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LIMB DEMONSTRATION PROJECT EXTENSION AND COOLSIDE DEMONSTRATION

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ABSTRACT

This report presents results from the Limestone Injection Multistage Burner (LIMB) Demonstration Project Extension. LIMB is a furnace sorbent injection technology designed for the reduction of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from coal-fired utility boilers. The testing was conducted on the 105 MWe, coal-fired, Unit 4 boiler at Ohio Edison's Edgewater Station in Lorain, Ohio. In addition to the LIMB Extension activities, the overall project included demonstration of the Coolside process for SO_2 removal for which a separate report has been issued.

The primary purpose of the DOE LIMB Extension testing, which began in April 1990, was to demonstrate the generic applicability of LIMB technology. The program sought to characterize the SO_2 emissions that result when various calcium-based sorbents are injected into the furnace, while burning coals having sulfur content ranging from 1.6 to 3.8 weight percent. The four sorbents used included calcitic limestone, dolomitic hydrated lime, calcitic hydrated lime, and calcitic hydrated lime with a small amount of added calcium lignosulfonate.

The original EPA project focused on tests with calcitic hydrated lime while burning a 3.0 weight percent sulfur Ohio coal, although tests with the lignosulfonate-doped material were added after pilot studies appeared to show enhanced reactivity. The results indicated SO_2 removal efficiencies of greater than 70 percent are possible while operating at a close approach to the adiabatic saturation temperature of the flue gas. Efficiencies on the order of 60 percent were found in tests without close approach operation.

The results presented in this report include those obtained for the various coal/sorbent combinations. They further characterize the SO_2 removal to be expected with and without humidification to close approach to saturation over a range of calcium/sulfur stoichiometries. The effects of injection at different elevations in the furnace are explored, and in the case of limestone as the sorbent, the influence of particle size distribution is quantified.

This report also addresses the effects of the LIMB process on boiler and plant operations. The increased particulate loading in the boiler and downstream equipment has the greatest impact on operations. Without effective sootblowing, heat transfer rapidly degrades when the lime sorbents are used. Particulate removal equipment must be capable of handling the increased

loading. Moreover, the quicklime component of the ash requires that precautionary measures be taken to avoid and/or minimize potential difficulties from steaming and high pH conditions in service water when handling and transporting the ash.

B&W DRB-XCL™ low-NO_x burners were used throughout the project as these had been installed as part of the original EPA LIMB demonstration. The report discusses the resultant NO_x emission control in light of such operational parameters as load, excess air, and pulverizers/burners in service. These variables were monitored more carefully during the current demonstration in an attempt to explain some of the more subtle variations in NO_x emissions first seen in the earlier project.

Lastly, the possible applications of the technology in the utility industry are discussed in terms of equipment and process economics. Comparisons are made to both wet flue gas desulfurization systems and to the Coolside process.

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LIST OF ACRONYMS AND SYMBOLS

ACRONYMS

ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
B&W	The Babcock & Wilcox Company
CAAA	1990 Clean Air Act Amendments
CFR	Code of Federal Regulations
CCT	DOE Clean Coal Technology Program
CEMS	Continuous emission monitoring system
CF	Construction factor
CFR	Code of Federal Regulations
CTECo	Commercial Testing & Engineering Company
DCS	Distributed control system
DOE	U.S. Department of Energy
EC	(Individual) equipment cost
EED	B&W Environmental Equipment Division
EP	Extraction procedure (toxicity test in RCRA)
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	Electrostatic precipitator
FGD	Flue gas desulfurization
HHV	High heating value of coal (fuel)
HVAC	Heating, ventilation, and air conditioning
I&C	Instrumentation and controls
ID	Induced draft (fans); inner diameter (pipes and tubes)
IDC	Interest during construction (also known as allowance for funds used during construction, AFUDC)
IEC	Installed equipment cost
L/G	Liquid-to-gas ratio
LIMB	Limestone injection multistage burner technology

LIST OF ACRONYMS AND SYMBOLS (continued)

ACRONYMS (continued)

LSFO	Limestone forced oxidation FGD technology
MCR	Maximum continuous rating (of a boiler)
NDIR	Non-dispersive infrared (analyzer)
OCDO	Ohio Coal Development Office
PETC	DOE Pittsburgh Energy Technology Center
PON	DOE Program Opportunity Notice
PTC	ASME Performance Test Code
PVC	Polyvinyl chloride
QA	Quality assurance
QAPP	Quality Assurance Project Plan
QC	Quality control
RCRA	Resource Conservation and Recovery Act
R&D	Research and development
SCA	Specific collection area of an ESP
TAG™	EPRI's *TAG*™ *Technical Assessment Guide*
TCR	Total capital requirement
TPI	Total plant investment
T/R	Transformer/rectifier
UT	Ultrasonic Testing
UV	Ultraviolet (light)

SYMBOLS

C	Elemental carbon
Ca	Elemental calcium
$CaCO_3$	Calcium carbonate
CaO	Calcium oxide, quicklime
$Ca(OH)_2$	Calcium hydroxide, hydrated calcitic lime
$Ca(OH)_2 \cdot MgO$	Type-N hydrated dolomitic lime

LIST OF ACRONYMS AND SYMBOLS (continued)

SYMBOLS (continued)

$CaSO_3$	Calcium sulfite
$CaSO_4$	Anhydrous calcium sulfate
$CaSO_4 \cdot 2H_2O$	Calcium sulfate dihydrate, gypsum
CO	Carbon monoxide
CO_2	Carbon dioxide
H	Elemental hydrogen
H_2O	Water
MgO	Magnesium oxide
N	Elemental nitrogen
Na	Elemental sodium
Na_2CO_3	Sodium carbonate, soda ash
NO	Nitric oxide
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxides, especially a mixture of NO and NO_2
O	Elemental oxygen
O_2	Molecular oxygen, oxygen gas
S	Elemental sulfur
SO_2	Sulfur dioxide
ΔP	Pressure drop, pressure differential
ΔT_{as}	Approach to adiabatic saturation temperature

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SECTION 1
EXECUTIVE SUMMARY

INTRODUCTION

Limestone Injection Multistage Burner (LIMB) technology combines furnace sorbent injection for the reduction of sulfur dioxide (SO_2) with the use of burners designed to minimize the formation of nitrogen oxides (NO_x). In 1987, Babcock & Wilcox (B&W) and the Ohio Edison Company agreed to extend the full-scale demonstration of LIMB technology under the sponsorship of the U. S. Department of Energy (DOE), through its Clean Coal Technology Program, and the State of Ohio Coal Development Office (OCDO). The original LIMB demonstration had begun in 1984 under the sponsorship of the U. S. Environmental Protection Agency (EPA) and OCDO.[1] The DOE project also provided for demonstration of the Coolside flue gas desulfurization (FGD) process, a duct sorbent injection technology, between July 1989 and February 1990. A separate report discusses the results of that effort.[2] The DOE LIMB Extension test program was conducted between April 1990 and August 1991. All demonstration tests, LIMB and Coolside, were carried out on the 105 MWe, coal-fired Unit 4 boiler at Ohio Edison's Edgewater Station in Lorain, Ohio.

OBJECTIVES

The primary purpose of the LIMB Extension was to demonstrate the generic applicability of LIMB technology. The program sought to characterize the SO_2 emissions that result when various calcium-based sorbents are injected into the furnace, while burning coals with a range of sulfur content from 1.6 to 3.8 percent. The effects of certain process variables on SO_2 removal efficiency were demonstrated. These included inlet calcium/sulfur stoichiometry (Ca/S) for each sorbent used, inlet SO_2 concentration resulting from coals of different sulfur content, the degree of humidification, injection at various elevations (temperatures), and particle size distribution for the limestone sorbent. The impact of sorbent injection on particulate emissions is also examined in terms of the opacity, while NO_x emissions are characterized as a result of continued use of the DRB-XCL™ burners. Operability and reliability of the LIMB system are described in light of the variations made, leading to an overall economic comparison of LIMB, Coolside, and wet limestone forced oxidation (LSFO) FGD technology.

TEST CONDITIONS

The LIMB Extension test program was designed to determine the SO_2 removal efficiency for four sorbents: calcitic limestone ($CaCO_3$), type-"N" atmospherically hydrated dolomitic lime [$Ca(OH)_2 \cdot MgO$], and calcitic hydrated lime [$Ca(OH)_2$], both alone and with added calcium lignosulfonate (hereafter referred to as ligno lime). These tests were conducted over a range of Ca/S molar ratios and humidification conditions, while burning Ohio coals with nominal sulfur contents of 1.6, 3.0, and 3.8 weight percent. Close approach testing, as it is used in this report, is defined as a 20°F* approach to the adiabatic saturation temperature of the flue gas, measured at the humidifier outlet. For the coals used, the saturation temperature was approximately 125°F. Minimal humidification of the flue gas, or testing without close approach, is defined as operation at a humidifier outlet temperature sufficient to maintain electrostatic precipitator (ESP) performance, typically 250 to 275°F. The coal/sorbent combinations of 3.0 percent sulfur with calcitic hydrated lime and ligno lime, tested during the EPA-sponsored program, were not repeated here. However, the 3.0 percent sulfur coal/ligno lime combination was used to verify equivalent system operation following conversion of equipment back to a furnace injection configuration after the Coolside duct injection tests were complete. The ability to maintain compliance with the plant's emission limits was demonstrated during continuous operation of the LIMB system while burning the higher sulfur coals. Test runs conducted under rigorous steady-state conditions were usually two to six hours in duration.

Tests were performed with two more finely ground calcitic limestones. This occurred because the more coarse material originally used resulted in an unexpectedly low SO_2 removal efficiency (discussed in more detail later in this section). Plans for tests with the 3.8 percent sulfur coal and limestone were canceled when even the finest limestone failed to show removal

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[*] For those more familiar with metric units, see the conversion table in Appendix A.

efficiencies that would maintain compliance with the plant's 30-day rolling average emission limit of 3.4 lb $SO_2/10^6$ Btu during tests over a range of stoichiometries.

The same analytical methodology used during the EPA-sponsored program, including both manual sampling and the use of a continuous emission monitoring system (CEMS), was continued throughout the DOE project. The CEMS provided continuous measurements of SO_2, NO_x, O_2, CO, and CO_2 concentrations in the flue gas just before the stack. (The 2300°F temperature at the point of injection precluded the use of any continuous monitors in the furnace.) Radian Corporation personnel maintained the CEMS and performed, or arranged, for all sample analyses, except for those performed by Ohio Edison on truck and bunker coal samples. The latter analyses of truck and bunker samples were monitored on a daily basis to assure use of the desired coal during any test period. Calcitic lime samples were analyzed on-site for available lime [as $Ca(OH)_2$]. Commercial Testing and Engineering Company (CTECo) analyzed limestone for total calcium and dolomitic lime for both calcium and magnesium by atomic absorption spectrophotometry.

An on-site Leco sulfur analyzer was used during tests as a more immediate measure of coal sulfur. Pulverized coal samples for this analysis were automatically sampled from the burner pipes, usually on an hourly basis during the more rigorous test periods. This was done to verify the stability of the "inlet" SO_2 condition. Ultimate analyses of composite pulverized coal samples were performed by CTECo on a five work day/week basis. Again, this was the same procedure used during the original EPA LIMB Demonstration.

SO_2 EMISSIONS

The primary independent variables in the study were sorbent type and sulfur content of the coal burned. The different sorbents were tested, when possible, while burning each of the three different coals. Other test variables were Ca/S stoichiometry, humidifier outlet temperature, and injection level. The previous EPA LIMB testing had demonstrated that SO_2 removal efficiencies of 55 to 60 percent were obtainable while injecting commercial calcitic hydrated lime at an inlet Ca/S molar ratio of 2.0 with minimal humidification. This testing had also shown that removal efficiencies of approximately 65 percent were possible while injecting ligno lime.

For each coal/sorbent combination, SO_2 removal efficiency is primarily dependent upon stoichiometry. During the LIMB Extension tests, the Ca/S ratio was generally varied from 0.8 to

2.2. A curve-fitting algorithm using a standard least-squares approach was used to compare the stoichiometry/removal efficiency data. The comparative figures presented show the first order fit of the data for the range of stoichiometries tested, with the fit forced through zero percent SO_2 removal for the no injection case. A second order fit with a diminishing increase in removal for higher stoichiometries would be expected from theoretical considerations, however, its use produced erroneously shaped curves in those cases where a relatively small number of individual tests were performed. The first and second order fits were compared for some cases where there were sufficient data points. Since the removal efficiencies at a Ca/S of 2.0 differed by only a few percentage points, the first order fits were considered to form a better overall representation of the comparisons discussed.

Effect of Coal Sulfur Content

The sulfur content of the coal, as reflected in the SO_2 concentration of the flue gas, appeared to have a small, but perceptible, effect on the SO_2 removal efficiency. It was found that the higher the sulfur content, the greater the SO_2 removal for a given sorbent at a comparable stoichiometry. This is thought to be due to the greater driving force the increased SO_2 concentration has on the reaction. A five to seven percent absolute difference in SO_2 removal exists between 1.6 and 3.8 percent sulfur coal for any one sorbent at a stoichiometry of 2.0. While it might be argued that this difference is within the error limits of the calculations, the fact that it was consistently seen for all of the sorbents tested suggests that the effect is indeed real. The removal efficiencies while burning the 3.0 percent sulfur coal fell approximately midway between the other two.

Effect of Sorbent Type

During the LIMB Extension, ligno lime and calcitic hydrated lime exhibited the highest removal efficiencies of the sorbents tested at any given stoichiometry. SO_2 reductions on the order of 60 percent were obtained at a Ca/S ratio of 2.0 with minimal humidification. Dolomitic hydrated lime effected about 50 percent removal at the same conditions. Removals ranged from about 20 to 40 percent for calcitic limestone depending on the choice of grind (particle size distribution).

The SO_2 removal efficiencies achieved with the ligno lime while burning the nominal 3.8 and 1.6 percent sulfur coals during the LIMB Extension tests were somewhat less than those obtained during the EPA-sponsored project. This had not been anticipated. When testing resumed after the Coolside demonstration in April 1990, ligno lime was injected to determine if removal efficiencies were the same as had been attained earlier. The coal being burned at the time had a nominal 3.0 percent sulfur content, the same as had been used during the EPA tests. SO_2 removal efficiencies of 60 to 65 percent were comparable to the tests run prior to Coolside at a stoichiometry of 2.0. Therefore, testing with the other sorbents began. When ligno lime was again tested in February 1991, this time while burning the 3.8 and 1.6 percent sulfur coals, the removal efficiencies were closer to 60 and 55 percent, respectively. It had been expected that slightly higher removals would be obtained when burning the 3.8 percent sulfur coal, as had been observed with the other sorbents. No specific reason(s) for the difference could be found in either the particle size distributions or analytical data on the sorbents, though the differences are suspected to be due to subtle changes in porosity and/or surface area. These may be related in turn to a variation in the calcium lignosulfonate used to prepare the material. Another possible explanation is a higher degree of agglomeration, resulting from the use of a Fuller-Kinyon pump in place of the rotary valve during the February 1991 tests, is responsible for the lower removal. None of these explanations, however, could be confirmed within the time and financial constraints of the project.

Effect of Limestone Particle Size

Initial tests were run using a commercial limestone with a particle size distribution of 80 percent less than 44 μm (325 mesh). This limestone was chosen because it was representative of readily available material from commercial suppliers. While injecting this sorbent, removal efficiencies of about 22 percent were obtained at a stoichiometry of 2.0, while burning nominal 1.6 percent sulfur coal. SO_2 reductions of 30 to 35 percent had been expected with the limestone on the basis of pilot tests,[3,4] however, and possible reasons for this high a discrepancy were reviewed. After analytical errors were eliminated, the only variable that could easily be changed was the fineness of the sorbent. Using a grade of limestone in which all particles were less than 44μm in size, a removal efficiency of approximately 32 percent was achieved at a stoichiometry of 2.0. In order to determine what the upper limit in removal efficiency might be for calcitic limestone, an even finer limestone was then tested. This material was one for which the particle size distribution showed virtually all particles to be less than 10 μm. It produced removal efficiencies on the order of 37 to 40 percent at the 2.0 Ca/S condition.

All the limestones were obtained in truckload quantities. The very fine (100 percent less than 10μm) material may not be considered a viable alternative for this application because its cost on a truckload basis is on the order of four times that of either of the other two. It is noted that all the lime sorbents are as fine or finer than this very fine grind of limestone. The higher SO_2 removal efficiencies of lime and the finer grinds of limestone are attributed, in part, to the greater surface area available for the SO_2 absorption reaction associated with the smaller particle size.

Effect of Injection Level

During the design phase of the EPA project, the optimum location for injection was identified as being on the front wall of the Edgewater furnace at elevation 181 ft where the average temperature was expected to be approximately 2300°F. This elevation corresponds to a level in this furnace just opposite the nose. Tests during the EPA LIMB Demonstration confirmed that injection at this level yielded higher SO_2 removal for the calcitic hydrated limes than injection at elevation 187 ft (injection at elevation 191 ft was not tested during the EPA project after a lower efficiency was obtained at elevation 187 ft). The tests run during the LIMB Extension produced similar results. The removals at the 181 and 187 ft levels were higher than those at the 191 ft elevation. Removal efficiencies while injecting at a stoichiometry of two at these levels were about five percent absolute higher than those at the 191 ft level.

The distinction between the 181 and 187 ft elevations was not as clear cut as it had been during the EPA-sponsored tests, when fewer individual tests were run. The more extensive testing conducted during the LIMB Extension suggests that more significant differences appear when material is injected at elevation 191 ft. At this level the temperature is thought to be a 200 to 300°F cooler and the flue gas flow patterns are less than favorable for adequate dispersion of the sorbent.

Effect of Humidification

Operation of the humidifier down to a 20°F approach to saturation permitted characterization of the additional SO_2 removal obtainable under most of the conditions. Humidification to close approach enhances SO_2 removal efficiencies by approximately 10 percent absolute over the range of stoichiometries tested. This was true for each of the sorbents tested.

NO_x EMISSIONS

The DRB-XCL™ burners, installed as part of the initial LIMB demonstration, continued to operate and be evaluated during the LIMB Extension project. The overall average NO_x emissions during the demonstration was 0.43 lb/10^6 Btu. Emissions of 0.44 lb/10^6 Btu were calculated both for the 24 hr and 30 day rolling average values for the demonstration period. The emission rate did not appear to be sensitive to load conditions, although there appeared to be some variation within the scatter that might be controllable. In order to identify the source of the variation, attempts were made to correlate NO_x emissions with load, flue gas O_2 concentration, pulverizers/burners in service, CO emissions, and coal fineness. Unfortunately, no consistent correlation was found between NO_x and any of these variables. Likewise, use of the SO_2 sorbents did not appear to have any effect on NO_x emissions.

PARTICULATE EMISSIONS

Humidification of the flue gas continued to be effective in maintaining the particulate emission control performance of the ESP during the DOE LIMB Extension. Opacity was generally in the two to five percent range during injection of each of the sorbents (compared to the plant opacity limit of 20 percent). This was similar to what had been observed during the EPA project. Only two differences were noted, the first being that the calcitic limestone did not seem to require as much humidification, either because its larger particle size made particulate collection easier and/or the fact that the cooler air heater outlet flue gas temperature required relatively little humidification water to maintain the temperature of the gas entering the ESP. The second difference occurred during use of the dolomitic lime which seemed to require a somewhat lower humidifier outlet temperature setpoint (250°F *vs.* 275°F) to maintain the desired opacity. Simultaneous measurements of inlet and outlet particulate loadings required to characterize particulate collection efficiencies for each of the sorbents were not conducted since there were no opportunities for the two weeks of steady-state operation at conditions that would have been necessary to rigorously evaluate ESP performance.

OPERABILITY AND RELIABILITY

Operations during the LIMB Extension continued much the same as during the EPA LIMB

Demonstration.[1] There were, however, a few operational aspects that became apparent due to the use of previously untested sorbents and/or more extensive tests. Probably the most notable of these was the limitation of the sootblowing system at the Edgewater facility. Prior to the LIMB Extension tests the sootblowers were converted from compressed air to steam. Actual steam consumption varied depending upon the degree of sootblowing required for each sorbent type, feed rate, and the extent to which heat transfer was decreased. The effect of sorbent type and feed rate on heat transfer could not be readily quantified since operator preferences also imposed some variation.

The air-to-steam sootblower conversion was undertaken in an effort to maintain a more normal air heater outlet temperature of about 300°F, rather than the 350°F temperatures seen during the EPA testing. After the conversion, the sootblowers could be cycled five to six times a shift, where it previously had been once or twice per shift. While the increased capacity helped somewhat at lower injection rates, the higher stoichiometric conditions still produced high outlet temperatures (up to a high of 375°F for the dolomitic lime/3.8 percent sulfur coal combination at a Ca/S ratio of 2.0, a condition representing the highest sorbent mass feed rate). This suggests that the limitation was due not so much to the capacity of the sootblower system, but rather the number and location of the sootblowers themselves. Since the temperatures appear to rise most dramatically in the vicinity of the primary superheater and economizer, additional sootblowers appear advisable in those areas.

Injection of the coarse (80 percent less than 44 μm) limestone sorbent into the furnace left the air heater outlet temperature almost unchanged at approximately 300°F. This was unexpected in that more severe fouling had been anticipated. The phenomenon appears to be related to particle size, but no specific explanation has been identified at this point in time. The finer limestones tended to produce higher air heater outlet temperatures, though the data is limited since lesser total quantities of these materials were injected.

The impact of LIMB on ESP performance results from a change in particle size distribution, an increase in the resistivity of the ash due to the change in composition, and an increase in loading. Tests that would conclusively define the relative importance of each were beyond the scope of the project. Nevertheless, the observations made in the preceding section indicate the nature of the effects on the ESP.

Another operational change noted during the LIMB Extension was in the area of waste handling and disposal. Here the effects of using either dolomitic lime or calcitic limestone were somewhat different than what had been found with the calcitic limes. The dilution of the ash by the unreactive MgO component of the dolomitic sorbent leads to increased ash loading and solids handling at the back end of the process. Since the MgO component does not hydrate appreciably at atmospheric pressure, this LIMB ash exhibited a lower level of steaming when water was added to the ash. The use of limestone, on the other hand, tended to produce greater quantities of steam during wetting of the ash in the unloading facility. This was due to the lower utilization of the sorbent for an equivalent injection stoichiometry.

As part of the overall assessment of the technology, records of operating time and downtime were kept in order to provide further indications of process and equipment availability. The data indicate that the system was available about 95 percent of the time it was called upon to operate. This is necessarily only a best approximation of what might be expected of a fully commercial system, since LIMB system operation during the project focused on obtaining performance data over a wide variety of conditions. Changes from one set of operational parameters to another involved frequent shutdowns to reestablish baseline conditions. Moreover, there were some periods when operation was intentionally delayed in order to control project cost by conserving sorbent when it was not required to maintain emission compliance. As might be expected, this occurred primarily when the 1.6 percent sulfur coal was being burned.

SUMMARY OF ECONOMIC COMPARISONS

The comparative economics of the LIMB, Coolside, and LSFO FGD processes were developed for several different scenarios. LIMB economics were determined without including low NO_x burner costs in order that the comparison relate only to the FGD portion of the technology. Costs are predicated on several other considerations of the differences among the processes and their intended applications that are essential to understanding the extent to which comparisons are valid. Primary among these is that the LIMB and Coolside processes were intended to provide moderate levels of removal at low capital cost. Moreover, it was anticipated that it was particularly well-suited for the relatively small, older plants in which wet scrubbers would be particularly difficult to justify. LSFO FGD, on the other hand, is a mature technology that historically has been applied to achieve in excess of 90 percent SO_2 reduction. Passage of the Clean Air Act Amendments (CAAA) in 1990 appears to be driving performance goals to the state-of-the-art LSFO technology used in this evaluation. While the effective cost of such technology decreased in the maturation process over the past twenty years, its higher capital cost and lower reagent usage rate are more easily justified for newer, larger plants burning higher sulfur coals. Overriding all of these, site-specific considerations can influence the economics of all three processes dramatically, as is commonly recognized in the industry.

For the reasons just stated, comparisons with LSFO FGD are quite difficult. Several options were considered in order to try to overcome the inherent differences. These included operation of an LSFO system at less than optimum conditions to achieve performance at the lower levels of the other two technologies. A second alternative was to examine bypass of a portion of the flue gas such that the overall removals would coincide, with the LSFO process still operating at 95 percent removal efficiency. Arguments against making such assumptions were thought to be at least as valid as presenting each technology in its own realm of applicability. When viewed in the light of the caveats in the preceding paragraph, the limitations of comparison with the LSFO process are readily apparent.

