in general throughout the analyses.) Both distributional assumptions produce very similar results in terms of the predicted behavior of thirty-day averages taken on a rolling basis.

These conclusions, as well as many other observations, are discussed in more detail in the body of this report.

2.0 PREDICTED BEHAVIOR OF THIRTY DAY AVERAGES OF EFFICIENCY

This chapter describes the main results of this analysis. The principal question of interest is the behavior of thirty-day moving averages of efficiency, and specifically the rate at which such averages would dip below selected thresholds. The behavior of the moving or rolling average was examined for various true (average) efficiencies, variabilities, and time dependencies.

In a setting where penalties could be imposed when such averages fell below a regulatory threshold, EPA would expect to set the threshold level so that facilities designed, constructed, and operated in accordance with good engineering practice would produce very infrequent threshold crossings, while facilities not in accord with good engineering practice would show averages below the threshold on a more frequent basis. That is, the threshold should correspond to some value approximately at the minimum expected to be seen regularly from well-engineered and operated facilities. This analysis is not designed to analyze what levels of performance correspond to good engineering practice, but to show the relation between the operating characteristics of a facility and the rates at which various threshold values of thirty-day averages would be crossed. This information can then be combined by EPA with expert knowledge of the achievable levels of engineering and operating performance in designing regulatory policies.

Although the precise method of computing the thirty-day average might vary somewhat, this analysis has assumed that a daily average efficiency is generated each day from more frequent measurements of emissions, and that these daily averages are then averaged for a period

of thirty days. Such thirty-day averages might be computed each day, each week, each month, or at any other frequency, based on the thirty-day period ending with the computation day. The behavior of averages at various computation frequencies will be discussed. We believe that this general scheme contains most policies of interest. In the case of possible changes in the precise methods of computing averages from hourly or more frequent data, the analysis encompasses policies with essentially the same effects as those which might be adopted. All the analyses have assumed that data would be available for each day of operations.

In order to predict the behavior of the averages involved, assumptions must be made about several basic properties of the measurements of scrubbing efficiency at a facility. These assumptions concern the long-run level of scrubbing efficiency achieved, the type and amount of daily variability which will be observed, and any temporal patterns or correlations which might be expected in the observed efficiency.

Before presenting any numerical analyses of the issues, it is necessary to define the various types of measurements which were used in describing and analyzing the process. The level of scrubbing efficiency achieved will be discussed in terms of several different related quantities. For some purposes, it is necessary to consider the measured <u>daily efficiency</u>: this quantity is produced by reducing more frequent measurements of inlet and outlet sulfur concentrations to a daily efficiency figure. These measurements may also be considreed in terms of the equivalent measurements of <u>emissivity</u>, which is 1-efficiency, so that an efficiency of 90 percent corresponds to an emissivity of 10 percent.

Daily efficiency or emissivity measurements (which were the basic data used in the detailed data analyses of actual facilities, as

described in chapter 3.0, and which also form a basis in terms of which all these analyses were conducted) are observed to vary when measured repeatedly at a single facility. This variation is stochastic or probabilistic, rather than deterministic, in nature. That is, the exact measurement which will be obtained at some future time is not completely determined from our knowledge of the process, but includes elements of randomness.

Describing the randomness in the daily measurements involves describing the distribution of the daily measurements (that is, the frequencies with which the measurement takes on various values) and the interrelations among the daily measurements for different days. The distribution of the daily measurements is typically described in terms of a measure of the center of the measurements observed (such as the mean, the geometric mean, or the median) a measure of the variability of the measurements about this center (such as the standard deviation or geometric standard deviation), and the particular shape or type of distribution which descirbes the variability (such as the normal or lognormal distribution). The interrelationships between measurements on various days are typically measured in terms of the correlation between measurements on successive days.

The mean (sometimes called the arithmetic mean) of the measurements is simply the long-run average of the measurements. The geometric mean is the value which would be obtained by taking the antilogarithm of the mean of the logarithms of the measurements. The geometric mean of measurements is always less than the arithmetic mean, no matter how the measurements are distributed. The median of measurements is the value such that 50 percent of the measurements are above it and 50 percent

below. The standard deviation of measurements is the root-mean-square average of the deviations of the measurements about their own mean. The geometric standard deviation is the root-mean-square average of the deviations of the logarithms of the measurements about the mean of the logarithms. The correlation (or autocorrelation), of a sequence of measurements varies between -1 and +1. a correlation of +1 indicates perfect correlation -- that is, in our case, successive measurements at a single facility would be identical. A correlation of 0 indicates no dependence between successive measurements. Correlations below 0 indicate that high measurements are followed by low and low by high.

All of these terms may be applied to any sequence of measurements. In the specific problem at hand, they may be applied to daily efficiency measurements, daily emissivity measurements, or thirty-day averages of either. Generally, daily efficiencies are discussed in this analysis in terms of the geometric mean emissivity (or the equivalent efficiency) and the geometric standard deviation of emissivity. This geometric standard deviation may be thought of as a percentage variability in the measurements so that a geometric standard deviation of 0.20 would indicate a daily variation of about 20 percent of the daily mean. These scales of measurement were chosen because they were those which had been used in past studies of the same general topics. The thirty-day averages are typically discussed in terms of the frequencies with which particular levels of emissivity would be exceeded by the thirty-day averages or in terms of their mean and standard deviation (arithmetic, not geometric).

2.1 SCOPE OF ANALYSES

In the specific problem at hand, the evidence supports the use of a model in which observed dependencies in sequences of efficiency measurements are viewed as produced by correlations between immediately successive days. The evidence on this point is discussed in the next chapter. In such a model (an autoregressive model of lag one) the only correlation parameter required to describe the pattern is the basic correlation between the observations on successive days. All other dependencies are then computable from this correlation coefficient. In terms of these parameters, the region of the parameter space examined in this analysis was:

(1) Long-run geometric mean emissivities of six percent to nine percent, with particular attention to the value of eight percent, corresponding to a 92 percent efficiency.[1]

(2) Daily geometric standard deviations of 0.20 to 0.50 and distributions of measurements described by a probability distribution of emissivities similar to the lognormal or normal distribution, probably having more similarity to the lognormal (see chapter 3.0). It must be remembered that these daily variabilities in emissivity lead to much smaller variabilities in the thirty-day-efficiency. For example, a typical facility with daily emissivities of the order of nine percent with a

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[1]Although the 92 percent figure is not the geometric mean efficiency but the efficiency corresponding to the geometric mean of emissivity, we will, when approoriate, refer to such values as geometric means without intending to mislead.

50 percent variability would have daily efficiencies of 91 percent, with a daily error of 4.5 percent, and thirty-day average efficiencies of about 91 percent with a variability of only about one percent.

(3) Day-to-day correlations between successive observations of 0.0 to 0.7.

The results of this analysis address three topics:

(1) The average number of times per year that thirty-day average efficiencies, computed daily (360 times per "year"), would be below various thresholds as a function of the facility operating parameters assumed.

(2) The minimum long-run level of efficiency which a facility would have to maintain to limit its average threshold crossings on the same rolling average to one per year, one per two years, one per five years, or one per ten years as a function of the level of variability and correlation of daily observations at the facility. These efficiencies are presented in terms of geometric means, keeping the method of description for all daily data consistent. At these levels, the long-run rate of excessive emissivity measured in terms of thirty-day rolling averages, would be held to the one per year or other rate as given. The actual number of excesses in a specific year would, of course, vary, so that at a rate of one per year, some years would have two, for example, and others zero.

(3) The potential effects of changing the frequency of computation of the averages on the rate at which threshold crossing would occur.

Following the presentation of these results, a very brief section discusses the methods of computation used to generate the estimates.

2.2 ANALYSIS RESULTS

The most basic and fundamental results of this analysis simply describe the mean, standard deviation, and distribution of the thirty-day averages as functions of the elementary process parameters describing the level of efficiency, the variability of the daily observations, and the autocorrelation. Exhibit 2-1 shows the means and standard deviations of the thirty-day rolling averages for a sampling of parameter values in the region examined. Several observations can be made from that data. The most basic is simply that the mean efficiency is different than the efficiency level described by the geometric mean emissivity. This difference simply reflects the differences in meaning between the mean and the geometric mean. The difference would remain even if the data had beem normally distributed: the geometric mean of a normally-distributed datum is not identical to its mean, and the relation between the two values in the parameter region of interest is almost precisely the relation between the same parameters in the lognormal distribution.

A second observation is that the variabilities of the thirty-day averages are much lower than the variabilities of the daily data. This reduction in variability is the basic reason why taking averages of sequences of observations is useful in obtaining consistent estimates of actual performance levels. The third observation which can be made from the exhibit is that both the mean and the standard deviation of the thirty-day averages are clearly influenced by the variability and autocorrelation in the efficiency process, as well as by the level of efficiency.

EXHIBIT 2-1: MEAN AND STANDARD DEVIATION OF 30-DAY AVERAGES

Process Parameters			Thirty-Day Average	
Geom. Mean	Geom. Std. Dev.	Autocor.	Mean	Std. Dev.
.9100	.2000	0.0000	.9082	.0034
.9100	.2000	.3000	.9082	.0045
.9100	.2000	.5000	.9082	.0057
.9100	.2000	.7000	.9082	.0075
.9100	.3000	0.0000	.9059	.0053
.9100	.3000	.3000	.9059	.0070
.9100	.3000	.5000	.9059	.0088
.9100	.3000	.7000	.9059	.0118
.9100	.4000	0.0000	.9025	.0074
.9100	.4000	.3000	.9025	.0098
.9100	.4000	.5000	.9025	.0122
.9100	.4000	7000	.9025	.0163
.9100	.5000	0.0000	.8980	.0099
.9100	.5000	.3000	.8980	.0130
.9100	.5000	.5000	.8980	.0162
.9100	.5000	.7000	.8980	.0215
.9200	.2000	0.0000	.9184	.0030
.9200	.2000	.3000	.9184	.0040
.9200	.2000	.5000	.9184	.0051
.9200	.2000	.7000	.9184	.0068
.9200	.3000	0.0000	.9163	.0047
.9200	.3000	.3000	.9163	.0063
.9200	.3000	.5000	.9163	.0078
.9200	.3000	.7000	9163	.0105
.9200	.4000	0.0000	.9133	.0066
.9200	.4000	.3000	.9133	.0087
.9200	.4000	.5000	.9133	.0109
.9200	.4000	.7000	.9133	.0145
.9200	.5000	0.0000	.9093	.0088
.9200	.5000	.3000	.9093	.0116
.9200	.5000	.5000	.9093	.0144
.9200	.5000	.7000	.9093	.0191
.9300	.2000	0.0000	.9286	.0026
.9300	.2000	.3000	.9286	.0035
.9300	.2000	.5000	.9286	.0044
.9300	.2000	.7000	.9286	.0059
.9300	.3000	0.0000	.9268	.0041
.9300	.3000	.3000	.9268	.0055
.9300	.3000	.5000	.9268	.0068
.9300	.3000	.7000	.9268	.0092
.9300	.4000	0 0000	.9242	.0058
.9300	.4000	.3000	.9242	.0076
.9300	.4000	.5000	.9242	.0095
.9300	.4000	.7000	.9242	.0127
.9300	.5000	0.0000	9207	.0077
.9300	.5000	.3000	.9207	.0101
.9300	.5000	.5000	.9207	.0126
.9300	.5000	.7000	.9207	.0167
.9400	.2000	0.0000	.9388	.0023
.9400	.2000	.3000	.9388	.0030
.9400	.2000	.5000	.9388	.0038
.9400	.2000	.7000	.9388	.0051
.9400	.3000	0.0000	.9372	.0035
.9400	.3000	.3000	.9372	.0047
.9400	.3000	.5000	.9372	.0059
.9400	.3000	.7000	.9372	.0078
.9400	.4000	0.0000	9350	.0049
.9400	.4000	.3000	.9350	.0065
.9400	.4000	.5000	.9350	.0082
.9400	.4000	.7000	.9350	.0109
.9400	.5000	0.0000	.9320	.0066
.9400	.5000	.3000	.9320	.0087
.9400	.5000	.5000	.9320	.0108
.9400	.5000	.7000	.9320	.0143

Additional analyses not easily presented in tabular form addressed the shape of the distribution of the thirty-day rolling averages. Questions had been raised about whether these averages would be distributed normally. The distribution was found to be very nearly, although not exactly, normal. Although the averages were much more nearly normal than the approximately lognormal daily measurements, all of the analyses took account of the remaining non-normality; no results were based on normal approximations.

The data in exhibit 2-1 was presented in terms of facility operating parameters which were simply chosen to sample the region of greatest interest. The actual values of the basic process parameters are available for some experiments at specific facilities. Exhibit 2-2 shows the parameters describing the processes at these facilities. The actual statistical analysis of the data to produce these estimates of the parameters is described in chapter 3.0. Exhibit 2-3 shows the means and standard deviations of thirty-day average efficiency observations which would be expected if a new facility with a 92 percent geometric mean efficiency had the same operating conditions (process variability and autocorrelation) as with each of the individual existing facilities.

As can be seen in these exhibits, there is considerable variation among the results at the individual sites. There cannot be a strictly statistical decision as the degree to which any particular site represents good engineering and operating practices, state-of-the-art systems, well-calibrated and maintained measuring equipment, and otherwise is appropriate for use in extrapolations to future facilities. Any analyses of these issues must be made by engineers rather than statisticians. Accordingly, the remaining analyses of the behavior of the thirty-day

EXHIBIT 2-2: PROCESS PARAMETERS OF ACTUAL FACILITIES

Unit	Geometric Mean	Geometric Standard Deviation	Auto-Correlation
Louisville North	84.4	.295	.6955
Louisville South	83.3	.343	.6949
Pittsburgh I	80.8	.234	.4683
Pittsburgh II	85.4	.212	-.1428
Philadelphia	97.0	.359	.2524
Chicago	89.2	.118	.6983
Shawnee TCA	88.5	.182	.5995
Shawnee Venturi	96.0	.368	.8897
Conesville A	86.0	.447	.7131
Conesville B	92.5	.474	.6255
Lawrence	95.4	.835	.6386

EXHIBIT 2-3: THIRTY-DAY AVERAGE MEAN AND STANDARD DEVIATION FOR 92%-EFFICIENT FACILITIES WITH VARIABILITY AND AUTOCORRELATION OF ACTUAL FACILITIES

Variability and Autocorrelation from:	Mean	Standard Deviation
Louisville North	91.64%	1.03%
Louisville South	91.52%	1.22%
Pittsburgh I	91.78%	0.57%
Pittsburgh II	91.82%	0.32%
Philadelphia	91.47%	0.73%
Chicago	91.94%	0.39%
Shawnee TCA	91.87%	0.52%
Shawnee Venturi	91.44%	2.05%
Conesville A	91.16%	1.66%
Conesville B	91.05%	1.48%
Lawrence	88.70%	3.70%

average processes will continue to be presented, as was the initial material in exhibit 2-1, in general parametric terms. The appropriate cases from these parametric results may then be selected by engineers to be used in any further analyses.

In using the parametric results, it may be appropriate to examine the expected behavior of processes with one or more parameters equal to those of specific existing facilities (as was done in generating exhibit 2-3), or to consider the fact that the measurements from existing facilities are from finite, and generally fairly limited, data samples, and to consider the possible errors in estimation which may be present. When this second technique is used, it may be of interest to know that the Shawnee TCA and Pittsburgh II (taken together, assuming that their true long-run levels of variability are identical as the data suggests) have a 95 percent confidence interval on the long-run geometric standard deviation running from 0.16 to 0.23, and that Lousiville North and South taken together have a 95 percent confidence interval from 0.29 to 0.36. (The corresponding 99 percent intervals are from 0.15 to 0.25 for Shawnee TCA and Pittsburgh II and 0.28 to 0.38 for the Louisville facilities.)

Exhibit 2-4 shows the rate (in occurrences per 360-day year) at which 30-day averages of efficiency computed daily would fail to meet a threshold level of 90 percent efficiency for a facility with an actual efficiency level of 92 percent[1] and variability parameters as shown. Each estimated rate is shown with an associated standard error of estimate in parentheses. These estimates are for a facility with a lognormal distribution of emissivity. Facilities with high values of

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[1]Corresponding to a geometric mean emissivity of eight percent.

EXHIBIT 2-4: FREQUENCY OF OCCURENCE (OCCASIONS PER YEAR) OF BELOW - 90% AVERAGES IN A 92% EFFICIENT FACILITY WITH LOGNORMAL OBSERVATIONS

GEOMETRIC DAILY VARIABILITY	PROCESS AUTOCORRELATION 0	0.3	0.5	0.7
.2	0.0	0.002 (.002)	0.189 (.031)	2.514 (.095)
.3	0.320 (.0215)	2.670 (.0865)	9.900 (.332)	25.045 (.7705)
.4	10.233 (.180)	26.3935 (.186)	41.2375 (.3975)	62.4455 (.7365)
.5	52.241 (.2655)	72.1565 (.3950)	87.608 (.5515)	102.496 (.9325)

Lognormal distribution.
Figures in parentheses are standard errors.

either variability (40 percent or greater) or day-to-day correlation (0.7 or greater) would be expected to fail to meet the threshold more than one time per year, with facilities with high values of both variability and correlation failing to meet the threshold for major fractions of their operating days.

Exhibit 2-5 shows a comparison of these results with those which would be expected on similar facilities where the variability of the emissivity was normal[1] rather than lognormal. As can be seen in the exhibit, the pattern of dependency between the plant operating parameters and the rate at which the threshold is not met remains essentially the same. That is, the rate of threshold failures does not depend in any major way on the shape of the statistical distribution of the observations (within the general area of reasonability).

Exhibit 2-6 shows the expected rate at which thirty-day averages below thresholds other than 90 percent would occur for various variability and correlation parameters. Exhibits 2-7 through 2-9 show this same information for geometric mean emissivities other than eight percent (corresponding to more or less efficient facilities). All of these exhibits were derived using the lognormal distribution of emissivity observations; rates of threshold failure for the normal case differ by only small amounts, just as in the 92 percent-efficient cases.

Exhibits 2-10 through 2-13 show the efficiency levels (1.00 - geometric mean emissivities) at which facilities with various variability and correlation parameters would maintain a rate of threshold failure no higher than one per year (with rolling averages computed daily). These

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[1]Truncated at 0 efficiency.

EXHIBIT 2-5: FREQUENCY OF OCCURENCE (OCCASIONS PER YEAR) OF BELOW-90% AVERAGES IN A 92% EFFICIENT FACILITY WITH NORMAL OR LOGNORMAL OBSERVATIONS

GEOMETRIC DAILY VARIABILITY		PROCESS AUTOCORRELATION 0	0.3	0.5	0.7
.2	Lognormal:	0.0	0.002 (.002)	0.189 (.031)	2.514 (.095)
	Normal:	0.0	0.009	0.051	1.206
.3	Lognormal:	0.320 (.0215)	2.670 (.0865)	9.900 (.332)	25.045 (.7705)
	Normal:	0.090	1.639	6.678	21.403
.4	Lognormal:	10.233 (.180)	26.3935 (.186)	41.2375 (.3975)	62.4455 (.7365)
	Normal:	7.742	22.777	39.689	64.527
.5	Lognormal:	52.241 (.2655)	72.1565 (.3950)	87.608 (.5515)	102.496 (.9325)
	Normal:	52.061	75.449	92.764	112.50

Lognormal distribution cases above normal cases.

Figures in parentheses are standard errors.

EXHIBIT 2-6: FREQUENCY OF OCCURENCE (OCCASIONS PER YEAR) OF BELOW-THRESHOLD AVERAGES IN A 92% EFFICIENT FACILITY

(with standard errors in parentheses)

GEOMETRIC DAILY VARIABILITY		PROCESS AUTOCORRELATION 0	0.3	0.5	0.7
.2	30-day μ	0.9184	0.9184	0.9184	0.9184
	30-day σ	.0030	.0040	.0051	.0068
	eff<90%	0.0	0.002 (.002)	0.189 (.031)	2.514 (.095)
	" <89%	0.0	0.0	0.0	0.0565 (.017)
	" <88%	0.0	0.0	0.0	0.0
	" <87%	0.0	0.0	0.0	0.0
	" <86%	0.0	0.0	0.0	0.0
	" <85%	0.0	0.0	0.0	0.0
.3	30-day μ	0.9163	0.9163	0.9163	0.9163
	30-day σ	.0047	.0063	.0078	.0105
	eff<90%	0.320 (.0215)	2.670 (.0865)	9.900 (.332)	25.045 (.7705)
	" <89%	0.0	0.0285 (.007)	0.690 (.1195)	4.6465 (.319)
	" <88%	0.0	0.0	0.040 (.0145)	0.6595 (.0765)
	" <87%	0.0	0.0	0.0	0.0705 (.023)
	" <86%	0.0	0.0	0.0	0.0
	" <85%	0.0	0.0	0.0	0.0
.4	30-day μ	0.9133	0.9133	0.9133	0.9133
	30-day σ	.0066	.0087	.0109	.0145
	eff<90%	10.233 (.180)	26.3935 (.186)	41.2375 (.3975)	62.4455 (.7365)
	" <89%	0.2905 (.0405)	2.9645 (.1565)	8.743 (.1325)	23.1665 (.228)
	" <88%	0.009 (.0085)	0.2175 (.0355)	1.026 (.296)	7.3055 (.118)
	" <87%	0.0	0.0045 (.004)	0.159 (.0575)	2.058 (.108)
	" <86%	0.0	0.0	0.011 (.0055)	0.5675 (.072)
	" <85%	0.0	0.0	0.0	0.1195 (.0325)
.5	30-day μ	0.9093	0.9093	0.9093	0.9093
	30-day σ	.0088	.0116	.0144	.0191
	eff<90%	52.241 (.2655)	72.1565 (.3950)	87.608 (.5515)	102.496 (.9325)
	" <89%	7.6355 (.2150)	20.1945 (.3015)	35.3195 (.6525)	55.534 (.562)
	" <88%	0.6805 (.0835)	4.0905 (.1800)	11.973 (.2725)	27.5385 (.3285)
	" <87%	0.044 (.0225)	0.720 (.0610)	3.570 (.1295)	12.81 (.2015)
	" <86%	0.0	0.1075 (.0360)	1.0565 (.073)	5.71 (.0935)
	" <85%	0.0	0.0135 (.0120)	0.299 (.0555)	2.408 (.0725)

Conditions:

Facility with 8 % geometric mean emissivity (92% efficiency)

Lognormal distribution of observations

EXHIBIT 2-7: FREQUENCY OF OCCURENCE (OCCASIONS PER YEAR) OF BELOW-THRESHOLD AVERAGES IN A 94% EFFICIENT FACILITY

(with standard errors in parentheses)

GEOMETRIC DAILY VARIABILITY		PROCESS AUTOCORRELATION 0	0.3	0.5	0.7
	30-day μ	0.9388	0.9388	0.9388	0.9388
	30-day σ	.0023	.0030	.0038	.0051
.2	eff<90%	0.0	0.0	0.0	0.0
	" <89%	0.0	0.0	0.0	0.0
	" <88%	0.0	0.0	0.0	0.0
	" <87%	0.0	0.0	0.0	0.0
	" <86%	0.0	0.0	0.0	0.0
	" <85%	0.0	0.0	0.0	0.0
	30-day μ	0.9372	0.9372	0.9372	0.9372
	30-day σ	.0035	.0047	.0059	.0078
.3	eff<90%	0.0	0.0	0.0015 (.0015)	0.023 (.0155)
	" <89%	0.0	0.0	0.0	0.0
	" <88%	0.0	0.0	0.0	0.0
	" <87%	0.0	0.0	0.0	0.0
	" <86%	0.0	0.0	0.0	0.0
	" <85%	0.0	0.0	0.0	0.0
	30-day μ	0.9350	0.9350	0.9350	0.9350
	30-day σ	.0049	.0065	.0082	.0109
.4	eff<90%	0.0	0.0	0.117 (.0415)	1.5815 (.0695)
	" <89%	0.0	0.0	0.007 (.003)	0.2745 (.0465)
	" <88%	0.0	0.0	0.0	0.083 (.033)
	" <87%	0.0	0.0	0.0	0.0225 (.0125)
	" <86%	0.0	0.0	0.0	0.003 (.003)
	" <85%	0.0	0.0	0.0	0.0
	30-day μ	0.9320	0.9320	0.9320	0.9320
	30-day σ	.0066	.0087	.0108	.0143
.5	eff<90%	0.0065 (.0025)	0.375 (.0885)	2.0455 (.1405)	9.6195 (.253)
	" <89%	0.0	0.0175 (.0055)	0.307 (.047)	3.173 (.1835)
	" <88%	0.0	0.0	0.032 (.012)	1.0375 (.082)
	" <87%	0.0	0.0	0.0045 (.0045)	0.3505 (.0395)
	" <86%	0.0	0.0	0.0005 (.0005)	0.1025 (.0195)
	" <85%	0.0	0.0	0.0	0.026 (.0135)

Conditions:

Facility with 6% geometric mean emissivity (94% efficiency)

Lognormal distribution of observations

EXHIBIT 2-8: FREQUENCY OF OCCURENCE (OCCASIONS PER YEAR) OF BELOW-THRESHOLD AVERAGES IN A 93% EFFICIENT FACILITY (with standard errors in parentheses)

GEOMETRIC DAILY VARIABILITY		PROCESS AUTOCORRELATION 0	0.3	0.5	0.7
.2	30-day μ	0.9286	0.9286	0.9286	0.9286
	30-day σ	.0026	.0035	.0044	.0059
	eff<90%	0.0	0.0	0.0	0.022 (.0195)
	" <89%	0.0	0.0	0.0	0.0
	" <88%	0.0	0.0	0.0	0.0
	" <87%	0.0	0.0	0.0	0.0
	" <86%	0.0	0.0	0.0	0.0
	" <85%	0.0	0.0	0.0	0.0
.3	30-day μ	0.9268	0.9268	0.9268	0.9268
	30-day σ	.0041	.0055	.0068	.0092
	eff<90%	0.0	0.006 (.006)	0.1475 (.030)	2.0385 (.0485)
	" <89%	0.0	0.0	0.0065 (.0065)	0.1465 (.042)
	" <88%	0.0	0.0	0.0	0.0015 (.0015)
	" <87%	0.0	0.0	0.0	0.0
	" <86%	0.0	0.0	0.0	0.0
	" <85%	0.0	0.0	0.0	0.0
.4	30-day μ	0.9242	0.9242	0.9242	0.9242
	30-day σ	.0058	.0076	.0095	.0127
	eff<90%	0.0675 (.0155)	0.887 (.203)	4.3635 (.1895)	15.3025 (.418)
	" <89%	0.0	0.0255 (.0075)	0.450 (.045)	4.031 (.197)
	" <88%	0.0	0.0	0.0395 (.0195)	0.842 (.0795)
	" <87%	0.0	0.0	0.015 (.0085)	0.1755 (.035)
	" <86%	0.0	0.0	0.0	0.385 (.011)
	" <85%	0.0	0.0	0.0	0.0045 (.004)
.5	30-day μ	0.9207	0.9207	0.9207	0.9207
	30-day σ	.0077	.0101	.0126	.0167
	eff<90%	2.799 (.175)	10.9885 (.0935)	22.9385 (.635)	41.890 (.932)
	" <89%	0.107 (.022)	1.5165 (.097)	6.2575 (.0925)	18.276 (.611)
	" <88%	0.0045 (.0045)	0.186 (.0195)	1.4525 (.073)	7.522 (.3035)
	" <87%	0.0	0.036 (.0155)	0.299 (.039)	2.764 (.150)
	" <86%	0.0	0.0045 (.0035)	0.0585 (.0165)	1.036 (.0745)
	" <85%	0.0	0.0	0.0	0.385 (.0425)

Conditions:

Facility with 7 % geometric mean emissivity (93% efficiency)

Lognormal distribution of observations

EXHIBIT 2-9: FREQUENCY OF OCCURENCE (OCCASIONS PER YEAR) OF BELOW-THRESHOLD AVERAGES IN A 91% EFFICIENT FACILITY

(with standard errors in parentheses)

GEOMETRIC DAILY VARIABILITY

		PROCESS AUTOCORRELATION			
		0	0.3	0.5	0.7
.2	30-day μ	0.9082	0.9082	0.9082	0.9082
	30-day σ	.0034	.0045	.0057	.0076
	eff<90%	3.696 (0.2160)	14.539 (0.02665)	29.7325 (0.641)	52.027 (0.725)
	" <89%	0.0	0.048 (0.012)	0.6345 (0.042)	4.790 (0.310
	" <88%	0.0	0.0	0.0	0.1955 (0.034)
	" <87%	0.0	0.0	0.0	0.001 (0.001)
	" <86%	0.0	0.0	0.0	0.0
	" <85%	0.0	0.0	0.0	0.0
.3	30-day μ	0.9059	0.9059	0.9059	0.9059
	30-day σ	.0053	.0070	.0088	.0118
	eff<90%	48.869 (0.604)	71.1785 (1.3085)	88.5115 (0.166)	106.3675 (1.333
	" <89%	0.982 (0.1015)	6.1075 (0.1885)	16.2275 (0.408)	35.5775 (0.744)
	" <88%	0.004 (0.004)	0.1645 (0.019)	1.529 (0.113)	8.8645 (0.257
	" <87%	0.0	0.001 (0.001)	0.086 (0.016)	1.611 (0.113
	" <86%	0.0	0.0	0.003 (0.0025)	0.211 (0.032
	" <85%	0.0	0.0	0.0	0.0455 (0.016)
.4	30-day μ	0.9025	0.9025	0.9025	0.9025
	30-day σ	.0074	.0098	.0122	.0163
	eff<90%	128.6885 (1.47)	139.3355 (1.36)	143.7005 (1.0485)	148.656 (0.472
	" <89%	18.807 (0.5955)	39.2805 (0.7885)	55.9655 (1.2265)	76.5555 (0.103)
	" <88%	1.028 (0.0335)	6.584 (0.1465)	16.220 (6.255)	34.416 (0.319
	" <87%	0.0275 (0.0155)	0.6855 (0.035)	3.5445 (0.245)	14.0615 (0.182
	" <86%	0.0005 (0.0005)	0.0545 (0.0145)	0.679 (0.785)	5.1245 (0.965)
	" <85%	0.0	0.0035 (0.003)	0.119 (0.027)	1.7045 (0.041)
.5	30-day μ	0.8980	0.8980	0.8980	0.8980
	30-day σ	.0099	.0130	.0162	.0215
	eff<90%	201.053 (1.0585)	191.8035 (1.6735)	186.161 (0.9625)	178.337 (0.919
	" <89%	72.932 (0.6025)	91.156 (0.9785)	104.3855 (0.3075)	115.7075 (0.911)
	" <88%	15.5555 (0.224)	32.1115 (0.8079)	49.1955 (0.482)	68.561 (0.537
	" <87%	2.190 (0.147)	9.0455 (0.202)	20.091 (0.2525)	37.7685 (0.394)
	" <86%	0.2365 (0.037)	2.098 (0.041)	7.296 (0.1815)	19.691 (0.267
	" <85%	0.0165 (0.006)	0.4935 (0.016)	2.4165 (0.068)	10.008 (0.212

Conditions:

Facility with 9 % geometric mean emissivity (91% efficiency)

Lognormal distribution of observations

EXHIBIT 2-10: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER YEAR

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0054)	91.8	91.0	90.1	89.3	88.5	87.7
.21	(.0057)	91.9	91.1	90.3	89.4	88.6	87.8
.22	(.0060)	92.0	91.2	90.4	89.6	88.7	87.9
.23	(.0063)	92.1	91.3	90.5	89.7	88.9	88.1
.24	(.0065)	92.1	91.4	90.6	89.8	89.0	88.2
.25	(.0068)	92.2	91.4	90.7	89.9	89.1	88.3
.26	(.0071)	92.3	91.5	90.8	90.0	89.2	88.5
.27	(.0074)	92.4	91.6	90.9	90.1	89.4	88.6
.28	(.0077)	92.5	91.7	91.0	90.2	89.5	88.7
.29	(.0080)	92.6	91.8	91.1	90.3	89.6	88.8
.30	(.0083)	92.6	91.9	91.2	90.4	89.7	89.0
.31	(.0087)	92.7	92.0	91.3	90.6	89.8	89.1
.32	(.0090)	92.8	92.1	91.4	90.7	89.9	89.2
.33	(.0093)	92.9	92.2	91.5	90.8	90.1	89.4
.34	(.0096)	93.0	92.3	91.6	90.9	90.2	89.5
.35	(.0099)	93.1	92.4	91.7	91.0	90.3	89.6
.36	(.0103)	93.1	92.5	91.8	91.1	90.4	89.7
.37	(.0106)	93.2	92.6	91.9	91.2	90.5	89.8
.38	(.0109)	93.3	92.6	92.0	91.3	90.6	90.0
.39	(.0113)	93.4	92.7	92.1	91.4	90.8	90.1
.40	(.0116)	93.5	92.8	92.2	91.5	90.9	90.2
.41	(.0119)	93.6	92.9	92.3	91.6	91.0	90.3
.42	(.0123)	93.6	93.0	92.4	91.7	91.1	90.5
.43	(.0127)	93.7	93.1	92.5	91.8	91.2	90.6
.44	(.0130)	93.8	93.2	92.6	91.9	91.3	90.7
.45	(.0134)	93.9	93.3	92.7	92.0	91.4	90.8
.46	(.0138)	94.0	93.4	92.8	92.1	91.5	90.9
.47	(.0141)	94.0	93.4	92.8	92.2	91.7	91.1
.48	(.0145)	94.1	93.5	92.9	92.4	91.8	91.2
.49	(.0149)	94.2	93.6	93.0	92.5	91.9	91.3
.50	(.0153)	94.3	93.7	93.1	92.6	92.0	91.4
.51	(.0157)	94.4	93.8	93.2	92.7	92.1	91.5
.52	(.0161)	94.4	93.9	93.3	92.8	92.2	91.6
.53	(.0165)	94.5	94.0	93.4	92.9	92.3	91.8
.54	(.0169)	94.6	94.0	93.5	93.0	92.4	91.9
.55	(.0174)	94.7	94.1	93.6	93.1	92.5	92.0
.56	(.0178)	94.7	94.2	93.7	93.2	92.6	92.1
.57	(.0182)	94.8	94.3	93.8	93.2	92.7	92.2
.58	(.0187)	94.9	94.4	93.9	93.3	92.8	92.3
.59	(.0192)	95.0	94.5	93.9	93.4	92.9	92.4
.60	(.0196)	95.0	94.5	94.0	93.5	93.0	92.5

Facility autocorrelation = 0.55

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-11: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER YEAR

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0058)	91.9	91.1	90.3	89.5	88.6	87.8
.21	(.0061)	92.0	91.2	90.4	89.6	88.8	88.0
.22	(.0064)	92.1	91.3	90.5	89.7	88.9	88.1
.23	(.0067)	92.2	91.4	90.6	89.8	89.0	88.2
.24	(.0070)	92.3	91.5	90.7	89.9	89.2	88.4
.25	(.0073)	92.3	91.6	90.8	90.0	89.3	88.5
.26	(.0076)	92.4	91.7	90.9	90.2	89.4	88.6
.27	(.0080)	92.5	91.8	91.0	90.3	89.5	88.8
.28	(.0083)	92.6	91.9	91.1	90.4	89.7	88.9
.29	(.0086)	92.7	92.0	91.2	90.5	89.8	89.0
.30	(.0089)	92.8	92.1	91.3	90.6	89.9	89.2
.31	(.0093)	92.9	92.2	91.4	90.7	90.0	89.3
.32	(.0096)	93.0	92.3	91.5	90.8	90.1	89.4
.33	(.0099)	93.0	92.3	91.7	91.0	90.3	89.6
.34	(.0103)	93.1	92.4	91.8	91.1	90.4	89.7
.35	(.0106)	93.2	92.5	91.9	91.2	90.5	89.8
.36	(.0110)	93.3	92.6	92.0	91.3	90.6	89.9
.37	(.0113)	93.4	92.7	92.1	91.4	90.7	90.1
.38	(.0117)	93.5	92.8	92.2	91.5	90.9	90.2
.39	(.0121)	93.6	92.9	92.3	91.6	91.0	90.3
.40	(.0124)	93.6	93.0	92.4	91.7	91.1	90.5
.41	(.0128)	93.7	93.1	92.5	91.8	91.2	90.6
.42	(.0132)	93.8	93.2	92.6	91.9	91.3	90.7
.43	(.0135)	93.9	93.3	92.7	92.0	91.4	90.8
.44	(.0139)	94.0	93.4	92.8	92.2	91.5	90.9
.45	(.0143)	94.0	93.4	92.9	92.3	91.7	91.1
.46	(.0147)	94.1	93.5	92.9	92.4	91.8	91.2
.47	(.0151)	94.2	93.6	93.0	92.5	91.9	91.3
.48	(.0155)	94.3	93.7	93.1	92.6	92.0	91.4
.49	(.0159)	94.4	93.8	93.2	92.7	92.1	91.5
.50	(.0164)	94.4	93.9	93.3	92.8	92.2	91.7
.51	(.0168)	94.5	94.0	93.4	92.9	92.3	91.8
.52	(.0172)	94.6	94.1	93.5	93.0	92.4	91.9
.53	(.0177)	94.7	94.1	93.6	93.1	92.5	92.0
.54	(.0181)	94.8	94.2	93.7	93.2	92.7	92.1
.55	(.0186)	94.8	94.3	93.8	93.3	92.8	92.2
.56	(.0190)	94.9	94.4	93.9	93.4	92.9	92.4
.57	(.0195)	95.0	94.5	94.0	93.5	93.0	92.5
.58	(.0200)	95.1	94.6	94.1	93.6	93.1	92.6
.59	(.0205)	95.1	94.6	94.2	93.7	93.2	92.7
.60	(.0210)	95.2	94.7	94.2	93.8	93.3	92.8

Facility autocorrelation = 0.60

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-12: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER YEAR

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0062)	92.0	91.2	90.4	89.6	88.8	88.0
.21	(.0066)	92.1	91.3	90.5	89.7	88.9	88.2
.22	(.0069)	92.2	91.4	90.6	89.9	89.1	88.3
.23	(.0072)	92.3	91.5	90.8	90.0	89.2	88.4
.24	(.0076)	92.4	91.6	90.9	90.1	89.3	88.6
.25	(.0079)	92.5	91.7	91.0	90.2	89.5	88.7
.26	(.0082)	92.6	91.8	91.1	90.3	89.6	88.9
.27	(.0086)	92.7	91.9	91.2	90.5	89.7	89.0
.28	(.0089)	92.8	92.0	91.3	90.6	89.9	89.1
.29	(.0093)	92.8	92.1	91.4	90.7	90.0	89.3
.30	(.0096)	92.9	92.2	91.5	90.8	90.1	89.4
.31	(.0100)	93.0	92.3	91.6	90.9	90.2	89.5
.32	(.0104)	93.1	92.4	91.7	91.1	90.4	89.7
.33	(.0107)	93.2	92.5	91.8	91.2	90.5	89.8
.34	(.0111)	93.3	92.6	92.0	91.3	90.6	89.9
.35	(.0115)	93.4	92.7	92.1	91.4	90.7	90.1
.36	(.0118)	93.5	92.8	92.2	91.5	90.9	90.2
.37	(.0122)	93.6	92.9	92.3	91.6	91.0	90.3
.38	(.0126)	93.6	93.0	92.4	91.7	91.1	90.5
.39	(.0130)	93.7	93.1	92.5	91.8	91.2	90.6
.40	(.0134)	93.8	93.2	92.6	92.0	91.3	90.7
.41	(.0138)	93.9	93.3	92.7	92.1	91.5	90.8
.42	(.0142)	94.0	93.4	92.8	92.2	91.6	91.0
.43	(.0146)	94.1	93.5	92.9	92.3	91.7	91.1
.44	(.0150)	94.1	93.6	93.0	92.4	91.8	91.2
.45	(.0154)	94.2	93.7	93.1	92.5	91.9	91.3
.46	(.0159)	94.3	93.7	93.2	92.6	92.0	91.5
.47	(.0163)	94.4	93.8	93.3	92.7	92.1	91.6
.48	(.0167)	94.5	93.9	93.4	92.8	92.3	91.7
.49	(.0172)	94.6	94.0	93.5	92.9	92.4	91.8
.50	(.0176)	94.6	94.1	93.6	93.0	92.5	91.9
.51	(.0181)	94.7	94.2	93.7	93.1	92.6	92.1
.52	(.0185)	94.8	94.3	93.7	93.2	92.7	92.2
.53	(.0190)	94.9	94.4	93.8	93.3	92.8	92.3
.54	(.0195)	94.9	94.4	93.9	93.4	92.9	92.4
.55	(.0200)	95.0	94.5	94.0	93.5	93.0	92.5
.56	(.0205)	95.1	94.6	94.1	93.6	93.1	92.6
.57	(.0210)	95.2	94.7	94.2	93.7	93.2	92.8
.58	(.0215)	95.2	94.8	94.3	93.8	93.3	92.9
.59	(.0220)	95.3	94.9	94.4	93.9	93.5	93.0
.60	(.0226)	95.4	94.9	94.5	94.0	93.6	93.1

Facility autocorrelation = 0.65

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-13: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER YEAR

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0068)	92.2	91.4	90.6	89.8	89.0	88.2
.21	(.0071)	92.3	91.5	90.7	89.9	89.2	88.4
.22	(.0075)	92.3	91.6	90.8	90.1	89.3	88.5
.23	(.0079)	92.4	91.7	90.9	90.2	89.4	88.7
.24	(.0082)	92.5	91.8	91.1	90.3	89.6	88.8
.25	(.0086)	92.6	91.9	91.2	90.4	89.7	89.0
.26	(.0090)	92.7	92.0	91.3	90.6	89.8	89.1
.27	(.0093)	92.8	92.1	91.4	90.7	90.0	89.3
.28	(.0097)	92.9	92.2	91.5	90.8	90.1	89.4
.29	(.0101)	93.0	92.3	91.6	90.9	90.2	89.5
.30	(.0105)	93.1	92.4	91.7	91.1	90.4	89.7
.31	(.0109)	93.2	92.5	91.9	91.2	90.5	89.8
.32	(.0112)	93.3	92.6	92.0	91.3	90.6	90.0
.33	(.0116)	93.4	92.7	92.1	91.4	90.8	90.1
.34	(.0120)	93.5	92.8	92.2	91.5	90.9	90.2
.35	(.0124)	93.6	92.9	92.3	91.6	91.0	90.4
.36	(.0128)	93.7	93.0	92.4	91.8	91.1	90.5
.37	(.0133)	93.8	93.1	92.5	91.9	91.3	90.6
.38	(.0137)	93.8	93.2	92.6	92.0	91.4	90.8
.39	(.0141)	93.9	93.3	92.7	92.1	91.5	90.9
.40	(.0145)	94.0	93.4	92.8	92.2	91.6	91.0
.41	(.0150)	94.1	93.5	92.9	92.3	91.7	91.2
.42	(.0154)	94.2	93.6	93.0	92.4	91.9	91.3
.43	(.0158)	94.3	93.7	93.1	92.6	92.0	91.4
.44	(.0163)	94.4	93.8	93.2	92.7	92.1	91.5
.45	(.0167)	94.4	93.9	93.3	92.8	92.2	91.7
.46	(.0172)	94.5	94.0	93.4	92.9	92.3	91.8
.47	(.0177)	94.6	94.1	93.5	93.0	92.5	91.9
.48	(.0182)	94.7	94.2	93.6	93.1	92.6	92.0
.49	(.0186)	94.8	94.2	93.7	93.2	92.7	92.2
.50	(.0191)	94.9	94.3	93.8	93.3	92.8	92.3
.51	(.0196)	94.9	94.4	93.9	93.4	92.9	92.4
.52	(.0201)	95.0	94.5	94.0	93.5	93.0	92.5
.53	(.0206)	95.1	94.6	94.1	93.6	93.1	92.6
.54	(.0212)	95.2	94.7	94.2	93.7	93.2	92.7
.55	(.0217)	95.2	94.8	94.3	93.8	93.3	92.9
.56	(.0222)	95.3	94.9	94.4	93.9	93.4	93.0
.57	(.0228)	95.4	94.9	94.5	94.0	93.6	93.1
.58	(.0233)	95.5	95.0	94.6	94.1	93.7	93.2
.59	(.0239)	95.5	95.1	94.7	94.2	93.8	93.3
.60	(.0245)	95.6	95.2	94.7	94.3	93.9	93.4

Facility autocorrelation = 0.70

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

minimum efficiency critical values are accurate to within at least 0.2 percent (two tenths of one percent). Exhibits 2-14 through 2-25 show similar data for threshold failure rates of one per two years, one per five years, and one per ten years. (Given the randomness of the process, there is no set of operating conditions that can achieve a true zero rate of failure; some failures will occur randomly under any conditions.)

Policies in which averages are computed less frequently than daily, but are still thirty-day averages for the last thirty-days at the time of computation (for example, averages computed weekly or monthly) would, of course, result in fewer threshold failures per year for all facilities, whether or not operated in accordance with good practice, simply because there would be fewer occasions per year on which failures could occur. The effect on the rate of failures per year is, in fact, exactly proportional to the frequency of computation of the average.[1] Thus, if weekly averaging were used, in which a thirty-day average was computed for the thirty-day period ending, for example, on each Friday, the rate of threshold failures per year for any set of operating parameters would simply be one-seventh of that shown in the preceding exhibits. If averages are computed once every thirty days, the rate of failures per year would be one-thirtieth of that in the exhibits, etc. The exhibited critical operating levels at which one failure per year would occur, of course, no longer apply if the frequency of average computation is changed.

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[1]This fact can be proven completely mathematically for all the processes considered here, whether involving the normal, lognormal, or other distribution. Somewhat in violation of intuition, the proposition remains true no matter what the correlation structure of the daily observations.

EXHIBIT 2-14: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER TWO YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0054)	91.9	91.1	90.3	89.5	88.7	87.9
.21	(.0057)	92.0	91.2	90.4	89.6	88.8	88.0
.22	(.0060)	92.1	91.3	90.5	89.7	88.9	88.1
.23	(.0063)	92.2	91.4	90.6	89.8	89.0	88.3
.24	(.0065)	92.3	91.5	90.7	89.9	89.2	88.4
.25	(.0068)	92.4	91.6	90.8	90.1	89.3	88.5
.26	(.0071)	92.4	91.7	90.9	90.2	89.4	88.7
.27	(.0074)	92.5	91.8	91.0	90.3	89.5	88.8
.28	(.0077)	92.6	91.9	91.1	90.4	89.7	88.9
.29	(.0080)	92.7	92.0	91.2	90.5	89.8	89.1
.30	(.0083)	92.8	92.1	91.4	90.6	89.9	89.2
.31	(.0087)	92.9	92.2	91.5	90.7	90.0	89.3
.32	(.0090)	93.0	92.3	91.6	90.9	90.2	89.5
.33	(.0093)	93.1	92.4	91.7	91.0	90.3	89.6
.34	(.0096)	93.1	92.5	91.8	91.1	90.4	89.7
.35	(.0099)	93.2	92.5	91.9	91.2	90.5	89.8
.36	(.0103)	93.3	92.6	92.0	91.3	90.6	90.0
.37	(.0106)	93.4	92.7	92.1	91.4	90.8	90.1
.38	(.0109)	93.5	92.8	92.2	91.5	90.9	90.2
.39	(.0113)	93.6	92.9	92.3	91.6	91.0	90.3
.40	(.0116)	93.6	93.0	92.4	91.7	91.1	90.5
.41	(.0119)	93.7	93.1	92.5	91.8	91.2	90.6
.42	(.0123)	93.8	93.2	92.6	92.0	91.3	90.7
.43	(.0127)	93.9	93.3	92.7	92.1	91.4	90.8
.44	(.0130)	94.0	93.4	92.8	92.2	91.6	91.0
.45	(.0134)	94.1	93.5	92.9	92.3	91.7	91.1
.46	(.0138)	94.1	93.5	93.0	92.4	91.8	91.2
.47	(.0141)	94.2	93.6	93.1	92.5	91.9	91.3
.48	(.0145)	94.3	93.7	93.2	92.6	92.0	91.4
.49	(.0149)	94.4	93.8	93.3	92.7	92.1	91.6
.50	(.0153)	94.5	93.9	93.3	92.8	92.2	91.7
.51	(.0157)	94.5	94.0	93.4	92.9	92.3	91.8
.52	(.0161)	94.6	94.1	93.5	93.0	92.5	91.9
.53	(.0165)	94.7	94.2	93.6	93.1	92.6	92.0
.54	(.0169)	94.8	94.2	93.7	93.2	92.7	92.1
.55	(.0174)	94.8	94.3	93.8	93.3	92.8	92.3
.56	(.0178)	94.9	94.4	93.9	93.4	92.9	92.4
.57	(.0182)	95.0	94.5	94.0	93.5	93.0	92.5
.58	(.0187)	95.1	94.6	94.1	93.6	93.1	92.6
.59	(.0192)	95.1	94.7	94.2	93.7	93.2	92.7
.60	(.0196)	95.2	94.7	94.3	93.8	93.3	92.8

Facility autocorrelation = 0.55

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-15: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER TWO YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0058)	92.0	91.2	90.4	89.6	88.8	88.0
.21	(.0061)	92.1	91.3	90.5	89.7	88.9	88.2
.22	(.0064)	92.2	91.4	90.6	89.9	89.1	88.3
.23	(.0067)	92.3	91.5	90.8	90.0	89.2	88.4
.24	(.0070)	92.4	91.6	90.9	90.1	89.3	88.6
.25	(.0073)	92.5	91.7	91.0	90.2	89.5	88.7
.26	(.0076)	92.6	91.8	91.1	90.3	89.6	88.9
.27	(.0080)	92.7	91.9	91.2	90.5	89.7	89.0
.28	(.0083)	92.8	92.0	91.3	90.6	89.9	89.1
.29	(.0086)	92.8	92.1	91.4	90.7	90.0	89.3
.30	(.0089)	92.9	92.2	91.5	90.8	90.1	89.4
.31	(.0093)	93.0	92.3	91.6	90.9	90.2	89.5
.32	(.0096)	93.1	92.4	91.7	91.0	90.4	89.7
.33	(.0099)	93.2	92.5	91.8	91.2	90.5	89.8
.34	(.0103)	93.3	92.6	91.9	91.3	90.6	89.9
.35	(.0106)	93.4	92.7	92.1	91.4	90.7	90.1
.36	(.0110)	93.5	92.8	92.2	91.5	90.9	90.2
.37	(.0113)	93.6	92.9	92.3	91.6	91.0	90.3
.38	(.0117)	93.6	93.0	92.4	91.7	91.1	90.5
.39	(.0121)	93.7	93.1	92.5	91.8	91.2	90.6
.40	(.0124)	93.8	93.2	92.6	92.0	91.3	90.7
.41	(.0128)	93.9	93.3	92.7	92.1	91.4	90.8
.42	(.0132)	94.0	93.4	92.8	92.2	91.6	91.0
.43	(.0136)	94.1	93.5	92.9	92.3	91.7	91.1
.44	(.0139)	94.1	93.6	93.0	92.4	91.8	91.2
.45	(.0143)	94.2	93.6	93.1	92.5	91.9	91.3
.46	(.0147)	94.3	93.7	93.2	92.6	92.0	91.5
.47	(.0151)	94.4	93.8	93.3	92.7	92.1	91.6
.48	(.0155)	94.5	93.9	93.4	92.8	92.3	91.7
.49	(.0159)	94.5	94.0	93.5	92.9	92.4	91.8
.50	(.0164)	94.6	94.1	93.6	93.0	92.5	91.9
.51	(.0168)	94.7	94.2	93.6	93.1	92.6	92.1
.52	(.0172)	94.8	94.3	93.7	93.2	92.7	92.2
.53	(.0177)	94.9	94.3	93.8	93.3	92.8	92.3
.54	(.0181)	94.9	94.4	93.9	93.4	92.9	92.4
.55	(.0186)	95.0	94.5	94.0	93.5	93.0	92.5
.56	(.0190)	95.1	94.6	94.1	93.6	93.1	92.6
.57	(.0195)	95.2	94.7	94.2	93.7	93.2	92.8
.58	(.0200)	95.2	94.8	94.3	93.8	93.3	92.9
.59	(.0205)	95.3	94.9	94.4	93.9	93.4	93.0
.60	(.0210)	95.4	94.9	94.5	94.0	93.6	93.1

Facility autocorrelation = 0.60

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-16: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER TWO YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0062)	92.1	91.3	90.6	89.8	89.0	88.2
.21	(.0066)	92.2	91.5	90.7	89.9	89.1	88.4
.22	(.0069)	92.3	91.6	90.8	90.0	89.3	88.5
.23	(.0072)	92.4	91.7	90.9	90.2	89.4	88.6
.24	(.0076)	92.5	91.8	91.0	90.3	89.5	88.8
.25	(.0079)	92.6	91.9	91.2	90.4	89.7	88.9
.26	(.0082)	92.7	92.0	91.3	90.5	89.8	89.1
.27	(.0086)	92.8	92.1	91.4	90.7	89.9	89.2
.28	(.0089)	92.9	92.2	91.5	90.8	90.1	89.4
.29	(.0093)	93.0	92.3	91.6	90.9	90.2	89.5
.30	(.0096)	93.1	92.4	91.7	91.0	90.3	89.6
.31	(.0100)	93.2	92.5	91.8	91.1	90.5	89.8
.32	(.0104)	93.3	92.6	91.9	91.3	90.6	89.9
.33	(.0107)	93.4	92.7	92.0	91.4	90.7	90.1
.34	(.0111)	93.5	92.8	92.2	91.5	90.9	90.2
.35	(.0115)	93.6	92.9	92.3	91.6	91.0	90.3
.36	(.0118)	93.6	93.0	92.4	91.7	91.1	90.5
.37	(.0122)	93.7	93.1	92.5	91.9	91.2	90.6
.38	(.0126)	93.8	93.2	92.6	92.0	91.3	90.7
.39	(.0130)	93.9	93.3	92.7	92.1	91.5	90.9
.40	(.0134)	94.0	93.4	92.8	92.2	91.6	91.0
.41	(.0138)	94.1	93.5	92.9	92.3	91.7	91.1
.42	(.0142)	94.2	93.6	93.0	92.4	91.8	91.2
.43	(.0146)	94.3	93.7	93.1	92.5	92.0	91.4
.44	(.0150)	94.3	93.8	93.2	92.6	92.1	91.5
.45	(.0154)	94.4	93.9	93.3	92.7	92.2	91.6
.46	(.0159)	94.5	94.0	93.4	92.9	92.3	91.8
.47	(.0163)	94.6	94.0	93.5	93.0	92.4	91.9
.48	(.0167)	94.7	94.1	93.6	93.1	92.5	92.0
.49	(.0172)	94.7	94.2	93.7	93.2	92.6	92.1
.50	(.0176)	94.8	94.3	93.8	93.3	92.8	92.2
.51	(.0181)	94.9	94.4	93.9	93.4	92.9	92.4
.52	(.0185)	95.0	94.5	94.0	93.5	93.0	92.5
.53	(.0190)	95.1	94.6	94.1	93.6	93.1	92.6
.54	(.0195)	95.1	94.7	94.2	93.7	93.2	92.7
.55	(.0200)	95.2	94.7	94.3	93.8	93.3	92.8
.56	(.0205)	95.3	94.8	94.4	93.9	93.4	92.9
.57	(.0210)	95.4	94.9	94.4	94.0	93.5	93.1
.58	(.0215)	95.4	95.0	94.5	94.1	93.6	93.2
.59	(.0220)	95.5	95.1	94.6	94.2	93.7	93.3
.60	(.0226)	95.6	95.2	94.7	94.3	93.8	93.4

Facility autocorrelation = 0.65

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-17: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER TWO YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0068)	92.3	91.5	90.7	90.0	89.2	88.4
.21	(.0071)	92.4	91.6	90.9	90.1	89.3	88.6
.22	(.0075)	92.5	91.7	91.0	90.2	89.5	88.7
.23	(.0079)	92.6	91.9	91 1	90.4	89.6	88.9
.24	(.0082)	92.7	92.0	91.2	90.5	89.8	89.0
.25	(.0086)	92.8	92.1	91.4	90.6	89.9	89.2
.26	(.0090)	92.9	92.2	91.5	90.8	90.1	89.3
.27	(.0093)	93.0	92.3	91.6	90.9	90.2	89.5
.28	(.0097)	93.1	92.4	91.7	91.0	90.3	89.6
.29	(.0101)	93.2	92.5	91.8	91.1	90.5	89.8
.30	(.0105)	93.3	92.6	91.9	91.3	90.6	89.9
.31	(.0109)	93.4	92.7	92.1	91.4	90.7	90.1
.32	(.0112)	93.5	92.8	92.2	91.5	90.9	90.2
.33	(.0116)	93.6	92.9	92.3	91.6	91.0	90.4
.34	(.0120)	93.7	93.0	92.4	91.8	91.1	90.5
.35	(.0124)	93.8	93.1	92.5	91.9	91.3	90 6
.36	(0128)	93.9	93 2	92.6	92 0	91 4	90.8
.37	(0133)	93.9	93.3	92.7	92.1	91.5	90.9
.38	(.0137)	94.0	93.4	92.8	92.2	91.6	91.0
.39	(.0141)	94.1	93.5	92.9	92.4	91.8	91.2
.40	(.0145)	94.2	93.6	93.1	92.5	91.9	91.3
.41	(.0150)	94.3	93.7	93.2	92.6	92.0	91.4
.42	(.0154)	94.4	93.8	93.3	92.7	92.1	91.6
.43	(.0158)	94.5	93.9	93.4	92.8	92.3	91.7
.44	(.0163)	94.6	94.0	93.5	92.9	92.4	91.8
.45	(.0167)	94.6	94.1	93.6	93.0	92.5	92.0
.46	(.0172)	94.7	94.2	93.7	93.1	92.6	92.1
.47	(.0177)	94.8	94.3	93.8	93.3	92.7	92.2
.48	(.0182)	94.9	94.4	93.9	93.4	92.8	92.3
.49	(.0186)	95.0	94.5	94.0	93.5	93.0	92.5
.50	(.0191)	95.1	94.6	94.1	93.6	93.1	92.6
.51	(.0196)	95.1	94.6	94.2	93.7	93.2	92.7
.52	(.0201)	95.2	94.7	94.3	93.8	93.3	92.8
.53	(.0206)	95.3	94.8	94.3	93.9	93.4	92.9
.54	(.0212)	95.4	94.9	94.4	94.0	93.5	93.1
.55	(.0217)	95.4	95.0	94.5	94.1	93.6	93.2
.56	(.0222)	95.5	95.1	94.6	94.2	93.7	93.3
.57	(.0228)	95.6	95.2	94.7	94.3	93.8	93.4
.58	(.0233)	95.7	95.2	94.8	94.4	93.9	93.5
.59	(.0239)	95.7	95.3	94.9	94.5	94.0	93.6
.60	(.0245)	95.8	95.4	95.0	94.6	94.2	93.7

Facility autocorrelation = 0.70

[1]In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-18: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER FIVE YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0054)	92.0	91.2	90.4	89.7	88.9	88.1
.21	(.0057)	92.1	91.3	90.6	89.8	89.0	88.2
.22	(.0060)	92.2	91.5	90.7	89.9	89.1	88.3
.23	(.0063)	92.3	91.6	90.8	90.0	89.3	88.5
.24	(.0065)	92.4	91.7	90.9	90.1	89.4	88.6
.25	(.0068)	92.5	91.8	91.0	90.3	89.5	88.8
.26	(.0071)	92.6	91.9	91.1	90.4	89.6	88.9
.27	(.0074)	92.7	92.0	91.2	90.5	89.8	89.0
.28	(.0077)	92.8	92.1	91.4	90.6	89.9	89.2
.29	(.0080)	92.9	92.2	91.5	90.7	90.0	89.3
.30	(.0083)	93.0	92.3	91.6	90.[illegible]	90.2	89.5
.31	(.0087)	93.1	92.4	91.7	91.0	90.3	89.6
.32	(.0090)	93.2	92.5	91.8	91.1	90.4	89.7
.33	(.0093)	93.2	92.6	91.9	91.2	90.5	89.9
.34	(.0096)	93.3	92.7	92.0	91.3	90.7	90.0
.35	(.0099)	93.4	92.8	92.1	91.4	90.8	90.1
.36	(.0103)	93.5	92.9	92.2	91.6	90.9	90.3
.37	(.0106)	93.6	93.0	92.3	91.7	91.0	90.4
.38	(.0109)	93.7	93.0	92.4	91.8	91.2	90.5
.39	(.0113)	93.8	93.1	92.5	91.9	91.3	90.7
.40	(.0116)	93.9	93.2	92.6	92.0	91.4	90.8
.41	(.0119)	93.9	93.3	92.7	92.1	91.5	90.9
.42	(.0123)	94.0	93.4	92.8	92.2	91.6	91.0
.43	(.0127)	94.1	93.5	92.9	92.3	91.7	91.2
.44	(.0130)	94.2	93.6	93.0	92.4	91.9	91.3
.45	(.0134)	94.3	93.7	93.1	92.6	92.0	91.4
.46	(.0138)	94.4	93.8	93.2	92.7	92.1	91.5
.47	(.0141)	94.4	93.9	93.3	92.8	92.2	91.7
.48	(.0145)	94.5	94.0	93.4	92.9	92.3	[illegible].8
.49	(.0149)	94.6	94.1	93.5	93.0	92.4	91.9
.50	(.0153)	94.7	94.1	93.6	93.1	92.5	92.0
.51	(.0157)	94.8	94.2	93.7	93.2	92.7	92.1
.52	(.0161)	94.8	94.3	93.8	93.3	92.8	92.3
.53	(.0165)	94.9	94.4	93.9	93.4	92.9	92.4
.54	(.0169)	95.0	94.5	94.0	93.5	93.0	92.5
.55	(.0174)	95.1	94.6	94.1	93.6	93.1	92.6
.56	(.0178)	95.1	94.7	94.2	93.7	93.2	92.7
.57	(.0182)	95.2	94.7	94.3	93.8	93.3	92.8
.58	(.0187)	95.3	94.8	94.4	93.9	93.4	92.9
.59	(.0192)	95.4	94.9	94.4	94.0	93.5	93.1
.60	(.0196)	95.4	95.0	94.5	94.1	93.6	93.2