The differences between LIMB and Coolside are less pronounced, providing a greater significance to their comparative economics. Nevertheless, site-specific considerations become especially important. Whereas humidification to a close approach to the flue gas saturation temperature is absolutely needed for Coolside, LIMB can require little to none depending on the nature and quantity of sorbent injected, though SO_2 removal can be enhanced by operation under close approach conditions. The site-specific concern arises out of the larger amount of space required to permit essentially complete evaporation to achieve close approach operation. The other fundamental difference between these two technologies, sorbent injection in the furnace for LIMB, and in a downstream location for Coolside, becomes a matter of preference for the individual operating utility.

For the economic comparison, the approach used was one commonly used in the industry. Capital costs are presented in the conventional units of $/kW, and operating and annual levelized costs in mill/kWh and/or $/ton of SO_2 removed. The processes were compared for three different coal sulfur concentrations and four different reference plant sizes. The process designs were based on optimized commercial retrofit installations. Under what are thought to be reasonably equivalent and representative sets of operating conditions, the SO_2 removal efficiencies of the LIMB, Coolside, and LSFO processes were set at 60, 70, and 95 percent, respectively. Although LIMB was also shown to be capable of 70 percent SO_2 removal with humidification to close approach, the costs for such a mode of operation are considered to be essentially the same as those required for Coolside. For this reason, costs were developed for a slightly lower performance LIMB system operating with minimal humidification in an existing duct.

Total installed capital costs and levelized annual operating costs were developed for each of the process\coal\plant size combinations. The results were analyzed and compared to determine the economic applicability of each process. On a $/kW basis, the installed capital cost of the LSFO process was found to be about 2.5 times higher than that of the Coolside process, and about 4.8 times higher than the LIMB process. The installed capital cost of the Coolside process was found to be about 1.9 times higher than the LIMB process.

On a $/ton of SO_2 removed basis, the annual levelized costs showed that Coolside was economically favored over LSFO for plant sizes up to 500 MWe (net), while burning 1.5 weight percent sulfur coal, up to 220 MWe while burning 2.5 weight percent sulfur coal, and up to 100 MWe while burning 3.5 weight percent sulfur coal.

LIMB was economically favored over LSFO for all plant sizes while burning 1.5 weight percent sulfur coal, up to 450 MWe while burning 2.5 weight percent sulfur coal, and up to 240 MWe while burning 3.5 weight percent sulfur coal.

LIMB was economically favored over Coolside for all the cases compared. Adding the capability to operate a LIMB system at close approach to the saturation temperature to enhance SO_2 removal would tend to reduce this advantage, however.

Cost sensitivity analyses were also undertaken to determine the effects of certain economic variables on costs. It was determined that decreasing the plant capacity factor favored the LIMB and Coolside processes, as did decreasing the book life of the plant. Varying the reagent costs had a greater effect on LIMB and Coolside economics, while having only a moderate effect on the LSFO process economics.

SECTION 2
INTRODUCTION

Within the past decade increasing emphasis has been placed on the control of pollutant emissions from a variety of sources in the United States. Prominent among these are SO_2 and NO_x, gases that can result from the combustion of fossil fuels and are commonly considered to be among the major sources of acid rain. The automotive and power industries are therefore intimately involved in the process of technology development to mitigate potential damage. The largest man-made, stationary sources of both gases are coal-fired utility boilers which account for about 65% of the SO_2 and 29% of the NO_x emissions in the United States.[5]

The CAAA of 1990 now constitute the primary regulatory directive that delineates control requirements for SO_2 and NO_x emissions from utilities. This legislation provides for phased compliance and gives utilities the ability to choose the technology needed to meet emission limits. Since they were passed in November 1990, the utility industry has chosen fuel switching and wet flue gas desulfurization systems (FGD scrubbers) as the primary means of meeting the CAAA's Phase I requirements on larger units. Those requirements place a 2.5 lb/10^6 Btu cap on SO_2 emissions, with a target date of January 1, 1995. After that, other technologies are expected to be regarded as viable, given a wide variety of site-specific considerations. Limestone Injection Multistage Burner (LIMB) is one such technology. The process involves the injection of a calcium-based sorbent into the furnace for SO_2 capture. This is coupled with the use of low NO_x burners, to reduce emissions of nitrogen oxides.

BACKGROUND

It was in anticipation of the CAAA legislation that the EPA promoted a series of bench- and pilot-scale research projects during the early 1980s. These studies were directed toward development of relatively low cost, moderate efficiency, SO_2 and NO_x emission control technologies. They were aimed at older, smaller, fossil-fired utility boilers which would not be candidates for wet FGD. At about the same time, the Ohio Edison Company undertook a program to participate in emerging technology development. They did this to be in a better position to evaluate the technical, operational, and economic aspects of such technologies. By 1984, the two programs led to the full-scale demonstration of the LIMB process. EPA sponsored the project with co-funding by OCDO and B&W, the prime contractor.

Concurrently with the early LIMB tests, the U.S. Department of Energy (DOE) initiated the Clean Coal Technology (CCT) Program. The program is a jointly funded, government-industry effort that takes the most promising advanced coal-based technologies and, over the next decade, moves them into the commercial marketplace through demonstration. The goal of the program is to make available to the U.S. energy marketplace, particularly the industrial and utility sectors, a number of advanced and environmentally responsive coal technologies. The program seeks to demonstrate the commercial feasibility of technologies that have already reached the proof-of-concept stage.

The program is presently being implemented through a series of five competitive solicitations. When the program is completed, technical, environmental, economic, and operational data will be available for a broad range of clean coal technology options. This data is expected to reduce the uncertainties of subsequent commercial scale applications.

Government and industry signed the first Clean Coal cooperative agreements (not contracts) during 1987. The industrial partner in each project contributes a minimum of 50 percent of the total cost. The B&W LIMB Clean Coal project was among those selected by the DOE under the first solicitation and was administered out of DOE's Pittsburgh Energy Technology Center (PETC). Numerous other public and private organizations, including state and utility/industry research groups, provide important co-funding and project support. OCDO and CONSOL Inc. (formerly Consolidation Coal Company) filled that role for the LIMB project. Ohio Edison was the host utility, making the Unit 4 boiler at the Edgewater Station available for the demonstration.

B&W concluded the full-scale demonstration tests of LIMB technology under the EPA contract in June 1989. The testing was limited to the calcitic hydrated lime and ligno lime while burning 3.0 percent sulfur Ohio coal. The CCT program provided the opportunity to build upon the base EPA LIMB Demonstration by extending it to a broader range of coals and sorbents. Another incentive was the potential for increased SO_2 capture by humidification of the flue gas. Still another was an outgrowth of CONSOL's work with the Coolside process, an in-duct flue gas desulfurization technology, and B&W's (spray) dry scrubbing technology, both of which suggested the desirability of further development of the Coolside and LIMB processes. Both the Coolside and dry scrubbing processes rely on controlled humidification of the flue gas to a close approach to the adiabatic saturation temperature. The success of the early LIMB tests with respect to SO_2 removal and the potential of overcoming the deleterious effects of LIMB ash on ESP performance, were additional reasons for combining and extending the technology demonstrations in the CCT project.

Thus the participants applied for and received DOE CCT funding for the LIMB Demonstration Project Extension and Coolside Demonstration. The project was divided into the two separate, but related, demonstrations of the technologies on the same boiler at Ohio Edison's Edgewater Station in Lorain, Ohio.

The LIMB and Coolside processes are expected to be competitive in overall cost of SO_2 emission control with conventional wet FGD processes, and with significantly lower capital costs. The technologies are considered to be most applicable to older coal-fired plants and are expected to be especially economical in plants with small to intermediate size boilers with load factors between about 40 and 75 percent. As is true with most FGD processes, the practicality of LIMB or Coolside as retrofit technologies depends on site specific considerations. The design of the boiler, the convective pass, the air heater, and ash removal system are all major factors, as is the plant's life expectancy.

PROJECT OBJECTIVES AND SCOPE

The primary objective of the LIMB Extension portion of the project was to demonstrate the broader applicability of the technology to coals over a range of sulfur content. For NO_x, the objective continued to be demonstration of emissions less than 0.5 lb/10^6 Btu. The emphasis, however, was focused on SO_2, for which the demonstration aimed at characterizing the performance of various sorbents as a function of Ca/S stoichiometry. These sorbents were to range from relatively low cost materials that might be selected because of local availability, to higher cost materials of greater reactivity. Coals with three nominal sulfur concentrations were tested, when possible, while injecting each of four sorbents. By comparison, the EPA LIMB Demonstration had had as its initial SO_2 objective the demonstration of 50 percent or more removal with one calcium-based sorbent at a Ca/S ratio of 2.0 while burning a 3.0 percent sulfur Ohio coal. Interest in testing additional sorbents was spurred by early success in achieving this objective, attributed to the thorough investigation of the chemical and physical processes involved. Even when early tests resulted in ESP performance degradation, research had shown humidification as a solution to the problem's being caused by high resistivity LIMB ash. As a result, interest in testing additional sorbents and other coals, along with the Coolside process, continued to develop.

The other major objective of the project was to use the information accumulated in the course of the demonstration and apply it to the design of hypothetical commercial systems. This was to form the basis for capital and operating cost estimates that would then be compared to the economics of state-of-the-art FGD technology, currently considered to be wet limestone scrubbers utilizing forced oxidation to produce gypsum, $CaSO_4 \cdot 2H_2O$. The remainder of this report presents the technical results obtained during the LIMB Extension, together with a discussion of the commercial LIMB, Coolside, and wet LSFO FGD system designs and the economic evaluations and comparisons drawn from them.

SECTION 3
PROCESS DESIGN/EQUIPMENT

PROCESS FUNDAMENTALS

The basic mechanics of the LIMB process are simple. A calcium-based sorbent is injected into the furnace to capture SO_2 in the flue gas. Low NO_x burners are used to control these emissions. No complicated pieces of equipment are necessary. The overall process chemistry is likewise simple. Sorbent is injected into the furnace where the following reactions take place:

<u>Calcination</u>

Limestone $$CaCO_3 + \text{heat} \rightleftarrows CaO + CO_2 \tag{1a}$$

Hydrated Lime $$Ca(OH)_2 + \text{heat} \rightleftarrows CaO + H_2O \tag{1b}$$

<u>Sulfation with Oxidation</u>

$$CaO + SO_2 + 0.5\ O_2 \rightleftarrows CaSO_4 + \text{heat} \tag{2}$$

Subsequently, water reacts with the excess quicklime (CaO) and $CaSO_4$ at lower temperatures according to:

<u>Hydration</u>

$$CaO + H_2O \rightleftarrows Ca(OH)_2 + \text{heat} \tag{3}$$

$$CaSO_4 + 2\ H_2O \rightleftarrows CaSO_4 \cdot 2H_2O + \text{heat} \tag{4}$$

The importance of the mechanics and chemistry on the SO_2 removal performance and operability of the LIMB system should be kept in mind as fundamental in the discussion to follow. While the details are documented in the research and development conducted before and during the original LIMB demonstration,[1,3,4] several general concepts are noteworthy. Primary among these is the need to assure effective mixing of any sorbent with the flue gas. Extensive mathematical and cold flow modeling was conducted to understand the temperature and velocity profiles in the furnace and of the flue gas in the humidifier. These were considered essential to achieve effective sorbent dispersion in the former case and to minimize wall wetting in the latter. The need for this modeling will be site specific in any future commercial system depending on the similarities of the application to installations preceding it.

Process chemistry is intimately tied to the sorbent dispersion process for a few reasons. While the chemical equations represent the overall reactions, it was important to consider the kinetics and thermodynamics of individual reactions in relation to the time/temperature profiles involved. The calcination reactions, for example, develop reactive surface area for the sulfation reaction when sintering of the particles is minimized by avoiding high temperature zones. Similarly, temperatures above about 2400°F where any $CaSO_4$ formed becomes thermodynamically unstable. Understanding the mechanics of the humidification process is likewise essential in order to assure that the water introduced cools the gas uniformly to minimize wall-wetting and the deposit formation that can then occur. Related to this, the highly exothermic hydration of quicklime can give rise to voluminous steam evolution if water is added during ash handling operations as it was at Edgewater. The reader is referred to the literature cited above for more extensive discussions of this background than is possible here.

BACKGROUND

Numerous bench- and pilot-scale studies on sorbent injection were undertaken in the United States during the 1960s in anticipation of passage of the original Clean Air Act. This work culminated in a full-scale demonstration of the process on a 150 MWe boiler at Tennessee Valley Authority's Shawnee Station from 1969 to 1971.[6] The results of those limestone injection tests were less than encouraging at the time since technologies with high (on the order of 90 percent) levels of SO_2 reduction were generally desired. Instead, SO_2 removal efficiencies typically fell in the 20 to 30 percent range. Accordingly, commercial interest in the technology faded.

Performance improvements in the process, and a number of potential applications, renewed interest in sorbent injection technology in the late 1970s and early 1980s. One technique tested called for mixing limestone with the fuel, and then burning the mixture in multistage, low NO_x burners. This gave rise to the acronym LIMB (Limestone Injection Multistage Burner). Removal efficiencies as high as 80 percent at a Ca/S stoichiometry of 3.0 were achieved in pilot studies. These first LIMB tests, along with subsequent experiments that evolved from them, yielded some important results, namely:

- Limestone was not the only sorbent that could be used since some others were capable of producing even greater SO_2 capture
- Alternate methods of injecting sorbent offered equal or better performance than did

injection through the burners

- Surface area of the reactant is very important
- The temperature window for the sulfation reaction was identified to be roughly 2300 to 1600°F, with the former being near the thermodynamic limit of the reaction and the latter a kinetic limit.

The early research also showed that there were factors that could adversely affect removal efficiency.[3,4] Reactant surface area was found to diminish rapidly in the furnace environment. Exposing the reactant to prolonged furnace temperatures in excess of 2300°F can sinter calcined lime and reduce surface area. Pore plugging also degraded surface area as a result of SO_2 reaction with lime. Thus the process is straightforward: inject sorbent into the furnace with effective mixing and dispersion in the proper temperature window to maximize SO_2 capture. The success of the EPA and DOE LIMB demonstrations projects is considered to be the result of the much more thorough understanding of the time/temperature profiles of the furnace, coupled with matching the injection process to the fundamental chemical kinetics.

EDGEWATER DEMONSTRATION SITE

Ohio Edison's Edgewater station is located on the south shore of Lake Erie in Lorain, Ohio. Figure 1 shows the layout of the Edgewater Station. The boiler used for the demonstration is a B&W unit, first commissioned in June 1957. The boiler is designated as No. 13 at the plant, and generates steam for the Unit 4 turbine with a nameplate rating of 105 MWe. A schematic of the boiler is presented in Figure 2. The boiler has a convective secondary superheater, a reheater, a horizontal primary superheater, an economizer, and a tubular air heater. All sootblowers, except the four in the air heater, were converted to steam before the LIMB Extension tests began. Four new steam sootblowers had been installed in the primary superheat area prior to the EPA LIMB Demonstration. Four B&W "E" pulverizers supply coal to the twelve B&W DRB-XCL™ low NO_x burners that replaced circular burners, again as part of the original demonstration. The burners are arranged three across by four high on the front wall of the furnace. A retrofit Lodge-Cottrell ESP with a design specific collection area (SCA) of 612 $ft^2/10^3$ ACFM replaced a smaller original device in 1982.

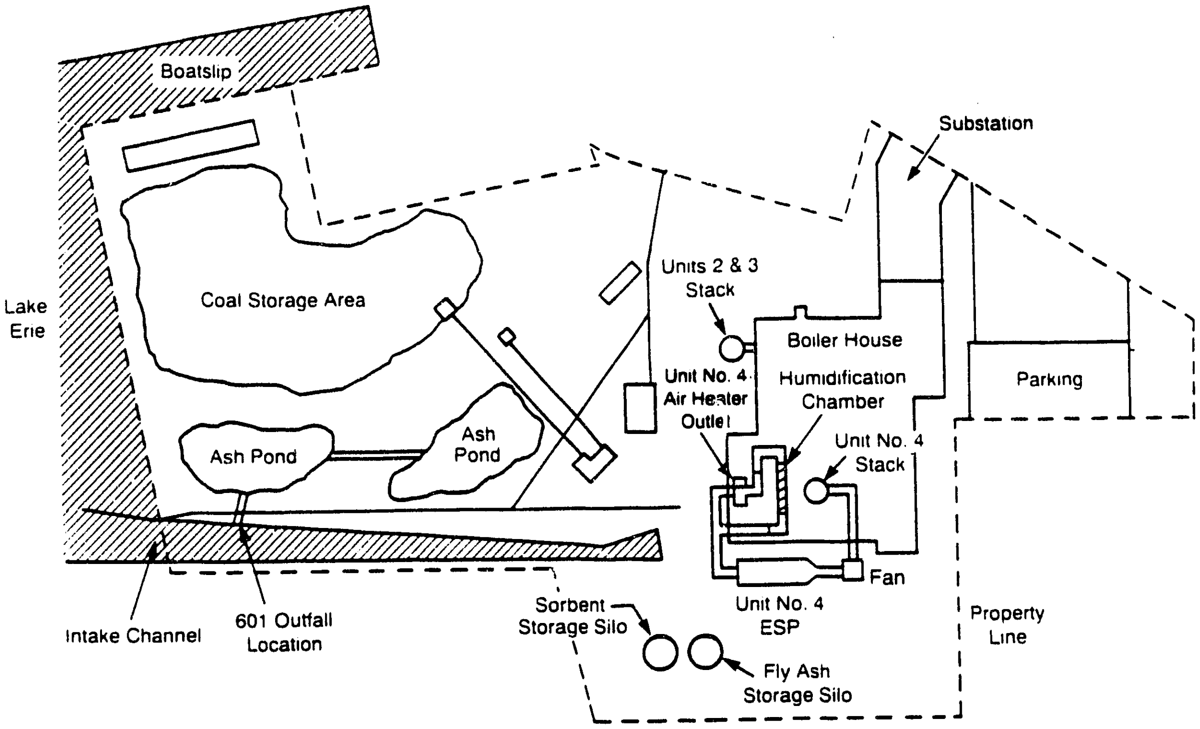


Figure 1. Edgewater plant site layout

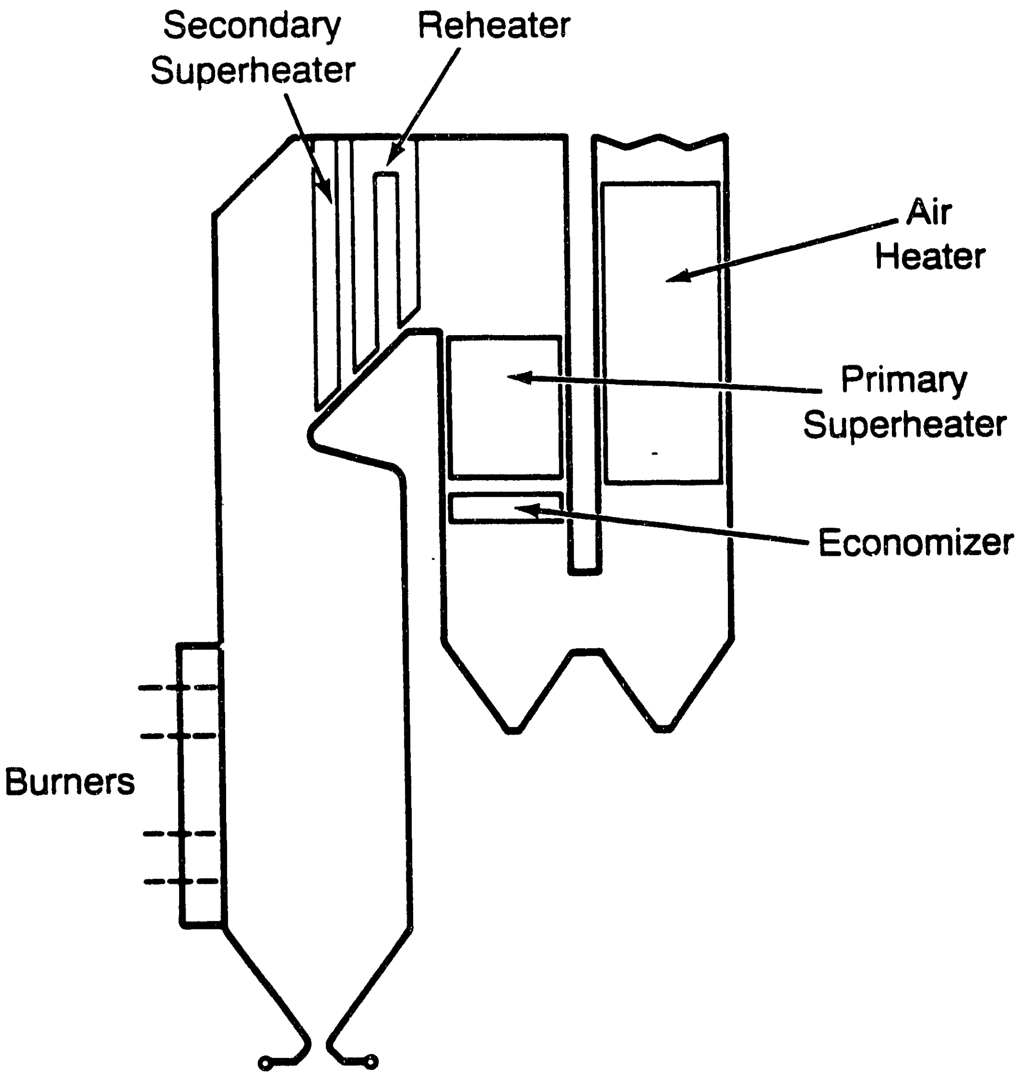


Figure 2. Host boiler schematic

LIMB PROCESS/EQUIPMENT DESCRIPTION

Relatively few pieces of equipment are required for injection of sorbent into the furnace. However, the system designed and installed at Edgewater contained special features and instrumentation that would not otherwise be required for a commercial system. For example, highly accurate differential weight loss feeders were provided in order that precise amounts of sorbent could be fed to the furnace. This, along with much of the instrumentation, was necessary to obtain accurate and reliable data on the system's performance. Such precise delivery of sorbent would not be necessary in a commercial application. Figure 3 is a process flow diagram of the LIMB system showing the major equipment described in the balance of this section. A more complete equipment list is provided in Appendix B.

Bulk sorbent is delivered to the site by truck. The sorbent is unloaded into a large outside storage silo. Conveying equipment located underneath the silo transfers material to a smaller silo inside the boilerhouse. A rotary valve below this silo fills a gravimetric feeder which in turn feeds a solids pump or a rotary valve. The solids pump was added during the LIMB Extension to replace one of the two rotary valves originally installed. This pump proved to be a much more reliable device that sealed against the conveying air pressure more reliably than did the rotary valve. This improved the stability of the feeders, since backpressure effects were a source of continuing concern with the rotary valves, particularly at high feed rates.

A compressor supplies air to convey the sorbent from the solids pump or rotary valve to distribution bottles above the boiler, where the flow splits to go to each of the injection ports. The injection nozzles have an inner pipe through which sorbent passes and an outer annulus for booster air. The booster air is used to increase the momentum flux of the injection jet of particles into the boiler. Sorbent reacts with SO_2 in the flue gas in the furnace and then exits through the air heater. The humidifier is installed in the ductwork between the air heater outlet and the ESP inlet. Water flow to atomizing nozzles is controlled to maintain a constant humidifier outlet temperature. The two-fluid nozzles use compressed air to atomize water.

The ash is collected in the ESP hoppers, from which it is then pneumatically conveyed to a storage silo. A rotary valve below the silo feeds a pug mill where water is added for hydration of any remaining quicklime component in the ash and dust-free unloading to a waiting truck. The wetted ash is then taken by truck to a landfill.