Facility autocorrelation = 0.55

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-19: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER FIVE YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0058)	92.2	91.4	90.6	89.8	89.0	88.2
.21	(.0061)	92.3	91.5	90.7	89.9	89.2	88.4
.22	(.0064)	92.4	91.6	90.8	90.1	89.3	88.5
.23	(.0067)	92.5	91.7	90.9	90.2	89.4	88.7
.24	(.0070)	92.6	91.8	91.1	90.3	89.6	88.8
.25	(.0073)	92.6	91.9	91.2	90.4	89.7	89.0
.26	(.0076)	92.7	92.0	91.3	90.6	89.8	89.1
.27	(.0080)	92.8	92.1	91.4	90.7	90.0	89.3
.28	(.0083)	92.9	92.2	91.5	90.8	90.1	89.4
.29	(.0086)	93.0	92.3	91.6	90.9	90.2	89.5
.30	(.0089)	93.1	92.4	91.8	91.1	90.4	89.7
.31	(.0093)	93.2	92.5	91.9	91.2	90.5	89.8
.32	(.0096)	93.3	92.6	92.0	91.3	90.6	90.0
.33	(.0099)	93.4	92.7	92.1	91.4	90.8	90.1
.34	(.0103)	93.5	92.8	92.2	91.5	90.9	90.2
.35	(.0106)	93.6	92.9	92.3	91.7	91.0	90.4
.36	(.0110)	93.7	93.0	92.4	91.8	91.1	90.5
.37	(.0113)	93.8	93.1	92.5	91.9	91.3	90.6
.38	(.0117)	93.9	93.2	92.6	92.0	91.4	90.8
.39	(.0121)	93.9	93.3	92.7	92.1	91.5	90.9
.40	(.0124)	94.0	93.4	92.8	92.2	91.6	91.0
.41	(.0128)	94.1	93.5	92.9	92.3	91.8	91.2
.42	(.0132)	94.2	93.6	93.0	92.5	91.9	91.3
.43	(.0135)	94.3	93.7	93.1	92.6	92.0	91.4
.44	(.0139)	94.4	93.8	93.2	92.7	92.1	91.5
.45	(.0143)	94.4	93.9	93.3	92.8	92.2	91.7
.46	(.0147)	94.5	94.0	93.4	92.9	92.3	91.8
.47	(.0151)	94.6	94.1	93.5	93.0	92.5	91.9
.48	(.0155)	94.7	94.2	93.6	93.1	92.6	92.0
.49	(.0159)	94.8	94.3	93.7	93.2	92.7	92.2
.50	(.0164)	94.9	94.3	93.8	93.3	92.8	92.3
.51	(.0168)	94.9	94.4	93.9	93.4	92.9	92.4
.52	(.0172)	95.0	94.5	94.0	93.5	93.0	92.5
.53	(.0177)	95.1	94.6	94.1	93.6	93.1	92.6
.54	(.0181)	95.2	94.7	94.2	93.7	93.2	92.8
.55	(.0186)	95.2	94.8	94.3	93.8	93.3	92.9
.56	(.0190)	95.3	94.9	94.4	93.9	93.5	93.0
.57	(.0195)	95.4	94.9	94.5	94.0	93.6	93.1
.58	(.0200)	95.5	95.0	94.6	94.1	93.7	93.2
.59	(.0205)	95.6	95.1	94.7	94.2	93.8	93.3
.60	(.0210)	95.6	95.2	94.8	94.3	93.9	93.4

Facility autocorrelation = 0.60

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-18: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER FIVE YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0054)	92.0	91.2	90.4	89.7	88.9	88.1
.21	(.0057)	92.1	91.3	90.6	89.8	89.0	88.2
.22	(.0060)	92.2	91.5	90.7	89.9	89.1	88.3
.23	(.0063)	92.3	91.6	90.8	90.0	89.3	88.5
.24	(.0065)	92.4	91.7	90.9	90.1	89.4	88.6
.25	(.0068)	92.5	91.8	91.0	90.3	89.5	88.8
.26	(.0071)	92.6	91.9	91.1	90.4	89.6	88.9
.27	(.0074)	92.7	92.0	91.2	90.5	89.8	89.0
.28	(.0077)	92.8	92.1	91.4	90.6	89.9	89.2
.29	(.0080)	92.9	92.2	91.5	90.7	90.0	89.3
.30	(.0083)	93.0	92.3	91.6	90.[illegible]	90.2	89.5
.31	(.0087)	93.1	92.4	91.7	91.0	90.3	89.6
.32	(.0090)	93.2	92.5	91.8	91.1	90.4	89.7
.33	(.0093)	93.2	92.6	91.9	91.2	90.5	89.9
.34	(.0096)	93.3	92.7	92.0	91.3	90.7	90.0
.35	(.0099)	93.4	92.8	92.1	91.4	90.8	90.1
.36	(.0103)	93.5	92.9	92.2	91.6	90.9	90.3
.37	(.0106)	93.6	93.0	92.3	91.7	91.0	90.4
.38	(.0109)	93.7	93.0	92.4	91.8	91.2	90.5
.39	(.0113)	93.8	93.1	92.5	91.9	91.3	90.7
.40	(.0116)	93.9	93.2	92.6	92.0	91.4	90.8
.41	(.0119)	93.9	93.3	92.7	92.1	91.5	90.9
.42	(.0123)	94.0	93.4	92.8	92.2	91.6	91.0
.43	(.0127)	94.1	93.5	92.9	92.3	91.7	91.2
.44	(.0130)	94.2	93.6	93.0	92.4	91.9	91.3
.45	(.0134)	94.3	93.7	93.1	92.6	92.0	91.4
.46	(.0138)	94.4	93.8	93.2	92.7	92.1	91.5
.47	(.0141)	94.4	93.9	93.3	92.8	92.2	91.7
.48	(.0145)	94.5	94.0	93.4	92.9	92.3	[illegible].8
.49	(.0149)	94.6	94.1	93.5	93.0	92.4	91.9
.50	(.0153)	94.7	94.1	93.6	93.1	92.5	92.0
.51	(.0157)	94.8	94.2	93.7	93.2	92.7	92.1
.52	(.0161)	94.8	94.3	93.8	93.3	92.8	92.3
.53	(.0165)	94.9	94.4	93.9	93.4	92.9	92.4
.54	(.0169)	95.0	94.5	94.0	93.5	93.0	92.5
.55	(.0174)	95.1	94.6	94.1	93.6	93.1	92.6
.56	(.0178)	95.1	94.7	94.2	93.7	93.2	92.7
.57	(.0182)	95.2	94.7	94.3	93.8	93.3	92.8
.58	(.0187)	95.3	94.8	94.4	93.9	93.4	92.9
.59	(.0192)	95.4	94.9	94.4	94.0	93.5	93.1
.60	(.0196)	95.4	95.0	94.5	94.1	93.6	93.2

Facility autocorrelation = 0.55

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-19: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER FIVE YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0058)	92.2	91.4	90.6	89.8	89.0	88.2
.21	(.0061)	92.3	91.5	90.7	89.9	89.2	88.4
.22	(.0064)	92.4	91.6	90.8	90.1	89.3	88.5
.23	(.0067)	92.5	91.7	90.9	90.2	89.4	88.7
.24	(.0070)	92.6	91.8	91.1	90.3	89.6	88.8
.25	(.0073)	92.6	91.9	91.2	90.4	89.7	89.0
.26	(.0076)	92.7	92.0	91.3	90.6	89.8	89.1
.27	(.0080)	92.8	92.1	91.4	90.7	90.0	89.3
.28	(.0083)	92.9	92.2	91.5	90.8	90.1	89.4
.29	(.0086)	93.0	92.3	91.6	90.9	90.2	89.5
.30	(.0089)	93.1	92.4	91.8	91.1	90.4	89.7
.31	(.0093)	93.2	92.5	91.9	91.2	90.5	89.8
.32	(.0096)	93.3	92.6	92.0	91.3	90.6	90.0
.33	(.0099)	93.4	92.7	92.1	91.4	90.8	90.1
.34	(.0103)	93.5	92.8	92.2	91.5	90.9	90.2
.35	(.0106)	93.6	92.9	92.3	91.7	91.0	90.4
.36	(.0110)	93.7	93.0	92.4	91.8	91.1	90.5
.37	(.0113)	93.8	93.1	92.5	91.9	91.3	90.6
.38	(.0117)	93.9	93.2	92.6	92.0	91.4	90.8
.39	(.0121)	93.9	93.3	92.7	92.1	91.5	90.9
.40	(.0124)	94.0	93.4	92.8	92.2	91.6	91.0
.41	(.0128)	94.1	93.5	92.9	92.3	91.8	91.2
.42	(.0132)	94.2	93.6	93.0	92.5	91.9	91.3
.43	(.0135)	94.3	93.7	93.1	92.6	92.0	91.4
.44	(.0139)	94.4	93.8	93.2	92.7	92.1	91.5
.45	(.0143)	94.4	93.9	93.3	92.8	92.2	91.7
.46	(.0147)	94.5	94.0	93.4	92.9	92.3	91.8
.47	(.0151)	94.6	94.1	93.5	93.0	92.5	91.9
.48	(.0155)	94.7	94.2	93.6	93.1	92.6	92.0
.49	(.0159)	94.8	94.3	93.7	93.2	92.7	92.2
.50	(.0164)	94.9	94.3	93.8	93.3	92.8	92.3
.51	(.0168)	94.9	94.4	93.9	93.4	92.9	92.4
.52	(.0172)	95.0	94.5	94.0	93.5	93.0	92.5
.53	(.0177)	95.1	94.6	94.1	93.6	93.1	92.6
.54	(.0181)	95.2	94.7	94.2	93.7	93.2	92.8
.55	(.0186)	95.2	94.8	94.3	93.8	93.3	92.9
.56	(.0190)	95.3	94.9	94.4	93.9	93.5	93.0
.57	(.0195)	95.4	94.9	94.5	94.0	93.6	93.1
.58	(.0200)	95.5	95.0	94.6	94.1	93.7	93.2
.59	(.0205)	95.6	95.1	94.7	94.2	93.8	93.3
.60	(.0210)	95.6	95.2	94.8	94.3	93.9	93.4

Facility autocorrelation = 0.60

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-20: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER FIVE YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0062)	92.3	91.5	90.8	90.0	89.2	88.4
.21	(.0066)	92.4	91.6	90.9	90.1	89.4	88.6
.22	(.0069)	92.5	91.8	91.0	90.3	89.5	88.8
.23	(.0072)	92.6	91.9	91.1	90.4	89.6	88.9
.24	(.0076)	92.7	92.0	91.2	90.5	89.8	89.1
.25	(.0079)	92.8	92.1	91.4	90.6	89.9	89.2
.26	(.0082)	92.9	92.2	91.5	90.8	90.1	89.4
.27	(.0086)	93.0	92.3	91.6	90.9	90.2	89.5
.28	(.0089)	93.1	92.4	91.7	91.0	90.3	89.7
.29	(.0093)	93.2	92.5	91.8	91.2	90.5	89.8
.30	(.0096)	93.3	92.6	92.0	91.3	90.6	89.9
.31	(.0100)	93.4	92.7	92.1	91.4	90.8	90.1
.32	(.0104)	93.5	92.8	92.2	91.5	90.9	90.2
.33	(.0107)	93.6	92.9	92.[illegible]	91.7	91.0	90.4
.34	(.0111)	93.7	93.0	92.4	91.8	91.1	90.5
.35	(.0115)	93.8	93.1	92.5	91.9	91.3	90.7
.36	(.0118)	93.9	93.2	92.6	92.0	91.4	90.8
.37	(.0122)	94.0	93.3	92.7	92.1	91.5	90.9
.38	(.0126)	94.0	93.4	92.9	92.3	91.7	91.1
.39	(.0130)	94.1	93.5	93.0	92.4	91.8	91.2
.40	(.0134)	94.2	93.6	93.1	92.5	91.9	91.3
.41	(.0138)	94.3	93.7	93.2	92.6	92.0	91.5
.42	(.0142)	94.4	93.8	93.3	92.7	92.2	91.6
.43	(.0146)	94.5	93.9	93.4	92.8	92.3	91.7
.44	(.0150)	94.6	94.0	93.5	92.9	92.4	91.8
.45	(.0154)	94.7	94.1	93.6	93.0	92.5	92.0
.46	(.0159)	94.7	94.2	93.7	93.2	92.6	92.1
.47	(.0163)	94.8	94.3	93.8	93.3	92.7	92.2
.48	(.0167)	94.9	94.4	93.9	93.4	92.9	92.4
.49	(.0172)	95.0	94.5	94.0	93.5	93.0	92.5
.50	(.0176)	95.1	94.6	94.1	93.6	93.1	92.6
.51	(.0181)	95.1	94.7	94.2	93.7	93.2	92.7
.52	(.0185)	95.2	94.7	94.3	93.8	93.3	92.8
.53	(.0190)	95.3	94.8	94.4	93.9	93.4	93.0
.54	(.0195)	95.4	94.9	94.5	94.0	93.5	93.1
.55	(.0200)	95.5	95.0	94.5	94.1	93.6	93.2
.56	(.0205)	95.5	95.1	94.6	94.2	93.7	93.3
.57	(.0210)	95.6	95.2	94.7	94.3	93.9	93.4
.58	(.0215)	95.7	95.3	94.8	94.4	94.0	93.5
.59	(.0220)	95.8	95.3	94.9	94.5	94.1	93.6
.60	(.0226)	95.8	95.4	95.0	94.6	94.2	93.7

Facility autocorrelation = 0.65

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-21: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER FIVE YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0068)	92.4	91.7	90.9	90.2	89.4	88.7
.21	(.0071)	92.6	91.8	91.1	90.3	89.6	88.8
.22	(.0075)	92.7	91.9	91.2	90.5	89.7	89.0
.23	(.0079)	92.8	92.1	91.3	90.6	89.9	89.2
.24	(.0082)	92.9	92.2	91.5	90.7	90.0	89.3
.25	(.0086)	93.0	92.3	91.6	90.9	90.2	89.5
.26	(.0090)	93.1	92.4	91.7	91.0	90.3	89.6
.27	(.0093)	93.2	92.5	91.8	91.2	90.5	89.8
.28	(.0097)	93.3	92.6	92.0	91.3	90.6	89.9
.29	(.0101)	93.4	92.7	92.1	91.4	90.8	90.1
.30	(.0105)	93.5	92.8	92.2	91.5	90.9	90.2
.31	(.0109)	93.6	93.0	92.3	91.7	91.0	90.4
.32	(.0112)	93.7	93.1	92.4	91.8	91.2	90.5
.33	(.0116)	93.8	93.2	92.6	91.9	91.3	90.7
.34	(.0120)	93.9	93.3	92.7	92.1	91.4	90.8
.35	(.0124)	94.0	93.4	92.8	92.2	91.6	91.0
.36	(.0128)	94.1	93.5	92.9	92.3	91.7	91.1
.37	(.0133)	94.2	93.6	93.0	92.4	91.8	91.3
.38	(.0137)	94.3	93.7	93.1	92.5	92.0	91.4
.39	(.0141)	94.4	93.8	93.2	92.7	92.1	91.5
.40	(.0145)	94.4	93.9	93.3	92.8	92.2	91.7
.41	(.0150)	94.5	94.0	93.4	92.9	92.3	91.8
.42	(.0154)	94.6	94.1	93.5	93.0	92.5	91.9
.43	(.0158)	94.7	94.2	93.7	93.1	92.6	92.1
.44	(.0163)	94.8	94.3	93.8	93.2	92.7	92.2
.45	(.0167)	94.9	94.4	93.9	93.3	92.8	92.3
.46	(.0172)	95.0	94.5	94.0	93.5	93.0	92.5
.47	(.0177)	95.1	94.6	94.1	93.6	93.1	92.6
.48	(.0182)	95.1	94.6	94.2	93.7	93.2	92.7
.49	(.0186)	95.2	94.7	94.3	93.8	93.3	92.8
.50	(.0191)	95.3	94.8	94.4	93.9	93.4	92.9
.51	(.0196)	95.4	94.9	94.5	94.0	93.5	93.1
.52	(.0201)	95.5	95.0	94.5	94.1	93.6	93.2
.53	(.0206)	95.5	95.1	94.6	94.2	93.8	93.3
.54	(.0212)	95.6	95.2	94.7	94.3	93.9	93.4
.55	(.0217)	95.7	95.3	94.8	94.4	94.0	93.5
.56	(.0222)	95.8	95.3	94.9	94.5	94.1	93.7
.57	(.0228)	95.8	95.4	95.0	94.6	94.2	93.8
.58	(.0233)	95.9	95.5	95.1	94.7	94.3	93.9
.59	(.0239)	96.0	95.6	95.2	94.8	94.4	94.0
.60	(.0245)	96.1	95.7	95.3	94.9	94.5	94.1

Facility autocorrelation = 0.70

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-22: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER TEN YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0054)	92.1	91.3	90.6	89.8	89.0	88.2
.21	(.0057)	92.2	91.5	90.7	89.9	89.1	88.3
.22	(.0060)	92.3	91.6	90.8	90.0	89.3	88.5
.23	(.0063)	92.4	91.7	90.9	90.2	89.4	88.6
.24	(.0065)	92.5	91.8	91.0	90.3	89.5	88.8
.25	(.0068)	92.6	91.9	91.1	90.4	89.7	88.9
.26	(.0071)	92.7	92.0	91.3	90.5	89.8	89.1
.27	(.0074)	92.8	92.1	91.4	90.7	89.9	89.2
.28	(.0077)	92.9	92.2	91.5	90.8	90.1	89.4
.29	(.0080)	93.0	92.3	91.6	90.9	90.2	89.5
.30	(.0083)	93.1	92.4	91.7	91.0	90.3	89.6
.31	(.0087)	93.2	92.5	91.8	91.1	90.5	89.8
.32	(.0090)	93.3	92.6	91.9	91.3	90.6	89.9
.33	(.0093)	93.4	92.7	92.0	91.4	90.7	90.1
.34	(.0096)	93.5	92.8	92.2	91.5	90.8	90.2
.35	(.0099)	93.5	92.9	92.3	91.6	91.0	90.3
.36	(.0103)	93.6	93.0	92.4	91.7	91.1	90.5
.37	(.0106)	93.7	93.1	92.5	91.8	91.2	90.6
.38	(.0109)	93.8	93.2	92.6	92.0	91.3	90.7
.39	(.0113)	93.9	93.3	92.7	92.1	91.5	90.9
.40	(.0116)	94.0	93.4	92.8	92.2	91.6	91.0
.41	(.0119)	94.1	93.5	92.9	92.3	91.7	91.1
.42	(.0123)	94.2	93.6	93.0	92.4	91.8	91.2
.43	(.0127)	94.2	93.7	93.1	92.5	91.9	91.4
.44	(.0130)	94.3	93.8	93.2	92.6	92.1	91.5
.45	(.0134)	94.4	93.9	93.3	92.7	92.2	91.6
.46	(.0138)	94.5	93.9	93.4	92.8	92.3	91.7
.47	(.0141)	94.6	94.0	93.5	93.0	92.4	91.9
.48	(.0145)	94.7	94.1	93.6	93.1	92.5	92.0
.49	(.0149)	94.7	94.2	93.7	93.2	92.6	92.1
.50	(.0153)	94.8	94.3	93.8	93.3	92.7	92.2
.51	(.0157)	94.9	94.4	93.9	93.4	92.9	92.3
.52	(.0161)	95.0	94.5	94.0	93.5	93.0	92.5
.53	(.0165)	95.1	94.6	94.1	93.6	93.1	92.6
.54	(.0169)	95.1	94.6	94.2	93.7	93.2	92.7
.55	(.0174)	95.2	94.7	94.3	93.8	93.3	92.8
.56	(.0178)	95.3	94.8	94.3	93.9	93.4	92.9
.57	(.0182)	95.4	94.9	94.4	94.0	93.5	93.0
.58	(.0187)	95.4	95.0	94.5	94.1	93.6	93.2
.59	(.0192)	95.5	95.1	94.6	94.2	93.7	93.3
.60	(.0196)	95.6	95.1	94.7	94.3	93.8	93.4

Facility autocorrelation = 0.55

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-23: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER TEN YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0058)	92.3	91.5	90.7	89.9	89.2	88.4
.21	(.0061)	92.4	91.6	90.8	90.1	89.3	88.5
.22	(.0064)	92.5	91.7	91.0	90.2	89.4	88.7
.23	(.0067)	92.6	91.8	91.1	90.3	89.6	88.8
.24	(.0070)	92.7	91.9	91.2	90.5	89.7	89.0
.25	(.0073)	92.8	92.0	91.3	90.6	89.9	89.1
.26	(.0076)	92.9	92.1	91.4	90.7	90.0	89.3
.27	(.0080)	93.0	92.3	91.6	90.8	90.1	89.4
.28	(.0083)	93.1	92.4	91.7	91.0	90.3	89.6
.29	(.0086)	93.2	92.5	91.8	91.1	90.4	89.7
.30	(.0089)	93.3	92.6	91.9	91.2	90.6	89.9
.31	(.0093)	93.3	92.7	92.0	91.3	90.7	90.0
.32	(.0096)	93.4	92.8	92.1	91.5	90.8	90.2
.33	(.0099)	93.5	92.9	92.2	91.6	90.9	90.3
.34	(.0103)	93.6	93.0	92.4	91.7	91.1	90.4
.35	(.0106)	93.7	93.1	92.5	91.8	91.2	90.6
.36	(.0110)	93.8	93.2	92.6	92.0	91.3	90.7
.37	(.0113)	93.9	93.3	92.7	92.1	91.5	90.8
.38	(.0117)	94.0	93.4	92.8	92.2	91.6	91.0
.39	(.0121)	94.1	93.5	92.9	92.3	91.7	91.1
.40	(.0124)	94.2	93.6	93.0	92.4	91.8	91.2
.41	(.0128)	94.3	93.7	93.1	92.5	92.0	91.4
.42	(.0132)	94.3	93.8	93.2	92.6	92.1	91.5
.43	(.0135)	94.4	93.9	93.3	92.8	92.2	91.6
.44	(.0139)	94.5	94.0	93.4	92.9	92.3	91.8
.45	(.0143)	94.6	94.1	93.5	93.0	92.4	91.9
.46	(.0147)	94.7	94.1	93.6	93.1	92.5	92.0
.47	(.0151)	94.8	94.2	93.7	93.2	92.7	92.1
.48	(.0155)	94.8	94.3	93.8	93.3	92.8	92.3
.49	(.0159)	94.9	94.4	93.9	93.4	92.9	92.4
.50	(.0164)	95.0	94.5	94.0	93.5	93.0	92.5
.51	(.0168)	95.1	94.6	94.1	93.6	93.1	92.6
.52	(.0172)	95.2	94.7	94.2	93.7	93.2	92.7
.53	(.0177)	95.2	94.8	94.3	93.8	93.3	92.9
.54	(.0181)	95.3	94.9	94.4	93.9	93.5	93.0
.55	(.0186)	95.4	94.9	94.5	94.0	93.6	93.1
.56	(.0190)	95.5	95.0	94.6	94.1	93.7	93.2
.57	(.0195)	95.6	95.1	94.7	94.2	93.8	93.3
.58	(.0200)	95.6	95.2	94.8	94.3	93.9	93.4
.59	(.0205)	95.7	95.3	94.8	94.4	94.0	93.6
.60	(.0210)	95.8	95.4	94.9	94.5	94.1	93.7

Facility autocorrelation = 0.60

[1]In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-24: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER TEN YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0062)	92.4	91.6	90.9	90.1	89.4	88.6
.21	(.0066)	92.5	91.8	91.0	90.3	89.5	88.8
.22	(.0069)	92.6	91.9	91.1	90.4	89.7	88.9
.23	(.0072)	92.7	92.0	91.3	90.5	89.8	89.1
.24	(.0076)	92.8	92.1	91.4	90.7	89.9	89.2
.25	(.0079)	92.9	92.2	91.5	90.8	90.1	89.4
.26	(.0082)	93.0	92.3	91.6	90.9	90.2	89.5
.27	(.0086)	93.1	92.4	91.8	91.1	90.4	89.7
.28	(.0089)	93.2	92.6	91.9	91.2	90.5	89.8
.29	(.0093)	93.3	92.7	92.0	91.3	90.7	90.0
.30	(.0096)	93.4	92.8	92.1	91.5	90.8	90.1
.31	(.0100)	93.5	92.9	92.2	91.6	90.9	90.3
.32	(.0104)	93.6	93.0	92.3	91.7	91.1	90.4
.33	(.0107)	93.7	93.1	92.5	91.8	91.2	90.6
.34	(.0111)	93.8	93 2	92 6	92 0	91 3	90.7
.35	(0115)	93 9	93.3	92 7	92 1	91.5	90.9
.36	(.0118)	94.0	93.4	92.8	92.2	91.6	91.0
.37	(.0122)	94.1	93.5	92.9	92.3	91.7	91.1
.38	(.0126)	94.2	93.6	93.0	92.4	91.9	91.3
.39	(.0130)	94.3	93.7	93.1	92.6	92.0	91.4
.40	(.0134)	94.4	93.8	93.2	92.7	92.1	91.5
.41	(.0138)	94.5	93.9	93.3	92.8	92.2	91.7
.42	(.0142)	94.5	94.0	93.5	92.9	92.4	91.8
.43	(.0146)	94.6	94.1	93.6	93.0	92.5	91.9
.44	(.0150)	94.7	94.2	93.7	93.1	92.6	92.1
.45	(.0154)	94.8	94.3	93.8	93.2	92.7	92.2
.46	(.0159)	94.9	94.4	93.9	93.4	92.8	92.3
.47	(.0163)	95.0	94.5	94.0	93.5	93.0	92.5
.48	(.0167)	95.1	94.6	94.1	93.6	93.1	92.6
.49	(.0172)	95.1	94.6	94 2	93.7	93.2	92.7
.50	(.0176)	95.2	94.7	94.3	93.8	93.3	92.8
.51	(.0181)	95.3	94.8	94.4	93.9	93.4	92.9
.52	(.0185)	95.4	94.9	94.5	94.0	93.5	93.1
.53	(.0190)	95.5	95.0	94.5	94.1	93.6	93.2
.54	(.0195)	95.5	95.1	94.6	94.2	93.7	93.3
.55	(.0200)	95.6	95.2	94.7	94.3	93.9	93.4
.56	(.0205)	95.7	95.3	94.8	94.4	94.0	93.5
.57	(.0210)	95.8	95.3	94.9	94.5	94.1	93.6
.58	(.0215)	95.8	95.4	95.0	94.6	94.2	93.8
.59	(.0220)	95.9	95.5	95.1	94.7	94.3	93.9
.60	(.0226)	96.0	95.6	95.2	94.8	94.4	94.0

Facility autocorrelation = 0.65

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

EXHIBIT 2-25: MINIMUM GEOMETRIC MEAN EFFICIENCIES REQUIRED TO MAINTAIN NO MORE THAN ONE FAILURE PER TEN YEARS

Daily Std. Dev. (in log)	Std. Dev. of 30-Day Average[1]	Minimum Efficiency For Threshold Shown					
		<90%	<89%	<88%	<87%	<86%	<85%
.20	(.0068)	92.6	91.8	91.1	90.3	89.6	88.8
.21	(.0071)	92.7	91.9	91.2	90.5	89.7	89.0
.22	(.0075)	92.8	92.1	91.3	90.6	89.9	89.2
.23	(.0079)	92.9	92.2	91.5	90.8	90.1	89.3
.24	(.0082)	93.0	92.3	91.6	90.9	90.2	89.5
.25	(.0086)	93.1	92.4	91.7	91.0	90.4	89.7
.26	(.0090)	93.2	92.5	91.9	91.2	90.5	89.8
.27	(.0093)	93.3	92.7	92.0	91.3	90.7	90.0
.28	(.0097)	93.4	92.8	92.1	91.5	90.8	90.1
.29	(.0101)	93.5	92.9	92.2	91.6	90.9	90.3
.30	(.0105)	93.6	93.0	92.4	91.7	91.1	90.5
.31	(.0109)	93.7	93.1	92.5	91.9	91.2	90.6
.32	(.0112)	93.8	93.2	92.6	92.0	91.4	90.8
.33	(.0116)	93.9	93.3	92.7	92.1	91.5	90.9
.34	(.0120)	94.0	93.4	92.8	92.2	91.6	91.1
.35	(.0124)	94.1	93.5	93.0	92.4	91.8	91.2
.36	(.0128)	94.2	93.6	93.1	92.5	91.9	91.3
.37	(.0133)	94.3	93.8	93.2	92.6	92.0	91.5
.38	(.0137)	94.4	93.9	93.3	92.7	92.2	91.6
.39	(.0141)	94.5	94.0	93.4	92.9	92.3	91.8
.40	(.0145)	94.6	94.1	93.5	93.0	92.4	91.9
.41	(.0150)	94.7	94.2	93.6	93.1	92.6	92.0
.42	(.0154)	94.8	94.3	93.7	93.2	92.7	92.2
.43	(.0158)	94.9	94.4	93.8	93.3	92.8	92.3
.44	(.0163)	95.0	94.4	93.9	93.4	92.9	92.4
.45	(.0167)	95.0	94.5	94.0	93.5	93.1	92.6
.46	(.0172)	95.1	94.6	94.1	93.7	93.2	92.7
.47	(.0177)	95.2	94.7	94.2	93.8	93.3	92.8
.48	(.0182)	95.3	94.8	94.3	93.9	93.4	92.9
.49	(.0186)	95.4	94.9	94.4	94.0	93.5	93.1
.50	(.0191)	95.5	95.0	94.5	94.1	93.6	93.2
.51	(.0196)	95.5	95.1	94.6	94.2	93.7	93.3
.52	(.0201)	95.6	95.2	94.7	94.3	93.9	93.4
.53	(.0206)	95.7	95.3	94.8	94.4	94.0	93.5
.54	(.0212)	95.8	95.3	94.9	94.5	94.1	93.7
.55	(.0217)	95.8	95.4	95.0	94.6	94.2	93.8
.56	(.0222)	95.9	95.5	95.1	94.7	94.3	93.9
.57	(.0228)	96.0	95.6	95.2	94.8	94.4	94.0
.58	(.0233)	96.1	95.7	95.3	94.9	94.5	94.1
.59	(.0239)	96.1	95.8	95.4	95.0	94.6	94.2
.60	(.0245)	96.2	95.8	95.5	95.1	94.7	94.3

Facility autocorrelation = 0.70

[1] In computing the 30-day average variability, a geometric mean emission level of 92% was assumed.

2.3 METHODOLOGY

Monte-Carlo simulation techniques were used to generate the data in for the lognormal-distribution processes in exhibits 2-4 through 2-9. The IBM Scientific Subroutine Package uniform random number generator RANDU was used to generate the basic pseudo-random number stream for the analyses. Box and Muller's technique was used for generating pseudo-random normal random deviates (with an accuracy in the resultant distribution of at least six digits).[1] Lognormal deviates were generated by the exponential function from these normal deviates. All the estimates were generated using non-overlapping random-number streams of 720,000 days (2,000 years). The standard errors of the estimates were estimated by treating the 2,000 years as four replicated experiments of 500 years each. The computations were performed to 32 and 64 bit accuracy on a Hewlett-Packard Series 1000 Model F computer, and the runs consumed about 40 CPU hours of computation. The simulation was checked by comparing statistics for which exact results were known from theory, and all cases agreed to three or more digit accuracies (with sample periods of 8,000,000 days in this testing).

The normal-distribution estimates were generated by exact solution of the mathematical system, to accuracy of five or more decimals. Completely exact solutions of the lognormal case were not available, which led to the use of Monte-Carlo simulation. The critical values given in exhibits 2-10 through 2-25 could not be found with the required accuracy by simulation in the two-week term of this analysis, because

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[1]This technique is significantly more accurate in its results than those usually used in good statistical practice. It was used because of the requirement to estimate very small probabilities.

such a determination by simulating all points necessary to search for the critical values would have required approximately 2000 hours of computer time. Accordingly, mathematical methods were used to compute these values to within 0.2 percent. These methods, although derived from standard techniques, were developed specifically for this analysis. The techniques involve first using series approximations to the lognormal distribution function and to its thirtieth convolution with itself, so as to obtain accurate estimates of the third and fourth moments and cumulants of the statistical distribution of the thirty-day averages. (The first and second moments are known exactly in closed form.) These estimates are then used in Edgeworth and Cornish-Fisher series expansions of the distribution of the thirty-day averages, from which expected rates of threshold failures and critical values can be completed. It was found that only one non-normal term of the Edgeworth expansion was required to achieve the desired accuracy. These methods were compared with the simulation techniques to verify their accuracy (and the accuracy of the computer implementations used.) All results were within 0.1 percent of the correct values as determined by simulation, indicating that the expansions are somewhat more accurate in the region of interest than the guaranteed bound of 0.2 percent we obtained analytically. The exact expression used to compute the critical minimum-efficiency values reported above is given in exhibit 2-26.