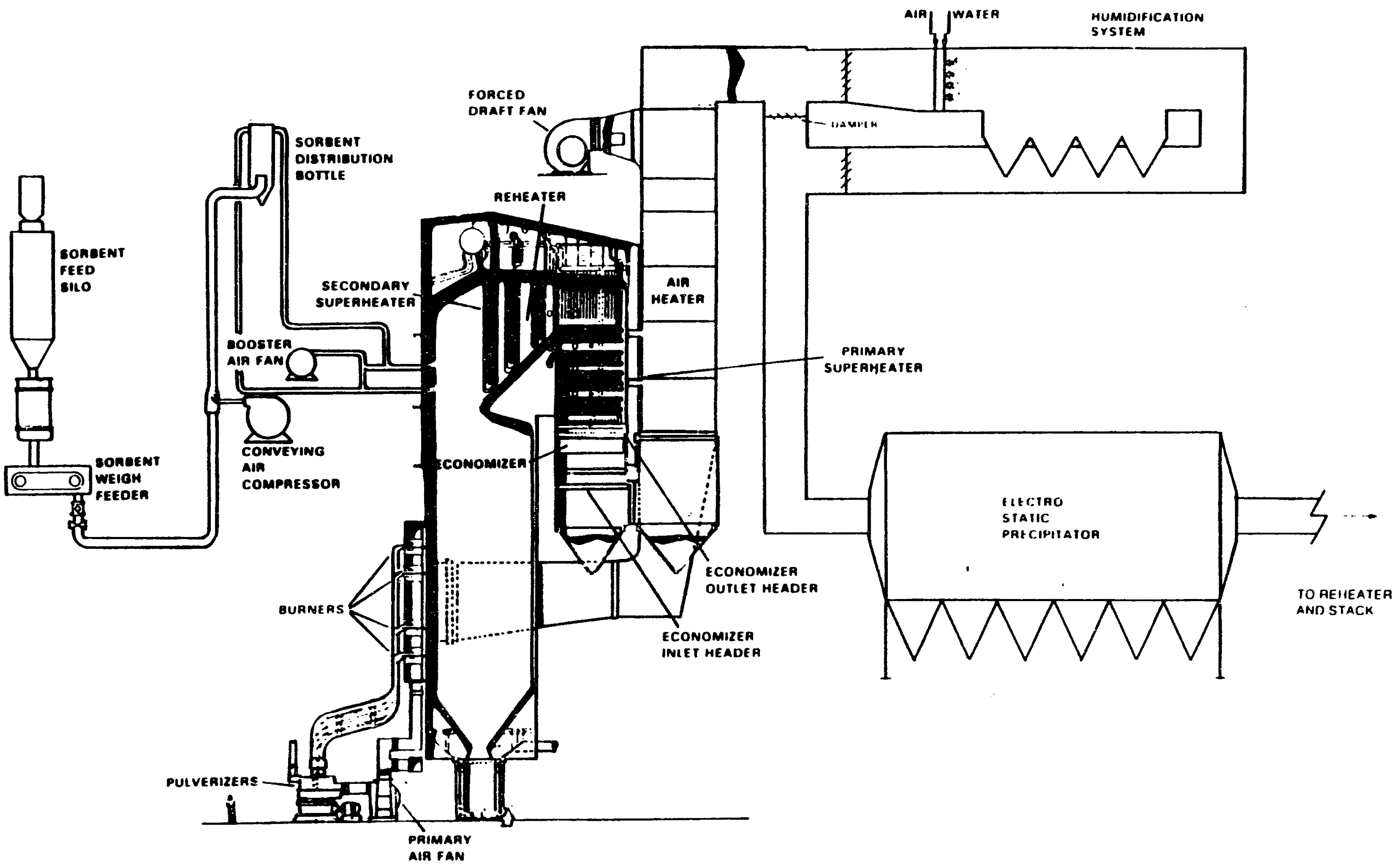


Figure 3. The LIMB process at Edgewater

The LIMB equipment requires only a minimal amount of space. The lime storage silo and an acid storage tank were the only pieces of equipment added outside the boilerhouse. The humidifier was constructed on top of the boilerhouse where the original ESP, decommissioned in 1982, had been located. The acid was used to neutralize the water used by the hydraulic exhauster to create the vacuum for the ash conveying system. This was necessary because the unreacted lime in the ash, even in small amounts, could cause the pH of the water to rise to unacceptable levels unless some treatment was provided. The acid neutralization system was also used to treat the runoff from the ash unloading area which could also give rise to high pH levels through the collective system of drains and sumps in the area.

SYSTEM DESIGN

Proper sorbent contact with flue gas in the reaction temperature window of 2300 to 1600°F and the significance of reactant surface area were the primary factors considered in the design of the LIMB system.[7,8] Before the system could be designed for the Edgewater boiler, an accurate physical location of the sulfation temperature window inside the boiler had to be determined. Moreover, the location of this window was load specific. Sorbent feed, from the silo to the individual nozzles, needed to be evenly distributed, accurate, and non-slugging. Modifications to the ash handling system were required to handle the two- to threefold increase in ash quantity. The ash then had to be disposed of in an environmentally acceptable manner.

Early tests pointed toward the need for some further definition of design requirements for the flue gas humidification system, particularly in regard to achieving the close approach to saturation desired for enhanced SO_2 removal with LIMB, as well as for the Coolside demonstration.[9-11] The residence time of water droplets in the humidifier had to be long enough to allow for complete evaporation. (The humidification system used B&W atomizers which produced droplet size distributions with Sauter mean diameters on the order of 25 to 30 μm.) If the humidifier cross-sectional area were too small, the gas velocity would be too high and cause unevaporated water to exit the humidifier and impinge on walls and turning vanes downstream. Ash would then build up on the wetted surfaces. Too large a cross-sectional area in the humidifier would slow the gas down so much that water droplets and ash would not be carried with the gas, leading to deposit formations on the floor.

Other issues critical to optimization of the humidifier design were the type and number of nozzles and determination of the spacing between the nozzles themselves, as well as from the adjoining walls. Good distribution of the flue gas was essential to avoid areas of high water concentration which again would result in wet areas and subsequent ash build-up. Another concern, site specific to Edgewater, was the gas side pressure drop. A flue gas reheater was needed to protect the existing gunite stack lining during operation at close approach to saturation. In addition, the placement of the humidifier in a bypass mode because of the test nature of the project, contributed to increased pressure drop to be overcome by the induced draft (ID) fan. Although some energy was recouped by the momentum imparted by the jets of atomization air, it had to be ascertained that the increased pressure drop was within the capacity of the existing fan.

Each of these considerations are discussed in more detail in the following sections.

BOILER CONSIDERATIONS/CHARACTERIZATION

Because temperature and velocity profiles in the boiler were so critical to sorbent utilization, the original EPA program had provided for actual measurement of these variables both at full and reduced load near the planned injection plane and at the furnace exit (entrance to the convection pass). These values compared well with predictions from a proprietary mathematical boiler model. The velocities also compared well with those determined in a 1/15 scale model of the boiler which was used for flow characterization and visualization of the sorbent injection process. This model was also used for methane tracer studies to determine the extent of sorbent mixing to be expected in the full-scale unit.[12]

Modelling and direct measurement indicated that the ideal sulfation temperature window in the Edgewater boiler was located in the upper furnace, from a plane just above the nose across to the entrance to the convective pass. The residence time for a sorbent particle in this zone where the temperature drops from approximately 2300 to 1600°F was on the order of one second.

SORBENT FEED/INJECTION SYSTEM CONSIDERATIONS

In order to achieve proper sorbent dispersion, it was critical that the material be delivered from the feed silo to each of the injection nozzles in as even a distribution as possible. The sorbent had to flow out of the nozzles and into the boiler in a "non-pulsing" manner. Pressure and visual checks confirmed that this was the case. The sorbent feed system was similar to those B&W has designed for delivery of "micronized" (finely pulverized) coal to blast furnaces.

Once the sorbent has been delivered to the nozzles, the particles must disperse uniformly into the furnace. Characterization of the flow and temperature profiles within the boiler led to the installation of sorbent injection nozzles at three levels on the front wall. The lowest level of injectors was located at the 181 ft plant elevation. There are eight nozzles at this level, with approximately equidistant spacing from each other and the side walls. A second row of nozzles is located six feet higher. There are twelve nozzles at this elevation, eight along the front wall directly above the eight at the 181 ft elevation. There are also two nozzles on each of the side walls at this elevation. These side wall nozzles were not used during the LIMB Extension since tests during the EPA LIMB Demonstration had shown that they had no readily noticeable effect on SO_2 removal. The highest level of injectors was located at the 191 ft plant elevation. Here eight nozzles were again located on the boiler's front wall, spaced exactly as the injectors on the levels below.

As originally installed, the nozzles could be tilted through a 30° arc. Testing during the EPA project revealed that there were no appreciable advantages gained by tilting the nozzles to any angle, as the removal efficiency remained steady when the nozzles were tilted through the 30° arc.

The design of the nozzles was such that sorbent flows through an inner pipe while booster air flows through an outer annulus. The booster air raises the momentum flux of the jet of sorbent particles and pushes them farther out into the boiler than they would be carried by the conveying air alone.

ELECTROSTATIC PRECIPITATOR DESIGN CONSIDERATIONS

An important issue during the early design stages of the project was whether the ESP would be able to handle the two- to threefold increase in particulate loading caused by sorbent injection. Not only would there be an increase in loading, but the particles themselves would have a higher resistivity than normal fly ash and a finer size. All three factors serve to degrade ESP performance.[13] Based on past experience and modelling, it was felt during the early stages of the EPA LIMB Demonstration that the large (612 $ft^2/10^3$ ACFM) SCA of the ESP would still permit adequate performance and meet emissions and opacity requirements. Nevertheless, it was at this point in time that planning for humidification and Coolside operation began to take shape, with the potential benefits for ESP performance being recognized as well. The first full scale injection tests in September 1987 later demonstrated that some humidification was indeed required due to the high resistivity of the ash obtained with calcitic hydrated lime as the sorbent.

HUMIDIFIER DESIGN CONSIDERATIONS

The most important factor in humidifier operation is that it be sized for the proper velocity, and hence residence time, for essentially complete water droplet evaporation . Without this, droplets impinge on walls and outlet turning vanes and ducts. The wetted surfaces then become sites for ash build-up and the formation of hard deposits that can further alter gas and droplet flow patterns, exponentially increasing the rate of deposit accumulation.

Spacing of the two-fluid atomizing nozzles inside the humidification chamber was also extremely important. The nozzles had to be placed in array that would allow the greatest coverage of the cross-sectional area of the duct. They could not be placed so closely together, however, that the droplets would coalesce into larger ones that would not evaporate. At the same time, the nozzles could not be positioned so close to the walls that impingement and deposit formation would occur.

To assure that these design criteria were met, commercially available nozzles were evaluated by testing them over a range of potential operating conditions. The initial screening consisted primarily of determining the droplet size distributions produced at a number of conditions. The superior performers were then tested in an array mounted in a 60 ft long. 36 ft^2 square duct (the "6 x 6") through which heated air was blown over the range of velocities being considered for Edgewater. Measurements were made of velocities, droplet size distributions, and the extent of evaporation as a function of distance from the atomizer array and approach to saturation. At the same time, a 1/12 scale cold flow model of the humidifier was constructed and operated to investigate gas flow patterns and pressure drop. A mathematical model, based on B&W's proprietary DRYMO model, was used to gain greater insight into the humidification process. Both the cold flow and mathematical model predictions were compared with data obtained in the "6 x 6". For the patented B&W Mark XII atomizers eventually selected and the site-specific considerations of Edgewater, the humidifier was designed for a 2 sec residence time in order to achieve essentially complete evaporation of the droplets.[10,14]

ASH REMOVAL CONSIDERATIONS

The increase in loading through the boiler and the change in the chemical composition necessitated the upgrade of the ash removal system. This system utilizes a vacuum to transport ash from hoppers beneath air heater, economizer, and the ESP to a storage silo. The vacuum is created by a hydraulic exhauster. Prior to the EPA program, the system was upgraded to produce additional vacuum and increase ash transport capability. The eductor is that part of the device where the transport air, which may contain entrained ash particles, contacts water used to create the vacuum. The build-up that occurs slowly at the wet-dry interface with normal fly ash was accelerated due to the cementitious properties of the LIMB ash. A manually controlled dust pugger was therefore added to maintain a clear path through the throat of the eductor.

In anticipation of condensation leading to deposit formation in the ash conveying lines, again due to the cementitious properties of the ash, a 144 kW electric duct heater was installed to raise the ambient air used to a temperature of 400°F before it contacted the ash. After a couple of inadvertent failures of this system during the original demonstration, it was discovered that the precaution was unnecessary as there were no indications that any appreciable deposits could be attributed to condensation. Use of the heater was therefore discontinued.

Ash from the Unit 4 air heater and economizer hoppers had been routed to the Unit 3 ash silo before the EPA project began. A change was required so that all lime-containing ash would be routed only to the Unit 4 ash silo. A header system was therefore installed below these hoppers to permit transport to the Unit 4 silo.

ASH HANDLING AND DISPOSAL CONSIDERATIONS

The ash collected in the ESP is stored in a silo before it is unloaded into trucks for transport to a landfill. During the design phase of the project it had to be determined what measures had to be taken for proper handling and disposal, given the anticipated differences in chemical and physical properties of the LIMB ash. Studies were conducted on ash obtained from sorbent injection tests being performed at Ontario Hydro's Lakeview Station. In addition, LIMB ash collected from a pilot combustor at Southern Research Institute was used to characterize some of the ash under laboratory conditions.[15]

Water addition to control fugitive dust of regular fly ash took place in a pug mill situated under the storage silo. This system was upgraded in order to provide the additional water capacity required to hydrate the CaO (quicklime) and $CaSO_4$ components of the LIMB ash to $Ca(OH)_2$ and $CaSO_4 \cdot 2H_2O$ (gypsum), respectively. Due to the strongly exothermic nature of the quicklime reaction with water, the capacity included provision for an estimated 50 percent loss of the total water added as steam. The pug mill discharges the wetted ash directly into a waiting dump truck. During the design stage of the project the steaming was taken into account and a single large fan was supplied to keep the steam from obstructing the unloading operator's view. Experience with the system suggests that a system of strategically placed fans would have been preferable to accommodate changes in wind direction and speed through the truck bay. However, due to the relatively short planned duration of the demonstration, and to cost and space constraints, what proved to be a marginally acceptable system as just described, was used at Edgewater. Assuming a wetted ash system is desired, a better system would be one which would allow at least brief interim placement of the wetted ash to permit steaming to subside. This occurs within about 15 min after the water is added, so a radial stack out system would work well. A dry unloading system would permit potential use of the ash as a byproduct, and still leave open the possibility of wetting the ash at the disposal site.

The ash samples collected from Ontario Hydro and Southern Research Institute were subjected to the Extraction Procedure (EP) Toxicity Test as specified in the Resource Conservation and Recovery Act (RCRA).[16] The tests showed that leachable toxic materials were far below levels considered to be hazardous. Ohio Edison's existing ash disposal landfill site was therefore used for disposal of LIMB ash from the EPA demonstration. In addition, approximately 120 truckloads of LIMB ash were used to construct two separate test cells in April 1989. These cells were designed and constructed under a separate DOE contract with Radian Corporation to permit long term monitoring of their chemical and structural condition, and of the leachate and runoff that comes from them.[17] This work continues even today and may yet be followed for several years to come if thoughts of a project extension come to pass.

pH CONSIDERATIONS

The possibility of high pH conditions in plant water discharges existed as a result of the lime component of the ash. Ash entering the water either through the pneumatic ash transport system or from spills necessitated provision for neutralization. Fairly large quantities could be involved if a bag failed in the baghouse on top of the ash silo. This would cause ash to be pulled directly into the eductor. The free lime in the ash would cause the pH of the water used in the exhauster system to rise. The neutralization system was therefore designed to accommodate lowering the pH of this stream. Overall the system was designed to neutralize about 5000 lb/hr for a few hours, an amount sufficient to neutralize minor yard spills or a bag failure in the ash conveying system. Early in the EPA demonstration the first few ash spills made it obvious that the piping system for the yard drains bypassed the neutralization system. Rerouting of the piping system, with pH sensors located both upstream and downstream of the sulfuric acid addition point, maintained control thereafter. This orientation of the pH probes provided a system with combined feed-forward and feedback controls.

BURNER CONSIDERATIONS

The B&W DRB-XCL™ burners used throughout the LIMB Extension are discussed only briefly here, since the report on the original EPA LIMB Demonstration provides detailed descriptions of the design characteristics, as well as results of all the baseline and characterization tests conducted.[1] Moreover, results during this project continued to indicate the lack of any correlation between burner performance and SO_2 levels. These burners, which replaced the original B&W circular register burners, were designed to provide low NO_x emissions by achieving a greater degree of control of the fuel/air mixing process to minimize the high temperature conversion (oxidation) of nitrogen in the combustion air to NO and NO_2 (NO_x).

The burner consists of a centrally located nozzle for the pulverized fuel/air mixture and two secondary air zones. The design incorporates flexibility for retrofit applications and can utilize different nozzle configurations . The DRB-XCL™ burner for a new boiler or an opposed-fired retrofit would utilize a conical diffuser/deflector arrangement to distribute the fuel/air mixture in the nozzle. This provides a low nozzle exit angle, leading toward lower NO_x generation and longer flames. An impeller is utilized in the coal nozzle to disperse the fuel into the secondary air very rapidly for single wall-fired retrofits such as at Edgewater where flame length was a concern. Although NO_x emissions might be somewhat higher due to the increased turbulence at the flame's base, the impeller has a beneficial effect on flame length. The optimal configuration employed at Edgewater consists of a conical diffuser/deflector arrangement with flame stabilizing rings on the second and fourth burner rows from the bottom, and 30° impellers and distribution cones in the first and third rows. The flame stabilizing ring recycles air back toward the coal nozzles which holds the base of the flame close to the burner.

SECTION 4
DETAILED SYSTEM DESCRIPTION

This section contains a detailed description of major subsystems of the LIMB design, including all of the modifications that have taken place since the original design for the EPA LIMB Demonstration. The major modifications are summarized in the last part of the section.

MAJOR LIMB SUBSYSTEM DESIGN DETAILS

Sorbent Storage and Transfer System

The sorbent storage and transfer system is shown in Figure 4. The sorbent storage silo is designed to hold up to 400 tons of sorbent which equates to about a 43 hr supply of lime or a 73 hr supply of limestone. Sorbent is delivered to the silo in 20 to 25 ton truckloads. The trucks are self-unloading and pneumatically convey the sorbent to the top of the silo. The silo is vented by a locally controlled bag filter. Facilities exist for two trucks to unload simultaneously.

When the feed silo in the boilerhouse detects a low level, transfer equipment under the storage silo automatically starts. The sorbent flows out of the storage silo through an automatically controlled slide gate valve. There is an aerated bin bottom which promotes flow out of the silo. Dry air is supplied to the aerator by a dedicated lobe-type blower and an air dryer. After passing through the knife gate valve and a rotary valve, the sorbent enters a Fuller-Kinyon solids pump. The pump is a positive displacement screw pump. Sorbent is compacted as it is pushed through the barrel and provides a seal against the conveying air which transports the sorbent from the pump to the feed silo. The source of the conveying air is a rotary vane compressor.

The sorbent exiting the screw pump is transported in dilute phase through an 8 in diameter carbon steel line to the boilerhouse where the feed silo is located. This silo can hold about a 2 hr supply of sorbent at full load conditions. The sorbent is separated from the transport air at the feed silo by an inlet alleviator. Transport air vents through a pulse jet filter.

The transfer system operates for about 20 min every 2 hr and 20 min, which, for calcitic hydrated lime, is roughly equivalent to injection of 15,000 lb/hr, or a Ca/S stoichiometry of 2.5

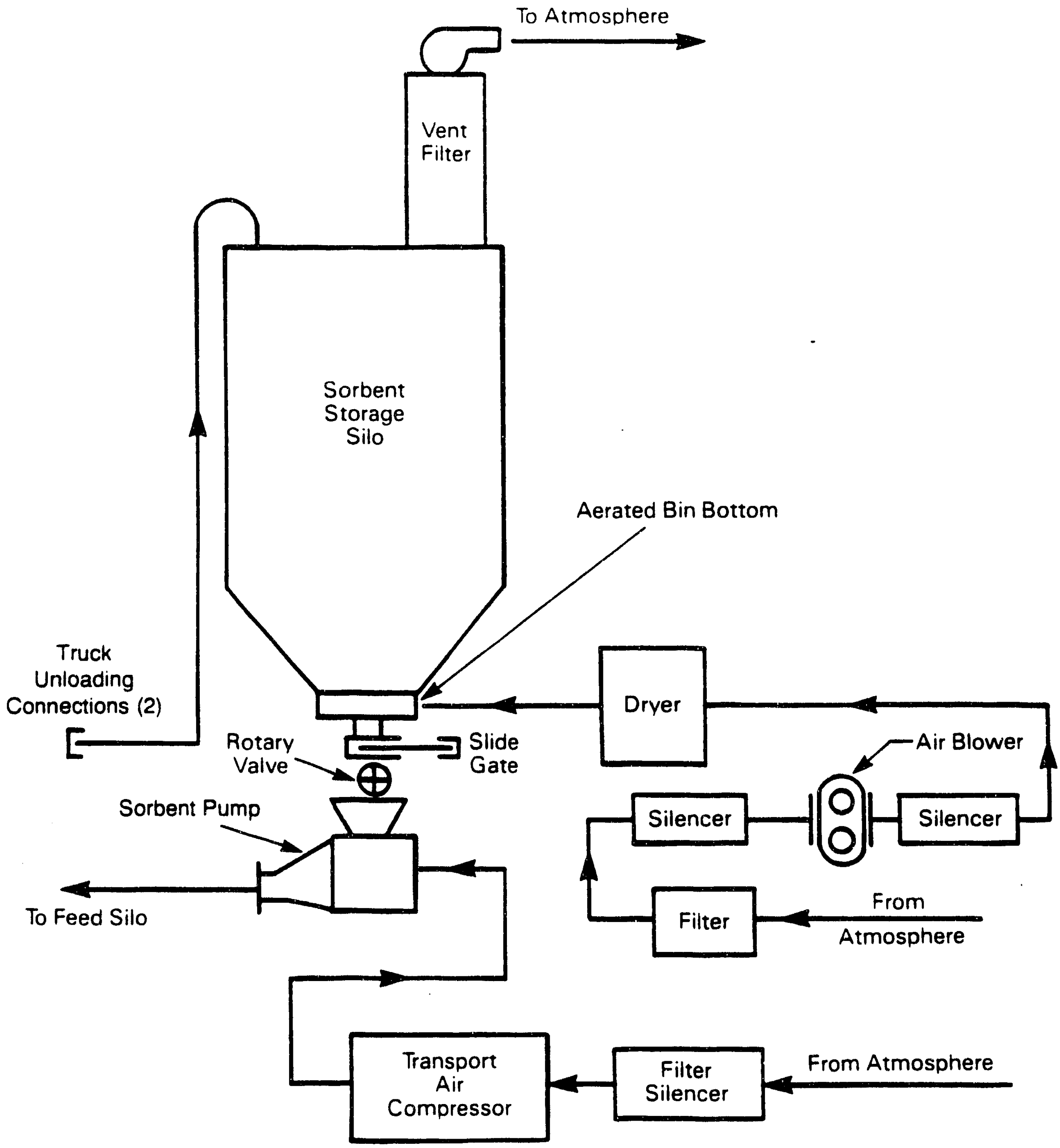


Figure 4. Sorbent storage and transfer system

while burning 3.0 percent sulfur coal at full load conditions. The storage-to-feed silo transfer system is designed to deliver 50 ton/hr of the less dense lime. Higher transfer rates were possible with limestone. The transfer equipment is designed to operate automatically. A control cabinet for the equipment is located near the base of the feed silo in the boilerhouse. The equipment can also be operated manually using hand on/off switches located near each piece of equipment.

Feed System

The feed system (Figure 5) delivers a precisely controlled amount of sorbent to the injection ports, and distributes it evenly across the boiler. The sorbent flows from the injectors in a non-slugging manner. There are two independent feed trains, providing the capability of feeding any two of the three injection levels at one time.

Differential weight loss feeders below the feed silo provide the accurate, controlled flow of sorbent to the injection system. A low level in the feeder hopper signals the need for a fill cycle to begin. Each of the "pant-legs" on the feed silo is equipped with a Vibranetics bin vibrator, which starts when the hopper fill cycle begins. A slide gate valve below the vibrator opens and a rotary valve, between the slide gate and the feeder, fills the hopper in a steady, non-flooding manner. The hopper fill cycle automatically shuts down on a high level signal.

Each differential weight loss feeder consists of a hopper on a hinged scale which determines the feed rate. An auger discharges sorbent from the bottom of the hopper. The sorbent feed rate can be controlled from the feeder either gravimetrically (weight-loss) or volumetrically (auger speed). Each of the two ways can be controlled either locally or remotely in the control room. The feed rate can be manually input or set to automatically follow boiler load.