EXHIBIT 2-26: FORMULA FOR ESTIMATING THE GEOMETRIC MEAN EFFICIENCY AT WHICH A LOGNORMAL PROCESS WILL ACHIEVE A RATE OF ROLLING-AVERAGE THRESHOLD FAILURES BELOW ONE PER YEAR[1]

$$1 - \frac{1 - Z}{\left(2.773 + 1.115 \dfrac{\sigma\left[60 + 4f(r^2) + 2f(r) + 4\sum_{1}^{29}(30-i)(i-1)r^{i} + 8\sum_{1}^{29}(30-i)\dfrac{r^{i+1}(1-r^{i-1})}{1-r}\right]}{18000\,[.0333 + .00222\, f(r)]^{3/2}}\right) X + e^{\sigma^2/2}}$$

with

$f(r) = r/(1-r) - y(1-r^{30})/(1-r)^2$ and similarly for $f(r^2)$

$r = (e^{\rho\sigma^2} - 1)/(e^{\sigma^2} - 1)$

$w = e^{\sigma^2/2}$

and

$x = [\, e^{\sigma^2}(e^{\sigma^2} - 1)(.0333 + .00222\, f(r))\,]^{1/2}$

where

σ and ρ are the parameters describing the variability and autocorrelation of the lognormal process and Z is the threshold at which the rate of failures is to be $\leq$ 1/year.

[1] Other critical rates involve changes in the constants 2.773 and 1.115.

3.0 DESCRIPTIVE STATISTICS ON FGD SYSTEM EFFICIENCY DATA

Basic descriptive statistics were required in construction of the model simulating the variable efficiency of steam generating units. The appropriate model structure and statistical distribution characteristics were determined from an examination of observations reported from eleven operating units. In addition, operating system parameters were varied over ranges determined partly on the basis of parameter estimates made from the data. This chapter consists of four sections describing the observations and statistical analyses of them.

Section 3.1 defines the variable analyzed and describes the data base used. A lognormal description of the analysis variable was used by EPA and Entropy in previous analysis of this data. Section 3.2 discusses the appropriateness of such a description. As was shown in the analysis reported in chapter 2.0, the issue of distributional form has little influence on the principal results. In section 3.3 the means, standard deviations, and autocorrelation factors are presented for each of the eleven units. Differences in these parameters among the eleven units are also noted. Additionally, the appropriateness of a first-order autogressive model is discussed. Section 3.4 discusses possible confounding of results caused by variation in the sulfur content of untreated emissions.

3.1 DATA SET

Data on the efficiency factor from eleven electric utility steam generating units were provided to VRI by the EPA. The data which was received in printed tabular form was believed to be that previously

analyzed by EPA and Entropy. The eleven units, the number of observations from each and the time period in which the observations were made are described in exhibit 3-1. Each observation represents a twenty-four hour average of FGD system efficiency calculated from the unput and output emission levels at each unit. (Efficiency was defined as the percentage of SO_2 removed from the gas flow through the scrubbing process.)

As shown in exhibit 3-1, the amount and time frame of the data differed significantly from one unit to the next. The limited number of observations from the Philadelphia and Pittsburgh II units make the data from these two facilities of limited use. The twenty-four data points from Conesville A and the twenty-one from Conesville B represent the only measurements taken over a six-month period. Further, the data set for any individual unit was generally characterized by intermittant data voids. This scattering of data points limits the degree of certainty with which any inferences concerning the correlation structure of the process should be reviewed.

3.2 LOGNORMAL TRANSFORMATION

3.2.1 THE UNTRANSFORMED VARIABLE

An analysis of the distribution of the efficiency values for each of the units indicated that at least four were clearly negatively skewed (see exhibit 3-2). Skewness, the third moment about the mean, measures the degree to which a distribution is unbalanced or "off-center". A negative skewness factor indicates a distribution with a long left-hand tail. A variable with a normal distribution is balanced and has a skewness of zero. Two of the units with significant skewness were also

EXHIBIT 3-1: ANALYSIS DATA BASE DESCRIPTION

Steam Generating Unit	Number of Observations	Time Period During Which Observations Were Made	
Louisville North	66	July 21, 1977 - Dec. 23, 1977	(156 days)
Louisville South	89	July 21, 1977 - Dec. 23, 1977	(156 days)
Pittsburgh I	20	Sept. 14, 1977 - Nov. 9, 1977	(57 days)
Pittsburgh II	11	Nov. 10, 1977 - Dec. 6, 1977	(27 days)
Philadelphia	8	Sept. 18, 1977 - Oct. 9, 1977	(22 days)
Chicago	52	Aug. 9, 1977 - Nov. 23, 1977 July 30, 1978 - Sept. 8, 1978	(107 days) (41 days)
Shawnee TCA	42	Dec. 7, 1978 - Jan. 25, 1979	(49 days)
Shawnee Venturi	31	Dec. 7, 1978 - Jan. 29, 1979	(51 days)
Conesville A	24	June 15, 1978 - Dec. 13, 1978	(183 days)
Conesville B	21	June 15, 1978 - Dec. 13, 1978	(183 days)
Lawrence	30	Jan. 16, 1979 - Feb. 21, 1979	(37 days)

EXHIBIT 3-2: SKEWNESS[1] AND KURTOSIS[2] FACTORS AND SIGNIFICANCE[3]

	UNTRANSFORMED VARIABLE (Efficiency)				TRANSFORMED VARIABLE Log (1 - efficiency)			
Unit	Skewness	Significant at .05	Kurtosis	Significant at .05	Skewness	Significant at .05	Kurtosis	Significant at .05
Louisville North	-.507	Yes	-.167	No	-.241	No	.006	No
Louisville South	-.480	No	-.409	No	-.302	No	-.118	No
Pittsburgh I	-.467	No	.062	No	-.206	No	.120	No
Pittsburgh II	-1.085	No	.357	No	.725	No	-.271	No
Philadelphia	-.765	No	.266	No	-.132	No	-.142	No
Chicago	-.972	Yes	3.707	Yes	.210	No	2.173	Yes
Shawnee TCA	-.629	Yes	-.015	No	.219	No	-.452	No
Shawnee Ventur	-.539	No	-.399	No	-.099	No	-.821	No
Conesville A	-.284	No	.005	No	-.574	No	-.660	No
Conesville B	-.351	No	-.574	No	-.654	No	.115	No
Lawrence	-1.333	Yes	1.140	Yes	-.022	No	-.854	No

[1]Skewness measures the degree to which the distribution is "off-center". A negative skew indicates a long left-hand tail. This factor is zero for a normal distribution.

[2]Kurtosis measures the degree of peakedness in the distribution. A positive value indicates a high peak and a negative value indicates a flatter peak. This factor is zero for normal distribution.

[3]"Significant at .05" indicates 95 percent certainty that the distribution is different from a normal distribution in this characteristic.

EXHIBIT 3-1: ANALYSIS DATA BASE DESCRIPTION

Steam Generating Unit	Number of Observations	Time Period During Which Observations Were Made	
Louisville North	66	July 21, 1977 - Dec. 23, 1977	(156 days)
Louisville South	89	July 21, 1977 - Dec. 23, 1977	(156 days)
Pittsburgh I	20	Sept. 14, 1977 - Nov. 9, 1977	(57 days)
Pittsburgh II	11	Nov. 10, 1977 - Dec. 6, 1977	(27 days)
Philadelphia	8	Sept. 18, 1977 - Oct. 9, 1977	(22 days)
Chicago	52	Aug. 9, 1977 - Nov. 23, 1977 July 30, 1978 - Sept. 8, 1978	(107 days) (41 days)
Shawnee TCA	42	Dec. 7, 1978 - Jan. 25, 1979	(49 days)
Shawnee Venturi	31	Dec. 7, 1978 - Jan. 29, 1979	(51 days)
Conesville A	24	June 15, 1978 - Dec. 13, 1978	(183 days)
Conesville B	21	June 15, 1978 - Dec. 13, 1978	(183 days)
Lawrence	30	Jan. 16, 1979 - Feb. 21, 1979	(37 days)

EXHIBIT 3-2: SKEWNESS[1] AND KURTOSIS[2] FACTORS AND SIGNIFICANCE[3]

	UNTRANSFORMED VARIABLE (Efficiency)				TRANSFORMED VARIABLE Log (1 - efficiency)			
Unit	Skewness	Significant at .05	Kurtosis	Significant at .05	Skewness	Significant at .05	Kurtosis	Significant at .05
Louisville North	-.507	Yes	-.167	No	-.241	No	.006	No
Louisville South	-.480	No	-.409	No	-.302	No	-.118	No
Pittsburgh I	-.467	No	.062	No	-.206	No	.120	No
Pittsburgh II	-1.085	No	.357	No	.725	No	-.271	No
Philadelphia	-.765	No	.266	No	-.132	No	-.142	No
Chicago	-.972	Yes	3.707	Yes	.210	No	2.173	Yes
Shawnee TCA	-.629	Yes	-.015	No	.219	No	-.452	No
Shawnee Ventur	-.539	No	-.399	No	-.099	No	-.821	No
Conesville A	-.284	No	.005	No	-.574	No	-.660	No
Conesville B	-.351	No	-.574	No	-.654	No	.115	No
Lawrence	-1.333	Yes	1.140	Yes	-.022	No	-.854	No

[1]Skewness measures the degree to which the distribution is "off-center". A negative skew indicates a long left-hand tail. This factor is zero for a normal distribution.

[2]Kurtosis measures the degree of peakedness in the distribution. A positive value indicates a high peak and a negative value indicates a flatter peak. This factor is zero for normal distribution.

[3]"Significant at .05" indicates 95 percent certainty that the distribution is different from a normal distribution in this characteristic.

found to have a significantly non-zero kurtosis. Kurtosis, a function of the fourth moment about the mean, is often considered to measure the degree of peakedness in the distribution. A positive value indicates a higher peak (and longer tails) than in the normal distribution and a negative value indicates a flatter peak. A variable with a normal distribution has a kurtosis of zero.

Since the negative skewness was a significant and consistant feature of the efficiency variable, the $\log_e$ transformation performed by both EPA and Entropy in previous analyses of the data might be expected to produce a variable with a more normal distribution.

3.2.2 THE TRANSFORMED VARIABLE

The transformation variable used is log (1-efficiency). For most of the units, the transformation improved the normality of the distribution significantly. This improvement can be seen in the skewness and kurtosis values for the untransformed and transformed variable, displayed in exhibit 3-2. The significance column of the display indicates the certainty with which the sample statistic implies an actual departure from the normal distribution.

Exhibit 3-3 presents the arithmetic medians, means, and standard deviations predicted for the observations under the lognormal assumption. Comparison of these predicted values with the actual sample statistics provides an intuitive feel for the goodness of fit of the lognormal distribution. The lognormal assumption results in accurate predictions except in the estimates of standard deviations at the Conesville and Lawrence units.

EXHIBIT 3-3: COMPARISON OF ARITHMETIC VALUES PREDICTED BY THE LOGNORMAL DISTRIBUTION ASSUMPTION WITH ESTIMATES FROM THE OBSERVATIONS

	Arithmetic Values Predicted By Lognormal Assumptions			Observed Estimates From Untransformed Variable		
Unit	Median	Mean	Standard Deviation	Median	Mean	Standard Deviation
Louisville North	84.4	83.8	4.9	84.6	83.8	4.7
Louisville South	83.3	82.2	6.2	83.3	82.3	5.9
Pittsburgh I	80.8	80.2	4.5	81.2	80.3	4.6
Pittsburgh II	85.4	85.0	3.2	86.1	85.1	3.4
Philadelphia	97.0	96.8	1.2	96.7	96.8	1.2
Chicago	89.2	89.1	1.3	88.9	89.1	1.3
Shawnee TCA	88.5	88.3	2.2	88.5	88.3	2.2
Shawnee Venturi	96.0	95.8	1.6	95.7	95.8	1.5
Conesville A	86.0	84.5	7.3	84.1	84.7	6.1
Conesville B	92.5	91.6	4.2	91.9	91.7	3.5
Lawrence	95.4	93.4	6.6	95.3	93.6	5.3

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[1]For lognormal distributions: (the quantity (1-efficiency) is lognormally distributed).

Median = e^{μ}

Mean = $e^{\mu}e^{\sigma^2/2}$

Standard Deviation = $e^{\mu}e^{\sigma^2/2}(e^{\sigma^2}-1)^{1/2}$

μ = mean of logarithmic variable.
σ = Standard deviation of logarithmic variable.

In spite of the apparent better agreement between the lognormal distribution and that data, Kolmogorov-Smirnov tests comparing both normal and lognormal distributions with the data indicated that either assumption could be accepted.

Overall, then, the lognormal distribution presents a slightly better characterization of the efficiency data than the normal. However, from the available data, it is evident that the lognormal description is not an ideal fit for all cases, and that the distribution is also very nearly normal in many of the cases.

3.3 ESTIMATED PARAMETERS AND COMPARABILITY AMONG UNITS

3.3.1 MEANS AND STANDARD DEVIATIONS

Exhibit 3-4 presents the medians, means, and standard deviations of the transformed variable, log (1-efficiency). The differences in the means and standard deviations among the eleven units can readily be seen from examination of the exhibit. Statistical tests[1] were performed on the differences in means and variances for each pair of units. (The variance is the square of the standard deviation.) The results of these tests are presented in exhibits 3-5 and 3-6. The level of significance indicates the probability of the observed difference occurring by chance if, in reality, there was no difference between the two means (or variances). For example, the significance of the difference in variances between the Louisville South and Pittsburgh I units is .0305. This means that if there were really no difference in the variances at these units,

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[1]T-tests were performed on the means and F-tests on the variances.

EXHIBIT 3-4: ESTIMATED PARAMETERS OF TRANSFORMED VARIABLE

UNIT	MEDIAN	MEAN (μ)	STANDARD DEVIATION (σ)
Louisville North	-1.8836	-1.8608	.295
Louisville South	-1.7910	-1.7868	.343
Pittsburgh I	-1.6885	-1.6492	.234
Pittsburgh II	-1.9729	-1.9223	.212
Philadelphia	-3.5143	-3.4927	.359
Chicago	-2.2047	-2.2217	.118
Shawnee TCA	-2.1840	-2.1608	.182
Shawnee Venturi	-3.1353	-3.2270	.368
Conesville A	-1.8798	-1.9626	.447
Conesville B	-2.5170	-2.5884	.474
Lawrence	-3.0791	-3.0714	.835

EXHIBIT 3-5: STATISTICAL SIGNIFICANCE OF DIFFERENCES IN VARIABILITIES AT DIFFERENT FACILITIES

SIGNIFICANCES OF DIFFERENCES IN SITES

Unit/Unit	Louisville North	Louisville South	Pittsburgh I	Pittsburgh II	Philadelphia	Chicago	Shawnee TCA	Shawnee Ventur	Conesville A	Conesville B	Lawrence
Louisville North											
Louisville South	.1037										
Pittsburgh I	.1288	.0305									
Pittsburgh II	.1277	.0492	.3882								
Philadelphia	.1905	.3721	.0652	.0645							
Chicago	.0000	.0000	.0000	.0026	.0000						
Shawnee TCA	.0000	.0000	.0891	.2335	.0025	.0017					
Shawnee Venturi	.0000	.2964	.0209	.0347	.5157	.0000	.0000				
Convesville A	.2145	.0405	.0028	.0092	.2845	.0000	.0000	.1574			
Convesville B	.0000	.0207	.0016	.0062	.2306	.0000	.0000	.1025	.3908		
Lawrence	.0000	.0000	.0000	.0000	.0136	.0000	0000	.0000	.0015	.0054	

[1]Significance refers to the probability that the observed difference could have occurred by chance even if there were no real difference in the factors compared. A significance of .05 or less is usually considered to be of statistical importance.

EXHIBIT 3-6: STATISTICAL SIGNIFICANCE OF DIFFERENCES IN GEOMETRIC MEAN EMISSIONS AT FACILITIES

SIGNIFICANCES OF DIFFERENCES IN SITES

Unit/Unit	Louisville North	Louisville South	Pittsburgh I	Pittsburgh II	Philadelphia	Chicago	Shawnee TCA	Shawnee Ventur	Conesville A	Conesville B	Lawrence
Louisville North		.2249	.0276	.6148	.0000	.0000	.0001	.0000	.2554	.0000	.0000
Louisville South			.1389	.2587	.0000	.0000	.0000	.0000	.0421	.0000	.0000
Pittsburgh I				.0530	.0000	.0000	.0000	.0000	.0060	.0000	.0000
Pittsburgh II					.0000	.0166	.0612	.0000	.7680	.0000	.0000
Philadelphia						.0000	.0000	.0747	.0000	.0000	.0050
Chicago							.4342	.0000	.0054	.0002	.0000
Shawnee TCA								.0000	.0395	.0000	.0000
Shawnee Venturi									.0000	.0000	.1061
Convesville A										.0000	.0000
Convesville B											.0000
Lawrence											

[1]Significance refers to the probability that the observed difference could have occurred by chance even if there were no real difference in the factors compared. A significance of .05 or less is usually considered to be of statistical importance.

3.05 percent of random samples drawn from these units would produce a difference in sample variance of the observed magnitude. A significance level of .05 or lower is usually considered to be clear evidence of a difference.

The variances at the Chicago and Shawnee TCA units were significantly lower than the variances at almost all of the other units. EPA officials noted that both of these units are well run and a low variability in efficiency was expected. The Pittsburgh II unit was described as being similar to the Shawnee TCA units, but because of the limited number of observations the results are of less interest. The significantly high variance at the Lawrence unit is believed by EPA officials to be the result of an unusually low sulfur content of the coal.

Because of the highly significant differences in the variances among the units examined and the inaccurate estimation of variance at the Conesville and Lawrence units, it is not appropriate to combine these variances for analysis.

3.3.2 AUTOCORRELATION

The lag-one autocorrelation estimates for each of the eleven units are presented in exhibit 3-7, along with the number of observations from which the estimates were drawn and the significance of the factor. (The observations included were those for which there was also an observation on the preceding or succeeding day.) The level of significance is dependent on the number of observations, hence the autocorrelation factor of 0.6255 at the Conesville B unit is not significant because it is based on only seven observations while the autocorrelation factor of 0.5995 at

EXHIBIT 3-7: FIRST-ORDER AUTOCORRELATION FACTORS ON THE VARIABLE LOG (1 - EFFICIENCY)

UNIT	N	Autocorrelation[1]	Significant at .05 level
Louisville North	49	.6955	yes
Louisville South	72	.6949	yes
Pittsburgh I	11	.4683	no
Pittsburgh II	7	-.1428	no
Philadelphia	5	.2524	no
Chicago	37	.6983	yes
Shawnee TCA	37	.5995	yes
Shawnee Venturi	25	.8897	yes
Conesville A	13	.7131	yes
Conesville B	7	.6255	no
Lawrence	27	.6386	yes

[1] The autocorrelation was determined by comparing day 't' with day 't-1'; the data was not collapsed and missing data was not filled in, so that only the observation days which were preceded or followed by another observation day were included.

Shawnee TCA is significant. It seems almost certain that first-order autocorrelation does, in fact, exist at most or all units. Entropy used an estimate of 0.7 in their simulation model. This appears to be an appropriate value if the model is dealing with a unit similar to one of the Louisville units. However, for units more similar to the Shawnee TCA unit, 0.6 would be a more reasonable estimate. Differences in operational procedures at the units are an unknown but probably relevant factor.

3.3.3 AUTOREGRESSIVE MODEL

The possibility of autocorrelation factors associated with lags of two or more was also examined. A first-order autogressive model is one in which the variable in time "t" is a function of the same variable in time "t-1". A second-order autogressive model was compared with a first-order autogressive model. A comparison of the residual led to the conclusion that the first-order autogressive model is appropriate. A further examination of partial correlations up to a lag of ten led to the conclusion that the first-order autogressive model is appropriate.

3.4 POSSIBLE CONFOUNDING FACTORS

It is recognized that many other factors may be related to the efficiency variable. It was suspected that the efficiency factor at a given unit might be related to the level of sulfur in the raw emissions. Data was available for all but the Lawrence unit on the pounds per million BTUs of sulfur in the gas before processing. The Pittsburgh I and Conesville scrubbers processed gas with a significantly higher average sulfur content than the other units (see exhibit 3-8). No

EXHIBIT 3-8: COMPARISON OF MEAN SULFUR CONTENT OF INPUT EMISSIONS AND MEAN EFFICIENCY

UNIT	MEAN SULFUR CONTENT OF INPUT EMISSIONS (lb/MMBTU)	MEAN OF EFFICIENCY (Arithmetic Equivalent of Transformed Variable)
Louisville North	5.653	83.8
Louisville South	5.687	82.2
Pittsburgh I	6.647	80.2
Pittsburgh II	5.462	85.0
Philadelphia	5.049	96.8
Chicago	5.643	89.1
Shawnee TCA	5.555	88.3
Shawnee Venturi	5.660	95.8
Conesville A	7.793	84.5
Conesville B	7.359	91.6
Lawrence	NA	93.4

relationship appeared to exist, however, between mean efficiency at a unit and the mean level of sulfur before scrubbing.

Within individual units, statistically significant correlations between efficiency and sulfur content were found at two units, the Chicago unit and the Shawnee TCA unit. At the Shawnee TCA unit, the relationship was the expected negative one (-.45) with increasing sulfur content leading to decreasing efficiency. At the Chicago unit, however, a positive correlation (.47) was found, with increasing sulfur content leading to increasing efficiency.

On the basis of the evidence, then, one must conclude that there is no predictable relation between the actual levels of sulfur emissions before scrubbing and the efficiency of the scrubbing operation, and that the analyses reported here are not contaminated by any confounding effect of this nature.

Many additional factors are of probable relevance in determining the efficiency levels of scrubbers. Operating procedures can be altered to compensate for high or low sulfur content as well as high or low electricity demands. The location and type of measuring device used can affect efficiency readings. The age, type, and condition of the scrubber equipment may also affect efficiency. The present data set does not offer any evidence of the types or magnitudes of any effects from these or other sources.

4.0 COMPARISON WITH ENTROPY RESULTS

This chapter summarizes the degree to which the findings in the preceding chapters appear to agree with the results developed by Entropy Environmentalists, Incorporated. It is organized into two sections which parallel the material presented in chapters 2.0 and 3.0. In the first section the number of exceedences predicted by Entropy are compared to those predicted by VRI, with a potential explanation of the observed differences. The second section compares the VRI and Entropy descriptions of the statistical structure characterizing the efficiency of eleven flue gas desulfurization (FGD) units at eight electric utility sites. The disparities between the Entropy and VRI estimates of process parameter values are examined, and rationales for these differences are discussed.

4.1 PREDICTED EXCEEDENCES

Although the details of Entropy's 1,000 year simulation were not available, VRI believes the material presented in chapter 2.0 nearly replicates the Entropy approach. Some differences between the VRI and Entropy simulated data are attributable to the inherent random nature of the simulation process itself and the slight improvement in confidence levels of VRI's figures produced as a consequence of the doubling of the number of simulated years (2,000 instead of 1,000). Where VRI used parameters comparable to those reported by Entropy, reasonably similar numbers of exceedences were predicted.

Although these results show generally the same pattern of effects, there are differences greater than can be explained by chance effects.

In view of the great care taken in this analysis, including special rechecking of the disparate results, we suspect that the Entropy results are probably less accurate where differences exist, possibly due to the use of less accurate random number generation and transformation techniques. In this connection, it is worth noting that VRI's estimates were generated using methods considerably more precise than usually found in good statistical practice. This extra precision was required in view of the requirements to make accurate estimates of extremely small probabilities.

Despite these minor differences, VRI's results substantiate Entropy's conclusion that the number of exceedences per year is extremely sensitive to the median (or mean) FGD system efficiency and the variability in this efficiency. VRI-simulated values nearly replicate Entropy's findings that the degree of autocorrelation can affect the number of exceedences although with less impact than variation in the mean and variance. VRI's analyses also provide information not provided by Entropy such as the data in exhibits 2-10 through 2-15; in these areas, no comparisons are possible.

4.2 PROCESS STRUCTURE

Analysis of the 24-hour FGD efficiency data indicate that the measured values of efficiency are not symetrically distributed about their mean, generally weakening any normal distribution hypothesis. VRI's analysis agrees with the Entropy and EPA findings that the quantity (1-efficiency) has a distribution which can be reasonably approximated by a lognormal distribution. There are many other candidate distributions

which might equally well be used to describe the observed distribution of efficiency values. As shown in chapter 2.0, adoption of other distributions would not significantly influence the analysis results, but instead might confuse major differences between the Entropy and VRI results with insignificant discrepancies. Consequently, the above analysis used primarily the lognormal distribution hypothesis proposed by EPA and concurred with by Entropy.

Entropy further found that the FGD efficiency data had significant first-order autocorrelation. VRI's results upheld this finding even though VRI's estimate of autocorrelation was based on consecutive calendar days rather than the method suggested by Entropy's statistical consultant which collapsed serial data into a string of days for which data were available. In addition, VRI's negative finding on the presence of higher order autocorrelation helped to validate the Entropy implicit assumption that first-order (one day) lags were sufficient to describe process time dependencies.

VRI used a data base which appeared to be approximately, but not exactly, the same as that employed in the Entropy analysis. Specific differences between the data provided are evidenced: (1) by disparities in the numbers of observations at particular sites; and (2) by differences in numerical estimates. Disparities in the numbers of observations occurred for two of the utilities reported, i.e.:

	Number of Observations	
Site	VRI	Entropy
Chicago	52	35
Shawnee TCA	42	37

Entropy does not report the number of observations from the Lawrence unit, so comparisons cannot be made. VRI-estimated parameter values for σ and μ generally differ from Entropy's estimates by no more than two percent except for the following sites.

	Logarithmic Parameter Values					
Site	μ_{VRI}	σ_E	μ_{VRI}	σ_E	μ_{VRI}	σ_E
Chicago	-2.222	-2.206	.118	.106	.698	.86
Shawnee TCA	-2.161	-2.168	.182	.186	.600	.65
Lawrence	-3.071	-3.437	.835	.676	.639	N/A

As noted above, VRI and Entropy were not using identical data bases for the Chicago and Shawnee TCA sites. It is expected that the differences at the Lawrence site may also be the result of a different data base. Finally, the Entropy data base combined observations from the Louisville north and south units into a single site (Cane Run) while they were treated separately in VRI's analysis. Entropy notes that averaging the results of these two units reduces the overall variability of the combined sites. This effect is illustrated by the difference between the two VRI logarithmic estimates of for Louisville (0.295 and 0.343) and the single average Louisville estimate reported by Entropy (0.289).

4.3 DIFFERENCES AMONG SITES

VRI and Entropy agree in finding that the evidence from existing utility boiler units shows statistically significant differences in the levels of variability at different sites. VRI has assumed that at least some of its variability represents differences in engineering design and operating practices, including some designs and/or operating practices

which may not represent the future state of the art for boiler units. VRI therefore did not combine all the data together to estimate future site variability. Entropy, in its analysis of these differences, did combine the data to generate forecasting intervals, discussed in terms of levels of correctness. In this analysis, Entropy assumed that future sites would have levels of variability distributed as broadly as the variabilities observed at existing sites. Thus, Entropy assumed that the data from each of the existing sites constitutes a sample representating appropriate state of the art design and operating practices which would be used in future facilites. Without this assumption, there is no justification for using forecasting intervals based on the complete range of variabilities.

Rather than adopt this strong assumption, VRI has chosen to present the bulk of its results in parametric form covering the range of variabilities, leaving engineering analysis (combined with the data from chapters 2.0 and 3.0) to identify the levels of variability which should actually be expected at future sites. EPA personnel suggested that Shawnee TCA and Pittsburgh II might be the best representatives of future practices. Statistical analysis of these two sites suggests that they had a common variability. Accordingly, a confidence interval for the variability at these sites was presented in chapter 2.0. A confidence interval is also presented there for the Louisville units.

APPENDIX E

EPA RESPONSE TO PETITIONS FOR RECONSIDERATION

federal register

Wednesday
February 6, 1980

Part IV

Environmental Protection Agency

Standards of Performance for New Stationary Sources for Electric Utility Steam Generating Units; Decision in Response to Petitions for Reconsideration

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[FRL 1404-6]

Standards of Performance for New Stationary Sources; Electric Utility Steam Generating Units; Decision in Response to Petitions for Reconsideration

AGENCY: Environmental Protection Agency (EPA).

ACTION: Denial of Petitions for Reconsideration of Final Regulations.

SUMMARY: The Environmental Defense Fund, Kansas City Power and Light Company, Sierra Club, Sierra Pacific Power Company and Idaho Power Company, State of California Air Resources Board, and Utility Air Regulatory Group submitted petitions for reconsideration of the revised new source performance standards for electric utility steam generating units that were promulgated on June 11, 1979 (44 FR 33580). The petitions were evaluated collectively since the petitioners raised several overlapping issues. When viewed collectively, the petitioners sought reconsideration of the standards of performance for sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x). In denying the petitions, the Administrator found that the petitioners had failed to satisfy the statutory requirements of section 307(d)(7)(B) of the Clean Air Act. That is, the petitioners failed to demonstrate either (1) that it was impractical to raise their objections during the period for public comment or (2) that the basis of their objection arose after the close of the period for public comment and the objection was of central relevance to the outcome of the rule. This notice also responds to certain procedural issues raised by the Environmental Defense Fund (EDF). It should be noted that the Natural Resources Defense Council (NRDC) filed a July 9, 1979, letter in which they concurred with the procedural issues raised by EDF.

DATES: Effective February 6, 1980.

Interested persons may advise the Agency of any technical errors by March 7, 1980.

ADDRESSES: EPA invites information from interested persons. This information should be sent to: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

Docket Number OAQPS-78-1 contains all supporting materials used by EPA in developing the standards, including public comments and materials pertaining to the petitions for reconsideration. The docket is available for public inspection and copying between 9:00 a.m. and 4:00 p.m., Monday through Friday at EPA's Central Docket Section, Room 2903B, Waterside Mall, 401 M Street, SW., Washington, D.C. 20460.

FOR FURTHER INFORMATION CONTACT: Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone (919) 541-5271.

SUPPLEMENTARY INFORMATION:

Background

On September 19, 1978, pursuant to Section 111 of the Clean Air Act Amendments of 1977, EPA proposed revised standards of performance to limit emissions of sulfur dioxide (SO_2), particulate matter, and nitrogen oxides (NO_x) from new, modified, and reconstructed electric utility steam generating units (43 FR 42154). A public hearing was held on December 12 and 13, 1978. In addition, on December 8, 1978, EPA published additional information on the proposed rule (43 FR 57834). In this notice, the Administrator set forth the preliminary results of the Agency's analysis of the environmental, economic, and energy impacts associated with several alternative standards. This analysis was also presented at the public hearing on the proposed standards. The public comment period was extended until January 15, 1979, to allow for comments on this information.

After the Agency had carefully evaluated the more than 600 comment letters and related documents, the Administrator signed the final standards on June 1, 1979. In turn, they were promulgated in the Federal Register on June 11, 1979.

On June 1, 1979, the Sierra Club filed a petition for judicial review of the standards with the United States Court of Appeals for the District of Columbia. Additional petitions were filed by Appalachian Power Company, et al., the Environmental Defense Fund, and the State of California Air Resources Board before the close of the filing period on August 10, 1979.

In addition, pursuant to section 307(d)(7)(B) of the Clean Air Act, the Environmental Defense Fund, Kansas City Power and Light Company, Sierra Club, Sierra Pacific Power Company and Idaho Power Company, State of California Air Resources Board, and Utility Air Regulatory Group petitioned the Administrator for reconsideration of the revised standards.

Section 307(d)(7)(B) of the Act provides that:

> Only an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review. If the person raising an objection can demonstrate to the Administrator that it was impracticable to raise such objection within such time or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of the rule, the Administrator shall convene a proceeding for reconsideration of the rule and provide the same procedural rights as would have been afforded had the information been available at the time the rule was proposed. If the Administrator refuses to convene such a proceeding, such person may seek review of such refusal in the United States Court of Appeals for the appropriate circuit (as provided in subsection (b)).

The Administrator's findings and responses to the issues raised by the petitioners are presented in this notice.

Summary of Standards

Applicability

The standards apply to electric utility steam generating units capable of firing more than 73 MW (250 million Btu/hour) heat input of fossil fuel, for which construction is commenced after September 18, 1978. Industrial cogeneration facilities that sell less than 25 MW of electricity, or less than one-third of their potential electrical output capacity, are not covered. For electric utility combined cycle gas turbines, applicability of the standards is determined on the basis of the fossil-fuel fired to the steam generator exclusive of the heat input and electrical power contribution of the gas turbine.

SO_2 Standards

The SO_2 standards are as follows:

(1) Solid and solid-derived fuels (except solid solvent refined coal): SO_2 emissions to the atmosphere are limited to 520 ng/J (1.20 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required at all times except when emissions to the atmosphere are less than 260 ng/J (0.60 lb/million Btu) heat input. When SO_2 emissions are less than 260 ng/J (0.60 lb/million Btu) heat input, a 70 percent reduction in potential emissions is required. Compliance with the emission

limit and percent reduction requirements is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average. The percent reduction is computed on the basis of overall SO_2 removed by all types of SO_2 and sulfur removal technology, including flue gas desulfurization (FGD) systems and fuel pretreatment systems (such as coal cleaning, coal gasification, and coal liquefaction). Sulfur removed by a coal pulverizer or in bottom ash and fly ash may be included in the computation.

(2) Gaseous and liquid fuels not derived from solid fuels: SO_2 emissions into the atmosphere are limiteed to 340 ng/J (0.80 lb/million Btu) heat input, and a 90 percent reduction in potential SO_2 emissions is required. The percent reduction requirement does not apply if SO_2 emissions into the atmosphere are less than 86 ng/J (0.20 lb/million Btu) heat input. Compliance with the SO_2 emission limitation and percent reduction is determined on a continuous basis by using continuous monitors to obtain a 30-day rolling average.

(3) Anthracite coal: Electric utility steam generating units firing anthracite coal alone are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit on a 30-day rolling average, and all other provisions of the regulations including the particulate matter and NO_x standards.

(4) Noncontinental areas: Electric utility steam generating units located in noncontinental areas (State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, and the Northern Marina Islands) are exempt from the percentage reduction requirement of the SO_2 standard but are subject to the applicable SO_2 emission limitation and all other provisions of the regulations including the particulate matter and NO_x standards.

(5) Resource recovery facilities: Resource recovery facilities which incorporate electric utility steam generating units that fire less than 25 percent fossil-fuel on a quarterly (90-day) heat input basis are not subject to the percentage reduction requirements but are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit. Compliance with the emission limit is determined on a continuous basis using continuous monitoring to obtain a 30-day rolling average. In addition, such facilities must monitor and report their heat input by fuel type.

(6) Solid solvent refined coal: Electric utility steam generating units firing solid solvent refined coal (SRC I) are subject to the 520 ng/J (1.20 lb/million Btu) heat input emission limit (30-day rolling average) and all requirements under the NO_x and particulate matter standards. Compliance with the emission limit is determined on a continuous basis using a continuous monitor to obtain a 30-day rolling average. The percentage reduction requirement, which is obtained at the refining facility itself, is 85 percent reduction in potential SO_2 emissions on a 24-hour (daily) averaging basis. Compliance is to be determined by Method 19. Initial full-scale demonstration facilities may be granted a commercial demonstration permit establishing a requirement of 80 percent reduction in potential emissions on a 24-hour (daily) basis.

Particulate Matter Standards

The particulate matter standard limits emissions to 13 ng/J (0.03 lb/million Btu) heat input. The opacity standard limits the opacity of emissions to 20 percent (6-minute average). The standards are based on the performance of a well-designed and operated baghouse or electrostatic precipitator.

NO_x Standards

The NO_x standards are based on combustion modification and vary according to the fuel type. The standards are:

(1) 86 ng/J (0.20 lb-million Btu) heat input from the combustion of any gaseous fuel, except gaseous fuel derived from coal;

(2) 130 ng/J (0.30 lb/million Btu) heat input from the combustion of any liquid fuel, except shale oil and liquid fuel derived from coal;

(3) 210 ng/J (0.50 lb/million Btu) heat input from the combustion of subbituminous coal, shale oil, or any solid, liquid, or gaseous fuel derived from coal;

(4) 340 ng/J (0.80 lb/million Btu) heat input from the combustion in a slag tap furnace of any fuel containing more than 25 percent, by weight, lignite which has been mined in North Dakota, South Dakota, or Montana;

(5) Combustion of a fuel containing more than 25 percent, by weight, coal refuse is exempt from the NO_x standards and monitoring requirements; and

(6) 260 ng/J (0.60 lb/million Btu) heat input from the combustion of anthracite coal, bituminous coal, or any other solid fuel not specified under (3), (4), or (5).

Continuous compliance with the NO_x standards is required, based on a 30-day rolling average. Also, percent reductions in uncontrolled NO_x emission levels are required. The percent reductions are not controlling, however, and compliance with the NO_x emission limits will assure compliance with the percent reduction requirements.

Emerging Technologies

The standards include provisions which allow the Administrator to grant commercial demonstration permits to allow less stringent requirements for the initial full-scale demonstration plants of certain technologies. The standards include the following provisions:

(1) Facilities using SRC I are subject to an emission limitation of 520 ng/J (1.20 lb/million Btu) heat input, based on a 30-day rolling average, and an emission reduction requirement of 85 percent, based on a 24-hour average. However, the percentage reduction allowed under a commercial demonstration permit for the initial full-scale demonstration plant using SRC I would be 80 percent (based on a 24-hour average). The plant producing the SRC I would monitor to ensure that the required percentage reduction (24-hour average) is achieved and the power plant using the SRC I would monitor to ensure that the 520 ng/J heat input limit (30-day rolling average) is achieved.

(2) Facilities using fluidized bed combustion (FBC) or coal liquefaction would be subject to the emission limitation and percentage reduction requirement of the SO_2 standard and to the particulate matter and NO_x standards. However, the reduction in potential SO_2 emissions allowed under a commercial demonstration permit for the initial full-scale demonstration plants using FBC would be 85 percent (based on a 30-day rolling average). The NO_x emission limitation allowed under a commercial demonstration permit for the initial full-scale demonstration plants using coal liquefaction would be 300 ng/J (0.70 lb/million Btu) heat input, based on a 30-day rolling average.

(3) No more than 15,000 MW equivalent electrical capacity would be allotted for the purpose of commercial demonstration permits. The capacity will be allocated as follows:

Technology	Pollutant	Equivalent electrical capacity MW
Solid solvent-refined coal	SO_2	6,000–10,000
Fluidized bed combustion (atmospheric)	SO_2	400–3,000
Fluidized bed combustion (pressurized)	SO_2	400–1,200
Coal liquefaction	NO_x	750–10,000

Compliance Provisions

Continuous compliance with the SO_2 and NO_x standards is required and is to be determined with continuous emission monitors. Reference methods or other approved procedures must be used to supplement the emission data when the

continuous emission monitors malfunction in order to provide emission data for at least 18 hours of each day for at least 22 days out of any 30 consecutive days of boiler operation.

A malfunctioning FGD system may be bypassed under emergency conditions. Compliance with the particulate standard is determined through performance tests. Continuous monitors are required to measure and record the opacity of emissions. The continuous opacity data will be used to identify excess emissions to ensure that the particulate matter control system is being properly operated and maintained.

Issues Raised in the Petitions for Reconsideration

I. SO_2 Maximum Emission Limitation of 520 ng/J (1.2 lb/Million Btu) Heat Input

The Environmental Defense Fund (EDF), Sierra Club, and State of California Air Resources Board (CARB) requested that a proceeding be convened to reconsider the maximum SO_2 emission limitation of 520 ng/J (1.2 lb/million Btu) heat input. In their petition, EDF set forth several procedural questions as the basis for their request. First, they maintained that they did not have the opportunity to comment on certain information which was submitted to EPA by the National Coal Association at an April 5, 1979, meeting and in subsequent correspondence. The information pertained to the impacts that different emission limitations will have on coal production in the Midwest and Northern Appalachia. They argued that this information materially influenced the Administrator's final decision. Further, they maintained that the Administrator's decision in setting the emission limitation was based on *ex parte* communications and improper congressional pressure.

The Sierra Club also raised objections to information developed during the post-comment period. They cited the information supplied by the National Coal Association, and the EPA staff analysis of the impact that different emission limitations would have on burnable coal reserves. In addition, they challenged the assumption that conservatism in utility perceptions of scrubber performance could create a significant disincentive against the burning of high-sulfur coal reserves. The Sierra Club maintained that this information is of "central relevance" since it formed the basis of the establishment of the final emission limitation and that the Sierra Club was denied the opportunity to comment on this information. Finally, the Sierra Club and CARB subscribed fully to arguments presented by EDF concerning ex parte communications.

Background

The potential impact that the emission limitation may have on high-sulfur coal reserves did not arise for the first time in the post-comment period. It was an issue throughout the rulemaking. In the proposal, the Agency stated that two factors had to be taken into consideration when selecting the emission limitation—FGD efficiency and the impact of the emission limitation on high-sulfur coal reserves (43 FR 42160, middle column). The proposal also indicated that, in effect, scrubber performance determines the maximum sulfur content of coals that can be fired in compliance with emission limitation even when coal preparation is employed. From the discussion it is clear that the Administrator recognized that midwestern high-sulfur coal reserves could be severely impacted if the emission limitation was not selected with care (43 FR 42160, middle column). In addition, the Administrator also specifically sought comment on the related question of new coal production as it pertained to consideration of coal impacts in the final decision (43 FR 42155, right column).

At the December 1978 public hearing on the proposed standards, the Agency specifically sought to solicit information on the impact that lower SO_2 emission limits (below 520 ng/J (1.2 lb/million Btu) heat input) would have on high-sulfur coal reserves. In response to questions from an EPA panel member and the audience, Mr. Hoff Stauffer of ICF, Inc. (an EPA consultant) testified that the potential impact of lower emission limitations on high-sulfur coal reserves would be greater in certain states than was indicated by the results of the macroeconomic analysis conducted by his firm. He added further that if the degree of reduction achievable through coal preparation or scrubbers changed from the values assumed in the analysis (35 percent for coal preparation on high-sulfur coal and 90 percent for scrubbers) the coal impacts would vary accordingly. That is, if greater reduction could be achieved by either coal preparation or by scrubbers the impacts would be reduced. Conversely, if the degree of reduction achievable by either coal preparation or scrubbers was less than the values assumed, the impacts would be more severe (public hearing transcript, December 12, 1978, pages 46–47).

The subject was broached again when Mr. Richard Ayres, representing the Natural Resources Defense Council and serving as introductory spokesperson for other public health and environmental organizations, was asked by the panel what effect lowering the emission limitation would have on local high-sulfur coal reserves. Mr. Ayres responded that a lower emission limitation may have the effect of requiring certain coals to be scrubbed more than required by the standard. He added that the utilities would have an economic choice of either buying local high-sulfur coal and scrubbing more or buying lower-sulfur coal which may not be local and scrubbing less. He further indicated that it was not clear that a lower limitation would have the effect of precluding any coal. In doing so, he noted that the "conclusion depended entirely on assumptions about the possible emission efficiencies of scrubbers." Finally, Mr. Ayres was asked whether as long as production in a given region increased that the requirement of the Act to maximize the use of local coal was satisfied. He responded that it was a "matter of degree" and that he would not say as long as production in a given region did not decline the statute was served (public hearing transcript, December 12, 1978, pages 77–80).

Mr. Robert Rauch, representing the Environmental Defense Fund, also recognized in his testimony that lowering the emission limitation to the level recommended by EDF (340 ng/J (0.8 lb/million Btu) heat input) would adversely impact high-sulfur coal reserves. In his testimony he stated "Adoption of the proposed lower ceiling would result in the exclusion of certain high-sulfur coal reserves from use in power plants subject to the revised standard." He added that the use of adipic acid and other slurry additives would enhance scrubber performance, thereby alleviating the impacts on high-sulfur coal (public hearing transcript, December 13, 1978, pages 189–191).

Mr. Joseph Mullan of the National Coal Association testified in response to a question from the hearing panel that lowering the emission limitation from 520 ng/J (1.2 lb/million Btu) heat input would preclude the use of certain high-sulfur coals. He added that the National Coal Association would furnish data on such impacts (public hearing transcript, December 13, 1978, page 246).

Turning now to the written comments on the proposed standard submitted jointly by the Natural Resources Defense Council and the Environmental Defense Fund, we see that they carefully assessed the potential impacts on high-sulfur coal reserves that could result

from various emission limitations. They concluded, "Generally, the higher the percent removal requirement, the smaller the percentage of coal reserves which are effectively eliminated for use by utility generating units." They went on to argue that if their recommended standard of 95 percent reduction in potential SO_2 emission was accepted a lower emission limitation could be adopted without adverse impacts on coal reserves (OAQPS-78-1, IV-D-631, page V-128).

Rationale for the Maximum Emission Limit

The testimony presented at the public hearing and the written comments served to confirm the Agency's initial position that scrubber performance and potential impacts on high-sulfur coal reserves had to be carefully considered when establishing the emission limitation. Meanwhile, it became apparent that the analysis performed by EPA's consultant on emission limits below 520 ng/J (1.2 lb/million Btu) heat input might not fully reflect the impacts on major high-sulfur coal production areas. This finding was evident by study of the consultant's report (OAQPS-73-1, IV-A-5, Appendix D) which showed that the model used to estimate coal production in Appalachia and the Midwest was relatively insensitive to broad variations in the emission ceiling. The Agency then concluded that the macroeconomic model was adequate for assessing national impacts on coal use, but lacked the specificity to assess potential dislocations in specific coal production regions. In effect the analysis tended to mask the impacts in specific coal producing regions through aggregation. Concern was also raised as to the validity of the modeling assumption that a 35 percent reduction in potential SO_2 emissions can be achieved by coal washing on all high-sulfur coal reserves.

In view of these concerns, EPA concluded shortly after the close of the comment period that additional analysis was needed to support the final emission limitation. In February, EPA began analyzing the impacts of alternative emission limits on local high-sulfur coal reserves. To account for actual and perceived efficiencies of scrubbers, the staff assumed three levels of scrubber control—85 percent, 90 percent, and 95 percent. In addition, two levels of physical coal cleaning were reflected. The first level was crushing to 1.5 inch top-size and the second was crushing to ⅜ inch top-size, both followed by wet beneficiation. In addition, by using seam-by-seam data on coal reserves and their sulfur reduction potential (developed for EPA's Office of Research and Development) it was possible to estimate the sulfur content of the final product coal based on reported chemical properties of coals in the reserve base (OAQPS-78-1, IV-E-12). Since this approach did not require the staff to assume a single level of sulfur reduction for all coal preparation plants, it introduced a major refinement to the analysis previously performed by EPA's consultant. The analysis was substantially completed in March 1979 (OAQPS-78-1, IV-B-57 and IV-B-72).

The April 5, 1979, meeting was called to discuss coal reserve data and the degree of sulfur removal achievable with physical coal cleaning (OAQPS-78-1, IV-E-10). The meeting gave EPA the opportunity to present the results of its analysis and to verify the data and assumptions used with those persons who are most knowledgeable on coal production and coal preparation. EPA sought broad representation at the meeting. Invitees including not only the National Coal Association but representatives from the Environmental Defense Fund, Natural Resources Defense Council, Sierra Club, Utility Air Regulatory Group, United Mine Workers of America, and other interested parties. The invitees were furnished copies of the materials presented at the meeting, subsequent correspondence from the National Coal Association, and minutes of the meeting.

The meeting served to confirm that the coal reserve and preparation data developed independently by the EPA staff were in close agreement with those prepared by the National Coal Association (NCA). In addition, the discussion led EPA to conclude that coal preparation technology which required crushing to ⅜-inch top-size would be unduly expensive, lead to unacceptable energy losses, and pose coal handling problems (OAQPS-78-1, IV-E-11). As a result, the Administrator revised his assessment of state-of-art coal cleaning technology (44 FR 33596, left column).

In an April 19, 1979, letter to the Administrator (OAQPS-78-1, IV-D-763), attorneys for the Environmental Defense Fund and the Natural Resources Defense Council submitted comments on the information presented by the National Coal Association at the April 5, 1979, meeting and in a subsequent NCA letter to the Administrator dated April 6, 1979. In their comments, they were critical of the National Coal Association's assumptions concerning scrubber performance and the removal efficiencies of coal preparation plants. They also noted that the Associaton's data was based on a small survey of the total coal reserves in the Midwest and Northern Appalachia. They argued further that coal blending could serve to reduce the adverse impact on high-sulfur coal caused by a lower emission limit. In doing so, they recognized that the application of coal blending would have to be undertaken on a case-by-case basis. Finally, they maintained that there is no evidence that the coal industry would be unable to meet increases in coal demand even if the National Coal Association's reserve data on coal preclusions were accepted. In conclusion, they noted that the Association's data was of questionable relevance since it was predicated on a maximum removal efficiency of 90 percent.

Subsequent correspondence from the National Coal Association served to reaffirm a point that had been made earlier in the rulemaking. That is, utilities would have a choice of either buying lower-sulfur coal and scrubbing to meet the percent removal requirement or buying higher-sulfur coal and scrubbing more than required by the standard in order to meet the emission limitation. In addition, they cited the conservative nature of utilities and stressed that this would be reflected in their coal buying practices. As was discussed at the public hearing and in the written comments such behavior by utilities would result in adverse impacts on the use of certain local high-sulfur coals.

In reaching final conclusions about the impact of the SO_2 standard on coal production, the Administrator judged that utilities would be inclined to select coals that would meet the emission limit with no more than 90 percent reduction in potential SO_2 emissions [1] (44 FR 33596, left column). With this assumption, the analysis revealed that an emission limit of less than 520 ng/J (1.20 lb/million Btu) heat input would create a disincentive to burn a significant portion of the coal reserves in the Midwest and Northern Appalachia (OAQPS-78-1, IV-B-72). If the emission limit had been set at 430 ng/J (1.0 lb/million Btu) heat input, 15 percent of the total reserve base in the Eastern Midwest (Illinois, Indiana, and Western Kentucky) would have been impacted. The impact in Northern Appalachia would be 6 percent and this impact would have been concentrated in the areas of Ohio and the northern part of West Virginia. If only currently

[1] The previous version of the EPA analysis had assumed either 85 or 90 percent control levels in addition to coal washing. That approach disregarded the fact that the net reduction in potential SO_2 emissions may have been greater than 90 percent in some cases.

owned coal reserves are considered, up to 19 percent of the high-sulfur coals in some regions would be impacted (OAQPS-78-1, IV-B-72). The Administrator judged that such impacts are unacceptable.

The final point made by NCA was that utility coal buying practice typically incorporates a margin of safety to ensure compliance with SO_2 emission limitations. Rather than purchasing a high-sulfur coal that would barely comply with the emission limit, the prudent utility would adopt a more conservative approach and purchase coal that would meet the emission limit with a margin of safety in order to account for uncertainty in coal sulfur variability. This approach, which reflects sound engineering principles, could result in the dislocation of some high-sulfur coal reserves.

The Administrator determined that consideration of a margin of safety in coal buying practice was reasonable. Using NCA's recommendation of an 8.5 percent margin (reported as "about 10 percent" in the preamble to promulgation), coal impacts were reanalyzed. This study showed additional coal market dislocations (OAQPS-78-1, IV-B-72). For example, in Illinois, Indiana, and Western Kentucky, the impact on coal reserves by a 430 ng/J (1.0 lb/million Btu) heat input emission limit increased from 15 percent without the margin to 22 percent when the margin was assumed. Considering only currently owned reserves, the impact increased from 19 percent to 30 percent. Even with the margin, the analysis predicted no significant impact for a 520 ng/J (1.2 lb/million Btu) heat input standard.

Having determined the extent of the potential coal impacts associated with a lower emission limit, the Agency then assessed the potential environmental benefits. The assessment revealed that by 1995 an emission limit of 430 ng/J (1.0 lb/million Btu) heat input would reduce national emissions by only 50 thousand tons per year relative to the 520 ng/J (1.2 lb/million Btu) heat input limit. That is, the projected emissions from new plants would be reduced from 3.10 million tons to a 3.05 million tons as a result of the more stringent emission limit (OAQPS-78-1, IV-B-75).

The petitions providing no information to either refute the assumptions or the findings of the final coal impact analysis. The Sierra Club argued that EPA had misinterpreted its own analysis of coal impacts (Sierra Club petition, page 9). They maintained that the EPA figures presented at the April 5 meeting (OAQPS-78-1, IV-E-11, attachment 3) supported establishment of a 340 ng/J (0.8 lb/million Btu) heat input standard. In doing so the Sierra Club ignored the analysis performed by the Agency after the April 5 meeting, particularly with respect to the Administrator finding that utilities would purchase coal which would meet the emission limit (with margin) with no more than 90 percent reduction in potential SO_2 emissions.

In conclusion, the decision as to the appropriate level of emission limitation rested squarely on two factors. First, the Administrator's finding that a 90 percent reduction in potential SO_2 emissions, measured as a 30-day rolling average, represented the emission reduction achievable through the use of the best demonstrated system of emission reduction, and second, that the marginal environmental benefit of a 430 ng/J (1.0 lb/million Btu) heat input standard coupled with a 90 percent reduction in potential SO_2 emissions could not be justified in light of the potential impacts on high-sulfur coal reserves. If he had determined, as some petitioners suggested, that higher removal efficiencies were achievable on high-sulfur coals, the emission limitation could have been established at a lower level without significant impacts on local high-sulfur coal reserves.

Environmental Defense Fund Procedural Issues

EDF's petition objected to the fact that after the close of the public comment period, representatives of the National Coal Association and a number of members of Congress talked to EPA officials and submitted documents to EPA arguing that the ceiling should be set at 520 ng/J (1.2. lbs/million Btu) heat input. EDF objected to these communications on a number of grounds. First, they argued that it was improper, under Section 307(d) of the Act, for the Agency to consider information submitted more than 30 days after the public hearing. Second, they objected that the Agency failed to make transcripts of the oral communications, and that, in any event, the summaries of those communications that the Agency placed in the docket were inadequate. Third, they implied that Agency officials received additional oral communications which were not documented in the rulemaking docket. Fourth, they objected that these written and oral communications were *ex parte* and therefore improper, citing, for example, *United States Lines, Inc.* v. *FMC*, 584 F. 2d 519 (D.C. Cir., 1978). Fifth, they argued that the Administrator's decision on the ceiling was based in part on information obtained in *ex parte* discussions and thus not placed in the docket as of the date of promulgation, in violation of Section 307(d). Finally, they argued that the communications from members of Congress constituted improper pressure on the Administrator's decision, citing, for example, *D.C. Federation of Civic Associations* v. *Volpe*, 459 F. 2d 1231 (D.C. Cir. 1972). EDF argued that these alleged procedural errors were of central relevance to the outcome of the rule, and that the Agency should therefore convene a proceeding to reconsider.

The Administrator does not believe that the procedures cited by EDF were improper. Moreover, as discussed below, any arguable errors were not of central relevance to the outcome of the rule, and therefore do not constitute grounds for granting EDF's petition to reconsider.

First, it was not improper for the Administrator to consider information submitted more than 30 days after the public hearing. Section 307(d)(5) requires that the Administrator consider documents submitted up to 30 days after the hearing. It does not forbid the Administrator to consider additional comments submitted after that 30-day period.

Second, the Agency's summaries of oral communications were adequate. Section 307(d)(5) does not require, as EDF argues, that Agency officials keep transcripts of their oral discussions with persons outside the Agency. It simply requires the Agency to make a transcript of the public hearing on a proposed rulemaking. Third, Agency officials wrote memoranda of all significant oral communcations between Agency officials and persons outside the executive branch, such as the two meetings with Senator Byrd, and the memoranda were promptly placed in the rulemaking docket. These memoranda accurately reflect the information and arguments communicated to the Agency.

Fourth, the oral and written communications cited by EDF were not *ex parte*. The Agency promptly placed the written comments in the rulemaking docket where they were available to the public. Also, the NCA sent copies of its written comments directly to the principal parties to the rulemaking, including EDF and NRDC. Similarly, the Agency placed the memoranda of oral communcations in the docket where they were available to the public. Any member of the public has had the opportunity to submit a petition for reconsideration if that information was used erroneously by EPA in setting the standard, and several persons have done so.

Fifth, contrary to EDF's assertion, the Administrator's decision on the

emission ceiling was not based on any information not in the docket.

Finally, it was not improper for the Administrator to listen to and consider the views of Senators and Congressmen, including Senator Byrd. It is not unusual for members of Congress to express their views on the merits of Agency rulemaking, and it is entirely proper for the Administrator to consider those views.

EDF objects particularly to a meeting the Administrator attended with Senator Byrd on April 26, 1979, arguing that the contact was *ex parte* and improperly influenced the Administrator's decision. Neither contention is correct. A memorandum summarizing the discussion at the meeting was placed in the docket, and members of the public have had the opportunity to comment on it, as EDF has done. No new information was presented to the Administrator at the meeting.

Senator Byrd's comments at this meeting also did not improperly influence the Administrator. Although the Senator strongly urged the Administrator to set the emission ceiling at a level that would not preclude the use of any significant coal reserves, the Administrator had already concluded from the 1977 Amendments to the Clean Air Act that the revised standards should not preclude significant reserves. This view was based on the Administrator's interpretation of the legislative intent of the 1977 Amendments and was reflected in the proposed emission ceiling of 520 ng/J (1.2 lbs/million Btu) heat input, as discussed in the preamble to the proposed standards (43 FR 42160).

This view was reaffirmed in the final rulemaking, based on the intent of the 1977 Amendments (44 FR 33595–33596). Although the Administrator was aware (as he would have been even in the absence of a meeting) of Senator Byrd's concern that a ceiling lower then 520 ng/J (1.2 lbs/million Btu) heat input would inappropriately preclude significant coal reserves, the Administrator's decision was not based on Senator Byrd's expression of concern. The Administrator had already concluded that anything more than a minimal preclusion of the use of particular coal reserves would, in the absence of significant resulting emission reductions, be inconsistent with the intent of the 1977 Amendments. Because the Agency's analysis showed that even an emission limit of 430 ng/J (1.0 lbs/million Btu) heat input could preclude the use of up to 22 percent of certain coal reserves without significantly reducing overall emissions, the Administrator's judgment was that a ceiling lower than 520 ng/J (1.2 lbs/million Btu) heat input was not justified. Thus, the views of Senator Byrd and other members of Congress, at most, served to reinforce the Administrator's own judgment that the proper level for the standard was 520 ng/J (1.2 lbs/million Btu) heat input. Even assuming, therefore, that it was improper for the Administrator to consider the views of members of Congress, this procedural "error" was not of central relevance to the outcome of the rule.

II. SO_2 Minimum Control Level (70 Percent Reduction of Potential Emissions)

The Kansas City Power and Light Company (KCPL), Sierra Club, and Utility Air Regulatory Group (UARG) requested that a proceeding be convened to reconsider the 70 percent minimum control level which is applicable when burning low-sulfur coals. Both the Sierra Club and UARG maintained that they did not have an opportunity to fully comment on either the final regulatory analysis or dry SO_2 scrubbing technology since the phase 3 macroeconomic analysis of the standard (44 FR 33603, left column) and supporting data were entered into the record after the close of the public comment period. Both claimed that their evaluation of this additional information provided insights which are of central relevance to the Administrator's final decision and that reconsideration of the standard is warranted. The KCPL petition did not allege improper administrative procedures, but asked for reconsideration based on their evaluation of the merits of the standard.

In seeking a more stringent minimum reduction requirement, the Sierra Club contended that dry SO_2 scrubbing is not a demonstrated technology and, therefore, no basis exists for a variable control standard. Alternatively, the Sierra Club maintained that if dry technology is considered demonstrated the record supports a more stringent minimum control level. With respect to the regulatory analysis, the petition charged that faulty analytical methodology and assumptions led the Agency to erroneous conclusions about the impacts of the promulgated standard relative to the more stringent uniform or full control alternative. They suggested that analysis performed using proper assumptions would support adoption of a uniform standard.

In support of a less stringent minimum reduction requirement, the UARG petition presented a regulatory analysis which was prepared by their consultant, National Economic Research Associates (NERA). Based on this study, UARG argued that a 50 percent minimum requirement would be superior in terms of emissions, costs, and energy impacts. Finally, they argued that a lower percent reduction would provide greater opportunity to develop dry SO_2 scrubbing technology.

In their petition KCPL sought either an elimination of the percent reduction requirement when emissions are 520 ng/J (1.2 lb/million Btu) heat input or less, or, as an alternative, a reduction in the 70 percent requirement. In support of their request, KCPL set forth several arguments. First, they cited the economic and energy impacts associated with the application of scrubbing technology on low sulfur coals. Second, they noted that a significant portion of sulfur in the coal they plan to burn will be removed in the fly ash. Finally, they asserted that health and welfare considerations do not warrant scrubbing of low sulfur coals since their uncontrolled SO_2 emissions are less than the emissions allowed by the standard for high-sulfur coals with 90 percent scrubbing.

The primary basis for the UARG and Sierra Club requests for reconsideration of the minimum control level was the Agency's phase 3 economic modeling analysis (44 FR 33602). Because the phase 3 analysis was completed after the close of the public comment period, it is important that the results of that study are viewed in proper perspective to their role in the Administrator's decision. The petitioners implied that the adoption of the 70 percent variable control standard was based solely on the phase 3 analysis and that the phase 3 analysis was a new venture by the Agency, and therefore, the public was excluded from active participation in the decision process. This notion is false.

Contrary to views of the UARG and the Sierra Club, the phase 3 study did not mark a significant departure from the Agency's earlier analysis of the issue of uniform versus variable control. No new economic modeling concepts were introduced nor were any modeling input assumptions changed from those presented in the phase 2 analysis. Instead, the phase 3 study served merely (a) to refine the analysis by incorporating consideration of dry SO_2 scrubbing in response to public comments and (b) to facilitate specification of the final standard. In effect, phase 3 brought together the results of an analysis that had proceeded under close public scrutiny for more than a year. In order to consider the full range of applicability of dry SO_2 scrubbing systems, it was necessary to introduce a new alternative standard—the variable control standard

with a 70 percent minimum control level. Introduction of this option was considered appropriate since it raised the same kind of economic, legal, and technical policy issues as the earlier analyses of 33, 50, and 90 percent minimum control options.