In the original design, each of the two gravimetric feeders delivered sorbent to a dedicated rotary valve, which then discharged the material into the conveying air stream. These rotary valves required constant adjustment and attention in order to maintain their ability to seal against the 20 psig conveying air. Failure to do so would cause the feed to the valves to become fluidized, with a subsequent loss in capacity. As part of the LIMB Extension, the "B" feed train rotary valve was replaced by a solids pump. This pump was equipped with a small baghouse to vent any air that might otherwise find its way into the feed lines. Any sorbent collected in the baghouse continued to be fed to the furnace as it had already passed the feeder control point for

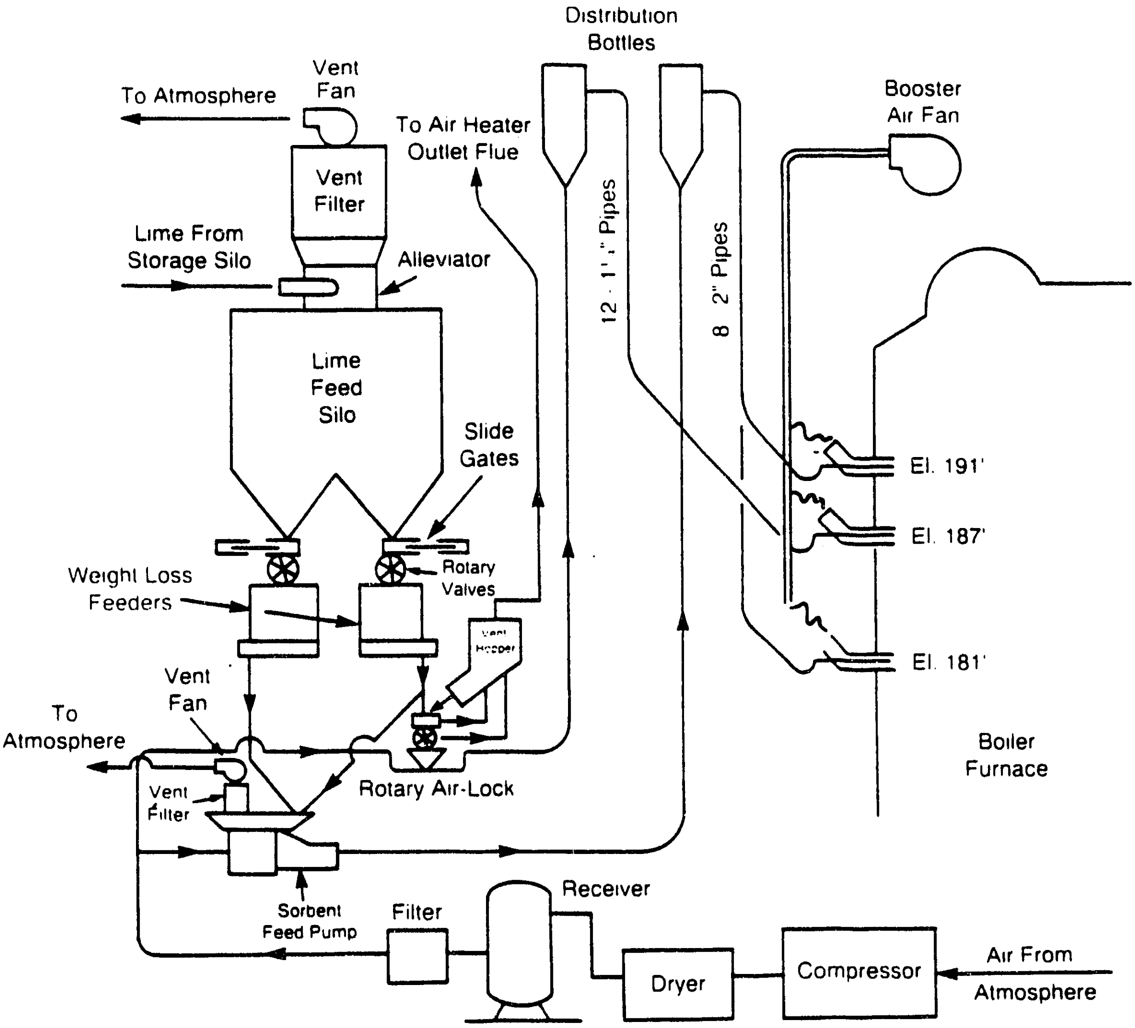


Figure 5. Sorbent feed system

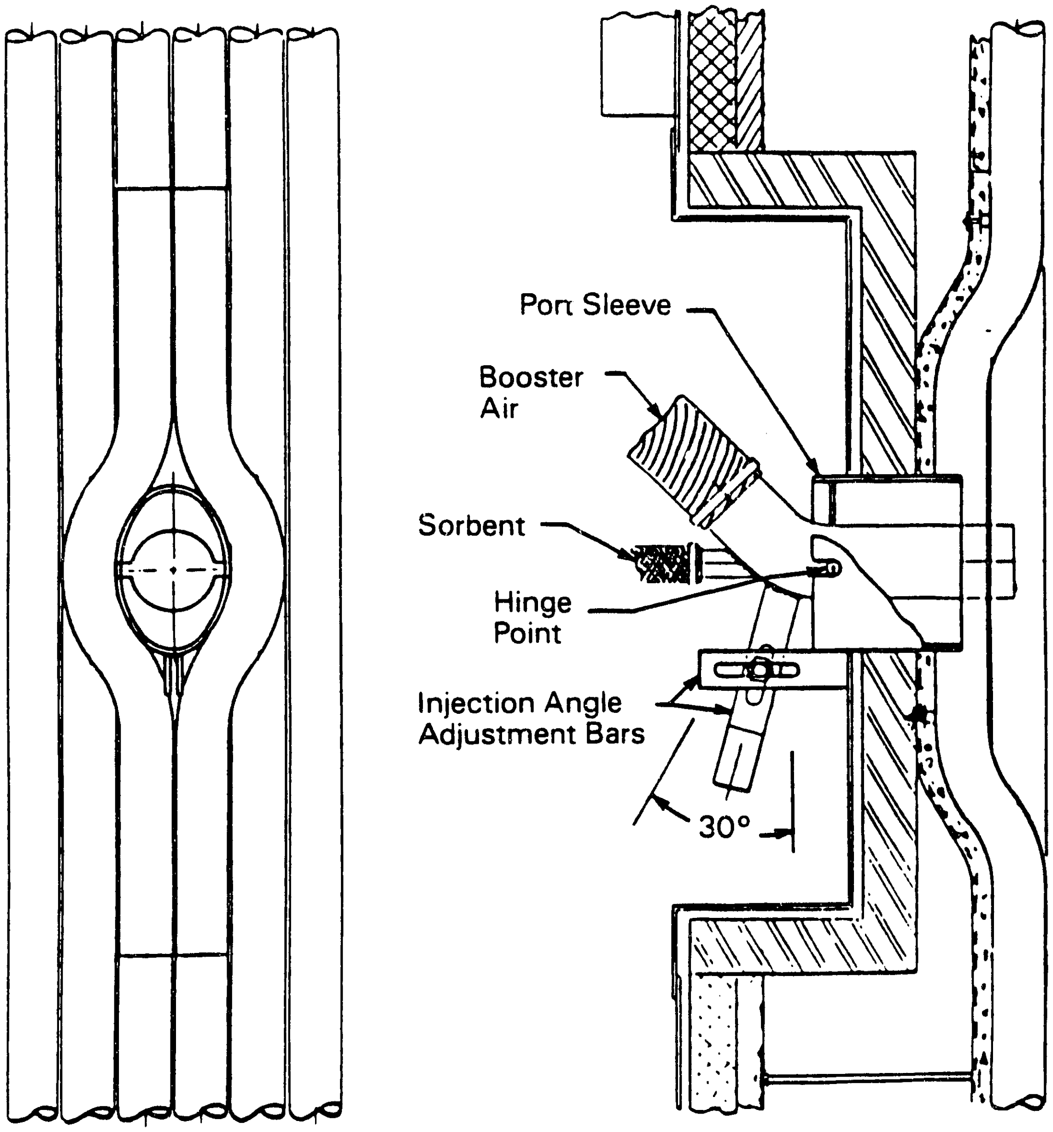
stoichiometry. This arrangement resolved the problem of the sorbent becoming fluidized. The "A" train was modified so that it could feed either the solids pump or its original rotary valve.

A rotary screw compressor supplies the conveying air. Air from the compressor passes through a dryer and into a receiver. It then goes through a coalescing filter and a control valve station. At the valve station, flow is automatically controlled to maintain proper dilute phase operation. The conveying air meets the sorbent feed at the pick-up point, directly downstream of the rotary valve or solids pump. A 4 in inner diameter (ID) hose connects the pick-up point to the distribution bottles.

The distribution bottles are designed to split the sorbent feed, from the rotary valve or solids pump, equally to each of the injectors in a non-slugging manner. In the normal configuration, one bottle feeds the injectors at the 187 ft plant elevation, and the other either the 181 or 191 ft elevation. Two inch ID lines connect the distribution bottle feeding the 181 or 191 foot elevation with the nozzles. These lines were changed from 1.25 in to 2 in ID in 1988. The original 1.25 in lines were retained between the bottle feeding the 187 ft elevation and the nozzles. The lines from the bottles to each of the nozzles were designed and sized so that equal resistance was created in each line. This minimized the possibility of uneven flow to each nozzle. The feed system was designed to deliver a smooth even distribution of flow to each nozzle. Visual and pressure checks confirm this to occur.

The original sorbent injection nozzles were comprised of a 1.5 in ID inner pipe and a concentric 3 in outer pipe, creating an annular area through which booster air flows. The nozzles could be tilted through a 30° arc. The nozzles at the lowest elevation could be tilted ±15° from horizontal. Those at the other two levels could be tilted from horizontal to 30° down from horizontal. Figure 6 shows an injector nozzle and its relation to the wall injection port.

A radial fan supplies booster air which flows through the outer annulus of the nozzles just described. The high velocity carries the sorbent particles further into the boiler than they would if only conveying air was used. Booster air flow is controlled by the distributed control system (DCS). A signal from a flow transmitter at the fan outlet is sent to the DCS, which then opens or closes a vortex damper at the fan inlet. The booster air also provides cooling air for the nozzles.



Front View

Side View

Figure 6. Injection nozzle and furnace wall port

Humidification System

The humidifier was constructed on the roof of the boilerhouse where the plant's original ESP was located. It was designed with 100 percent bypass capability so that Ohio Edison would not have to shut down the unit if there were problems with the humidifier. The bypass flue functions in parallel with the existing flue which runs between the air heater outlet and the ESP inlet. The layout of the humidifier and bypass system can be seen in Figure 7. Figure 8 is a schematic representation of the ductwork from the air heater to the stack.

When the boiler is on line, the humidifier system can be brought into service through use of modulating louver dampers. These same dampers provide a means for regulating flow through the humidifier should only partial treatment of the flue gas be desired. Should internal maintenance be required, the humidifier can be isolated, even while the boiler is on line, through use of guillotine shut-off dampers. Extensive safety interlocks protect against improper damper operation which could lead to overpressurization or implosion in the flue or boiler.

The humidifier, sized to maximize evaporation and minimize wall wetting, is 14.6 by 14.6 ft square and approximately 60 ft long. Its size allows for a 2 sec residence time at design conditions. This corresponds to an inlet flue gas velocity of 27 ft/sec. The humidifier was located over the hoppers of the retired ESP so that, if need be, plates could be removed and ash could be emptied from the chamber through these hoppers. Fortunately, this was never necessary. A drawing of the humidifier is shown in Figure 9. The hopper baffles shown in the figure were provided to minimize turbulence had it been necessary to remove the floor plates.

The structural support steel for the chamber was designed to hold a weight equivalent to that of the chamber with a build-up of one foot of ash in it. Strain gauges on the support legs of the chamber monitored the weight. The humidification equipment would be shut down if a "high" load was detected by these strain gauges.

The water used for humidification is supplied by the existing Unit 4 service water system. The water, stored in a tank on an upper floor of the boilerhouse, is used as cooling water for the atomizing air compressor as well. An in-line pump boosts the pressure to obtain the flow necessary for the compressor. The water then flows either through a basket strainer and into the storage tank, or back to the raw water intake channel. The level in the tank is maintained by a

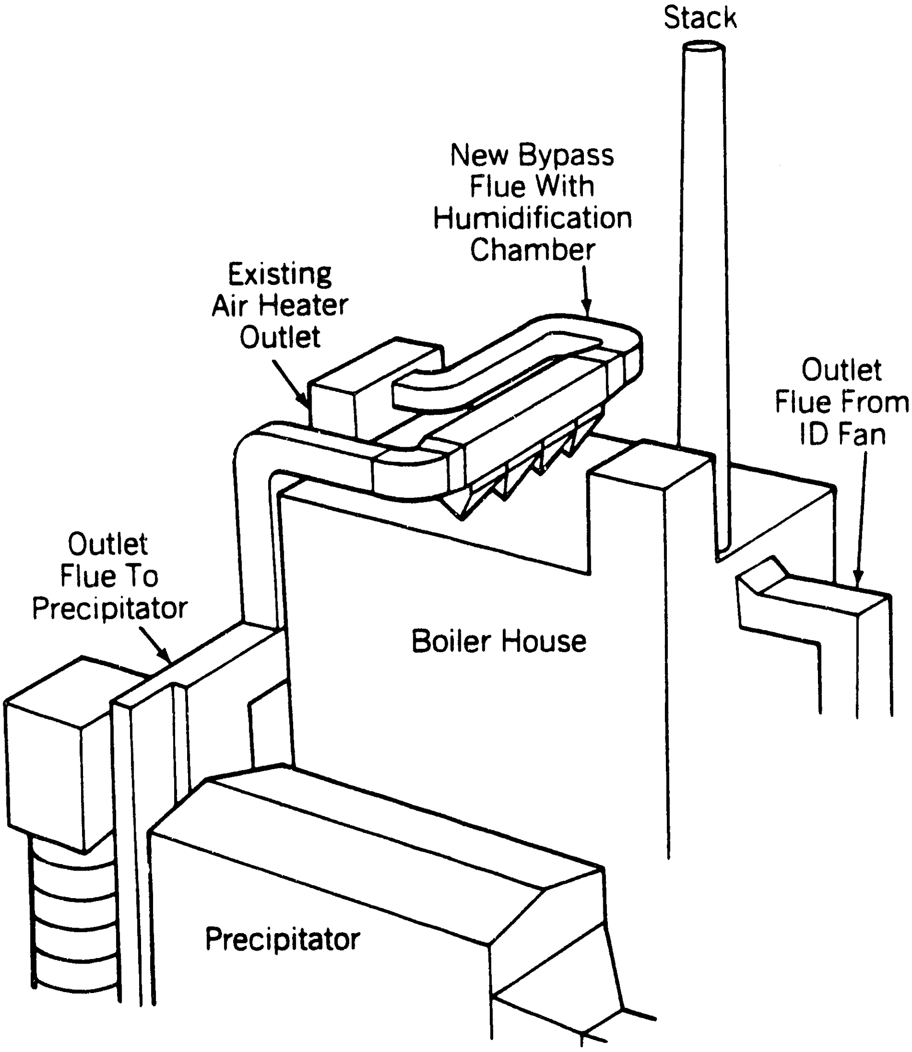


Figure 7. Bypass system orientation

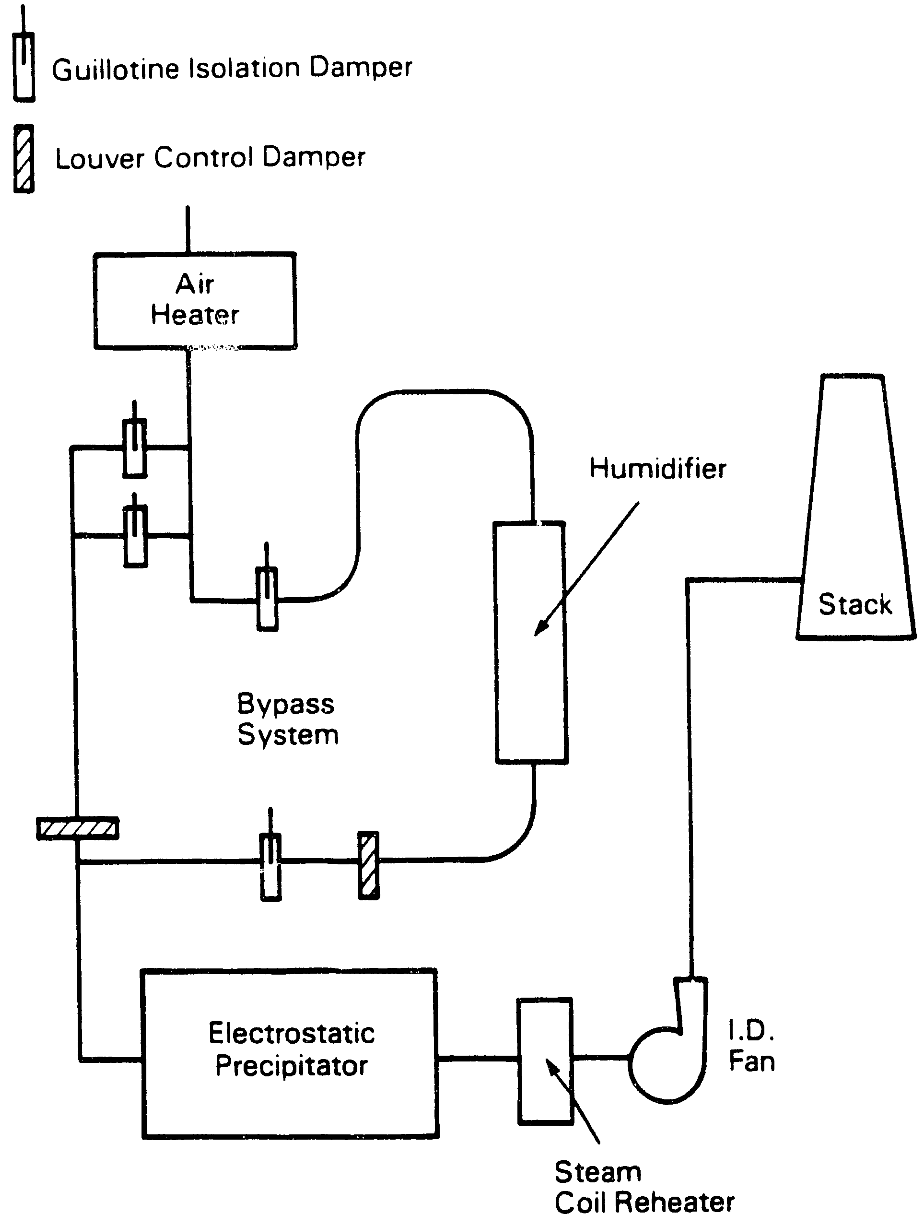


Figure 8. Bypass system schematic

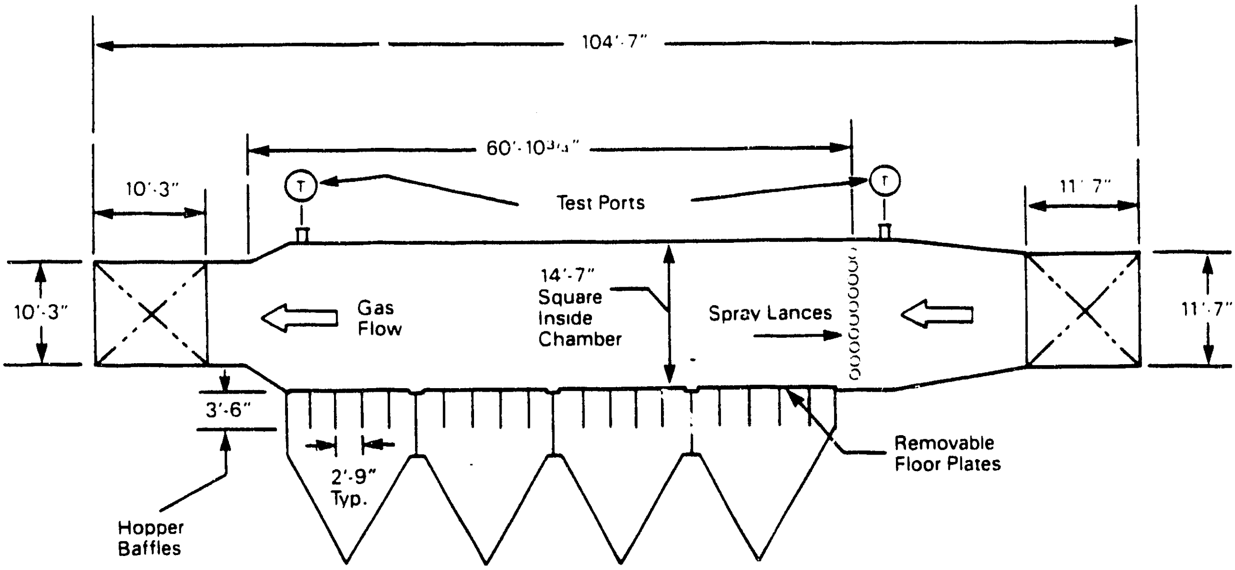


Figure 9. Humidification chamber detail

control valve.

The water for humidification is pumped from the storage tank through another duplex basket strainer to a valve station. The valve station controls the water flow to the humidification chamber based on the humidifier outlet temperature set point. The inlet pressure to this flow control station is maintained by a back-pressure control valve which returns water to the storage tank.

Between the flow control valve and the humidifier there is yet a third duplex basket strainer. The flow splits after the strainer and goes to the north and south atomizer supply headers. Each header can supply eleven lances. The water supply to the individual lances was designed to pass through an in-line "Y" strainer, three-way air purge valve, and an air operated ball valve. Atomizing air is used to operate this ball valve. This ensures that the ball valve closes and stops the water flow if there is no air flow to the lance. This prevents unatomized water from entering the chamber and causing serious problems, since unatomized water would quickly lead to massive ash accumulation and large quantities of deposits that would be difficult to remove.

Manual globe valves are installed on the water feed line to each lance to balance flow. These valves serve to equalize the pressure losses that are inherent in the vertical supply header. An automatic system operating on differential pressure signals was provided, but did not account for slight side-to-side differences in flue gas temperature and flow. The manual control valves allowed for fine tuning of the flows based on outlet temperature measurements. Once set, these valves would maintain the desired bias for days at a time, even with changes in unit load and gas flow. For the purposes of the tests conducted, flow transmitters were installed on each lance and the signal sent to the DCS.

A three-stage, centrifugal compressor pulls air through an inlet filter located on the roof to provide the atomization air required. The air passes through first and second stage intercoolers and moisture separators. The discharge from the third stage is sent to an air receiver.

A control valve maintains a set differential pressure between the air header and water header pressures. This valve is located just downstream of a "Y" filter in the air line directly downstream from the air receiver. After the control valve, the air header splits in the same fashion as the water header to form the north and south lance headers. These supply up to 22 B&W

patented lances, 11 each in the north and south spray deck enclosures. The lines routed from the header to the individual lances each have a manual shut off valve and a "Y" filter.

The patented B&W Mark XII atomizer was selected for use in the humidification chamber. Each lance holds five of these nozzles. The nozzles are of the two-fluid type in which water and air are mixed within the nozzle and blow out through orifices to provide the necessary atomization. The lance design places the nozzles inside nacelles to reduce pressure drop and ash build-up. Figure 10 shows a cross-sectional view of a nozzle inside a nacelle. The nozzle was chosen after performance tests showed it to be superior to other commercially available nozzles.

The arrangement of the lances and their numbers, as well as the number of atomizers, was determined by tests described earlier. The reason for the tests was to minimize wetting of the humidifier walls, floor, and ceiling. The lances also had to be placed so that the spray from the atomizers did not impinge on each other and cause coalescence of the spray into larger droplets.

The flow models and tests led to an atomizer array ten across by eleven high. The atomizers were spaced approximately 12 in apart. With five nozzles per lance, a total of 22 lances were necessary for the array. The lances are shaped like an airfoil. Eventually only 20 lances were used, ten on each side, after it was determined that the spray from the lowest row of atomizers could impact some material on the floor of the duct and cause accelerated build-up. Figure 11 shows the layout of the array with dimensions. Figure 12 shows the layout and a more detailed look at a lance.

The lances are hollow and open to the atmosphere outside the chamber. The negative pressure in the chamber causes air to be sucked through the vent and exit openings in the lances surrounding the nozzles. This air is referred to as shield air and serves to keep the atomized water from swirling back and contacting the surface of the lance and the nozzle. Wetting of these surfaces can cause a build-up of LIMB ash.

A reheat system was installed upstream of the stack at the ESP outlet to protect the gunite-lined stack for Unit 4 at the Edgewater Station. The condensing-type steam coil reheater was designed to increase the flue gas temperature 40°F above an anticipated 145°F coming from the humidifier. This was the temperature expected as a result of cooling the flue gas to a 20°F approach to the adiabatic saturation temperature.

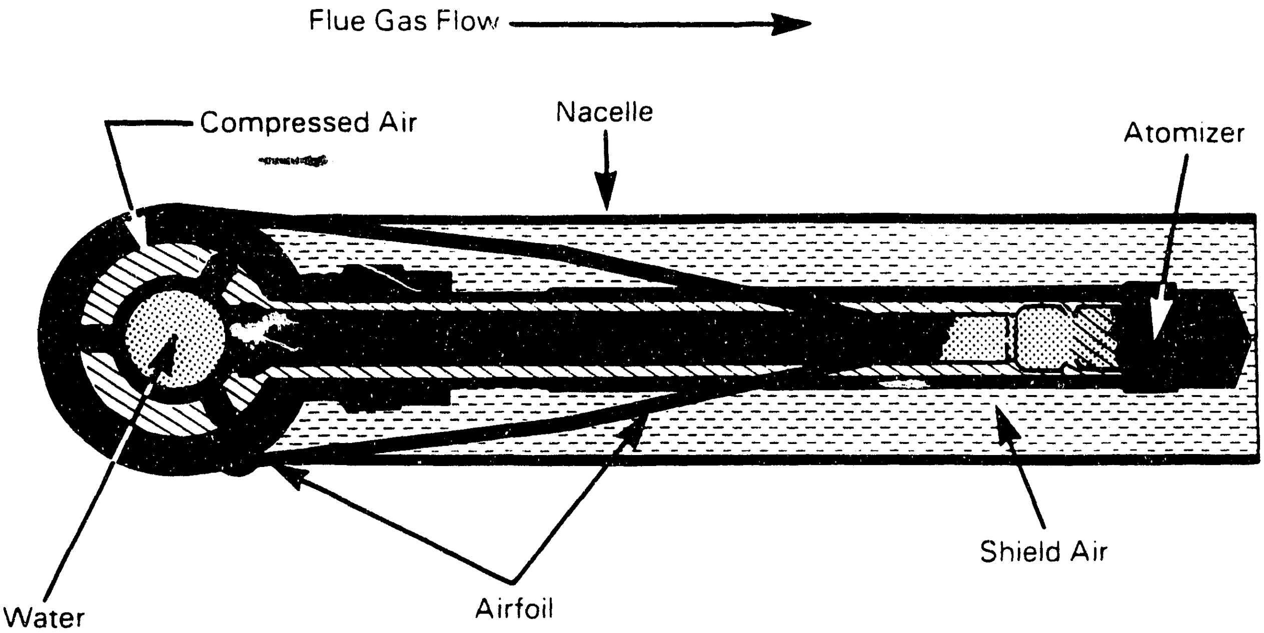


Figure 10. Cross section of atomizer with nacelle

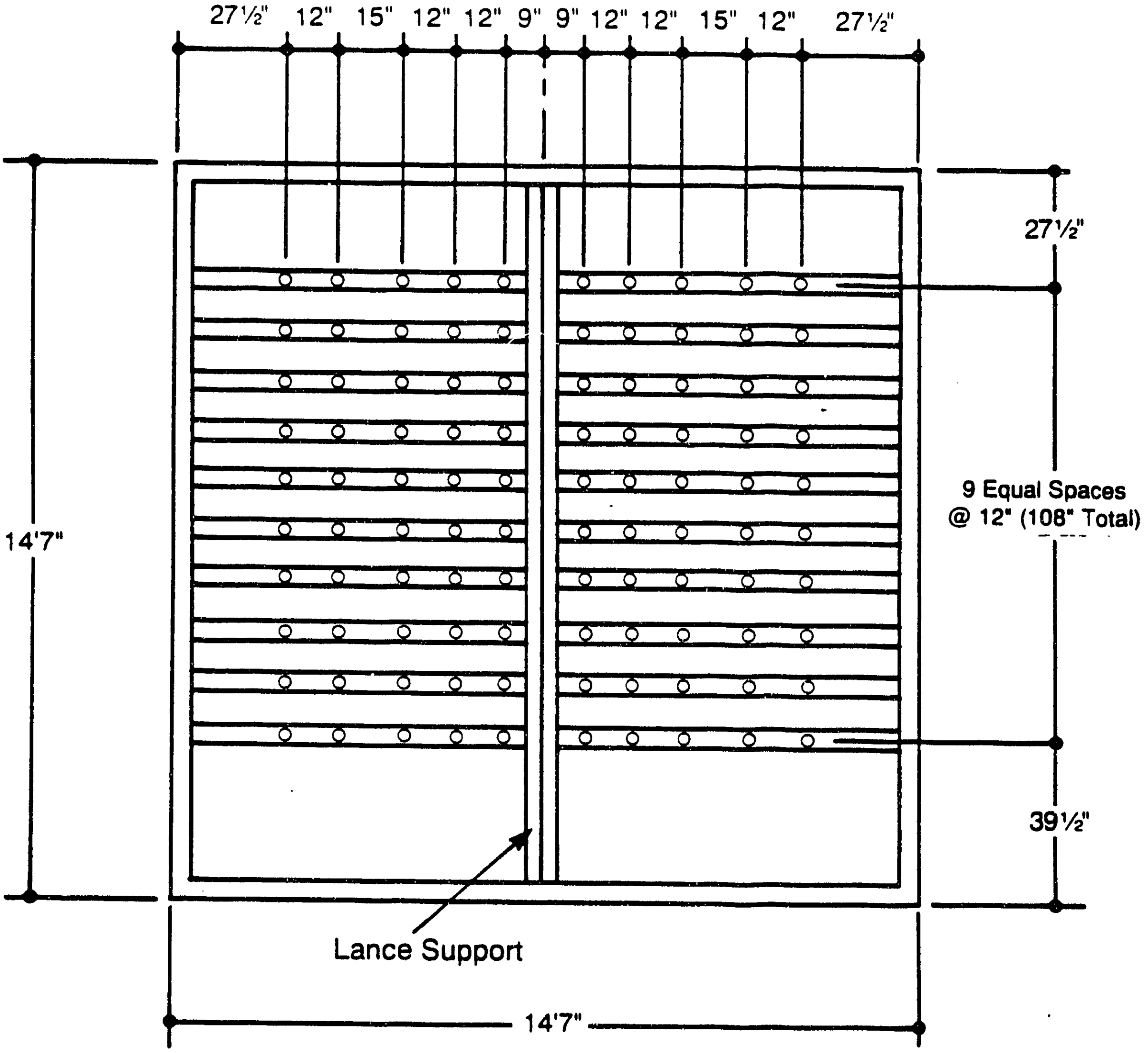


Figure 11. Edgewater Station humidifier atomizer array

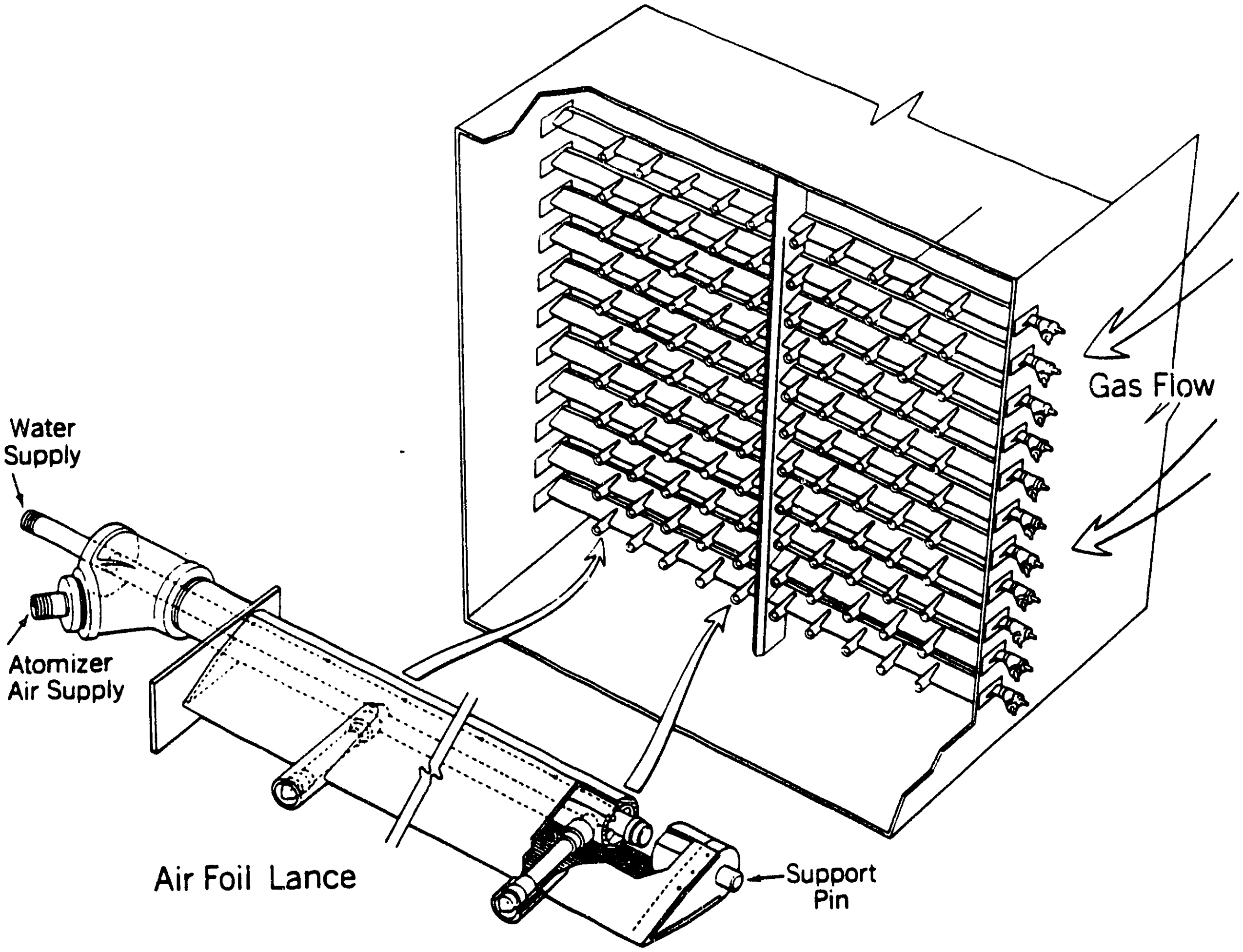


Figure 12. Airfoil lance and atomizer array

Saturated steam, at approximately 1600 psig from the boiler, feeds through a pressure reducing station and a flow control valve. It enters the reheater at 300 psig and 423°F. The reheater consists of four sections which are all independently valved. This allows for removal and maintenance on any of the sections while the others remain in service. Platforms and trolley beams were provided so this work could be performed if necessary.

Ash Removal System

A pneumatic conveying system uses a vacuum created by a hydraulic exhauster to pull ash from the air heater, economizer, and ESP hoppers, and transport it to the Unit 4 ash silo. The ash is separated from the air stream through use of a cyclone separator and a baghouse. The air stream continues to flow to the eductor in the exhauster system. A dust pugger was added to keep the throat of the eductor clear as the LIMB ash tended to build up more quickly than regular fly ash where the air and entrained ash mix with water. The air and water used to create the vacuum mix in the eductor and flow to an air separator. At this point the air is vented and the water flows to the ash settling pond. This water is neutralized with sulfuric acid as necessary to reduce the alkalinity caused by the LIMB ash particles that bypass the separation equipment.

Water is mixed with the LIMB ash in a pug mill under the ash storage silo to condition it for transport and disposal. The ash is fed to the pug mill through a variable speed rotary valve. Aeration pads in the bottom of the ash silo keep the ash flowing into the rotary valve. The rotary valve controls the rate of ash feed into the pug mill. The flow rate of water is also tightly controlled. Enough water is added to slake the free lime component and keep fugitive dust emissions to a minimum. The slaking reaction is exothermic and can result in the generation of voluminous clouds of condensed steam. Extra water is added to compensate for that which evaporates in the process. Adding too much water causes the mixture to turn to a sludge that, given the proper proportions, can harden through a series of cementitious reactions. Lesser quantities of water slow these reactions and also produce an ash with the consistency of a moist dirt that can readily be dumped from the trucks. A diagram of the ash handling system is shown in Figure 13.

The pug mill discharges directly to a dump truck waiting below. The water/quicklime reaction continues and the steam clouds gradually subside after about 10 to 15 minutes in the bed of the truck. The wetted ash is then taken by truck to a landfill. It is noted that even though the

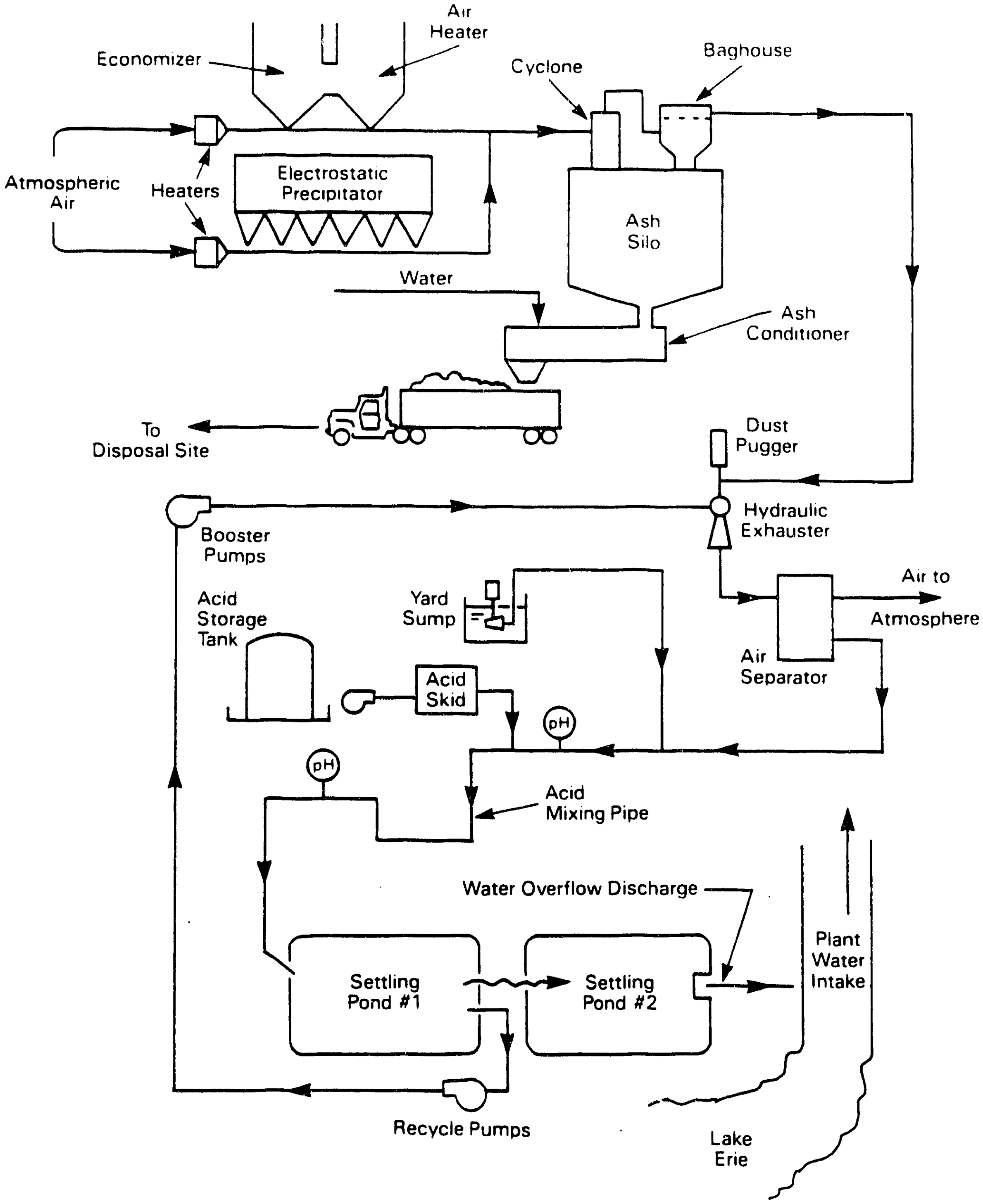


Figure 13. Ash removal and ash pond pH control

steaming subsides, the ash temperature decreases much more slowly than the steaming subsides. Ash temperatures in the truck bed have been measured as high as 260°F, and the main body of ash and any metal truck walls in contact with it will remain very hot for several hours. Ash treated at any given water/quicklime ratio and spread on the ground will cool more quickly, of course, with the rate dependent upon ambient conditions and the area available.

SYSTEM MODIFICATIONS

Sorbent Storage and Transfer System

The speed of the solids pump below the storage silo was increased to raise transfer capacity. This was accomplished by resheaving the V-belt drive. This was necessary because of the relatively low bulk density and fine particle size of the hydrated lime. In addition, the shaker-type baghouse on top of the lime feed silo was replaced with a greater capacity pulse jet unit fitted with Gore-Tex™ bags. This change permitted filling of the silo at the original design rate.

Sorbent Feed System

When the differential weight loss feeders would go into a fill cycle, sorbent would flow into them too rapidly and cause material to flood through. Rotary valves remedied the situation. By adding them at the discharge of the feed silo, the feeders filled in a slower, more controlled fashion.

The differential weight loss feeders were vented to the economizer outlet to minimize the flooding that occurred during fill cycles. The slightly negative pressure at the economizer outlet helped to keep the vent lines clear and reduce flooding.

A vent hopper was added to help relieve pressure in the rotary valves downstream of the feeders. The design of the hopper allowed for any sorbent entrained in the vented air to drop out and return to the valve. The vent hopper itself was vented to the air heater outlet. The slightly negative pressure helped to vent the hopper.

The feed system as it was initially designed used a dense phase air system to convey the sorbent from the pickup point below the rotary valve. Dilute phase air was then mixed in and used to convey the sorbent to the distribution bottle through a 2.5 in pipe. This method of conveyance created too much back pressure on the rotary valves. The high back pressure forced conveying air up through the valves and fluidized the sorbent entering the valve pocket which in turn reduced capacity. The dense phase system was eliminated and the 2.5 in pipe was changed to a 4 in ID hose. The removal of the dense phase conveying system eliminated all of the piping, valves, and transmitters associated with that part of the system.

A solids pump was added to replace one of the rotary valves. System capacity was difficult to maintain without repeated adjustment of the seals in the rotary valves. The installation of the solids pump ensured steady, reliable sorbent feed with only a fraction of the maintenance.

The inlet piping to the distribution bottles was increased to 4 in diameter to accommodate the 4 in ID hose installed to replace the original 2.5 in pipe. The lines from the distribution bottle feeding the 181 ft injection level nozzles were changed to 2 in ID from 1.25 in. The inner pipe in the nozzles on this level were changed from 2 in ID from 1.5 in.

Humidifier

The ten across by eleven high array of atomizing nozzles was changed to a ten by ten by removing the bottom lances on both the north and south sides. It was found that the spray from the bottom row was impinging on the floor and causing a build-up of ash. The remaining lances were changed to the design using nacelles for vent air to reduce the accumulation of ash on the nozzles. The lances were hollow and open to atmosphere outside the duct. The negative pressure in the duct pulls air past the nozzles and helps to reduce deposits on the atomizer tips. These changes led to improved humidifier performance.

Ash Removal System

The bags in the pulse jet bag filter on top of the ash silo were initially made of felt. These were replaced by Gore-Tex™ bags which handled the fine LIMB ash particles more efficiently.

pH Control

The yard sump in the ash unloading and storage silo area was rerouted to the neutralization equipment. This allowed water from wash-down in the unloading area to be treated before entering the ash pond. The area drains to a sump that collects water used to clean up yard spills.

A second pH probe was added to improve neutralization control. A length of polyvinyl chloride (PVC) pipe was added after the acid injection point. This acted as a mixing chamber so the acid and water would be thoroughly mixed before reaching the ash pond. The second pH probe confirmed that the water had been properly neutralized.

SECTION 5
TESTING

DATA ACQUISITION AND REDUCTION

Because the Clean Air Act and its amendments have historically emphasized the control of SO_2 emissions, the focal point of the LIMB Extension tests was the demonstration of the SO_2 removal capabilities of the sorbent injection process. While important in the overall view, emissions of NO_x and particulate receive less attention for additional reasons. First, NO_x emission control in LIMB was essentially set by the design parameters developed for the DRB-XCL™ burner before and during the original LIMB demonstration. While the LIMB Extension provided an opportunity to explore some possible causes of variations seen in the course of that project, data was obtained more passively as the conditions changed during normal boiler operation, rather than through a rigorous series of parametric tests.

The reasons for reduced emphasis on particulate emissions are twofold. The first is that ESP technology is regarded as a mature technology for which the effects of changing the independent variables are well established. The second is that the costs of conducting tests over the longer periods of time required to obtain steady-state conditions needed became prohibitive. One to two weeks at each test condition would have been necessary to develop truly meaningful data on particulate emission control. The benefits of conducting tests with much more frequent change in injection stoichiometry, and doing so over the range of boiler load, were regarded as having greater value. Continuous opacity data was considered to be a reasonable alternative as an indicator of the general impact of the technology on particulate emissions.

Performance of the total system -- boiler, sorbent injection system, and Radian Corporation's Continuous Emission Monitoring System (CEMS) -- was monitored by the B&W Boiler Performance Diagnostics System 140™. Since the data presented in this report were taken from the output of this device, the following describes how the data were collected and handled by the System 140™. As part of the original EPA LIMB project, this computerized data acquisition system was expanded beyond its normal boiler performance function to a customized device capable of monitoring the additional equipment and analyzers associated with the LIMB technology. It was also programmed to perform a variety of calculations specific to the technology, such as Ca/S stoichiometry, as well as to reduce the data from the CEMS according to EPA-accepted procedures.

The input data for the System 140™ consisted of approximately 700 temperature, pressure, flow, and gas concentration signals that were automatically read once a minute, together with manually entered coal, sorbent, and ash analyses that were updated as necessary. The system also accepted humidifier and pulverizer data, as well as ESP voltages and currents. Thus, the System 140™ served as the primary data recording device for the project. Extensive quality assurance/quality control measures begun during the original LIMB Demonstration were continued throughout the project and are summarized in Appendix C.

As each set of readings was taken, the System 140™ performed about 600 calculations that may be grouped into categories related to boiler performance, boiler cleanliness factors, sorbent injection parameters, humidification parameters, and emission data. Appropriate equations were incorporated to account for differences in sorbent chemistry. As time progressed, ten minute rolling averages of the input and calculated data were calculated for display in data lists and/or 2, 8, 24, or 168 hour trend charts as appropriate. In many cases the most recent individual input data were similarly displayed. In addition, hard copies of the data lists and trend charts were obtained as needed.

The System 140™ also performed several other functions associated with on-line error analysis, the redetermination of the LIMB system's performance based upon recalculation of the stored ten minute averages with updated, ultimate coal and sorbent analyses received several days after the fact, and x-y plotting of trended values. The recalculation feature was included such that the ultimate coal analyses could be entered at a later date when the analysis was complete.

The calculations of particular importance were those associated with the determination of coal firing rate and "inlet" SO_2, sorbent injection rate, and SO_2 emissions. These are described individually in the following paragraphs.