Within this context, many of the objections to the economic modeling are inappropriate grounds under section 307(d)(7)(B) for reconsideration since they do not involve information on which it was impracticable to comment during the public comment period. For example, the Sierra Club's comments regarding modeling assumptions merely restated those that had been incorporated by reference into their January 1979 comments (OAQPS-78-1, IV-D-631 and IV-D-626). The only new modeling issue raised during phase 3 was the application and cost of dry SO_2 scrubbing. These problems notwithstanding each of the issues raised by the various petitions were evaluated carefully and are discussed below.

Dry Scrubbing Technology

The Sierra Club and UARG both raised issues concerning dry SO_2 scrubbing technology in their petitions for reconsideration. While UARG concurred with EPA's basic approach with respect to dry scrubbing, they maintained that the Agency's objective of developing the full potential of this technology would be better served by a 50 percent minimum reduction requirement. On the other hand, the Sierra Club was most critical of EPA's consideration of dry scrubbing in the rulemaking. They maintained that the public was not afforded sufficient opportunity to comment on dry scrubbing technology. They argued that EPA had not identified dry scrubbing as a demonstrated technology nor had the Agency set forth any regulatory options that embraced the technology. They also asserted that the treatment of dry scrubbing in the rulemaking was inconsistent with Agency actions concerning other emerging technologies such as the establishment of commercial demonstration permits for solvent refined coal and fluidized bed combustion, and the rejection of catalytic ammonia injection for NO_x control on the grounds that it had not been employed on a full-scale facility. They also maintained that EPA had shown little interest in dry scrubbing prior to the spring of 1979 and seized upon it only after the need arose to justify a 70 percent minimum reduction requirement. Finally, the Sierra Club asserted that even if one assumed dry scrubbing is adequately demonstrated, the 70 percent reduction requirement is too low. In doing so, they cited information (Sierra Club petition, page 8) in the record that indicated that "up to 90 percent reduction" can be achieved with such systems.

A review of the public record belies these charges. The preamble to the proposed standards identified dry SO_2 scrubbing, including spray drying, as an alternative to wet FGD systems (43 FR 42160, left column). Subsequently, a number of individuals and organizations either submitted written comment or presented testimony at the public hearing in support of a variable control standard since it would not foreclose the development of dry SO_2 control technology. For example, the spokesman for the Public Service Company of Colorado (PSCC) testified that his firm was actively pursuing dry SO_2 control technology (dry injection of sodium-based reagents upstream of a baghouse) because it offered a number of advantages compared to wet technology. Advantages included lower energy consumption, fewer maintenance problems, and simplified waste disposal (public hearing transcript, December 13, 1978, pages 92-94). When questioned by the hearing panel, PSCC testified that 70 percent removal is achievable with dry scrubbing and that they would pursue the technology if a 70 percent requirement was adopted (public hearing transcript, December 13, 1978, page 102). Similarly, Northern States Power testified that adoption of a sliding scale would give impetus to their examination of dry SO_2 control systems which employ a spray absorber and a fabric filter (public hearing transcript, December 13, 1978, page 226). Finally, the Department of Public Utilities, City of Colorado Springs testified that they have a program to conduct on-site pilot tests of a spray-drying system for SO_2 control. It was also noted that if a sliding scale approach was adopted "we feel there is no question but that dry techniques would be used" (public hearing transcript, December 13, 1978, pages 266-267).

The Air Pollution Control Commission, Colorado Department of Health urged in their written comments that the proposed emission floor be raised to 172 ng/J (0.40 lb/million Btu) heat input in order to permit the development and application of dry control techniques such as the injection of dry absorbants into a baghouse. They noted that their recommendation would require approximately 65 percent reduction on a typical western low-sulfur coal (OAQPS-78-1, IV-D-212). The Washington Public Power Supply System also submitted written comments that affirmed the Agency's finding on dry scrubbers as set-forth in the proposal. They indicated that dry scrubbing was superior to wet technology when applied to western low-sulfur coal. They noted that the application of dry scrubbers would result in lower capital, fuel, and operation and maintenance costs, as well as lower water use and simplified waste disposal. They indicated further that the uncertainty of being able to achieve the proposed 85 percent reduction requirement would foreclose the installation of dry scrubbing technology. Therefore, they recommended that the proposed emission floor be raised to at least 210 ng/J (0.5 lb/million Btu) heat input (OAQPS-78-1, IV-D-330).

Because of these comments and the public hearing testimony, the Agency carried out additional investigations of dry scrubbing technology during the post-comment period. The findings of the analysis (44 FR 33582 and EPA 450/3-79-021, page 3-61) confirmed the views of the commenters that the adoption of a uniform percentage reduction requirement would have constrained the development of dry scrubbing technology. After carefully reviewing the available pilot plant data and information on the three full-scale units that are under construction, it was the Administrator's judgment that the technology employing spray dryers could achieve 70 percent reduction in potential SO_2 emissions on both low-sulfur alkaline and nonalkaline coals. Data on higher emission reduction levels such as those noted by the Sierra Club were discounted since they reflected short-term removal efficiencies (not representative of longer periods of performance) and they were achieved when high-alkaline content coals were fired. The Administrator's judgment was also tempered in this regard by the public comments which indicated that removal requirements higher than 70 percent would discourage the continued development of the technology. Similarly, these same commenters clearly indicated that the technology was capable of exceeding the 50 percent reduction requirement suggested by the Utility Air Regulatory Group.

The Sierra Club commented that EPA was inconsistent in its treatment of dry scrubbing and catalytic ammonia injection. In rejecting catalytic ammonia injection for NO_x control, the Administrator noted that it had not been adequately demonstrated. A review of the record reveals that the primary proponent of this technology, the State

of California Air Resources Board, also recognized that it was not sufficiently advanced at this time to be considered. Instead, they merely recommended that the standard require plants to set aside space so that catalytic ammonia injection could be added at some future date (OAQPS-78-1, IV-D-268). In comparison, dry scrubbing has undergone extensive testing at pilot plants, and there are three full-scale facilities under construction that will begin operation in the 1981-82 period.

With respect to commercial demonstration permits for solvent refined coal and fluidized bed combustion, the standard merely allows initial, full-scale demonstration units some flexibility. Subsequent commercial facilities will be required to meet the final standards. In adopting this provision, the Administrator recognized that initial full-scale demonstration units often do not perform to design specification, and therefore some flexibility was required if these capital intensive, front-end technologies were to be pursued. On the other hand, the Agency concluded that more conventional devices such as dry scrubbers could be scaled up to commercial-sized facilities with reasonable assurance that the initial facilities would comply with the applicable requirements. In view of this, the inclusion of dry scrubbing under the commercial demonstration permit provision was not appropriate.

Finally, in a letter dated September 17, 1979, to the Administrator, the Sierra Club submitted additional information to buttress its argument that dry scrubbing is not demonstrated technology. This letter cited EPA's "FGD quarterly Report" of Spring 1979. The report indicates that the direct injection of dry absorbents (such as nahcolite) into the gas stream may be a breakthrough, yet it calls for further pilot plant studies. The inference the Sierra Club drew from the article was that the EPA technical staff does not believe dry scrubbing is sufficiently developed to be considered in the rulemaking. The Sierra Club failed to recognize that there are several different dry scrubbing approaches in different stages of development. The "FGD Quarterly Report" does not pertain to the approach employing a spray dryer and baghouse with lime absorbent which serves as the basis for the Administrator's finding (EPA-450/3-70-021 at 3-61).

The Sierra Club also cited an article in the Summer 1979 "FGD Quarterly Report" on vendors' perspectives toward dry scrubbing. In doing so, the Sierra Club noted that the article indicates that vendors expressed an attitude of caution toward dry scrubbing which led the Sierra Club to conclude that the technology is not available. It should be noted from the article that only one of the vendors present was actively engaged in dry scrubbing and that firm was quite positive in their remarks. Babcock and Wilcox, who had conducted spray dryer pilot plant studies and is pursuing contracts for full-scale installations, commented that "while the dry scrubbing approach is new, the technology is proven."

Economic Modeling.

The Agency's regulatory analysis concluded that the variable control standard with a 70 percent minimum control level would result in equal or lower national sulfur dioxide emissions than the uniform 90 percent standard while having less impact on costs, waste disposal, and oil consumption (44 FR 33607, middle column and 33608). The Sierra Club petition charged that the Agency used an unrealistic model and faulty assumptions in reaching these conclusions. The petition alleged that utility behavior as predicted by the EPA model is "incredible" and that this incredible behavior leads to "the outlandish notion that stricter emission controls will lead to more emissions." The Administrator finds this allegation to be without merit.

The principle modeling concept being challenged is whether or not increased costs of constructing and operating a new plant (due to increased pollution control costs) will affect the utility operator's decisions on boiler retirement schedules, the dispatching of plants to meet electrical demand, and the rate of construction of new plants. The model used for the analysis assumed that utility companies over the long term will make decisions that minimize the cost of electricity generation. That is, (1) under any demand situation utilities will first operate their equipment with the lowest operating costs, and (2) existing generating capacity will be replaced only if its operating costs exceed the capital and operating costs of new equipment. While political, financial, or institutional constraints may bar cost-minimizing behavior in individual cases, the Administrator continues to believe that the assumption of such behavior is the most sound method of analyzing the impacts of alternative standards.

Under this approach, the model simultaneously adjusts both the utilization of existing plants and the construction schedule of new plants (subject to Subpart Da) based on the relative economics of generating electricity under alternative standards. Hence, average capacity factors for the population of new plants may vary among standards due to variations in the mix of base and intermediate loaded plants which are brought on line in any one year. But this does not mean, as concluded in the Sierra Club petition at page 8, that the model predicted that utilities would permit new base-loaded units to remain idle while they continue to build still more new units.

The petition also alleged that this modeling concept was introduced in the phase 3 analysis, which was completed after the close of the public comment period, and hence the modeling rationale was not subject to public review. The petition went on to criticize some of the assumptions in the model charging that they were not even mentioned in the record.

The Administrator finds no basis for the Sierra Club's assertion that the modeling methodology and input assumptions were not exposed for public review. First, the same model was used for the phase 1, 2, and 3 analyses. The basic model logic was explained in the preamble to the September proposal and comments were solicited specifically on the use of a cost optimization model for simulating utility decisions (43 FR 42162, left column).

Secondly, the model's input assumptions were subjected to broad review. Assumptions were presented in the September preamble and in even greater detail in the consultant's reports which are part of the record (OAQPS-78-1, II-A-42, II-A-90, and II-A-91). Following proposal, the Agency convened an interagency working group to review the macroeconomic model and the Agency's input assumptions (44 FR 33604, left column). Members of the group represented a spectrum of expertise and interests (energy, employment, environment, inflation, commerce). The group met numerous times over a period of two months, including meetings with UARG, NRDC, and Sierra Club. As a result of the group's recommendations, the phase 2 analysis was conducted. A full description of the analysis including changes to the modeling assumptions was presented at the public hearing and a detailed report was put into the record (OAQPS-78-1, IV-A-5). For the phase 3 analysis accompanying promulgation, the only change in modeling assumptions from phase 2 was the introduction of dry scrubbing technology. Based on the detailed record established, the Administrator concludes that the Sierra Club had ample opportunity to analyze and

comment on the Agency's analytical approach and did so by incorporating the EDF and NRDC comments into their January 1979 comments (OAQPS-78-1, (V-D-628).

The Sierra Club also criticized the conclusions of the Agency's regulatory analysis because the assumed oil prices were too low and the nuclear plant growth rate was too high. To assist in evaluating the petitions, two sensitivity tests were performed on the Agency's regulatory analysis. Using the phase 3 assumptions as a base, the analysis was rerun first assuming higher oil prices and then assuming both higher oil prices and a lower nuclear growth rate (OAQPS-78-1, VI-B-16). The studies addressed the promulgated standard, the full control option (uniform 90 percent control), and a variable control standard with a 50 percent minimum control requirement as recommended by UARG. The predictions for 1995 are summarized in Tables 2 and 3, respectively. For comparison, the phase 3 results are repeated in Table 1.

With respect to energy input assumptions, the oil prices used by the Agency for the phase 3 analysis were based on the Department of Energy's estimate of future crude oil prices. These estimates are now probably low because of the 1979 OPEC price increase which occurred after promulgation of the standard. For the sensitivity analysis, the following oil prices in 1979 dollars were assumed:

Assumed Oil Prices

(Dollars per Barrel)

	Sensitivity analysis	Phase 3
1985	25	16
1990	30	20
1995	38	26

These prices were obtained from conversations with DOE's policy analysis staff. The prices may appear low in comparison to the example of $41.00 per barrel spot market oil given in the Sierra Club petition, but the Sierra Club figure is misleading because utilities seldom purchase spot market oil. The meaningful parameter is the average refiners' acquisition cost, which was $21/barrel at the time of this analysis. The original nuclear capacity assumptions were based on the industry's announced plans for new capacity. For sensitivity testing, these estimates were modified by excluding nuclear power plants in the early planning stages while retaining those now under construction or for which, based on permit status, plans appear firm. The following assumptions of total nuclear capacity resulted:

Table 1.—*Summary of 1995 Impacts With Phase 3 Assumptions*[1]

	Level of control with 520 ng/J maximum emission limit			
	Current standards	Variable control, 50 pct minimum	Variable control, 70 pct minimum	Full control
National SO_2 Emissions (million tons)	23.8	20.6	20.5	20.7
East[2]	11.2	9.7	9.7	10.1
Midwest	8.3	8.0	8.0	7.9
West South Central	2.6	1.8	1.7	1.7
West	1.7	1.1	1.1	0.9
Incremental Annualized Cost (billions 1978 $)		2.9	3.3	4.4
Incremental Cost of SO_2 Reduction (1978 $/ton)		914	1,036	1,428
Oil Consumption (million bbl/day)	1.4	1.6	1.6	1.8
Coal Production (million tons)	1,767	1,745	1,752	1,761
Total Coal Capacity (GW)	554	537	537	520

[1] With wet and dry scrubbing and the following energy assumptions

	Oil prices ($ 1975)	Nuclear Capacity (GW)
Year		
1985	$12.90	97
1990	16.40	165
1995	21.00	228

[2] See 44 FR 33608 for designation of census regions

Table 2.—*Summary of 1995 Impacts With Higher Oil Prices* [1]

	Level of control with 520 ng/J maximum emission limit			
	Current standards	Variable control, 50 pct minimum	Variable control, 70 pct minimum	Full control
National SO_2 Emissions (million tons)	23.2	19.8	19.6	19.7
East [2]	10.9	9.1	9.1	9.5
Midwest	8.2	7.9	7.8	7.8
West South Central	2.6	1.7	1.6	1.5
West	1.6	1.1	1.0	0.9
Incremental Annualized Cost (billions 1978 $)		3.3	3.6	5.0
Incremental Cost of SO_2 Reduction (1978 $/ton)		957	977	1,049
Oil Consumption (million bbl/day)	0.9	0.9	0.9	0.9
Coal Production (million tons)	1,800	1,797	1,802	1,832
Total Coal Capacity (GW)	588	587	587	587

[1] With wet and dry scrubbing and the following energy assumptions:

	Oil prices ($ 1975)	Nuclear capacity (GW)
Year:		
1985	$20.20	97
1990	24.20	165
1995	30.70	228

[2] See 44 FR 33608 for designation of census regions.

Table 3.—*Summary of 1995 Impacts With Higher Oil Prices and Less Nuclear Growth* [1]

	Level of control with 520 ng/J maximum emission limit			
	Current standards	Variable control, 50 pct minimum	Variable control, 70 pct minimum	Full control
National SO_2 Emissions (million tons)	25.0	20.9	20.6	20.5
East [2]	12.0	9.8	9.7	10.1
Midwest	8.6	8.2	8.1	8.0
West South Central	8.6	1.8	1.7	1.6
West	1.7	1.2	1.1	0.9
Incremental Annualized Cost (billions 1978 $)		3.8	4.1	5.9
Incremental Cost of SO_2 Reduction (1978 $/ton)		863	914	1,259
Oil Consumption (million bbl/day)	0.9	0.9	0.9	0.9
Coal Production (million tons)	1,940	1,943	1,946	1,984
Total Coal Capacity (GW)	644	644	644	643

[1] With wet and dry scrubbing and the following energy assumptions:

	Oil prices ($ 1975)	Nuclear Capacity (GW)
Year:		
1985	$20.20	92
1990	24.20	141
1995	30.70	173

[2] See 44 FR 33608 for designation of census regions.

Assumed Nuclear Capacity

	Sensitivity analysis	Phase 3
1985	92 GW	97 GW
1990	141 GW	165 GW
1995	173 GW	228 GW

Environmentally, the impact of higher oil prices was to reduce SO_2 emissions (Table 2). For example, under the promulgated standard (hereafter referred to as "the standard") national SO_2 emissions in 1995 were projected to drop from 20.5 million tons predicted in phase 3 (44 FR 33608) to 19.6 million tons. This reduction occurred because the higher oil prices led to the retirement of about 50 gigawatts (GW) of existing oil-fired capacity. While these retirements increased the demand for new coal-fired plants, new plants (subject to Subpart Da) on average were less polluting than the oil-fired capacity they replaced. Therefore, the net effect of oil replacement on a broad regional basis was to reduce SO_2 emissions.

The relative impacts of the alternative standards under the sensitivity tests remained about the same. Sulfur dioxide emissions under the standard were still predicted to be lower than with either full control or the 50 percent variable standard. The emissions benefit relative to full control was reduced from 200,000 tons per year to 100,000 tons per year. Regionally, the effect of the higher oil prices on the relative impacts of the standards was mixed. In comparison to full control, the standard continued to reduce emissions in the East by 400,000 tons per year, but resulted in an additional 70,000 tons in the West and 100,000 tons in the West South Central (relative to phase 3). However, as pointed out above, emissions in all regions were less than or equal to those under the phase 3 oil price assumptions.

The cost of all the standards increased under the higher oil price assumption. This increase was due to the cost of additional coal capacity and corresponding emission control equipment. Relative to the standard, the cost of full control increased by $300 million per year over the $1.1 billion difference predicted under lower oil prices.

At the higher oil prices, 1995 oil consumption by utilities was predicted to be the same under all standards tested. Depending on the standard, consumption was 500,000 to 800,000 barrels per day lower than under the phase 3 projections with lower prices. The reason that the environmental standards had no effect on oil consumption was that at the assumed rate of oil price increase, all base- and intermediate-loaded oil capacity was retired by 1995 and the only remaining oil use was in combustion turbines used to meet peak demand.

Under the assumption of both high oil prices and slowed nuclear growth (Table 3), national and regional SO_2 emissions were predicted to be about the same as under the phase 3 projections. This effect was due to the counterbalancing emission impacts. As noted above, higher oil prices resulted in a net decrease in SO_2 emissions. But at the same time the reduced supply of nuclear generation capacity precipitated demand for an additional 55 GW of new coal capacity beyond that required under the projection with high oil prices. On a national level the emissions from these new coal-fired plants offset the emission reductions achieved by the oil replacements.

With this additional 55 GW of new coal-fired capacity, the environmental impact of alternative standards was more significant. Baseline emission projections (i.e., assuming no change to the original standard) increased from 23.8 million tons per year under the phase 3 energy assumptions to 25.0 million tons per year. Accordingly, the promulgated standard reduced national SO_2 emissions in 1995 by almost 4.5

million tons per year in contrast to about 3.5 million tons per year under both the phase 3 and the high oil price sensitivity projections.

While emission levels were roughly the same as under the phase 3 energy assumptions, the relative impacts of the alternative standards changed somewhat. National emissions were predicted to be 100,000 tons less under full control than under the standard. Relative to full control, the standard was still predicted to reduce emissions by about 400,000 tons in the East, but on a national basis this was offset by emission increases in the other regions. With higher oil prices and less nuclear capacity, the environmental benefit of full control in the West and West South Central was greater by about 100,000 tons, but this impact is masked in Table 3 due to rounding. The variable standard with a 50 percent minimum control level resulted in about 400,000 tons per year more emissions than full control and about 300,000 tons per year more than the standard.

The total cost of all the alternatives increased due to the increased coal capacity. Relative to the standard, the cost of the 50 percent variable control standard remained about the same. The full control standard, however, was significantly more expensive. The marginal cost of full control (relative to the standard) increased from $1.1 billion under the phase 3 energy assumptions to $1.8 billion.

Energy impacts were about the same as those predicted in the high oil price sensitivity runs. Oil consumption was still predicted at about 900,000 barrels per day under all alternative standards. Coal production under all alternatives increased by about 100 million tons per year.

Even considering the uncertainty of future oil prices and nuclear capacity, the Administrator found no basis for convening a proceeding on the modeling issue. The sensitivity runs did not show significant changes in the relative impacts of the alternatives. Under the sensitivity test with both high oil prices and slowed nuclear growth, full control for the first time showed lower emissions nationally than the standard. But the cost of this additional 100,000 tons of control was estimated at $1.8 billion, which represents more than a 40 percent increase in the incremental cost of the standad (Table 3). The principal environmental benefit of full control would be felt in the West and West South Central. Through case-by-case new source review ample authority exists to require more stringent controls as necessary to protect our pristine areas and national parks (44 FR 33584, left column). As a result, the Administrator continues to believe that the flexibility offered by the standard will lead to the best balance of energy, environmental, and economic impacts than either a uniform 90 percent standard or a 50 percent variable standard and hence better satisfies the purposes of the Act.

On the other side of the modeling issue, UARG charged that the Agency's regulatory analysis does not support a 70 percent minimum requirement. The petition called the Agency's control cost estimates unrealistic and presented a macroeconomic analysis which concluded that a 50 percent minimum requirement would result in a more favorable balance of cost, energy, and environmental impacts.

Response to the UARG petition was difficult because the UARG position was presented in two separate reports submitted at different times, and the two reports reached different conclusions. In the formal petition, UARG recommended 50 percent minimum control and promised a detailed report by NERA supporting their position. When the NERA report arrived six weeks later, if recommended 30 percent control. In light of this confusion, it was decided to review each report separately based on its own merits, but devote primary attention to the 50 percent recommendation. After reviewing UARG's macroeconomic analysis, the Administrator finds no convincing arguments for altering the conclusion that the 70 percent minimum removal requirement provides the best balance of impacts. In the formal petition, UARG's conclusion that a 50 percent standard is superior was based on a NERA economic analysis which assumed that only wet scrubbing technology was available to utilities. A detailed analysis of the NERA results was not possible because only summary outputs were supplied in their comments. But the results of this analysis seem to coincide with the Agency's conclusions that there are energy, environmental, and economic benefits, associated with standards that provide a lower cost control alternative for lower sulfur coals. The problem with the UARG initial analysis is that it overlooked the economic benefits of dry scrubbing.

In recognition of this shortcoming, UARG presented their estimate of the costs of dry scrubbing made by Battelle Columbus Laboratories (UARG petition, page 25) and then hypothesized without supporting analysis that "with realistic cost assumptions the advantages of a lower percent removal are likely to increase even further" (UARG petition, page 27). Table 4 compares Battelle's costs to those used in the EPA regulatory analysis. The two estimates are almost the same. More importantly, the two estimates agree that the cost of a 70 percent efficient dry system is not significantly greater than the cost of a 50 percent efficient system, and this conclusion had important implications in the specification of the standard. Based on these comparisons, the Administrator finds that the UARG petition supports the Agency's dry scrubbing cost assumptions and the finding that no significant cost benefit will result from a standard with a 50 percent minimum control level.

Table 4.—*Comparison of UARG and EPA dry SO_2 Scrubbing Costs* [1] *(Mills/kwh)*

Percent removal	Inlet sulfur (lbs SO_2/million Btu)	UARG	EPA
50	0.80	[2] 1.68	2.06
	2.00	[2] 2.13	2.44
70	0.80	1.97	2.68
	2.00	2.54	2.66

[1] Wet scrubbing costs range up to 5 mills/kwh
[2] UARG costs based on 55 percent removal

In their second report, UARG presented additional economic analyses by NERA. In those analyes, the impacts of 30, 50, and 70 percent minimum control standards were tested assuming that both wet and dry scrubbing technology were available. The analyses were performed with three different sets of control cost assumptions—EPA's costs, Battelle's costs, and an additional set of costs specified by NERA. The report concluded that the 70 percent standard is superior using EPA's costs but that under the other cost estimates the 30 percent standard is better. The cost effectiveness of alternative standards (dollars per ton of pollutant removed) was their principal basis of evaluation. UARG then alleged that EPA overestimated the differences in cost between wet and dry scrubbing and that this error led to the wrong conclusion about the impacts of the 70 percent minimum removal requirement. The EPA cost assumptions were criticized primarily because different methods were used to estimate dry and wet scrubbing costs. To justify their position, UARG presented estimates of wet and dry scrubbing costs developed by Battelle. UARG believes that Battelle understand scrubber costs, but that Battelle's relationship between wet and dry scrubbing costs is more accurate than EPA's (UARG petition, page 7). As noted above, Battelle agreed with the Agency's dry scrubbing costs, but for

wet scrubbing the Battelle costs were substantially lower than the Agency's.

Typically, when comparing results of studies, the Agency has detailed documentation with which to compare the methods of costing and analysis. In this case, the Administrator had documentation for neither the NERA costs nor the Battelle costs. The NERA costs were unreferenced and supported by neither engineering analysis nor vendor bids. They assumed that the capital cost of a dry scrubber is 10 percent less than that for a comparable wet scrubber and that the operating costs and energy requirements are the same for the two systems. The UARG petition promised a detailed report from Battelle, but the report was not delivered. Without a basis for evaluation, the Battelle and NERA costs can only be considered as hypothetical data sets for the purpose of sensitivity testing of the economic analysis. They cannot be considered as new information on SO_2 control costs.

The EPA cost estimates, on the other hand, have withstood several critical tests. The PEDCo cost model for wet scrubbers which was used by EPA was thoroughly reviewed by Department of Energy (DOE) consultants, and DOE concurred with the EPA estimates through the interagency working group. Later, the Agency's costs were again reviewed in detail against wet scrubber costs predicted by the Tennessee Valley Authority's scrubber design model. While the two models initially seemed to produce divergent results, careful analysis of the respective costing methodology showed that for similar design specifications the two models produced costs that were very close, the major difference stemming from different assumptions about the construction contingency fee (OAQPS-78-1, IV-B-50). The Administrator concluded from these cost comparisons that the Agency's flue gas desulfurization cost assumptions are reasonable.

The EPA dry scrubbing costs were based primarily on engineering studies submitted by electric utility companies and equipment vendors for the full-scale utility systems now on order or under construction. Using these studies, the EPA cost estimates were made in full cognizance of the basic assumptions used in the PEDCo wet scrubbing model. The result was that for economic modeling purposes (OAQPS-78-1, IV-A-25, page B-17) the dry scrubbing cost estimates in the background document (EPA 450/5-79-021, page 3-67) were increased to reflect similar fuel parameters, local conditions, and degree of design conservatism as reflected in the wet scrubbing costs. Since care was taken in aligning these costs, the Administrator does not accept UARG's allegation that EPA's costs for wet and dry scrubbing are invalid because they were developed on an inconsistent basis.

Even if EPA accepted UARG's unsubstantiated cost assumptions, the NERA sensitivity analyses provided no new insights nor did they materially contradict the Agency's basic conclusions about the standard. Using the Battelle costs and NERA's "alternative scrubber costs" as a range, NERA predicted that relative to 50 percent minimum control, a 70 percent standard would reduce national SO_2 emissions by an additional 250 to 450 thousand tons per year compared to about 100 thousand tons estimated by EPA (Table 1). NERA predicted the additional costs of a 70 percent minimum standard relative to a 50 percent requirement would be between $300 million and $400 million per year compared to $300 million predicted by EPA. It was only in moving to 30 percent control that the NERA results showed a distinct cost savings ($600 to $900 million) over the 70 percent level, but the 30 percent standard produced an additional 700 thousand tons per year of SO_2 under both of their control cost scenarios. The Administrator rejects the 30 percent standard advocated by UARG because the potential cost savings do not justify the potential emission increases. In conclusion, the trade-offs between costs and emissions shown by UARG are generally similar to those predicted by EPA in promulgating the standard and therefore do not support a different standard from the 70 percent variable standard adopted.

Other Issues

Kansas City Power and Light Company sought either an elimination of the percent reduction requirement when emissions are 520 ng/J (1.2 lbs/million Btu) heat input or less or as an alternative a reduction in the 70 percent minimum control requirement. In their arguments, KCPL cited annualized control costs for wet scrubbing of $11.4 million and an energy penalty of 70 thousand tons of coal per year to operate a scrubber. Second, they noted that 14 percent of the potential SO_2 emissions from the coal they plan to burn will be removed by the fly ash. Taking these two factors in account, KCPL computed a cost effectiveness ratio for a hypothetical 650 MW unit to be $3,600 per ton of sulfur removed and concluded that such control was too expensive. Finally, they concluded that scrubbing low-sulfur coals is not warranted since uncontrolled SO_2 emissions from their new plants will be less than the emissions allowed by the standard for high-sulfur coals with 90 percent scrubbing.

After careful review, the Administrator finds that the KCPL petition provided no legal or technical basis for reconsidering the final rule. First, the question of whether a plant burning low-sulfur coal should be required to meet the same percentage reduction requirement as those burning high-sulfur coal has been a central issue throughout this decision-making. Since this issue was raised in the proposal (43 FR 42155, left column), KCPL had ample opportunity to make their points during the public comment period. In fact, it was the recognition of this trade-off in emissions between high-sulfur and low-sulfur coal that led the Administrator to first consider the concept of variable control standards (43 FR 42155, right column). While sulfur removal by fly ash does not represent best demonstrated technology for SO_2 control, sulfur removal by fuel pretreatment, fly ash, and bottom ash may be credited toward meeting the 70 percent requirement.

Second, the KCPL petition does not allege the requisite procedural error that the standard was based on information on which they had no opportunity to comment. Their objections center primarily on the economic and energy impacts of wet SO_2 scrubbing on low-sulfur coal. These issues were clearly identified by the Agency in the background document supporting proposal (OAQPS-78-1, III-B-3, Chapters 5 and 7). Furthermore, the preamble to proposal specifically requested comments on the Agency's assumptions for the regulatory analysis (43 FR 42162, left column).

Finally, and more importantly, the major points made by KCPL are not of central relevance to the outcome of the rule because the information presented does not refute the Agency's data base on wet scrubbing. Consider the following comparisons to the assumptions of the EPA regulatory analysis.

(a) The control costs quoted by KCPL for a 650 MW unit were $31 million in capital and $6.2 million in operating expenses. The EPA assumptions applied to a comparably sized unit result in $55 million in capital costs and $7 million in operating expense.

(b) KCPL quoted an energy impact of 8 tons of coal per hour to operate the scrubber. Considering their operating requirement of 460 tons of coal per hour, the energy penalty of SO_2 control is 1.7

percent. The Agency's economic model assumed 2.2 percent.

(c) KCPL computed cost effectiveness of the standard at $3600 per ton of sulfur removed. This figure is based on a misunderstanding of the application of the fly ash removal credit toward the 70 percent removal requirement. According to the standard, the scrubbing requirement when assuming a 14 percent SO_2 removal in flyash is 65 percent rather than 56 percent as calculated by KCPL. At 65 percent scrubbing, the cost per ton of sulfur removed is $3100. This converts to a cost of $1550 per ton of sulfur dioxide removed which is similar to the costs estimated by EPA for low-sulfur coal applications (OAQPS-78-1, III-B-3 and IV-B-14).

Thus, the Administrator has already concluded that energy and economic costs greater than those cited by KCPL are justified to achieve the emission reductions required by the standard.