Coal Firing Rate and "Inlet" SO_2

It was decided early in the EPA project that the coal feeders at the Edgewater Station were of a type and vintage that would not readily provide the desired accuracy in feed rate. The determination of coal firing rate by the System 140™ was considered to be more reliable in that it calculates the rate based on the coal analysis and a series of heat and material balances derived from the temperatures, pressures, and flows measured throughout the boiler. While the exact equations within the System 140™ are derived from the original design of the Edgewater boiler and are considered proprietary, the pertinent portions here are quite similar to ASME PTC4.1 (American Society of Mechanical Engineers Performance Test Code), ASME Heat Loss Method, a standard calculation of boiler efficiency in which fuel rate is also determined. The product of the coal firing rate and the sulfur content of the coal is the basis for the sulfur term in the Ca/S stoichiometric ratio. The ratio of coal sulfur to its as-fired, high heating value (HHV) allows calculation of the "inlet" SO_2 on a lb/10^6 Btu basis according to the equation:

$$\text{Inlet } SO_2\text{, lb}/10^6\text{ Btu} = \frac{(\text{Coal S [wt \%], lb})\ (1\times10^6\text{ Btu}/10^6\text{ Btu})\ (64.062\text{ lb } SO_2)}{(100\text{ lb Coal})\ (\text{HHV, Btu/lb coal})\ (32.064\text{ lb S})}$$

Sorbent Injection Rate

Sorbent was fed from either of two Acrison differential weight loss feeders to any two of three elevations in the upper furnace. The feed rates output from the two feeders were summed by the System 140™ to give the total sorbent injection rate. The product of this value and the calcium content of the lime or limestone determined by analysis was the basis for the calcium term in the molar Ca/S stoichiometric ratio calculated as:

$$\text{Ca/S} = \frac{(\text{Sorbent, lb/hr})\ (\text{Sorbent } Ca(OH)_2\text{ [wt \%], lb})\ (32.064\text{ lb/lb mol S})\ (100\text{ lb Coal})}{(\text{Coal, lb/hr})\ (\text{Coal S [wt \%], lb})\ (74.1\text{ lb/lb mol } Ca(OH)_2)\ (100\text{ lb Sorbent})}$$

[This equation is for hydrated calcitic lime. Equivalent equations were used for the other sorbents.]

SO_2 and NO_x Emissions

Radian Corporation's CEMS continuously analyzed several gases in the duct between the ID fan, following the ESP, and the stack. The sampling point was confirmed to be a representative location according to EPA quality criteria.[18] Figure 14 shows the extractive system used. The analyzers were calibrated daily, excluding weekends and holidays. Calibration gases entered the system just downstream of the inlet filter in the ESP outlet duct. This verified the operation of the system in addition to confirming that there was no appreciable capture of SO_2 in the sampling system. The inlet filter itself was maintained at approximately 300°F, a temperature high enough to assure that no significant SO_2 removal occurred there as well. Heated sample lines carried the gas to a conditioner which removed moisture by condensing it. The dry gas then passed from the conditioner through a manifold which routed samples to each of the analyzers. The gases monitored continuously included SO_2, NO_x, O_2 (oxygen), CO_2, (carbon dioxide), and CO (carbon monoxide). Total hydrocarbons were also monitored early in the EPA project, but were found to be at or below detection limits over the course of several months. For this reason, use of this monitor was discontinued.

Most pertinently, SO_2 and NO_x (each parts per million by volume [ppmv]) and O_2 (vol %) values were read every minute by the System 140™. The SO_2 and NO_x concentrations were then converted to a lb/10^6 Btu basis using the standard "F-factor" equation and the measured O_2 concentration to correct for dilution. The difference between this outlet SO_2 value and the "inlet" value described earlier represented the removal which, when divided by the "inlet" SO_2, gave rise to the removal efficiency calculated by the System 140™, using the most recent ten minute rolling average values at any point in time. The equations used in the calculations were:

F_d, Dry Standard Cubic Feet (dscf) Flue Gas/10^6 Btu =

$$\left(\frac{1\times10^6\ \text{Btu}}{10^6\ \text{Btu}}\right)\left\{\frac{(3.64 \times H) + (1.53 \times C) + (0.57 \times S) + (0.14 \times N) - 0.46\ O)\ \text{dscf Flue Gas/lb Coal}}{\text{Coal HHV, Btu/lb}}\right\}$$

where H, C, S, N, and O are the weight percentages of these elements and HHV is the high heating value of the coal on an "as received" basis.

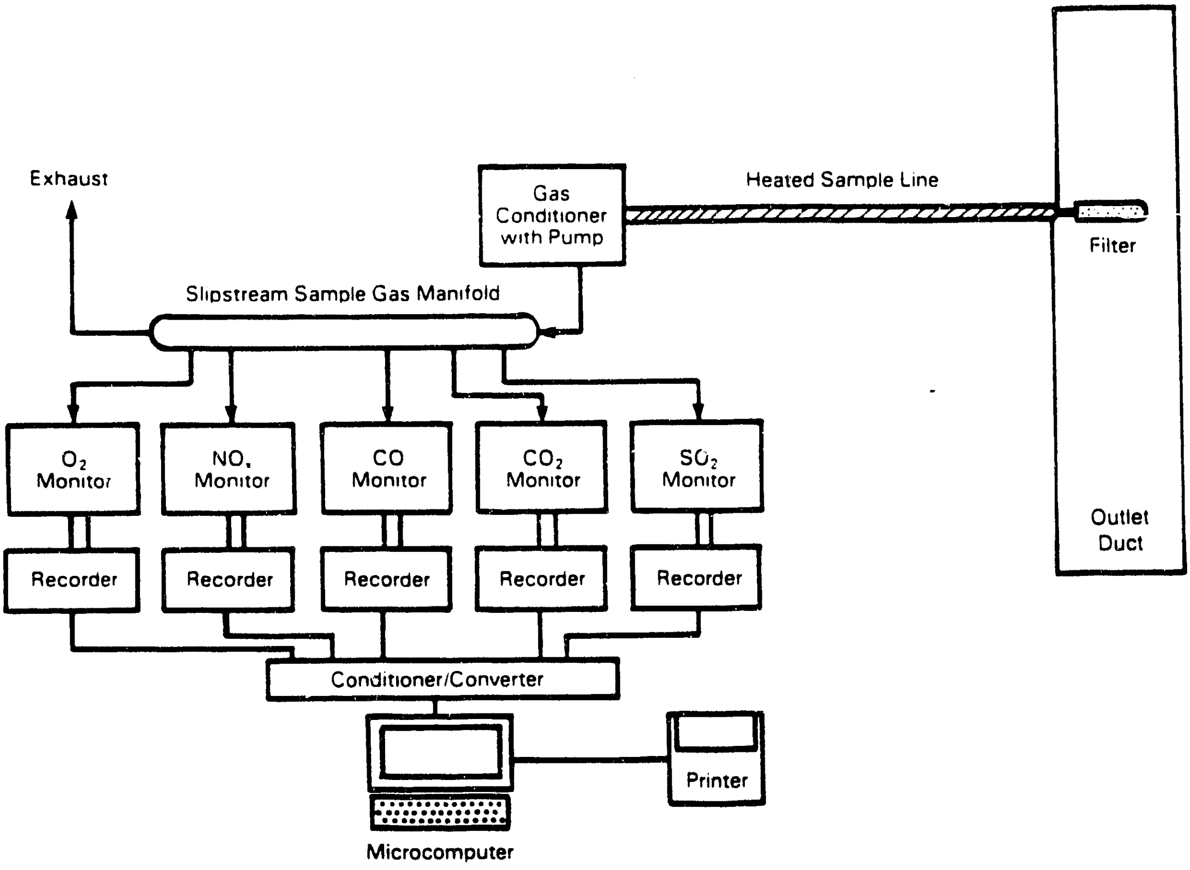


Figure 14. CEMS sample acquisition system

Outlet SO_2, lb/10^6 Btu =

$$(SO_2,\ \text{ppmv dry})\ \left(\frac{20.9\ \text{vol}\ \%\ O_2}{20.9 - O_2}\right)\ (F_d,\ \text{dscf}/10^6\ \text{Btu})\ (1.66\times10^{-7}\ \text{lb}\ SO_2/(\text{ppmv dscf}))$$

where O_2 is the volume percentage of oxygen in the flue gas measured at the same location where the corresponding SO_2 concentration (ppmv) is determined. All outlet gas concentrations were determined on a dry basis at the stack, and on a wet basis elsewhere (individual O_2 at the economizer outlet, air heater outlet, and humidifier inlet and outlet; SO_2, CO_2, and H_2O at the humidifier inlet/outlet where a dilution probe sampling and analytical system alternated between inlet and outlet sample gas. When appropriate for further calculations, gas concentrations measured on a wet basis were corrected to a dry basis, as for example:

$$SO_2,\ \text{ppmv dry} = (SO_2,\ \text{ppmv wet})\ \left(\frac{100\ \%}{100 - H_2O,\ \text{vol}\ \%}\right)$$

where H_2O is the volume percentage of water assumed or measured at the sample location.

Similarly,

Outlet NO_x as NO_2, lb/10^6 Btu =

$$(NO_x,\ \text{ppmv dry})\ \left(\frac{20.9\ \text{vol}\ \%\ O_2}{20.9 - O_2}\right)\ (F_d,\ \text{dscf}/10^6\ \text{Btu})\ (1.194\times10^{-7}\ \text{lb}\ NO_2/(\text{ppmv dscf}))$$

The SO_2 removal efficiency is then given by:

$$SO_2\ \text{Removal Efficiency, \%} = (100\ \%)\ \frac{(\text{Inlet}\ SO_2 - \text{Outlet}\ SO_2,\ \text{lb}/10^6\ \text{Btu})}{\text{Inlet}\ SO_2,\ \text{lb}/10^6\ \text{Btu}}$$

TEST CONDITIONS

Since the high temperatures in the furnace precluded the continuous measurement of the "inlet" SO_2 concentration, tracking of coal quality was of paramount importance during all sorbent injection tests. This began with "truck" and "bunker" samples collected and analyzed by Ohio Edison as part of their normal analytical procedures. These analyses, available approximately a week after the samples were collected, were generally used to assure that the coal quality of individual suppliers was generally within the desired tolerance, and occasionally to explain otherwise anomalous variations. In accordance with Ohio Edison's statistically designed sampling program, the truck samples were collected with a sampling auger and the bunker samples with a cross-cut coal stream sampler.

In order to have as invariant a composition as possible, Ohio Edison unloaded trucks at the rear of the coal pile and then bulldozed the coal forward through the pile. This tended to blend the coals together and lowered the variability of the coal loaded to the bunker. This lower variability is manifested in the lower standard deviations in the analyses of the bunker samples.

The coal analyses input into the System 140™ were based on the ultimate analyses of coal samples automatically collected from the pipes exiting each of the four pulverizers at Edgewater. The samples were generally obtained daily through the 5-day work week. Composite samples were sent to CTECo for the ultimate analyses, while 4 to 6 samples were typically analyzed with the on-site Leco sulfur analyzer periodically throughout test days. The Leco sulfur analysis, available within 30 to 45 min of sample collection, provided as close as possible a "real time" measure of the adequacy of the coal sulfur value being used in the System 140™, and of the variability of the sulfur during test periods. A significant change in this value would invalidate the period as a test.

The lower sulfur content found in the ultimate and Leco analyses, as compared to the bunker analyses, is believed to be due to the removal of pyritic sulfur in the "pyrite traps" built into the design of the coal pulverizers. No credit was taken for this sulfur removal, however, since the calculations were all performed on an "as-fired" basis. ("Inlet" SO_2 values were obtained from the SO_2 concentrations resulting from the coal actually burned).

Before a test could begin, a "baseline" or "zero" SO_2 removal efficiency for the system had to be established when no sorbent was being injected. This was accomplished by adjusting the value of the sulfur content of the coal analysis input to the System 140™. The removal efficiency, calculated as shown earlier in this section, had to remain steady near zero (typically within ±3% for 30 to 60 min) before a test could begin. This manipulation of the coal sulfur concentration was necessary to keep the System 140™ data base current with the coal being fired. By adjusting the sulfur concentration of the current coal analysis to force the removal to zero, the "inlet" SO_2 concentration was effectively being changed to make it agree with the measured outlet SO_2 concentration. This not only served to "zero" the system SO_2 removal, but also kept the coal analysis current with the coal being fired.

After the "zero baseline" SO_2 removal had been achieved, sorbent injection began. The desired Ca/S ratio was input into the control system and the injection equipment started. Visual inspection verified sorbent flow through all of the injection nozzles.

The system SO_2 removal would begin to climb immediately upon introduction of sorbent into the furnace, and after some length of time, level out. This usually required about one half hour. Sorbent injection would continue at the desired stoichiometry until the removal efficiency remained at a near constant level for at least a half hour, the minimum time considered acceptable for a test. (The average duration of the 223 tests conducted during the project was 134 min, with individual tests ranging from 30 to 710 min.) In addition to the uniformity and constancy of Leco coal sulfur, sorbent feed, and SO_2 removal, valid tests required that boiler operation remain constant as well. Thus, parameters such as load, coal flow, steam flow, and flue gas oxygen concentration (combustion air) likewise had to remain steady at the desired values throughout the test period.

The demonstration of system operability during non-test periods was also an important facet of the project, with unit load being the key parameter to which the LIMB control system responded. Thus, while performance was characterized during test conditions, reactions to unintended upsets such as pulverizer trips, as well as to such intentional ones as load changes, were just as much real "tests" of the technology. While steady-state performance data were, by definition, impossible during such incidents, LIMB system operability was shown almost always to be responsive with as rapid a proportional change in sorbent feed as the change that prompted it. The same was generally true for the humidifier as the water flow would change to accommodate changes in gas flow. Had it not, large deposits would have formed quickly given the fact that the unit's general pattern of operation carried it to full load during the day and minimum load (approximately 33 percent of full load) at night.

Finally, the DRB-XCL™ burners originally installed as part of the EPA LIMB project continued to function well throughout the LIMB Extension and produced overall NO_x emissions slightly lower than those seen during the earlier project. In this sense, the data collected over the whole range of boiler operating conditions can be thought of as constituting the "tests" of the low NO_x burner technology.

EXAMPLE OF A TEST

This section discusses one test period in detail to provide the reader with a more concrete example of how the data was acquired and reduced. The CEMS stripchart recorder trace for LIMB Extension test LE-85 is shown in Figure 15. The test is also identified as DL87-85 which indicates the injection of dolomitic lime at the 187 ft elevation. As can be seen, the SO_2 concentration remains constant until just after sorbent injection begins at 10:24. It rapidly drops about 35 percent, and then begins to level off at about 40 percent removal 30 to 40 min after sorbent was first injected. Test data are collected for about 5.5 hr, whereupon the sorbent feeder hoppers and lines are emptied. With all feed off by 17:00, the SO_2 concentration slowly returns toward its baseline level. The return to baseline is slow as residual, unreacted lime spread throughout the boiler is either purged or continues to react at reduced rate until it is consumed. The time required for this varied among the tests from about one to four hours depending to a large extent on the load and the operators' preferences in sootblowing. For this test, the return took about 1.5 hr.

In order to facilitate data reduction, selected 10 min average data collected in the System 140™ were routinely downloaded onto a floppy disk in a spreadsheet format. These data were then used to calculate average values either for relatively short, individual test periods in the case of SO_2 removal, or accumulated over a period of months for characterizing long term NO_x emissions. Table 1 shows some of the selected data copied to the floppy disk, to which notes have been added indicating exactly which data were used to define the "zero" baseline and average SO_2 removal efficiency of test LE-85 (DL87-85).

Analyzer calibrations, followed by any necessary adjustment of the coal sulfur, typically preceded each test. For test LE-85, the 07:15 Leco coal sulfur measurement had been 1.66 percent, quite close to the 1.56 later measured for the 14:00 sample, and to the 1.59 and 1.55 percentages measured on the daily composite samples analyzed on-site and by CTECo,

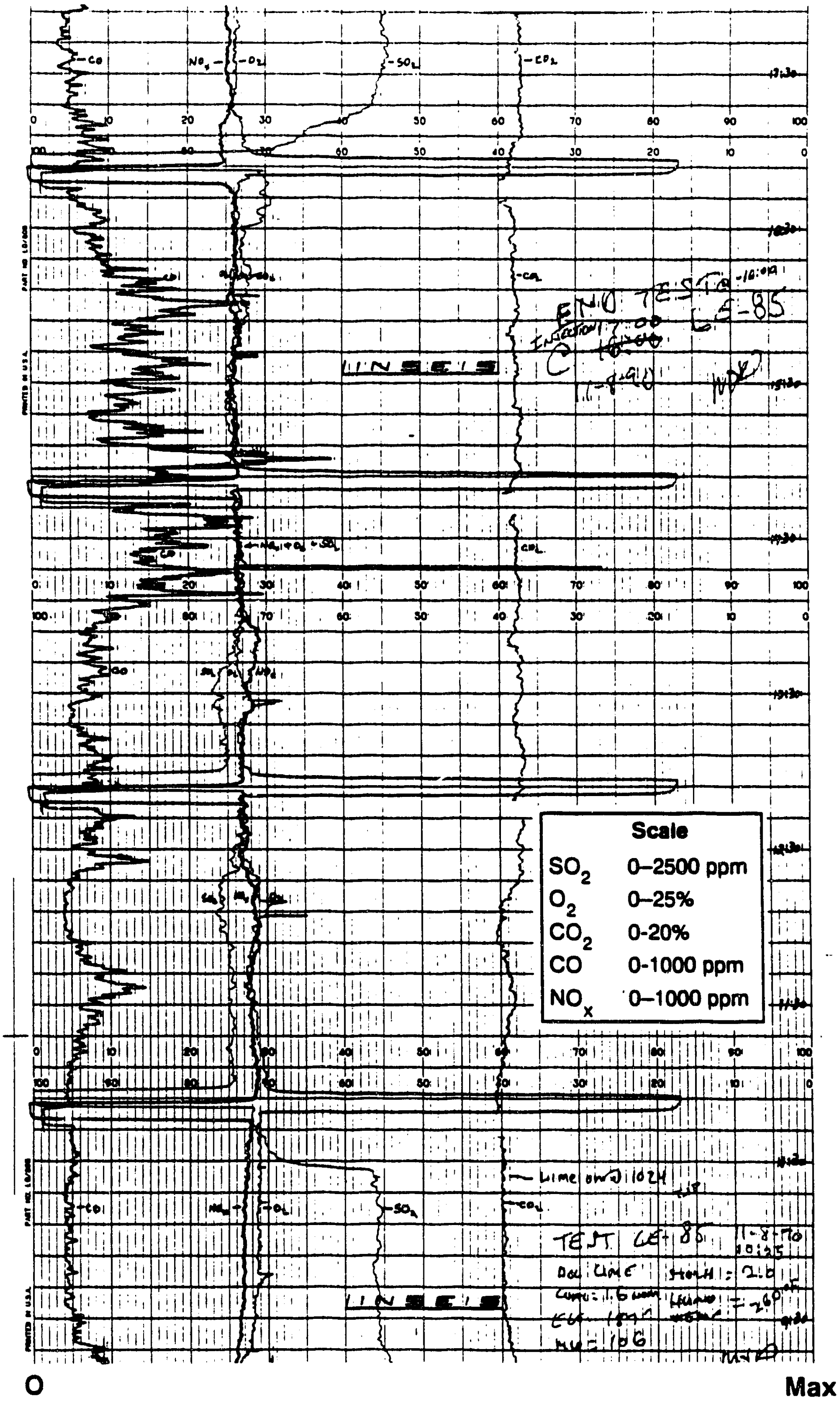


Figure 15. Typical CEMS trace during a test

TABLE 1. SELECTED TYPICAL DATA FROM A TEST PERIOD

Test	Time on 11/8/90	Ca/S Ratio	SO_2 Removal %	Outlet SO_2 $\frac{lb}{10^6\ Btu}$	Outlet NO_x $\frac{lb}{10^6\ Btu}$	Coal Firing Rate lb/hr x 10^{-3}	Main Steam Flow lb/hr x 10^{-3}	Gross Unit Load MWe	Lime Feed Rate lb/hr	Calc. Temp. at Nose °F	Flue Gas Leaving Furnace lb/hr x 10^{-3}	Humidifier Outlet Gas Temp. °F
	09:03:14		-4.239	2.743	0.4001	61.90	505.9	70.1		1970	772.7	261.3
	09:14:44		-5.273	2.749	0.4394	87.13	738.4	102.7		2293	946.8	293.1
	09:25:23		-3.592	2.703	0.4728	87.78	743.7	104.2		2262	990.1	281.7
	09:35:24		-3.768	2.706	0.4859	88.48	750.6	104.5		2255	1024.0	279.1
	09:45:24		-4.211	2.717	0.4951	88.05	745.2	104.7		2239	1020.0	277.8
Zero	09:55:24		-0.705	2.730	0.4954	90.07	762.3	104.6		2260	1036.0	277.2
Zero	10:05:25		-0.979	2.738	0.5001	88.63	747.7	104.6		2267	1017.0	276.7
Zero	10:15:25		-0.783	2.733	0.4988	87.86	741.9	104.2		2254	1011.0	276.6
	10:25:25	1.064	-0.402	2.721	0.5043	89.70	753.7	104.2	6873	2261	1041.0	270.0
	10:35:25	1.921	28.58	1.936	0.5098	88.63	748.4	103.4	9847	2249	1024.0	263.7
	10:45:25	1.985	35.66	1.744	0.5134	88.37	750.8	103.7	10101	2250	1021.0	261.6
	10:55:25					88.06	749.9	103.5	9977	2238	1054.0	258.7
DL87-85	11:05:25	1.975	41.07	1.597	0.5159	87.56	745.1	103.2	9932	2235	1026.0	257.2
DL87-85	11:15:25	1.973	42.21	1.566	0.5319	87.94	750.9	102.6	9963	2229	1025.0	256.0
DL87-85	11:25:25	1.960	41.65	1.582	0.5194	88.01	750.1	102.9	9912	2243	1016.0	256.1
DL87-85	11:35:26	1.963	43.05	1.544	0.5117	87.54	748.2	102.6	9865	2242	1006.0	256.2
DL87-85	11:45:27	1.985	43.31	1.538	0.4985	87.08	745.8	102.4	9923	2273	987.2	255.0
DL87-85	11:55:27	1.958	43.45	1.534	0.5162	87.14	745.8	102.5	9809	2232	1006.0	254.4
DL87-85	12:05:27	1.993	45.07	1.489	0.5306	87.49	746.2	102.1	9945	2187	1062.0	255.3
DL87-85	12:15:27	1.928	44.32	1.509	0.5304	88.53	760.3	101.3	9763	2125	1076.0	255.0
DL87-85	12:25:27	1.920	42.32	1.564	0.5091	87.54	752.5	101.9	9702	2158	1038.0	254.9
DL87-85	12:35:27	1.925	41.92	1.576	0.4790	89.92	765.8	103.6	9959	2207	1032.0	255.8
DL87-85	12:45:27	1.892	41.05	1.597	0.4874	90.99	765.6	103.1	9949	2218	1055.0	255.7
DL87-85	12:55:27					87.85	752.5	102.5	9912	2182	1021.0	255.8
DL87-85	13:05:27	1.985	43.44	1.533	0.4936	87.75	746.0	103.2	10023	2228	997.3	254.3
DL87-85	13:15:28	1.973	46.23	1.459	0.4772	87.87	753.2	102.7	10023	2211	994.7	254.3
DL87-85	13:25:28	1.933	46.87	1.441	0.4884	88.30	759.4	101.6	9831	2180	1016.0	254.6
DL87-85	13:35:28	1.943	47.81	1.415	0.5032	89.92	772.3	104.1	10052	2182	1050.0	256.0
DL87-85	13:45:28	1.913	45.41	1.479	0.4956	92.28	785.9	106.4	10128	2237	1061.0	256.7
DL87-85	13:55:28	1.897	42.07	1.570	0.5026	93.16	779.9	105.8	10180	2239	1071.0	257.1
DL87-85	14:05:28	1.932	40.72	1.607	0.4961	89.98	769.3	103.4	9972	2246	1027.0	255.8
DL87-85	14:15:28	1.958	41.27	1.593	0.4766	88.91	760.1	103.0	10270	2252	993.0	255.2
DL87-85	14:25:29	1.967	41.60	1.585	0.4624	88.48	753.9	103.3	10017	2260	988.8	254.6

continued

TABLE 1. (continued).