Conclusions on Minimum Control Level

After carefully weighing the arguments by the three petitioners, the Administrator can find no new information or insights which are of central relevance to his conclusions about the benefits of a variable control standard with a 70 percent minimum removal requirement. The Sierra Club and UARG correctly point out that the Agency's phase 3 analysis was completed after the close of the public comment period and that they were therefore unable to comment on the final step of the regulatory analysis. But in assessing these comments it is important to put the phase 3 analysis in proper context with its role in the final decision. The Administrator's conclusions about the responses of the utility industry to alternative standards were not based on phase 3 alone, but a series of economic studies spanning more than a year's effort. These analyses were performed under a range of assumptions of economic conditions, regulatory options, and flue gas desulfurization parameters. The phase 3 analysis was merely a fine tuning of the regulatory analysis to reflect dry scrubbing technology.

No new modeling concepts or assumptions were introduced in phase 3. The fundamental modeling concept as introduced in the September proposal (43 FR 42161, right column) has not changed. The model input assumptions were the same as those of the phase 2 analysis presented on December 8, 1978 (44 FR 54834, middle column), and at the December 12 and 13, 1978, public hearing. Detailed consultants' reports on the modeling analyses were available for comment before the close of the public comment period. This public record provided adequate opportunity for the public to comment both on the principal concepts and detailed implementation of the regulatory analysis before the close of the public comment period.

Even though new information was added to the record after the close of the comment period, none of the petitions raised valid objections to this information or cast any uncertainty that is germane to the final decision. The Administrator has very carefully weighed the petitioners comments on dry scrubbing and the UARG sensitivity analysis on pollution control costs. Not only did the UARG analysis generally confirm the conclusions of the EPA regulatory analysis, but it established that even if dry scrubbing costs vary substantially, the relative impacts of a 50 versus 70 percent minimum removal requirement change very little. The 70 percent standard was estimated to produce lower emissions for only slightly higher costs. Differences in cost effectiveness, which UARG seem to weigh most heavily, varied by only $2 to a maximum of $50 per ton of SO_2 removed across alternative cost estimates. In the final analysis none of the petitions repudiated the Agency's findings on the state of development, range of applicability, or costs of dry SO_2 scrubbing. In light of these findings, the Administrator finds the information in the petitions not of central relevance to the final rule and therefore denies the requests to convene a proceeding to reconsider the 70 percent minimum removal requirement.

III. SO_2 Maximum Control Level (90 percent reduction of potential SO_2 emissions)

Petitions for reconsideration submitted by the Utility Air Regulatory Group (UARG) and the Sierra Club questioned the basis for the maximum control level of 90 percent reduction in potential SO_2 emissions, 30-day rolling average. The other petitions did not address this issue. However, in a July 18, 1979, letter, the Environmental Defense Fund (EDF) requested EPA to review utilization of adipic acid scrubbing additives as a basis for a more stringent maximum control level. An additional analysis by UARG was forwarded to EPA on January 28, 1980. Although it was reviewed by EPA, a detailed response could not be prepared in the three days afforded EPA for comment prior to the court's deadline of January 31, 1980, for EPA to respond to the petitions. However, the only issue not previously raised by UARG (boiler load variation) has been addressed by this response.

With their petition, UARG submitted a statistical analysis of flue gas desulfurization (FGD) system test data which purportedly revealed certain flaws in the Agency's conclusions. The UARG petition maintained that a scrubber with a geometric mean (median) efficiency of 92 percent could not achieve the standard because of variations in its performance. UARG also maintained that the highest removal efficiency standard that can be justified by the Agency's data is 85 percent, 30-day rolling average. In the alternative, they suggested that the 90 percent, 30-day rolling average standard could be retained if an adequate number of exemptions were permitted during any given 30-day averaging period. On the other hand, the Sierra Club questioned why the standard had been established at 90 percent when the Agency had documented that well-designed, operated, and maintained scrubbers could achieve a median efficiency of 92 percent. In doing so, they argued that a 90 percent, 30-day rolling average standard was not sufficiently stringent.

After reviewing their petitions, the Administrator finds that the Sierra Club and UARG overlooked several significant factors which were of critical importance to the decision to promulgate a 90 percent, 30-day rolling average standard. The Sierra Club position was based on a misunderstanding of the statistical basis for the standard. The UARG analysis was flawed because it did not consider the sulfur removed by coal washing, coal pulverizers, bottom ash, and fly ash (hereafter, collectively referred to as sulfur reduction credits). Instead the UARG petition based its conclusions on the performance of the FGD system alone. In short, UARG did not analyze the promulgated standard (44 FR 33582, center column). Furthermore, UARG underestimated the minimum performance capability of scrubbers by assuming that future scrubbers would not even achieve the level of process control demonstrated by the best existing systems tested by EPA.

EPA has prepared two reports which re-analyze the same FGD test data considered in UARG's analysis. One report identified the important design and operating differences in the FGD systems tested (OAQPS-78-1, VI-B-14) by EPA and the second report provided additional statistical analyses of these data (OAQPS-78-1, VI-B-13). The results of the EPA analyses showed that:

1. Flue gas desulfurization systems can achieve a 30-day rolling average efficiency between 88 percent and 89

percent (base loaded boilers) or between 86 and 87 percent (peak loaded boilers) with no improvements in currently demonstrated process control.

2. Even if a new FGD system attained only 85 percent efficiency (30-day rolling average), a 90 percent reduction in potential SO_2 emissions can be met when sulfur reduction credits are considered.

To clarify the basis for the Agency's conclusions, the following discussion reviews the development of information used to establish the final percent reduction standard. Initially, EPA studied the application of FGD systems for the control of SO_2 emissions from power plants. As part of that effort, information which described the status and performance of FGD systems in the U.S. and Japan was inventoried and evaluated. These evaluations included the development of design information on how to improve the median efficiency of FGD systems based upon an extensive testing program at the Shawnee facility (OAQPS-78-1, II-A-75). The Shawnee test data and other data (OAQPS-78-1, II-A-71) on existing FGD systems were generated by short-term performance tests. These data did not define the expected performance range (the minimum and maximum SO_2 percent removal) of state-of-the-art FGD systems.

Because a continuous compliance standard was under consideration, information about the process variation of FGD systems was needed to project the performance range of scrubber efficiency around the median percent removal level. For the purpose of measuring process variation, several existing FGD systems were monitored with continuous measurement instrumentation. The selection of FGD systems to be tested was limited principally to the few FGD systems available which were attaining 80 to 90 percent median reduction of high-sulfur coal emissions. When examining the results of these tests, it should be recognized that they do not reflect the performance of a new FGD system specifically designed to attain a continuous compliance standard.

When the percent reduction standard was proposed, EPA projected the performance of newly designed FGD systems. The projection, referred to as the "line of improved performance" in the analysis, was principally based on the information on how to improve median system performance (OAQPS-78-1, III-B-4). The line showed that compliance with the proposed standard (85 percent reduction in potential SO_2 emissions, 24-hour average) could be attained with an FGD system if the only improvement made relative to an existing FGD system was to increase the median efficiency to 92 percent. The "line of improved performance" did not reflect the sulfur reduction credits that could be applied towards compliance with the proposed standard or the improvements in process control (less than 0.289 geometric standard deviation) that could be designed into a new facility. While these alternatives were discussed in detail and included within the basis for the proposed standard (OAQPS-78-1, III-B-4), the purpose of the "line of improved performance" was to show that even without credits or process control improvements, the proposed standard could be met. Upon proposal, the source owner was provided a choice of complying with the percent reduction standard by (1) an FGD system *alone* (85 percent reduction, 24-hour standard), or by (2) use of sulfur reduction credits together with an FGD system attaining less than 85 percent reduction.

After proposal, EPA continued to analyze regulatory options for establishing the final percent removal requirement. On December 8, 1978, economic analyses of these additional options were published in the **Federal Register** (43 FR 57834) for public comment. In this notice EPA stated that:

> Reassessment of the assumptions made in the August analysis also revealed that the impact of the coal washing credit had not been considered in the modeling analysis. Other credits allowed by the September proposal, such as sulfur removed by the pulverizers or in bottom ash and flyash, were determined not to be significant when viewed at the national and regional levels. The coal washing credit, on the other hand, was found to have a significant effect on predicated emissions levels and, therefore, was taken into consideration in the results presented here.

This statement gave notice that the effect of the coal washing credit on emission levels for the proposed control options had not been properly assessed in previous modeling anayses. In the economic analyses completed before proposal, the environmental benefits of the proposed standard were optimistic because it was assumed that all high-sulfur coal would be washed, but a corresponding reduction in the level of scrubbing needed for compliance was not taken into account. This error resulted in the analyses understimating the amount of national and regional SO_2 emissions that would have been allowed by the proposed standard. This problem was discussed at length at the public hearing on December 12, 1978 (OAQPS-78-1, IV-F-1, p. 11, 22, 28, and 29).

UARG addressed this question of coal washing in comments submitted in response to recommendations presented at the public hearing by the Natural Resources Defense Council (OAQPS-78-1, IV-F-1, p. 65, 12-12-78) that the final standards be based upon the removal of sulfur from fuel *together with* the removal of SO_2 from flue gases with a FGD system. In their comments (OAQPS-78-1, IV-D-725, Appendix A, p. 23), UARG had three main objections:

(1) All coals are not washable to the same degree.

(2) Coal cleaning may not be economically feasible.

(3) The Clean Air Act and the Resource Conservation and Recovery Act may preclude the construction of coal washing facilities at every mine.

EPA has reviewed these comments again and does not find that they change the Administrator's conclusion that washed coal can be used in conjunction with FGD systems to attain a 90 percent reduction in potential SO_2 emissions. First, EPA realizes that all coal is not equally washable. In the regulatory analaysis, the degree of coal washing was a function of the rank and sulfur content of the coal. Moreover, because of the variable control scale inherent in the standard, 75 percent of U.S coal reserves would require less than 90 percent reduction in potential SO_2 emissions. The remaining 25 percent are high sulfur coals on which the highest degree of sulfur removal by coal washing are acheived. Second, the washing assumptions used by the Agency reflected the percentage of sulfur removal currently being attained by conventional coal washing plants in the U.S. (OAQPS-78-1, IV-D-756). These washing percentages were therefore cost-feasible assumptions because they are typical of current washing practices. Finally, the Agency does not believe that environmental regulations will prohibit the cleaning of coal. The Clean Air Act and the Resource Conservation and Recovery Act may impose certain environmental controls, but would not prevent the routine construction of coal washing plants. Thus, the Agency concluded that the basis for the promulgated standard could be a combination of FGD control and fuel credits.

Based on these findings, EPA stated (44 FR 33582) that the 90 percent reduction standard "can be achieved at the individual plant level even under the most demanding conditions through the application of flue gas desulfurization (FGD) systems together with sulfur reductions achieved by currently practiced coal preparation techniques. Reductions achieved in the fly ash and

bottom ash are also applicable". Thus, FGD systems *together with* removal of sulfur from the fuel was the basis for the final standard. The standard prohibits the emission of more than "10 percent of the potential combustion concentration (90 percent reduction)." That is, the final standard requires 90 percent reduction of the potential emissions (the theoretical emissions that would result from combustion of fuel in an uncleaned state), not 90 percent removal by a scrubber.

Since UARG failed to take into consideration sulfur reduction credits, UARG analyzed a more stringent standard than was promulgated. Furthermore, EPA's review revealed that while the statistical methodology in the UARG analysis was basically correct, it was flawed by UARG's assumption about the process variation of a new FGD system. As a result, the statistical anaysis was improperly used by UARG to project the number of violations expected by a new FGD system.

To elaborate on the variability issue, page 14 of the UARG petition states:

> The range of efficiency variability values resulting from this analysis represents the range of efficiency variabilities that can be expected to be encountered at future FGD sites.

This assumption artificially inflated the amount of variability that would reasonably be expected in a new FGD system because it presumed that there were no major design and operational differences in the existing FGD systems tested and that the performance of new systems would not improve beyond that of systems tested by EPA. To estimate process variability of new FGD systems, UARG simply averaged together all data from all systems tested including malfunctioning systems (Conesville). EPA's review of these data showed that there were major design and operating differences in the existing FGD systems tested and that the process control could be improved in new FGD systems (OAQPS-78-1, VI-B-14). Therefore, not all of the FGD systems tested by EPA were representative of best demonstrated technology for SO_2 control.

These major differences in the FGD systems tested are apparent when the test reports are examined (OAQPS-78-1, VI-B-14). One of the tests was conducted when the FGD systems were not operating properly (Conesville). Two tests were conducted on regenerative FGD systems (Philadelphia and Chicago) which are not representative of a lime or limestone FGD system. Another test was on an adipic acid/lime FGD system (Shawnee-venturi). None of these tests were representative of the process variation of well-operated, lime or limestone FGD systems on a high-sulfur coal application (OAQPS-78-1, VI-B-14).

Only three systems were tested when (1) the unit was operating normally, and (2) pH control instrumentation was in place and operational (Pittsburgh, Shawnee-TCA, and Louisville). Only at Shawnee did EPA purposely have skilled engineering and technician personnel closely monitor the operation during the test (OAQPS-78-1, VI-B-14). Data from these systems best describe the process control performance of existing lime/limestone FGD systems.

During the Pittsburgh test, there were some problems with pH meters. The data was separated into Test I (pH meter inoperative) and Test II (pH meter operative). During Test I, operators measured pH hourly with a portable instrument (OAQPS-78-1, VI-B-14). Analysis of these data show low process variation during each test period (OAQPS-78-1, VI-B-13). Although the process variation during the second test was 10 percent lower, the difference was not found to be statistically significant. Data taken during each test (I and II) are representative of control attainable with pH controls only. Boiler load was relatively stable during the test. Average process variation as described by the geometric standard deviation was 0.21 and 0.23, respectively.

At Shawnee, only pH controls were in use, but additional attention was given to controlling the process by technical personnel. Boiler load was purposely varied. Geometric standard deviation was 0.18, which was similar to that recorded at Pittsburgh. UARG acknowledged that careful attention to control of the FGD operation by skilled personnel was an important factor in control of the Shawnee-TCA scrubber process (OAQPS-78-1, II-D-440, page 3). It was at the Shawnee test that the best control of FGD process variability by an existing FGD system was demonstrated (OAQPS-78-1, II-B-13).

The Louisville test appears to represent a special case. The average process variation was significantly higher (0.30 and 0.34 for the two units tested) than was recorded at the two other tests (Pittsburgh and Shawnee). An EPA contractor identified two factors which potentially could adversely affect process control at Louisville (OAQPS-78-1, VI-B-14). First, they noted that Louisville was originally designed in the 1960's and has had significant retrofit design changes which could affect process control. Second, the degree of operator attention given to process control is unknown. In addition, UARG showed that an additional factor which may affect the FGD process control is boiler load changes. Unlike a new boiler, the Louisville unit is an older boiler which has been placed into peaking service and therefore experiences significant load changes during the course of a day. As was the case with Pittsburgh and Shawnee, Louisville only uses pH controls to regulate the process. The process variation was analyzed and the maximum process variation of the Louisville system, at a 95 percent confidence level, was determined to be 0.36 geometric standard deviation (OAQPS-78-1, VI-B-13). This estimate of process variation represents a "worst case" situation since it reflects the degree of FGD variability at a peaking unit rather than on the more easily controlled immediate- or base-loaded applications.

In addition to basing their projections on nonrepresentative systems, UARG has also ignored information in a background information document (OAQPS-78-1, II-B-4, section 4.2.6) on feasible process control improvements which were currently used in Japan (OAQPS-78-1, II-I-359). An appraisal of the degree of process instrumentation and control in use at the existing FGD systems tested and a review of the feasible process control improvements which can be designed into new FGD systems was also reviewed (OAQPS-78-1, VI-B-14). As described in this review, none of systems tested had automatic process instrumentation control in operation. All adjustments to scrubber operation were made by intermittent, manual adjustments by an operator. Automatic process controls, which provide immediate and continuous adjustments, can reduce the process control response time and the magnitude of FGD efficiency variation. Even the best controlled FGD systems tested (the Shawnee FGD system, which was designed in the 1960's) employed only feedback pH process control systems (OAQPS-78-1, IV-J-20). None of these existing FGD systems were designed with the feedforward process control features now used in Japan (OAQPS-78-1, II-I-359) for the automatic adjustment of scrubber make-up in response to changing operating conditions. These systems respond to boiler load changes or the amount of SO_2 in the flue gases to be cleaned before they impact the scrubbing system. The use of such systems would improve the control of short-term FGD efficiency variation. At the FGD systems tested, the actual flue gas SO_2

concentration (affected by coal sulfur content) and gas volume (affected by boiler load) was not routinely monitored by the FGD system operators for the purpose of controlling the FGD operation as is currently practiced in Japan (OAQPS-78-1, II-I-359). Thus, even the best controlled existing systems tested were not representative of the control of process variation that would be expected in the performance of new FGD systems to be operated in the 1980's (OAQPS-78-1, VI-B-14). For the purpose of describing the range in performance of an FGD system using only feedback pH control and which are known to have received close attention by operating personnel, the data recorded at these two existing FGD systems (Pittsburgh, test II and Shawnee-TCA) have been used by EPA to project the maximum process variation that would result (0.23 geometric standard deviation) at a 95 percent confidence interval for a base loaded boiler. The data from Louisville was used to represent performance of a peak loaded boiler (0.36 geometric standard deviation at the 95 percent confidence level). These values are conservative because the data collected at the existing FGD systems tested are not representative of the lower process variation that would be expected in future FGD systems designed with improved process control systems (OAQPS-78-1, VI-B-14).

EPA's statistical analysis of scrubber efficency is in close agreement with the UARG analysis when the same process variation and amount of autocorrelation was assumed. EPA's analysis showed about the same autocorrelation effect (the tendency for scrubber efficiency to follow the previous day's performance) as UARG's analysis. A "worst-case" 0.7 autocorrelation factor was used in both analyses even though a more favorable 0.6 factor could have been used based upon the measured autocorrelation of the data at the Shawnee-TCA and Pittsburgh tests. A comparison of the minimum 30-day average performance of a FGD system based upon EPA and UARG process variation assumptions is given in Table 5a.

The EPA analysis (OAQPS-78-1, VI-B-13) summarized in Tables 5a and 5b shows the median scrubbing efficieny required to achieve various minimum 30-day rolling average removal levels (probability of 1 violation in 10 years). The three sets of estimates shown are based on (1) the same process control demonstrated at Pittsburgh, test II and loaded, well-operated existing plant (σ_g=0.20 on average and σ_g=0.23 at the 95 percent confidence level), (2) the same process control demonstrated at Louisville which represents a peak loaded, existing plant (σ_g=0.32 on average and σ_g=0.36 at the 95 percent confidence level), and (3) the poor process control projected by UARG (σ_g=0.29 on average and σ_g=0.43 at the 95 percent confidence level). The process variation is described on a 24-hour, geometric standard deviation (σ_g) basis to allow comparison with UARG's analysis. However, the minimum FGD efficiencies shown in Tables 5a and 5b are 30-day rolling averages.

It is evident from the analysis summarized in Table 5a that if a new FGD system could be operated at least as well as the two best controlled existing FGD systems tested, a 92 percent efficient scrubber (median) can achieve between 88 and 89 percent control on a 30-day rolling average Shawnee-TCA, which represents a base basis.[1] More than 89 percent minimum reduction could be obtained if the process variations in new FGD systems are kept under better control with new control system instruments and careful attention by operating personnel. Even the peak-loaded Louisville system, which has much higher process variability (σ_g=0.32 on average), could achieve 86 to 87 percent reduction.

When reviewing the results of analyses contained in Tables 5a and 5b, it must be kept in mind that they represent "worst case" projections of compliance capability. Neither the UARG nor EPA projections took into account load shifting or the effect of a spare FGD module as a means of countering worst-case system performance (as portrayed by the 95 percent confidence level).

[1] With a risk assumption of one violation per year (the assumption used by UARG) the minimum 30-day rolling average was between 89 percent and 90 percent control at the 95 percent confidence level (OAQPS-78-1, VI-B-13, page 1-4).

Table 5a.—*Median FGD Efficiency to Attain Minimum 30-day Rolling Average Standard for Base Loaded Units*[a]

Minimum 30-day rolling average FGD efficiency	Median efficiency for existing well-controlled FGD systems tested [EPA basis]		Median efficiency for all existing FGD systems tested [UARG basis]	
	Average [σ_g=0.20]	Maximum [σ_g=0.23]	Average [σ_g=0.29]	Maximum [σ_g=0.43]
90	92.6	92.9	93.5	94.9
89	91.8	92.2	92.9	94.4
88	91.1	91.5	92.2	93.8
87	90.3	90.8	91.6	93.3
86	89.6	90.1	90.9	92.8
85	88.8	89.3	90.3	92.3

[a] Estimates are based on probability of only 1 violation in 10 years. Process variation (σ_g is expressed as one geometric standard deviation, 24-hour basis). The maximum process variation is projected at the 95th percentile.

Table 5b.—*Median FGD Efficiency to Attain Minimum 30-day Rolling Average Standard for Peak Loaded Units.*[a]

Minimum 30-day rolling average FGD efficiency	Median efficiency for peak loaded, existing FGD systems tested [EPA basis]	
	Average [σ_g=0.32]	Maximum [σ_g=0.36]
90	93.8	94.2
89	93.2	93.6
88	92.6	93.1
87	92.0	92.5
86	91.4	91.9
85	90.8	91.3

[a] Estimates are based on probability of only 1 violation in 10 years. Process variation (σ_g) is expressed as one geometric standard deviation, 24-hour basis. The maximum process variation is projected at the 95th percentile.

EPA also contended that an FGD system supplier could miss the mark in designing a 92 percent median efficiency FGD system and that a miscalculation of only 1 or 2 percent in median efficiency would prevent the FGD system from complying with the final SO_2 percent reduction standard (UARG petition, Appendix B, p. 64). EPA specifically addressed this miss-the-mark argument when it established a variable control standard (70 percent to 90 percent reduction). In the preamble to the final standard EPA stated, "Finally, under a variable approach, a source could move to a lower sulfur content coal to achieve compliance if its control equipment failed to meet design expectations" (44 FR 33583, left column). An FGD system designed for high-sulfur coal would increase in scrubbing efficiency if a lower-sulfur coal were fired, and the amount of removal required for compliance would drop from 90 percent to as low as 70 percent reduction in potential SO_2 emissions.

Even if, as UARG contends, an FGD system on a 30-day rolling average basis (through poor design or operating practices) could only attain 85 percent reduction, the facility would comply with the promulgated 90 percent reduction standard when credits for sulfur removed by coal washing, pulverizers, and in bottom and fly ash are considered. These credits which can

be substantial, are summarized as follows:

1. *Coal washing.* On high-sulfur midwestern coals that would be subject to the 90 percent reduction requirement, an average of 27 percent sulfur removal was achieved by conventional coal washing plants in 1978 (OAQPS-78-1, IV-D-761). Even in Ohio where the lowest average coal washing reduction was recorded, 20 percent reduction was attained. These data represent current industry practice and do not necessarily represent full application of state-of-the-art in coal cleaning technology.

2. *Coal pulverizers.* Additional sulfur reductions are also attainable with coal pulverizers used at power plants. Coal is typically pulverized at power plants prior to combustion. By selecting a specific type of coal pulverizer (one that will reject pyrites from the pulverized coal), sulfur can be removed. One utility company reported to EPA that sulfur reductions of 12% to 38% (with 24% average removal) had been obtained (OAQPS-78-1, II-D-179) by the pulvizers alone when a program had been implemented to optimize the rejection of pyrites by the pulverizer equipment.

3. *Ash retention.* One utility company has reported 0.4% to 5.1% sulfur removal credit in bottom ash alone with eastern and midwestern coals and 7.3% to 15.9% removal with a western coal (OAQPS-78-1, II-B-72). To determine how much sulfur is removed by the bottom ash and fly ash combined, EPA conducted a study in which numerous boilers were tested. The amount of SO_2 emitted was compared to the potential SO_2 emissions in the coal. For eight western coals and six midwestern coals, an average sulfur retention of 20 percent and 10 percent, respectively, was found (OAQPS-78-1, IV-A-6). Thus, an average of at least 10 percent SO_2 reduction can be attributed to sulfur retention in coal ash.

These credits *together with* an FGD system continuously achieving as little as 85 percent reduction are sufficient to attain compliance with the final SO_2 percent reduction standard as is shown in Table 6:

Table 6.—*Impact of Sulfur Reduction Credits on Required FGD Control Efficiencies to Attain 90 Percent Overall SO_2 Reduction*

SO_2 removal method	Compliance Option A	Compliance Option B	Compliance Option C
Coal washing removal, percent	27	20	8
Pulverizer, fly ash, and bottom ash reduction, percent	10	4	0
FGD system removal, percent	85	87	89
Overall SO_2 reduction in potential emissions	90	90	90

Table 6 illustrates that even if the FGD system attained only 85 percent reduction as UARG has claimed, the 90 percent removal standard would be achieved (Option A) even if a coal washing plant attained only 27 percent reduction in sulfur (the average reduction reported by the National Coal Association for conventional coal washing plants, OAQPS-78-1, IV-D-761). In addition, Table 6 illustrates that less fuel credit is needed when the FGD system attains more than 85 percent reduction (Options B and C). For example, even if the minimum amount of coal washing curently being achieved (20 percent in Ohio) is attained, only 87 percent FGD reduction would be needed. Thus, less than average or only average sulfur reduction credits (i.e., only 8-27% coal washing and 0-10% pulverizer, bottom ash and fly ash credits) would be needed to comply with the 90 percent reduction standard even if the FGD system *alone* only attained 85 to 89 percent control. Moreover, for 75 percent of the nation's coal reserves which have potential emissions less than 260 ng/J (6.0 lbs/million Btu) heat input (OAQPS-78-1, IV-E-12, page 13), less than 90 percent reduction in potential SO_2 emissions would be needed to meet the standard.

The statistical analysis submitted by UARG does not address the basis (FGD and sulfur reduction credits) of the standard and therefore does not alter the conclusions regarding the achievability of the promulgated percent reduction standard. The prescribed level can be achieved at the individual plant level even under the most demanding conditions through the application of scrubbers together with sulfur reduction credits.

Finally, UARG's petition (p. 15) states that the final standard was biased by an error in the preamble (see table, 44 FR 33592) which incorrectly referred to certain FGD removal efficiencies as "averages" rather than as geometric "means" (medians). These removal efficiencies were properly referred to as "means" in the EPA test reports. This discrepancy had no bearing on EPA's decision to promulgate a 90 percent SO_2 standard. Even though UARG claims a bias was introduced, their consultant's report states (see Appendix B, Page 46):

> Therefore, even though EPA mistakenly used the term "average SO_2 removal" in the promulgation, it is obvious that when the phrase "mean FGD efficiency" is used, EPA is correctly referred to the *mean* (or median) of the long-normal distribution of (1-eff).

Thus, even though Entropy (UARG's consultant which prepared their statistical analysis in Appendix B) "discovered a discrepancy" as UARG alleges, they did not reach a conclusion as UARG has done, that a simple transcription error in preparation of the preamble undermined the credibility of EPA's analysis of the test data. In fact, the analysis of test data performed by EPA (OAQPS-78-1, II-B-4) used correct statistical terminology.

The Sierra Club also submitted a petition that questioned the promulgated 90 percent, 30-day rolling average standard. The petition asks "why the final percentage of removal for 'full scrubbing' was set at only 90 percent for a 30-day average" in view of the preamble to the proposal which mentions a 92 percent reduction (43 FR 42159). The petition states that "EPA indicated that 85 percent scrubbing on a 24-hour average was equivalent to 92 percent on a 30-day average." This statement is a misquotation. The preamble actually stated that "an FGD system that could achieve a 92 percent long-term (30 days or more) mean SO_2 removal would comply with the proposed 85 percent (24-hour average) requirement." The long-term mean referred to is the median value (geometric mean) of FGD system performance, not an equivalent standard. Reference in the preamble was made to the background information supplement (OAQPS-78-1, III-B-4) which provided "a more detailed discussion of these findings." The 92 percent removal is described therein as the median (geometric mean) of the statistical distribution defined by the "line of improved performance" in Figure 4-1. A median is the middle number in a given sequence of numbers. Thus for a sequence of 24-hour or 30-day rolling average efficiencies, the median SO_2 removal (92 percent) is a level at which one-half of the 30-day rolling average FGD system efficiencies would be higher and one-half would be lower. Since one-half of the expected removal efficiencies would be lower than the 92 percent median, a standard could not be set at that level. The standard must recognize the range of 30-day rolling average FGD efficiencies that would be expected. The petition is based upon a misconception as to the meaning of the 92 percent value (a median) and is therefore not new information of central relevance to this issue.

The Environmental Defense Fund requested that EPA consider the relevance of the lime/limestone-adipic acid tests at Shawnee to this rulemaking. Adipic acid has been found to increase FGD system performance by limiting the drop in pH that normally occurs at the gas/liquid interface during SO_2 absorption. Test runs at Shawnee

showed increased FGD performance (in one test series the efficiency increased from 71 percent to 93 percent) with no apparent adverse impact upon FGD system operation.

EPA agrees that use of adipic acid additive in lime/limestone scrubbing solutions appears very promising and is currently planning a full-scale FGD system demonstration. Several important areas are to be evaluated in the EPA test program. The handling and disposal characteristics of waste sludges from the scrubber must be evaluated to see that adipic acid does not affect control of leachates into groundwater. In addition, the consumption rate of adipic acid by the FGD system and its ultimate disposition must be evaluated. Furthermore, tests must be conducted to show whether or not the concentration of adipic acid in FGD system sludge poses significant environmental problems. In the absence of such data, EPA does not believe it prudent to include adipic acid as a basis for the current revised standard.

IV. Particulate Matter Standards

Only one of the four petitions for reconsideration raised issues concerning the particulate matter standard. In their petition, the Utility Air Regulatory Group (UARG) argued principally that baghouse technology was not demonstrated on large coal-fired utility boilers and that the 13 ng/J (0.03 lb/million Btu) heat input standard could not be achieved at reasonable costs with electrostatic precipitators on low-sulfur coal applications. They also noted that emission test data on a 350 MW baghouse application was placed in the record after the close of the comment period. In response to these data, UARG presented operating information on baghouse systems obtained from two coal-fired installations. In addition they restated arguments that had been raised in their January 1979 comments concerning EPA's data base and the potential effects of NO_x and SO_2 emission control on particulate emissions.

In reaching his decision that baghouse technology is adequately demonstrated, the Administrator took into account a number of factors. In addition to the emission test data and other technical information contained in the record, he placed significant weight on the fact that at least 26 baghouse-equipped coal-fired electric utility steam generators were operating prior to promulgation of the standard and that 28 additional units were planned to start operation by the end of 1982. He also noted that some of the utility companies operating baghouses on coal-fired steam generators were ordering more baghouses and that none of them had announced plans to decommission or retrofit a baghouse controlled plant because of operating or cost problems. The Administrator believed that this was a strong indication that some segments of the utility industry believe that baghouses are practical, economical, and adequately demonstrated systems for control of particulate emissions. These electric utility baghouses are being applied to a wide range of sizes of steam generators and to coals of varying rank and sulfur content. The Industrial Gas Cleaning Institute speaking for the manufacturers of baghouses submitted comments (OAQPS-78-1, IV-D-247) confirming that baghouses are adequately demonstrated systems for control of particulate emissions from coal-fired steam-electric generators of all sizes and types.