Test	Time on 11/8/90	Ca/S Ratio	SO_2 Removal %	Outlet SO_2 $\frac{lb}{10^6 Btu}$	Outlet NO_x $\frac{lb}{10^6 Btu}$	Coal Firing Rate lb/hr x 10^{-3}	Main Steam Flow lb/hr x 10^{-3}	Gross Unit Load MWe	Lime Feed Rate lb/hr	Calc. Temp. at Nose °F	Flue Gas Leaving Furnace lb/hr x 10^{-3}	Humidifier Outlet Gas Temp. °F
DL87-85	14:35:29	1.970	42.51	1.560	0.4677	87.92	750.9	103.0	9914	2254	981.6	254.7
DL87-85	14:45:29	1.960	43.10	1.544	0.4612	88.28	755.7	102.7	10215	2273	983.2	255.7
DL87-85	14:55:29					87.44	748.7	102.6	10002	2156	1083.0	256.1
DL87-85	15:05:29	1.940	43.67	1.528	0.4475	88.28	756.7	102.6	9964	2260	987.6	256.0
DL87-85	15:15:29	2.012	44.85	1.496	0.4639	88.75	763.2	102.1	10095	2142	1070.0	256.5
DL87-85	15:25:29	1.921	45.59	1.476	0.4586	88.79	764.4	102.1	9784	2187	1016.0	255.8
DL87-85	15:35:29	1.959	44.60	1.503	0.4480	88.44	761.4	102.2	9947	2191	1008.0	255.5
DL87-85	15:45:31	1.926	42.81	1.551	0.4588	89.55	762.3	104.3	10019	2115	1097.0	256.4
DL87-85	15:55:31	1.911	40.96	1.601	0.4699	90.75	762.8	103.0	9884	2211	1032.0	257.5
DL87-85	16:05:31	1.943	40.59	1.611	0.4544	89.65	755.7	103.7	10039	2239	1017.0	256.3
DL87-85	16:15:32	1.959	39.72	1.636	0.4498	88.69	761.4	102.3	9996	2219	999.4	256.7
DL87-85	16:25:33	1.945	41.56	1.586	0.4590	88.34	755.7	103.4	9848	2154	1067.0	256.3
	16:35:34	1.411	37.19	1.704	0.4567	88.42	760.6	102.4	6857	2111	1109.0	256.5
	16:45:34	1.328	35.43	1.752	0.4582	88.48	761.7	102.0	6584	2117	1077.0	256.4
	16:55:35					84.04	718.0	94.3	6209	2125	1014.0	255.2
	17:05:36	0.877	22.33	2.109	0.4177	81.63	698.9	94.6	3408	2173	936.0	255.5
	17:15:36		11.73	2.398	0.4293	83.86	701.2	97.1		2201	964.7	255.0
	17:25:36		4.324	2.601	0.4489	83.14	699.6	96.3		2174	978.5	254.5
	17:35:36		1.388	2.682	0.4469	81.92	689.8	96.6		2200	961.8	254.0
	17:45:36		0.909	2.695	0.4432	82.58	703.1	96.5		2178	974.2	254.0
	17:55:36		1.066	2.690	0.4446	82.67	701.2	96.2		2167	977.3	255.2
	18:05:36		-0.304	2.728	0.4485	82.36	699.6	96.4		2204	959.7	256.0
	18:15:36		-0.941	2.744	0.4426	83.91	706.3	96.9		2187	987.6	256.6
	18:25:36		-2.130	2.777	0.4457	82.99	698.3	97.1		2224	954.1	256.3
	18:35:36		-2.288	2.782	0.4422	82.53	697.7	96.9		2224	941.9	256.2
	18:45:36		-2.369	2.785	0.4318	82.37	700.7	96.7		2216	921.8	256.2
	18:55:36					83.07	702.9	95.9		2191	954.7	257.1
	19:05:36		-2.220	2.780	0.4152	82.10	697.6	96.6		2268	902.0	257.7
Zero: Average			-0.82	2.73	0.50	88.9	751	104.5		2260	1021	276.8
2 x Standard Deviation			0.23	0.01	0.00	1.8	17	0.4		11	21	0.5
DL87-85: Average		1.95	43.06	1.64	0.49	88.8	757	103.0	5042	2211	1026	255.7
2 x Standard Deviation		0.06	3.93	0.11	0.05	2.8	19	2.1	148	84	63	1.7

respectively. Just before the test, the coal sulfur used in the System 140™ was changed from 1.49 to 1.55 percent, resulting in the change in calculated SO_2 removal between the 09:45 and 09:55 updates in Table 1. (In the table, breaks in the emission-related data every two hours correspond to values disregarded during purge of condensed water from the CEMS gas conditioner. Momentary introduction of air for these purges gives rise to the large spikes in Figure 15.)

SO_2 removal efficiency remains near zero for the three updates before sorbent injection begins. By the 10:25 update, both feeder A and feeder B are showing flow. The removal efficiency rises rapidly at first, and then more slowly after 10:45. Beginning with the 11:05 average, it levels off in the 40 to 48 percent range for the following 330 min. After the test, sorbent injection slows during hopper and line purging (16:35 to 17:05). With the feed shut off, SO_2 removal returns to near zero by 18:05.

The 33 ten minute updates are then used to produce a test average 43.88 ± 3.93 percent SO_2 removal (corrected for the -0.82 percent "zero") at a 1.95 ± 0.06 Ca/S ratio. The variabilities correspond to twice the standard deviations and represent a 95 percent confidence level. The compilation of test data in this way then forms the basis for the discussion in the emissions results section to follow.

SO_2 REMOVAL TEST CONDITIONS

The primary variables studied during the LIMB Extension test period were sorbent type and sulfur content of the coal burned. Other independent variables were stoichiometry, humidifier outlet temperature (approach to saturation), and the sorbent injection level.

The project was designed to demonstrate the SO_2 removal efficiency of four sorbents: calcitic limestone ($CaCO_3$), type-N atmospherically hydrated dolomitic lime [$Ca(OH)_2 \cdot MgO$], and calcitic hydrated lime [$Ca(OH)_2$], both alone and with added calcium lignosulfonate (hereafter called ligno lime). The testing was conducted over a range of calcium/sulfur molar ratios (Ca/S) and humidification conditions, while burning Ohio coals with nominal sulfur contents of 1.6, 3.0, and 3.8 percent by weight. A chronological summary of the various facets of the LIMB Extension test program is shown in Table 2.

TABLE 2. CHRONOLOGICAL SUMMARY OF LIMB TESTING

	Nominal Coal Sulfur, wt%		
Sorbent	1.6	3.0	3.8
Commercial Calcitic Hydrated Lime	7/91-8/91	9/87[*], 11/88-6/89[*]	7/91
Ligno Lime	2/91-4/91, 5/91-6/91	9/87[*], 4/89[*], 5/89[*], 4/90-5/90	4/91-5/91
Dolomitic Hydrated Lime	7/90-10/90, 11/90, 12/90	10/90, 11/90	12/90,2/91
Limestone (90% < 44μm)	6/90-7/90	5/90-6/90	NT[†]
Limestone (100% < 44μm)	1/91[‡]	NP[**]	NP
Limestone (100% < 10μm)	1/91[‡]	NP	NP

[*] Testing took place during the EPA-sponsored project.

[†] NT = Not tested due to projected difficulty in maintaining compliance with the plant's emission limit of 3.4 lb/10^6 Btu.

[‡] Not planned, but attempted when lower than expected SO_2 removal was obtained with more coarse material.

[**] NP = Not planned.

The coal/sorbent combinations of 3.0 percent sulfur coal with calcitic hydrated lime and ligno lime, demonstrated during the EPA-sponsored program, were not repeated. The 3.0 percent sulfur coal/ligno lime combination was used to verify equivalent system operation, however. This took place following the conversion of equipment back to a furnace injection configuration after the Coolside duct injection tests were complete. The coal/sorbent combination of 3.8 percent sulfur/limestone was not tested. Results with the two lower sulfur coals indicated that compliance with the plant's 30-day rolling average emission limit of 3.4 lb SO_2 /10^6 Btu could not be maintained while testing this combination. Two more finely ground calcitic limestones were tested while burning nominal 1.6 percent sulfur coal. This was done because the more coarse material originally used resulted in unexpectedly low SO_2 removal (discussed in more detail in the next section).

For the coals used during the demonstration, the flue gas saturation temperature was approximately 125°F. Minimal humidification of the flue gas is defined as operation at a humidifier outlet temperature sufficient to maintain ESP performance. That temperature was typically 250 to 275°F. There were times during the demonstration that the humidifier did not have to run to maintain ESP performance. This was true during the limestone testing. During some of the early testing of dolomitic lime in August and September of 1990, runs were also made without humidification because the humidifier lance assemblies were not on site. These tended to be shorter (2 to 3 hr) tests. Close approach testing, as used in this report, is defined as tests conducted during operation at about a 20°F approach to the adiabatic saturation temperature of the flue gas, measured at the humidifier outlet.

The range of Ca/S stoichiometries tested for any one coal/sorbent combination was typically 0.8 to 2.2. Sometimes tests were performed outside this range, but not often. A couple of tests were run above 2.5 to assure the feed system's capability of delivering the higher mass feed rates with the dolomitic lime.

Research had shown that optimum sorbent reactivity and sulfation are obtained in the temperature range of roughly 1600 to 2300°F. The injectors were located where the flue gas temperature in the boiler is at the upper end of this range. This led to the selection of three different injection levels in the Edgewater boiler, at plant elevations 181, 187, and 191 ft. The 181 ft plant elevation is slightly below the nose of the boiler. The injection ports at this elevation are all located on the front wall opposite the nose (Figure 16). The 181 ft level corresponds to a temperature of about 2300°F in the boiler at full load. The higher injection levels correspond to temperatures a few hundred degrees cooler, since there was some concern during the design stages that even the 2300°F average temperature might be too high.

SCHEDULE

Sorbent was injected into the furnace not only to obtain parametric test data while demonstrating LIMB technology, but also to maintain the plant's 30-day rolling average, SO_2 emission limit of 3.4 $lb/10^6$ Btu while the higher sulfur coals were being burned. This required that the test schedule had to be interwoven with the normal variations in electrical demand placed upon the plant and the emissions that result from any given set of operating conditions. This led to the almost daily updating of a projected 30 day rolling average as a guide in selecting test conditions on any given day. Anticipated SO_2 emissions, based on results already obtained, were used to forecast what the impact would be with respect to the compliance limit. Conserving sorbent when it was not needed for test or compliance was likewise important as it minimized project costs. The overall schedule shown in Table 2 is the result of all these considerations.

In daily practice, sorbent was usually shut down for a short period of time each morning during the five-day work week, to calibrate the instruments and obtain a zero. It was then restarted for tests and to maintain compliance. Thus, the LIMB system operated almost

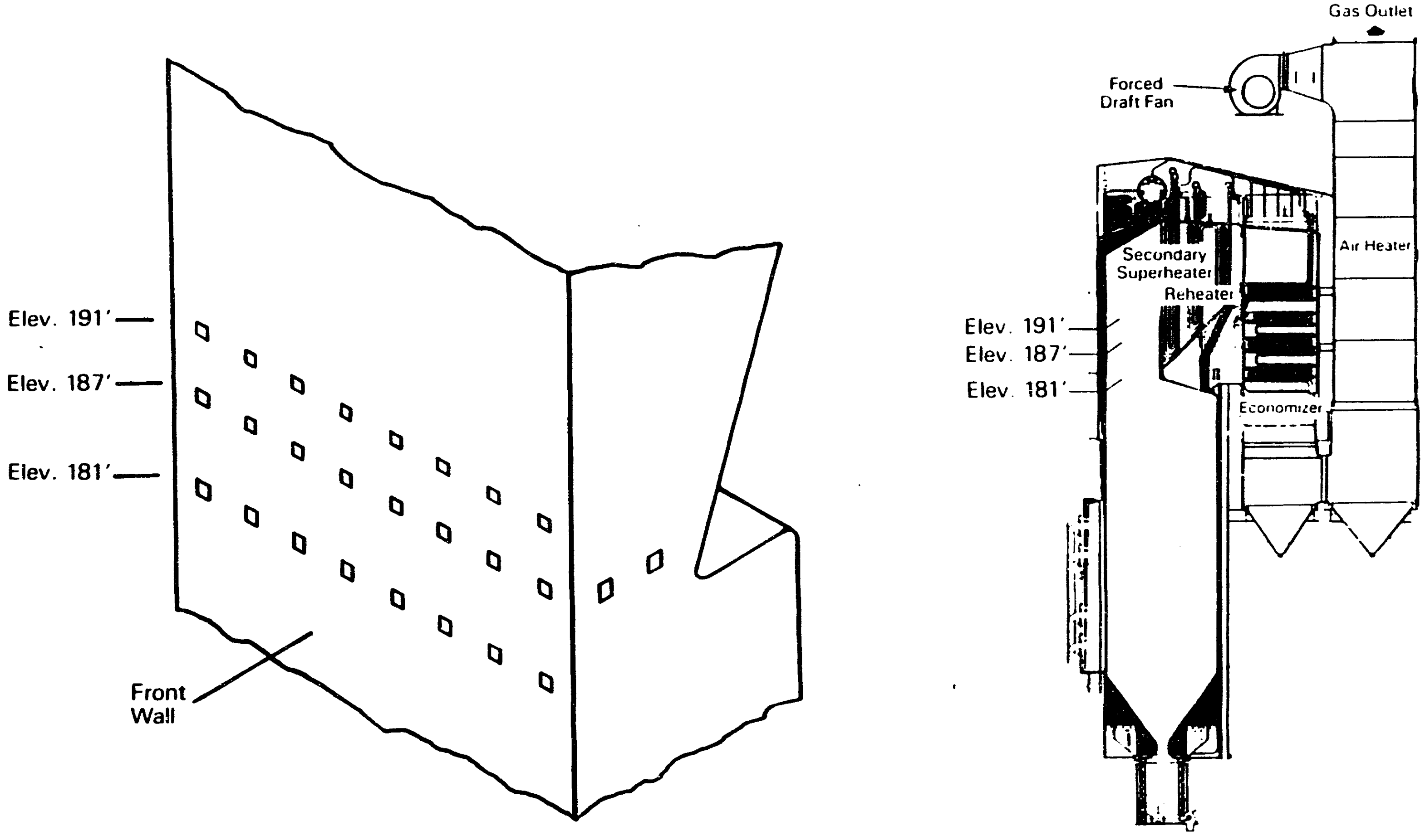


Figure 16. Sorbent injection locations

continuously during the time when high sulfur coal was being burned. When there was no danger of exceeding the plant's emission limit, the LIMB equipment was operated only for test purposes. This generally occurred during the use of the 1.6 percent sulfur coal and produced test runs of two to six hours. This operational philosophy conserved sorbent, minimizing project costs while still demonstrating the system's capability.

The test runs attempted during the LIMB Extension are listed in Appendix D. One column on this list indicates whether or not the run resulted in a test data point in the final plots of SO_2 removal efficiency as a function of Ca/S stoichiometry. If the test was not used, there is an explanation in the comments column. The column entitled "# of Ten Min Averages in Test" shows how many ten minute averages were used for the data point. This is the time the system was at steady-state, and does not include the time needed to zero the system or to reach steady-state conditions.

SECTION 6
EMISSIONS RESULTS

The highest furnace SO_2 removals measured during the LIMB Extension, on the order of 60 percent with minimal humidification and a 2.0 Ca/S stoichiometry, occurred when calcitic hydrated lime was used as the sorbent. Little, if any, difference in reactivity appeared between the ligno lime and the normal commercial material, unlike observations made during the EPA project when the former performed better. Dolomitic lime resulted in about 50 percent removal, and calcitic limestone 20 to 40 percent depending upon the particle size, under the same conditions. These removal efficiencies increase by approximately 10 percent absolute when the flue gas is saturated to within a 20°F approach to the adiabatic saturation temperature. The degree of SO_2 removal depends to a lesser extent on such factors as the inlet SO_2 concentration and the exact temperature within the sulfation temperature window (injection level). The B&W DRB-XCL™ burners continued to provide NO_x emissions on the order of 0.45 lb/10^6 Btu. Attempts were made during the LIMB Extension to identify the causes of variations first noticed during the EPA demonstration. Particulate emissions, as judged from the continuous opacity measurement, continued to remain at low (2 to 5 percent) levels when an appropriate degree of humidification was employed. Usually, this meant maintaining a humidifier outlet temperature of 250 to 275°F. Leading into the discussion of the test results, the three subsections immediately following describe details of data acquisition and reduction pertaining to the individual emission results.

SO_2 DATA

Tests were run in accordance with the procedures and practices outlined in the last section. All the data collected by the System 140 were stored on both a hard disk and magnetic tape as 10 min averages. Once each week selected data were copied from the hard disk onto a 5.25 in floppy disk to facilitate reduction and analysis. Each floppy disk is capable of holding seven days' worth of 10 min averages for twenty separate variables. At least five, and many times six, of these floppies were collected each week. These contained what was considered to be the more important of the approximately 1300 input and calculated parameters. Once every thirty days a new magnetic tape had to be installed, with the full tape being copied and stored.

The data on the floppy disks were converted to a format in which they could be manipulated on a computer spreadsheet (Table 1 is a partial example of the end result). The data are screened to reject values of -9999 automatically inserted by the System 140™when instrument were out of service (*e.g.*, during purge of the CEMS gas conditioner). At the same time any other obviously erroneous data is also rejected. The data are then broken down into specific periods representing the desired zero and test conditions, as is indicated in the first column of Table 1. In the process, other critical data, such as coal and sorbent feed rates and humidifier outlet temperature, are examined to determine if they have remained constant throughout the potential test period. If so, then the average and standard deviation is determined for the zero and test periods. The average SO_2 removal for the zero period is subtracted from that of the test period to yield the corrected system SO_2 removal for the average Ca/S stoichiometry of the test period.

The plots of SO_2 removal efficiency as a function of stoichiometry are then constructed from the averaged data for the various conditions. These include curves for the different combinations of coal and sorbent, injection at specific elevations, and humidifier outlet temperatures. A curve-fitting algorithm incorporating a standard least squares approach was used to compare the stoichiometry/removal efficiency data. The comparative figures displayed throughout this report show the first order fit of the data over the range of stoichiometries tested. Each fit was forced through zero percent SO_2 removal for the baseline condition. A second order fit with a diminishing increase in removal would be expected to describe the dependency more appropriately at higher stoichiometries. Its use, however, produced erroneously shaped curves in cases where a relatively small number of individual tests were performed. The first and second order fits indicated a difference of only a couple of percentage points at a stoichiometry of 2.0 for some cases where sufficient data points existed to make a comparison. Since this difference is well within the uncertainty interval, the first order plots are considered to be a reasonably accurate representation for comparisons made in this report. Individual points are shown in some of the graphs to provide the reader with a visual perception of the data fit. For others, only the curve-fit lines are presented to facilitate comparisons that would otherwise tend to be obscured by all the data points.

NO_x DATA

NO_x data was continuously collected by the System 140™ throughout the demonstration period, the only intentional interruptions being for analyzer calibrations and CEMS gas conditioner purge. With the exception of minor interruptions, the combined loss of only about five days' data was the result of four instrument failures throughout the entire LIMB Extension. As described above, the data were downloaded onto floppy disks once each week and screened as were the SO_2 data. Because data taken during the EPA LIMB Demonstration appeared to show some variations that might be controllable, attempts were made to correlate NO_x emissions with certain parameters. These included the independent variables of boiler load, percent oxygen in the flue gas, pulverizers/burners in service, and coal fineness. Even the potential correspondence with another dependent variable, CO emissions, was also explored. Unfortunately, no consistent correlation could be found.

The NO_x data were subsequently further reduced by compiling weighted hourly and daily averages which were then used to calculate 24 hr and 30 day rolling averages. This was done because regulatory agencies commonly require NO_x emission data in these terms. The weighting factor used was the coal firing rate.

PARTICULATE DATA

Ohio Edison's continuous monitor provided the opacity data collected by the System 140™. The data were treated in much the same way as the SO_2 and NO_x, with a daily calibration as the only regular interruption. Unweighted averages are used in the comparisons made later in this section. The opacity is regarded as a reasonable comparative indication of particulate emissions associated with the LIMB process, although much longer runs at steady-state conditions would have been required to define ESP performance more precisely.

TESTING

The LIMB Extension tests began in April 1990 with ligno lime being injected while burning 3.0 weight percent sulfur coal. This combination had been studied during the EPA project. These first few tests with this coal/sorbent combination confirmed equivalent system operation after the switch back to furnace injection from the Coolside duct injection configuration. The LIMB Extension tests ran through August 1991, with 289 tests being attempted.

Of the 289 tests (Appendix D), 224 provided the data plotted in the SO_2 removal *vs.* Ca/S stoichiometry curves that follow. Significant variation in coal sulfur content, changes in boiler operation, and mechanical malfunctions were the three most common reasons for aborting or otherwise not using test data. The comments column in Appendix D provides the general reason for not utilizing any given test's data. For reduction and analysis of the longer term NO_x and opacity data, only analyzer malfunctions caused data to be ignored.

The least number of points used for any one test were three ten-minute averages, the most, 71 ten-minute averages. These numbers do not reflect the time required to "zero" the SO_2 removal, begin sorbent injection, and reach steady-state. When these factors are added in, no test was less than two hours in duration. The average test was over three hours long.

COAL-SORBENT COMBINATIONS

The number of tests attempted and eventually used for the SO_2/stoichiometry plots are outlined in Table 3 for the various coal/sorbent combinations presented later in this section. There were fewer tests with the two finer limestones. Limited testing with these sorbents was undertaken only after the removal efficiencies obtained while injecting the more coarse material were less than expected. As noted earlier, the coal/sorbent combination of 3.8 percent sulfur and limestone was not attempted due to the difficulty projected in maintaining compliance with the plant's 30-day rolling average SO_2 emission limit of 3.4 lb/10^6 Btu.

TABLE 3. NUMBER OF TEST RUNS ATTEMPTED AND USED TO CHARACTERIZE SO_2 REMOVAL EFFICIENCY

	Nominal Coal Sulfur, wt%					
	1.6		3.0		3.8	
Sorbent	Attempted	Used	Attempted	Used	Attempted	Used
Calcitic Hydrated Lime	16	14	EPA*		15	8
Ligno Lime	43	34	15†	8†	23	23
Dolomitic Hydrated Lime	45	29	38	33	26	24
Limestone 80% < 44μm	18	12	28	20	NT‡	
Limestone 100% < 44μm	18	15	NP**		NP	
Limestone 100% < 10μm	4	4	NP		NP	

* Tests were run during the EPA sponsored demonstration.

† Tests were run to confirm system performance after the switch back to furnace injection from duct injection.

‡ NT = Not tested due to projected difficulty in maintaining compliance with the plant's emission limit of 3.4 lb/10^6 Btu.

** NP = Not planned.

The total amounts of each coal and sorbent used during the LIMB Demonstration are shown in Table 4. The numbers are presented to provide the reader with some idea of the magnitude of the effort on each of the combinations. However, because usages were frequently biased in one way or another for the purposes of the demonstration, the figures should not be used to infer average rates of consumption or stoichiometry. As might be expected, the quantity of dolomitic lime was the greatest due both to its unreactive magnesium component and the fact that full tests were run with all three coals. Prior EPA tests reduced the amounts of the commercial calcitic and ligno lime that had to be tested.

Tests with the calcitic limestone were limited to those with the 1.6 and 3.0 percent sulfur coal due to the lower removal efficiency obtained. As noted earlier, the two finer grinds of limestone were tested in reduced quantities to explore the effect of particle size differences. Only two truckloads of the finest limestone, loaded directly into an empty feed silo, were injected. While its use was considered important to define a limiting condition, longer term tests were not warranted. This is due to the fact that current processing techniques make the cost of this material about quadruple that of either of the two more coarse sizes tested.

TABLE 4. APPROXIMATE COAL AND SORBENT USAGE DURING THE DEMONSTRATION

Material		1.6 % S Coal ton	3.0 % S Coal ton	3.8 % S Coal ton
Coal	- DOE	176,578	44,359	28,147
	- EPA	NA*	132,727	NA
Calcitic Hydrated Lime	- DOE	600	0	598
	- EPA	2400†	4864	0
Ligno Lime	- DOE	600	100	600
	- EPA	0	1846	0
Dolomitic Hydrated Lime		1532	1600	1600
Limestone 80% < 44μm		988	900	0
Limestone 100% < 44μm		254	0	0
Limestone 100% < 10μm		20	0	0

* NA = Not available; 1.6 percent sulfur coal usage was primarily that during start-up/shakedown for the EPA tests.

† Very rough estimate for start-up/shakedown with the lower sulfur coal, though the total of 7264 ton used over the whole EPA LIMB Demonstration is accurate.

Table 5 contains typical analyses of the sorbents used. Samples were collected downstream of the differential weight loss feeders. An American Society for Testing and Materials (ASTM) titrimetric procedure for the determination of available lime was used for the commercial calcitic and ligno limes. The $CaCO_3$ content of the limestones was likewise determined titrimetrically. The analysis in the table includes the results for all three size distributions. Dolomitic lime samples were analyzed for both calcium and magnesium by atomic absorption spectrophotometry since it was not known how much variability might occur for each element. The calcium value was converted to equivalent $Ca(OH)_2$. As can be seen, the quality of the sorbents did not fluctuate appreciably.