In the proposal, EPA acknowledged that large baghouses of the size that would typically be used to meet the standard had only been recently activated. Further, the Agency announced that it planned to test a 350 MW unit (43 FR 42169, center column). The validated test data from this unit, located at the Harrington Station, demonstrated that the standard could be achieved at large facilities (OAQPS-78-1, V-B-1, page 4-1). The Agency also became aware that the operators of the facility were encountering start-up problems. After carefully evaluating the situation, the Agency concluded that the problems were temporary in nature (44 FR 33585, left column).

Furthermore, Appendix E of the UARG petition supports the Agency finding. According to Appendix E, the start-up problems experienced at Harrington Station (Unit #2) have not affected unit availability nor have they altered the utility's plans for equipping another large coal-fired steam generator at the site (Unit #3) with a baghouse. Appendix E noted, "The company feels that the baghouse achieved an availability equal to that of the electrostatic precipitator installed in unit 1" (UARG petition, Appendix E, page 2). The Appendix also examined two retrofit baghouse installations on boilers firing Texas lignite at the Monticello Station (Unit #1 and Unit #2). While the first unit that came on line experienced problems, Appendix E notes, "Since the start-up of Unit 2 bag filter, the baghouse has been operational at all times the boiler was on line (due to the solution of the majority of the problems associated with Unit 1 baghouse)" (UARG petition, Appendix E, page 5). These findings served to reinforce the Agency's conclusion that problems encountered at these initial installations are correctible.

Based on the Harrington and Monticello experience, UARG maintained that EPA did not properly consider the cost of activating and maintaining a baghouse. Contrary to UARG's position, the cost estimates developed by EPA provide liberal allowances for start-up and continued maintenance. For example, the Agency's cost estimates for a baghouse for a 350 MW power plant provided over $1.4 million for start-up and first year maintenance of which $440,000 was included for bag replacement (OAQPS-78-1, II-A-64 and VI-B-12). For subsequent years, $710,000 per year was allowed for routine maintenance of which $440,000 was included for bag replacement. In comparison, the UARG petition indicated that bag replacement costs during the first year of operation of the baghouse at the Harrington Station (350 MW capacity) would be $250,000 and the bag replacement costs at the two Monticello baghouse units (610 MW capacity total) would total about $642,000. From the information provided by UARG, it appears that the Agency has fully accounted for any potential costs that may be incurred during start-up or annual maintenance.

UARG further maintained that higher pressure drops encountered at these initial installations would increase the cost of power to operate a baghouse beyond those estimated by the Agency. The Administrator agrees that if higher pressure drops are encountered an increase in cost will be incurred. However, even assuming that the pressure drops initially experienced at the Harrington and Monticello Stations occur generally, the annual cost will not increase sufficiently to affect the Administrator's decision that the standard can be achieved at a reasonable cost. For example, the increase in pressure drop reported by UARG (UARG petition, page 43) at the Harrington station would result in a cost penalty of about $191,000 per year, which represents only a 4.5 percent increase in the total annualized baghouse costs projected by EPA (OAQPS-78-1, II-A-64, page 3-18) and

less than one percent increase in relation to utility operating costs. It should be reported, however, that as a result of corrective measures taken at Harrington station since start-up, the operating pressure drop reported by UARG has been reduced. If the pressure drop stabilizes at this improved level 2 kilopascals (8 inches H_2O) rather than the 2.75 kilopascals (11 inches H_2O) suggested by UARG the $191,000 cost penalty would be reduced by some $90,000 per year (OAQPS-78-1, VI-B-11 and UARG petition, page 43).

UARG also maintained that a period longer than 180 days after start-up is required to shake down new baghouse installations, and that EPA should amend 40 CFR 60.8, which requires compliance to be demonstrated within 180 days of start-up. UARG based these comments on the experience at the Harrington and Monticello Stations. It is important to understand that 40 CFR 60.8 only requires compliance with the emission standards within 180 days of start-up and does not require, or even suggest, that the operation of the facility be optimized within that time period. Optimization of a system is a continual process based on experience gained with time. On the other hand, a system may be fully capable of compliance with the standard before it is fully optimized.

In the case of the Harrington station the initial performance test was conducted by the utility during October 1978 (which was within four months of start-up). The initial test and a subsequent one were found however, to be invalid due to testing errors and therefore it was February 1979 before valid test results were obtained for the Harrington Unit (OAQPS-78-1, IV-B-1, page 42). This test clearly demonstrated achievement of the 13 ng/J (0.03 lb/million Btu) heat input emission level. These results were obtained even though the unit was still undergoing operation and maintenance refinements. With respect to the Monticello station, UARG reported that no actual performance test data are available (UARG petition, Appendix E, page 6).

UARG also maintained that baghouses are not suitable for peaking units because of the high energy penalty associated with keeping the baghouse above the dew point. EPA recognizes that baghouses may not be the best control device for all applications. In those instances where high energy penalties may be incurred in heating the baghouse above the dew point, the utility would have the option of employing an electrostatic precipitator. However, some utilities will be using baghouses for peaking units. For example, the baghouse control system on four subbituminous, pulverized coal-fired boilers at the Kramer Station have been equipped with baghouse preheat systems and that station will be placed in peaking service in the near future (OAQPS-78-1, VI-B-10).

UARG also argued that it may be necessary to install a by-pass system in conjunction with a baghouse to protect the baghouse from damage during certain operation modes. The use of such a system during periods of start-up, shutdown, or malfunction is allowed by the standard when in keeping with good operating practice.

The UARG petition implied that the test data base for electrostatic precipitator systems (ESP) is inadequate for determining that such systems can meet the standard. Contrary to UARG's position, the EPA data base for the standard included test data obtained under worst-case conditions, such as (1) when high resistivity ash was being collected, (2) during sootblowing, and (3) when no additives to enhance ESP performance were used (OAQPS-78-1, III-B-1, page 4-11 and 4-12). Even when all of the foregoing worst-case conditions were incurred simultaneously, particulate matter emission levels were still less than the standard. It should also be understood that none of the ESP systems tested were larger than the model sizes used for estimating the cost of control under worst-case conditions.

The UARG petition also questioned the Administrator's reasoning in failing to evaluate the economic impact of applying a 197 square meter per actual cubic meter per second (1000 ft ^{3}/1000 ACFM) cold-side ESP to achieve the standard under adverse conditions such as when firing low-sulfur coal. The Administrator did not evaluate the economic impact of applying a large, cold-side ESP because a smaller, less costly 128 square meter per actual cubic meter per second (650 ft ^{3}/1000 ACFM) hot-side ESP would typically be used. The Administrator believed that it would have been non-productive to investigate the economics of a cold-side ESP when a hot-side ESP would achieve the same level of emission control at a lower cost.

The UARG petition also suggested that hot-side ESP's are not always the best choice for low-sulfur coal applications. The Administrator agrees with this position. In some case, low-sulfur coals produce an ash which is relatively easy to collect since flyash resistivity is not a problem. Under such conditions it would be less costly to apply a cold-side ESP and therefore it would be the preferred approach. However, when developing cost impacts of the standard, the Agency focused on typical low-sulfur coal applications which represents worst case conditions, and therefore assessed only hot-side precipitators.

The UARG petition suggests that in some cases the addition of chemical additives to the flue gas may be required to achieve the standard with ESPs, and the Agency should have fully assessed the environmental impact of using such additives. The Administrator, after assessing all available data, concluded that the use of additives to improve ESP performance would not be necessary (OAQPS-78-1, III-B-1, page 4-11). Therefore, it was not incumbent upon EPA to account for the environmental impact of the use of additives other than to note that such additives could increase SO_3 or acid mist emissions. In instances where a utility elects to employ additives as a cost saving measure, their potential effect on the environment can be assessed on a case-by-case basis during the new source review process.

UARG also maintained that there are special problems with some low-sulfur coals that would preclude the use of hot-side ESPs and attached Appendix F in support of their position. Review of Appendix F reveals that while the author discussed certain problems related to the application of hot-side ESPs on some western low-sulfur coal, he also set forth effective techniques for resolving these problems. The author concluded, "The evidence of more than 11 years of experience indicates that hot precipitators are here to stay and very likely their use on all types of coal will increase."

UARG also argued that the data base in support of the final particulate standard for oil-fired steam generating units was inadequate. The standard is based on a number of studies of particulate matter control for oil-fired boilers. These studies were summarized and referenced in the BID for the proposed standard (OAQPS-78-1, III-B-1, page 4-39). These earlier studies (*Control of Particulate Matter from Oil Burners and Boilers*, April 1976, EPA-450/3-76-005; and *Particulate Emission Control Systems for Oil-fired Boilers*, December 1974, EPA-450/3-74-063) support the conclusion that ESP control systems are applicable to oil-fired steam generators and that such emission control systems can achieve the standard. The achievability of the standard was also confirmed by the Hawaiian Electric Company, a firm that would be significantly affected by the standard since virtually all their new

generating capacity will be oil-fired due to their location. In their comments the company indicated, "Hawaiian Electric Company supports the standards as proposed in so far as they impact upon the electric utilities in Hawaii" (OAQPS-78-1, IV-D-159).

UARG also argued that the Administrator had little or no data upon which to base a conclusion that the particulate standard is achievable for lignite-fired units. In making this assertion, UARG failed to recognize that the Agency had extensively analyzed lignite-fired units in 1976 and concluded that they could employ the same types of control systems as those used for other coal types (EPA-450/2-76-030a, page II-29). Additionally, review of the literature and other sources revealed no new data that would alter this finding (Some of the data considered includes OAQPS-78-1, II-I-59, II-I-312, and II-I-322) and the Agency continues to believe that the emission standards are achievable when firing all types of coal including lignite coal. UARG has not provided any information during the comment period or in their petition which would suggest any unique problems associated with the control of particulate matter from lignite-fired units.

The UARG petition alleged that the Administrator did not take into account the effect of NO_x control in conjunction with promulgation of the particulate standard. In developing the NO_x standard, the Administrator assessed the possibility that NO_x controls may increase ash combustibles and thereby affect the mass and characteristics of particulate emissions. The Administrator concluded, however, that the NO_x standard can be achieved without any increase in ash combustibles or any significant change in ash characteristics and therefore there would be no impact on the particulate standard (OAQPS-78-1, III-B-2, page 6-14).

UARG also raised the issue of sulfate carryover from the scrubber slurry and its potential effect on particulate emissions. EPA initially addressed this issue at proposal and concluded that with proper mist eliminator design and maintenance, liquid entrainment can be controlled to an acceptable level (43 FR 42170, left column). Since that time, no new information has been presented that would lead the Administrator to reconsider that finding.

In summary, UARG failed to present any new information on particulate matter control that is centrally relevant to the outcome of the rule.

V. NO_x Standards

The Utility Air Regulatory Group (UARG) sought reconsideration of the NO_x standards. They maintained that the record did not support EPA's findings that the final standards could be achieved by all boiler types, on a variety of coals, and on a continuous basis without an unreasonable risk of adverse side effects. In support of this position, they argued that while EPA's short-term emissions data provided insight into NO_x levels attainable by utility boilers under specified conditions during short-term periods, they did not sufficiently support EPA's standards based on continuous compliance. Further, they maintained that the continuous monitoring data relied on by the Agency does not support the general conclusions that all boiler types can meet the standards on a variety of coals under all operating conditions. They also argued that the Agency failed to collect or adequately analyze data on the adverse side effects of low-NO_x operations. Finally, they contended that vendor guarantees have been shown not to support the revised standards. The arguments presented in the petition were discussed in detail in an accompanying report prepared by UARG's consultant.

In general, the UARG petition merely reiterated comments submitted in January 1979. Their arguments concerning short-term test data, the potential adverse side effects of low-NO_x operation, and manufacturer's guarantees did not reflect new information nor were they substantially different from those presented earlier. For example, in their petition, UARG asserted that new information received at the close of comment period revealed that certain data EPA relied upon to conclude that low-NO_x operations do not increase the emissions of polycyclic organic matter (POM) are of questionable validity (UARG petition, page 56). This comment repeats the position stated in UARG's January 15, 1979, submittal (OAQPS 78-1, IV-D-611, attachment—KVB report, January 1979, page 86). More importantly, UARG failed to recognize that EPA did not rely on the tests in question and that the Agency noted in the BID for the proposed standards (OAQPS-78-1, III-B-2, page 6-12) that the data were insufficient to draw any conclusion on the effects of modern, low-NO_x Babcock and Wilcox burners on POM emissions. Instead, EPA based its conclusions in regard to POM on its finding that combustion efficiency would not decrease during low-NO_x operation and therefore, there would not be an increase in POM emissions (43 FR 42171, left column and OAQPS-78-1, III-B-2, page 9-6).

Similarly, UARG did not present any new data in regard to boiler tube corrosion. They merely restated the arguments they had raised in their January 1979 comments which questioned EPA's reliance on corrosion test samples (coupons). EPA believes that proper consideration has been given to the corrosion issues and substantial data exist to support the Administrator's finding that the final requirements are achievable without any significant adverse side effect (44 FR 33602, left column). In addition, UARG also maintained that the Agency should explain why it dismissed the 190 ng/J (0.45 lb/million Btu) heat input NO_x emission limit (44 FR 33602, right column) applicable to power plants in New Mexico. In dismissing the recommendation that the Agency adopt a 190 ng/J emission limit, the Administrator noted that the only support for such an emission limitation was in the form of vendor guarantees.

In relation to vendor guarantees, UARG maintained in their January comments and reiterate in their petition that EPA should not rely on vendor guarantees as support for the revised standards. EPA cannot subscribe to UARG's narrow position. While vendor guarantees alone would not provide a sufficient basis for a new source performance standard, EPA believes that consideration of vendor guarantees when supported by other findings is appropriate. In this instance, the vendor guarantees served to confirm EPA findings that the boiler manufacturers possess the requisite technology to achieve the final emission limitations. This approach was described by Foster Wheeler in their January 3, 1979, letter to UARG, (OAQPS 78-1, IV-D-611, attachment—KVB report, January 1979, page 119) that states, "When a government regulation, which has a major effect on steam generator design, is changed it is unreasonable to judge the capability of a manufacturer to meet the new regulation by evaluating equipment designed for the older less stringent regulation."

This observation is also germane to the arguments raised by UARG with respect to EPA data on short-term emission tests and continuous monitoring. In essence, UARG maintained that the EPA data base was inadequate because boilers designed and operated to meet the old 300 ng/J (0.7 lb/million Btu) heat input limitation under Subpart D have not been shown to be in continuous compliance with the

new standard under Subpart Da. While this statement is true, these units, which were designed and operated to meet the old standard, incurred only five exceedances of the new standards on a monthly basis. Moreover, a review of the available 34 months of continuous monitoring data from six utility boilers revealed that they all operated well below the applicable standard (OAQPS-78-1, V-B-1).

In addition, UARG argued that the available continuous monitoring data demonstrated that the Agency should not have relied on short-term test data. Citing Colstrip Units 1 and 2, they noted that less than one-third of the 30-day average emissions fell below the units' performance test levels of 125 ng/J (0.29 lb/million Btu) heat input and 165 ng/J (0.38 lb/million Btu) heat input, respectively. They further maintained that this had not been considered by the Agency. In fact, the Administrator recognized at the time of promulgation that emission values obtained on short-term tests could not be achieved continuously because of potential adverse side effects and therefore established emission limits well above the values measured by such tests (44 FR 42171, left column). In addition, EPA took into account the emission variability reflected by the available continuous monitoring data when it established a 30-day rolling average as the basis of determining compliance in the standards (44 FR 33586, left column).

UARG also maintained in their petition that EPA should not rely on the Colstrip continuous monitoring data because it was obtained with uncertified monitors. The Administrator recognized that the Colstrip data should not be relied on in absolute terms since monitors were probably biased high by approximately 10 percent (OAQPS 78-1, III-B-2, page 5-7). EPA's analysis of data revealed, however, that it would be appropriate to use the data to draw conclusions about variability in emissions since the shortcoming of the Colstrip monitors did not bias such findings. This data together with data obtained using certified continuous monitors at five other facilities (OAQPS 78-1, V-B-1, page 5-3) and the results from 30-day test programs (manual tests performed about twice per day) at three additional plants (OAQPS 78-1, II-B-62 and II-B-70) enabled the Administrator to conclude that emission variability under low-NO_x operating conditions was small and therefore the prescribed emission levels are achievable on a continuous basis.

UARG argued that since the only continuous monitoring data available was obtained from boilers manufactured by Combustion Engineering and on a limited number of coal types, the Agency did not have a sufficient basis for finding that the standards can be achieved by other manufacturers or when other types of coals are burned. The Administrator concluded after reviewing all available information that the other three major boiler manufacturers can achieve the same level of emission reduction as Combustion Engineering with a similar degree of emission variability (43 FR 42171, left column and 44 FR 33586, middle column). This finding was confirmed by statements submitted to UARG and EPA by the other vendors that their designs could achieve the final standards, although they expressed some concern about tube wastage potential (OAQPS-78-1, III-D-611, attachment-KVB report, pages 116-121 and IV-D-30). EPA has considered tube wastage (corrosion) throughout the rulemaking and has determined that it will not be a problem at the NO_x emission levels required by the standards (44 FR 33602, left column). With respect to different coal types, the Agency concluded from its analysis of available data that NO_x emissions are relatively insensitive to differing coal characteristics and therefore other coal types will not pose a compliance problem (43 FR 42171, left column and OAQPS-78-1, IV-B-24). UARG did not submit any data to refute this finding.

UARG also argued that the continuous monitoring data should have been accompanied by data on boiler operating conditions. EPA noted that the data were collected during extended periods representative of normal operations and therefore it reflected all operational transients that occurred. In particular, at Colstrip units 1 and 2 more than one full year of continuous monitoring data was analyzed for each unit. In view of this, EPA believes that the data base accurately reflects the degree of emission variability likely to be encountered under normal operating conditions. UARG recognized this in principle in their January 15 comments (Part 4, page 15) when they stated that "continuous monitors would measure all variations in NO_x emissions due to operational transients, coal variability, pollution control equipment degradation, etc."

In their petition, UARG restated their January 1979 comments that EPA's short-term test data were not representative and therefore should not serve as a basis for the standard. As noted earlier, EPA did not rely exclusively on short-term test data in setting the final regulations. In addition, contrary to the UARG claim, EPA believes that the boiler test configurations used to achieve low-NO_x operations reflect sound engineering judgement and that the techniques employed are applicable to modern boilers. This is not to say that the boiler manufacturers may not choose other approaches such as low-NO_x burners to achieve the standards. While recognizing that EPA's test program was concentrated on boilers from one manufacturer, sufficient data was obtained on the other major manufacturers' boilers to confirm the Agency's finding that they would exhibit similar emission characteristics (44 FR 33586, left column). Therefore, in the absence of new information, the Administrator has no basis to reconsider his finding that the prescribed emission limitations are achievable on modern boilers produced by all four major manufacturers.

VI. Emission Measurement and Compliance Determination

The Utility Air Regulatory Group (UARG) raised several issues pertaining to the accuracy and reliability of continuous monitors used to determine compliance with the SO_2 and NO_x standards. UARG particularly commented on the data from the Conesville Station. In addition, they also maintained that the sampling method for particulates was flawed. With respect to compliance determinations, UARG maintained that the method for calculating the 30-day rolling averages should be changed so that emissions before boiler outages are not included since they might bias the results. In addition, UARG argued that the standards were flawed since EPA had not included a statement as to how the Agency would consider monitoring accuracy in relation to compliance determination. With the exception of the method of calculating the 30-day rolling average and the comments on the Conesville station, the petition merely reiterated comments submitted prior to the close of the public comment period.

As to the reliability and durability of continuous monitors, information in the docket (OAQPS-78-1, II-A-88, IV-A-20, IV-A-21, and IV-A-22) demonstrates that on-site continuous monitoring systems (CMS) are capable and have operated on a long-term basis producing data which meet or exceed the minimum data requirements of the standards.

In reference to the Conesville project, UARG questioned why EPA dismissed the continuous monitoring results since it was the only long-term monitoring effort by EPA to gain instrument

operating experience. UARG maintained that this study showed monitor degradation over time and that it was representative of state-of-the-art monitoring system performance. This conclusion is erroneous. EPA does not consider the Conesville project adequate for drawing conclusions about monitor reliability because of problems which occurred during the project.

To begin with, UARG is incorrect in suggesting that the goal of the project was to obtain instrument operating experience. The primary purpose of the project was to obtain 90 days of continuous monitoring data on FGD system performance. Because of intermittent operation of the steam generator and the FGD system, this objective could not be achieved. As the end of the 90-day period approached, a decision was made to extend the test duration from three to six months. The intermittent system operation continued. As a result, when the FGD outages were deleted from the total project time of six months, the actual test duration was similar to those at the Louisville, Pittsburgh, and Chicago tests and did not, therefore, represent an extended test program.

EPA does not consider the Conesville results to be representative of state-of-the-art monitoring system performance. Because of the intermittent operation throughout the test period (OAQPS-78-1, IV-A-19, page 2), it became obvious that the goals of the program could not be met. As a result, monitoring system maintenance lapsed somewhat. For example, an ineffective sample conditioning system caused differences in monitor and reference method results (OAQPS-78-1, IV-A-20, page 3-2). If the EPA contractor had performed more rigorous quality assurance procedures, such as a repetition of the relative accuracy tests after monitor maintenance more useful results of the monitor's performance would have been obtained. Thus, the Conesville study re-emphasized the need for periodic comparisons of monitor and reference method data and the inherent value of sound quality assurance procedures.

The UARG petition suggested that the standards incorporate a statement as to how EPA will consider monitoring system accuracy during compliance determination. More specifically, UARG recommended that EPA define an error band for continuous monitoring data and explicitly state that the Agency will take no enforcement action if the data fall within the range of the error band. The Agency believes that such a provision is inappropriate. Throughout this rulemaking, EPA recognized the need for continuous monitoring systems to provide accurate and reproducible data. EPA also recognized that the accuracy of a CMS is affected by basic design principals of the CMS and by operating and maintenance procedures. For these reasons, the standards require that the monitors meet (1) published performance specifications (40 CFR Part 60 Appendix B) and (2) a rigorous quality assurance program after they are installed at a source. The performance specifications contain a relative accuracy criterion which establishes an acceptable combined limit for accuracy and reproducibility for the monitoring system. Following the performance test of the CMS, the standards specify quality assurance requirements with respect to daily calibrations of the instruments. As was noted in the rulemaking (44 FR 33611, right column), EPA has initiated laboratory and field studies to further refine the performance requirements for continuous monitors to include periodic demonstration of accuracy and reproducibility. In view of the existing performance requirements and EPA's program to further develop quality assurance procedures, the Administrator believes that the issue of continuous monitoring system accuracy was appropriately addressed. In doing so, he recognized that any questions of accuracy which may persist will have to be assessed on a case-by-case basis.

The UARG petition also raised as an issue the calculation of the 30-day rolling average emission rate. UARG maintained that the use of emission data collected before a boiler outage may not be representative of the control system performance after the boiler resumes operation. UARG indicated that boiler outage could last from a few days to several weeks and suggested that if an outage extends for more than 15 days, a new compliance period should be initiated. UARG also suggested that if a boiler outage is less than 15 days duration and the performance of the emission control system is significantly improved following boiler start-up, a new compliance period should be initiated. UARG argued that the data following start-up would be more descriptive of the current system performance and hence would provide a better basis for enforcement.

A basic premise of this rulemaking was that the standard should encourage not only installation of best control systems but also effective operating and maintenance procedures (44 FR 33595 center column, 33601 right column, and 33597 right column). The 30-day rolling average facilitates this objective. In selecting this approach, the Agency recognized that a 30-day average better reflects the engineering realities of SO_2 and NO_x control systems since it affords operators time to identify and respond to problems that affect control system efficiency. Daily enforcement (rolling average) was specified in order to encourage effective operating and maintenance procedures. Under this approach, any improvement in emission control system performance following start-up will be reflected in the compliance calculation along with efficiency degradations occurring before the outage. Therefore, the 30-day rolling average provides an accurate picture of overall control system performance.

On the other hand, the UARG suggestion would provide a distorted description of system performance since it would discount certain episodes of poor control system performance. That is, the system operator could allow the control system to degrade and then shut-down the boiler before a violation of the standard occurred. After start-up and any required maintenance, a new compliance period would commence, thereby excusing any excursions prior to a shut-down. In addition, since a new averaging period would be initiated the Agency would be unable to enforce the standard for the first 29 boiler operating days after the boiler had resumed operation. In the face of this potential for circumvention of the standards, the Administrator rejects the UARG approach.

UARG also reiterated their previous comments that EPA did not properly consider the accuracy and precision of Reference Method 5 for measuring particulate concentrations at or below 13 ng/J (0.03 lb/million Btu) heat input. EPA has recognized throughout this rulemaking that obtaining accurate and precise measurements of very low concentrations of particulate matter is difficult. In view of this, detailed and exacting procedures for the clean-up and analyses of the sample probe, filter holder, and the filter were specified in Method 5 to assure accuracy in determining the mass collected. Additionally, EPA has required that the sampling time be increased from 60 minutes to 120 minutes. This will increase the total sample volume from a minimum of 30 dscf to 60 dscf, thus increasing the total mass collected to about 100 mg at a loading of 13 ng/J (0.03 lb/million Btu) heat input. EPA has concluded that measurement of mass at this level can be reproduced within ±10 percent.

UARG also maintained that less than ideal sampling can cause particulate emission measurements to be inaccurate

and this has not been evaluated. EPA has addressed the question of determining representative locations and the number of sampling points in some detail in the reference methods and appropriate subparts. These procedures were designed to assure accurate measurements. EPA has also evaluated the effects of less than ideal sampling locations and concluded that generally the results would be biased below actual emissions. Assessment of the extent of possible biases in measurement data, however, must be made on a case-by-case basis.

UARG raised again the issue of acid mist generated by the FGD system being collected in the Reference Method 5 sample, therefore rendering the emission limit unachievable. EPA has recognized this problem throughout the rulemaking. In response to the Agency's own findings and the public comments, the standards permit determination of particulate emissions upstream of the scrubber. In addition, EPA announced that it is studying the effect of acid mist on particulate collection and is developing procedures to correct the collected mass for the acid mist portion.

VII. Applicability of Standards

Sierra Pacific Power Company and Idaho Power Company (collectively, "Sierra Pacific") petitioned the Administrator to reconsider the definition of "affected facility," asking that the applicability date of the standards be established as the date of promulgation rather than the date of proposal. 40 CFR 60.40a provides:

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

* * *

(2) For which construction or modification is commenced after September 18, 1978.

September 19, 1978, is the date on which the proposed standard was published in the Federal Register. EPA based this definition on sections 111(a)(2) and 111(b)(6) of the Act. Section 111(a)(2) provides:

The term "new source" means any stationary source, the construction or modification of which is commenced after the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under this section which will be applicable to such source.

Section 111(b)(6) includes a similar provision specifically drafted to govern the applicability date of revised standards for fossil-fuel burning sources (of which this standard is the chief example.) It provides:

Any new or modified fossil fuel-fired stationary source which commences construction prior to the date of publication of the proposed revised standards shall not be required to comply with such revised standards.

Sierra Pacific does not dispute that the Agency's definition of affected facility complies with the literal terms of sections 111(a)(2) and 111(b)(6). Sierra Pacific maintains, however, that the definition is unlawful, because the standard was promulgated more than 6 months after the proposal, in violation of sections 111(b)(1)(B) and 307(d)(10). Section 111(b)(1)(B) provides that a standard is to be promulgated within 90 days of its proposal. Section 307(d)(10) allows the Administrator to extend promulgation deadlines, such as the 90-day deadline in section 111(b)(1)(B), to up to 6 months after proposal. Sierra Pacific argues that section 111(a)(2) does not apply unless the deadlines in sections 111(b)(1)(B) and 307(d)(10) are met. In this case the final standard was promulgated on June 11, 1979, somewhat less than 9 months after proposal. (It was announced by the Administrator at a press conference on May 25, 1979, and signed by him on June 1, 1979.)

In the Administrator's view, the applicability date is properly the date of proposal. First, the plain language of section 111(a)(2) provides that the applicability date is the date of proposal. Second, the legislative history of section 111 shows that Congress did not intend that the applicability date should be the date of proposal only where a standard was promulgated within 90 days of proposal. Section 111(a)(2) took its present form in the conference committee bill that became the 1970 Clean Air Act Amendments, whereas the 90-day requirement came from the Senate bill, and there is no indication that Congress intended to link these two provisions.[2]

Moreover, this interpretation represents longstanding Agency practice. Even where responding to public comments delays promulgation more than 90 days, or more than 6 months, after proposal, the applicability dates of new source performance standards are established as the date of proposal. See 40 CFR Part 60, Subparts D *et seq.*

Sierra Pacific argues that its position has been adopted by EPA in "analogous" circumstances under the Clean Water Act. This is inaccurate. Section 306 of the Clean Water Act specifically provides that the date of proposal of a new source standard is the applicability date only if the standard is promulgated within 120 days of proposal (section 306(a)(2), (b)(1)(B)).

Sierra Pacific suggests that utilities are "unfairly prejudiced" by the applicability date, but does not submit any information to support this claim. In any event, there does not seem to be any substantial unfair prejudice. At the time of proposal, the Administrator had not decided whether a full or partial control alternative should be adopted in the final SO_2 standard. As a result, the Administrator proposed the full control alternative stating (43 FR 42154, center column):

* * * the Clean Air Act provides that new source performance standards apply from the date they are proposed and it would be easier for power plants that start construction during the proposal period to scale down to partial control than to scale up to full control should the final standard differ from the proposal.

In fact, the final SO_2 standard was less stringent than the proposed rule.

In this case, utilities were on notice on September 19, 1978, of the proposed form of the standard, and that the standard would apply to facilities constructed after that date. In March 1979, it became clear to the Agency that it would not be possible to respond to all the public comments and promulgate the final standards by March 19, as required by the consent decree in *Sierra Club* v. *Costle*, a suit brought to compel promulgation of the standard. (The comment period had only closed on January 15; EPA had received over 625 comment letters, totalling about 6,000 pages, and the record amounted to over 21,000 pages.) The Agency promptly contacted the other parties to *Sierra Club* v. *Costle*, and all the parties jointly filed a stipulation that the standard should be signed by June 1 and that the Administrator should not seek "any further extensions of time." This stipulation was well-publicized (see, for example, 9 Environment Reporter Current Developments 2246, March 30, 1979). Thus utilities such as Sierra Pacific had reasonable assurance that the standard would be signed by June 1, as it was.

Even assuming, as Sierra Pacific does, that section 111 required the standard to be promulgated by March 19, utilities had to wait only an additional period of 84 days to know the precise form of the promulgated standard. This delay is not substantial in light of the long lead times required to build a utility boiler, and in light of the fact that the pollution control techniques required to comply with the promulgated standard are substantially

[2] In any event, in the Administrator's view the 90-day requirement in section 111(b)(1)(B) no longer governs the promulgation or revision of new source standards. It has been replaced by procedures set forth in section 111(f) enacted by the 1977 amendments.

the same as those required by the proposed standard.

Sierra Pacific's proposal that the applicability date be shifted to the date of promulgation is also inconsistent with Congress' clear desire that the revised standard take effect promptly. See section 111(b)(6).

In conclusion, Sierra Pacific has submitted no new information, has not shown that it has been prejudiced in any way, and has simply presented an argument that is incorrect as a matter of law. Its objection is therefore not of central relevance and its petition is denied.

Dated: January 30, 1980.

Douglas M. Costle,

Administrator.

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16. ABSTRACT

Guidelines for the effectiveness and costs of retrofitting coal-fired power plants and other major stationary sources for control of particulates, NO_x, and SO_2 per the provisions of Section 169A of the Clean Air Amendments of 1977.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution Particulate Matter Nitrogen Oxides Sulfur Dioxide Air Pollution Control and Costs Steam Generating Units	Air Pollution Control	13-B

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