Particle size distributions were determined for the various sorbents during the project. Figures 17 to 22 present plots of these distributions. All the limes were much finer than the two more coarse limestones. The size distribution of the finest grind of limestone, however, approached that of the limes, and is thought to be at least partly responsible for its greater reactivity. Those of the two finer limestones compare well with the distributions given in the supplier's literature.

TABLE 5. TYPICAL SORBENT ANALYSES

Sorbent	Time Period		$Ca(OH)_2$, wt %	Ca, wt %	Mg, wt %	$CaCO_3$, wt %
Calcitic Hydrated Lime	07/09/91	Average	94.72	NA*	NA	NA
	to	Standard Deviation x 2	1.78			
	08/02/91	Number of Analyses	7			
Ligno Lime	03/13/91	Average	94.21	NA	NA	NA
	to	Standard Deviation x 2	1.28			
	05/24/91	Number of Analyses	13			
Dolomitic Hydrated Lime	08/24/90	Average	NA	34.17	18.76	NA
	to	Standard Deviation x 2		0.83	2.22	
	11/12/90	Number of Analyses		18	18	
Calcitic Limestone	05/31/90	Average	NA	NA	NA	96.01
	to	Standard Deviation x 2				4.08
	06/26/90	Number of Analyses				33
	and					
	01/08/91					
	to					
	02/01/91					

* NA = Not analyzed.

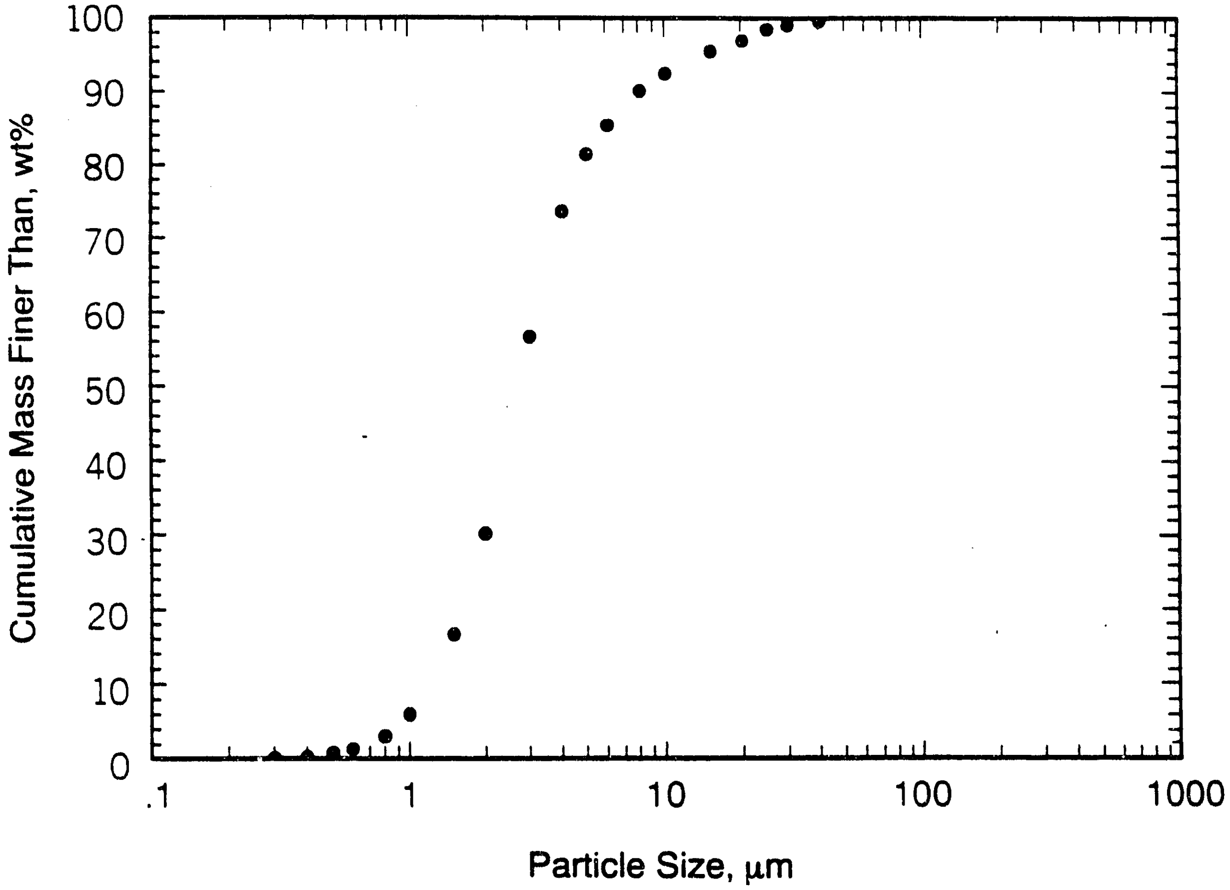


Figure 17. Typical particle size distribution of calcitic hydrated lime

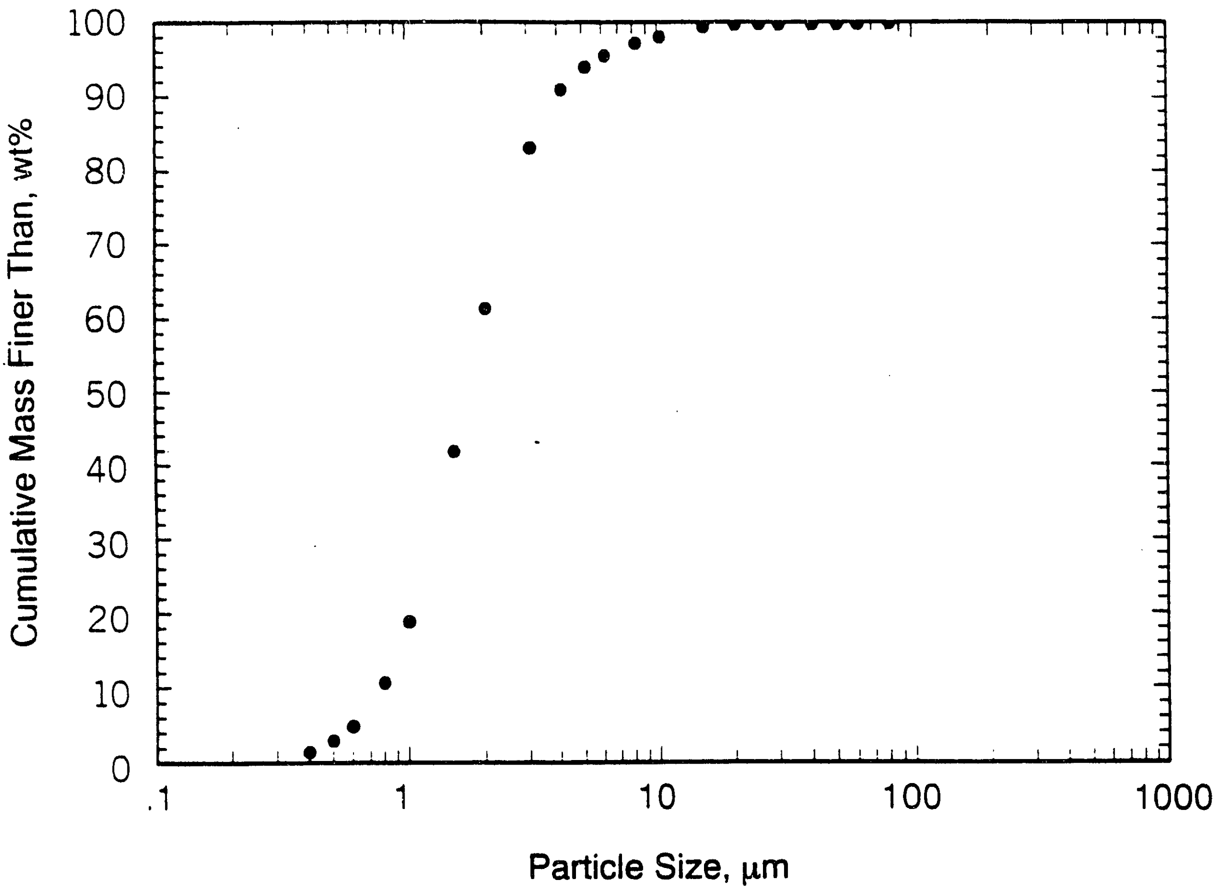


Figure 18. Typical particle size distribution of ligno lime

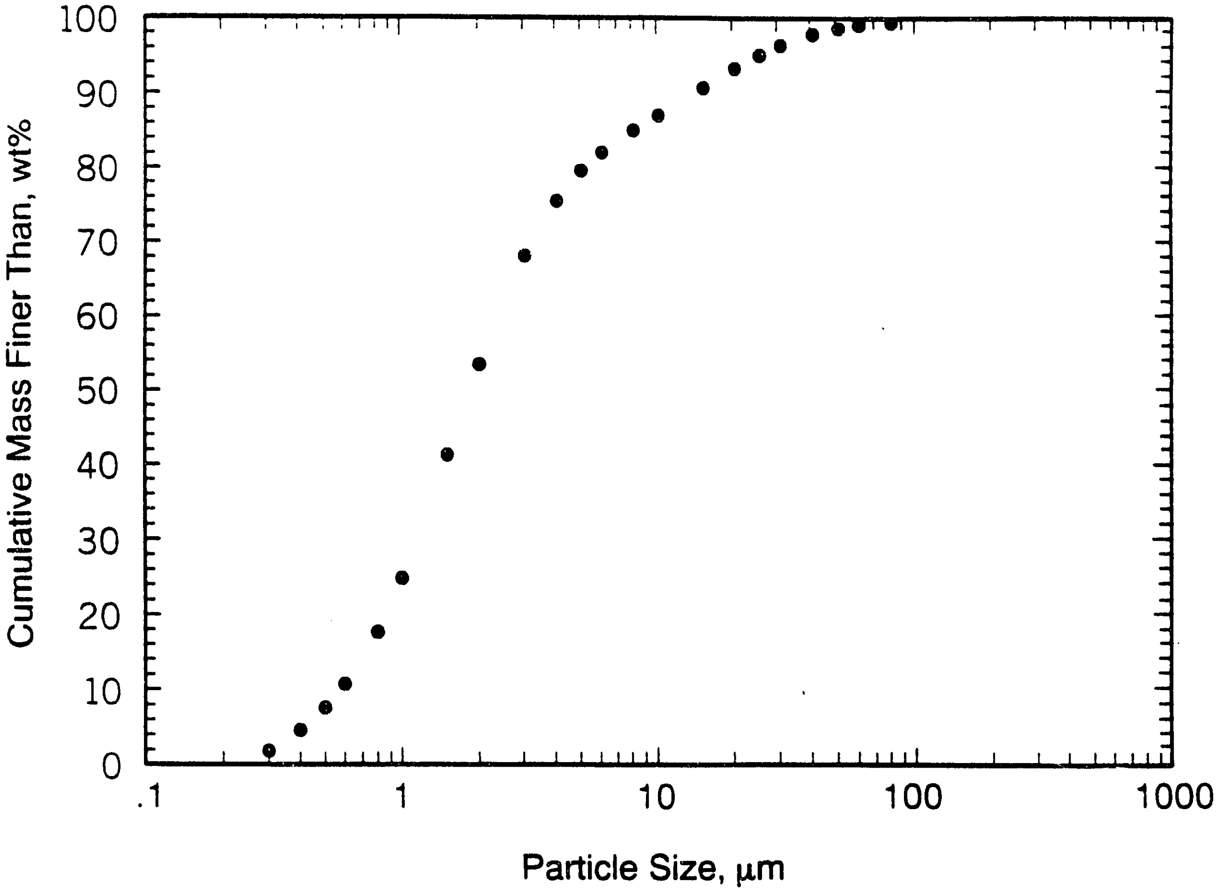


Figure 19. Typical particle size distribution of type-N dolomitic hydrated lime

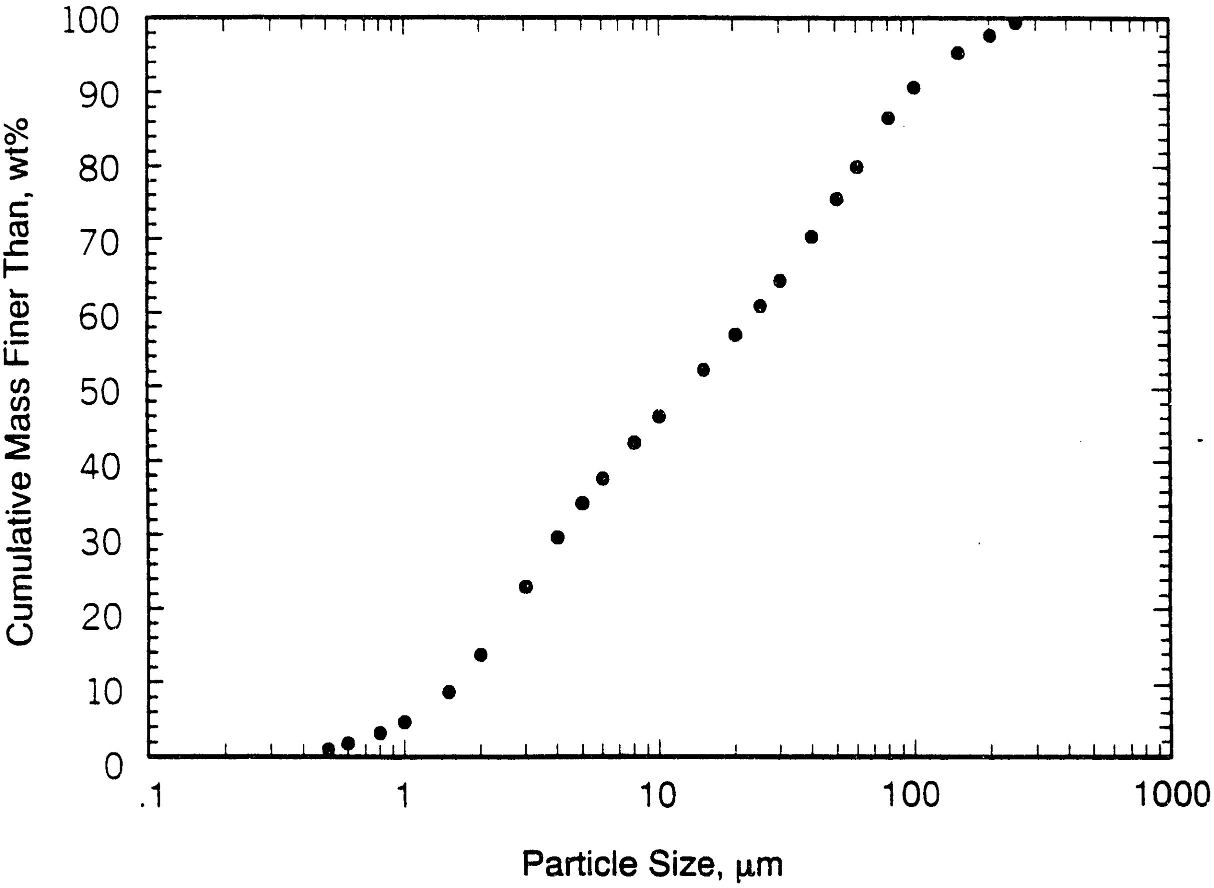


Figure 20. Typical particle size distribution of coarse limestone (80% < 44 µm)

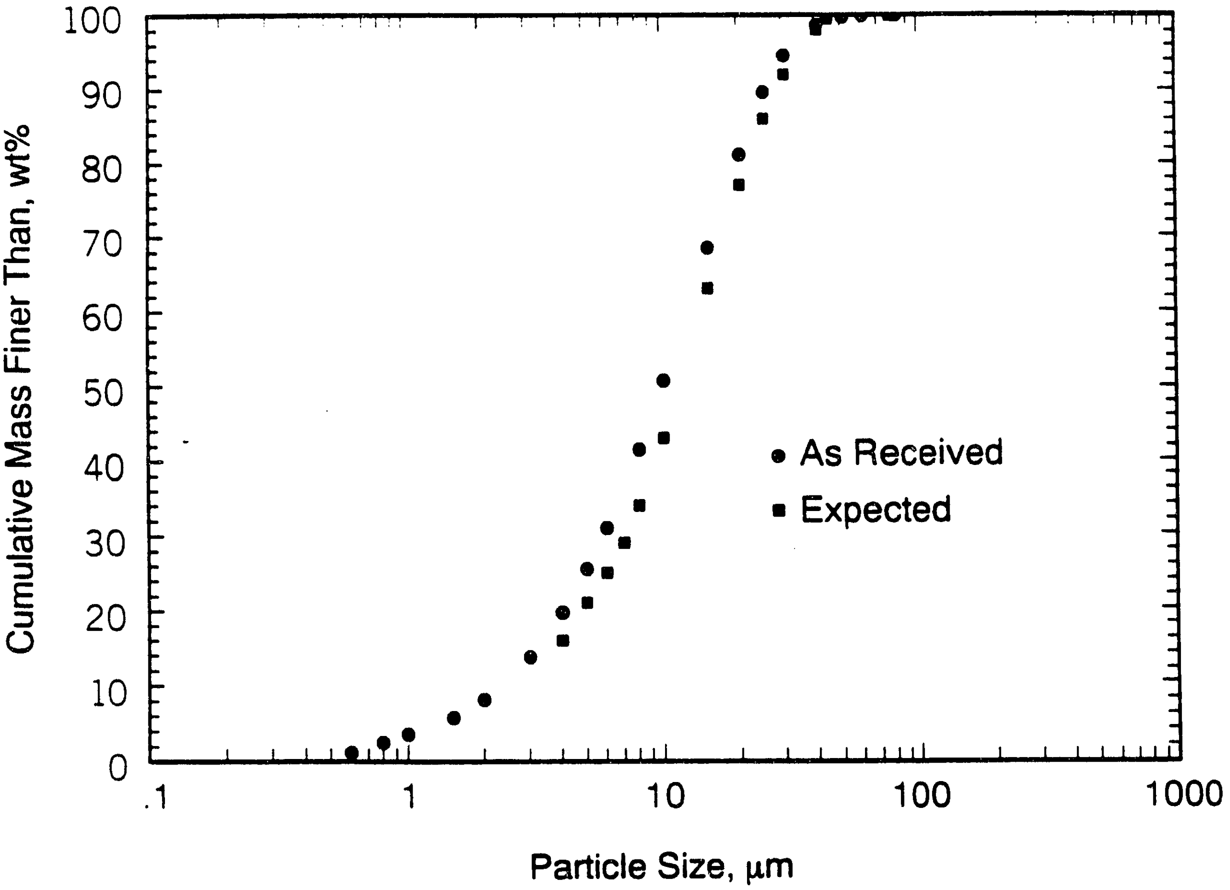


Figure 21. Typical particle size distribution of fine limestone (100% < 44 μm)

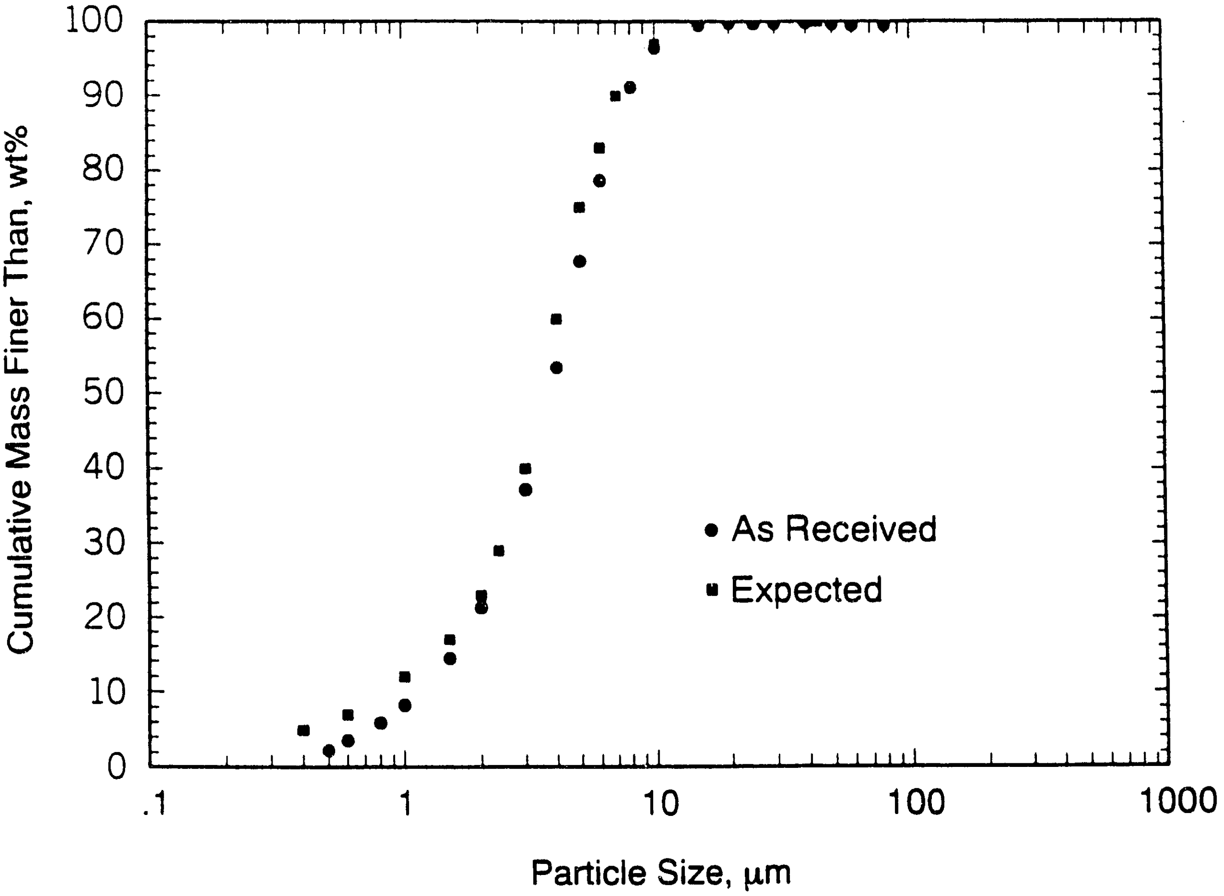


Figure 22. Typical particle size distribution of very fine limestone (100% < 10 μm)

As briefly described in Section 5, the variability of the coal sulfur content generally decreased between the truck and bunker sampling points, and again between the bunker and the burner coal pipe. This improved variability is attributed to the mixing that occurs as the coal is progressively moved through the yard and bunker, and eventually in the pulverizer just before entering the burner. In addition, the coal sulfur content itself drops between the bunker and the burner pipe sampling locations (one on the discharge of each pulverizer with an analysis of a composite sample being the norm). This is believed to be due primarily to the effectiveness of the pyrite traps that are part of the B&W "E" pulverizer design. The automatic samplers installed on the burner pipes were specifically placed in that location so that the samples would reflect the "as-burned" condition, rather than just what was loaded to the bunker. These trends are evident in analyses provided in Tables 6, 7, and 8 for the truck, bunker, and burner pipe samples, respectively. Table 9 similarly provides the data demonstrating the agreement in sulfur content between the CTECo analyses of burner pipe samples and those determined on site using the Leco analyzer.

SO_2 REMOVAL EFFICIENCY

The constant supply of sorbents and coals of known quality was essential to the project goal of demonstrating the generic applicability of the LIMB process. The experimental effort focused on quantifying the effects of the primary parameters to be considered by a utility contemplating use of the technology. These included coal sulfur content, type of sorbent, limestone particle size, injection level, and flue gas humidification. Since the degree of SO_2 removal desired might easily span a fairly broad range depending on the utility's overall compliance strategy, all were characterized over a range of Ca/S molar ratios.

As noted at the beginning of this section, a second order correlation between removal efficiency and stoichiometry probably best describes the overall result of a diminishing increase in removal as stoichiometry increases. Although much more sophisticated models[3,4] more properly describe the interrelated kinetics of the simultaneous calcination, sintering, and sulfation reactions taking place, the second order correlation might be thought of as representing a simpler contracting sphere or cube model that corresponds to a reacting sorbent particle whose surface gradually becomes coated with the reaction product. Diffusion of an increasingly lower concentration of SO_2 through the product layer and into the inner pores of the sorbent leads to an apparent lower reactivity of the sorbent overall. For the reasons described earlier, however, first order fits are

TABLE 6. SUMMARY OF COAL ANALYSES - TRUCK SAMPLES (Ohio Edison Analyses)

Nominal Coal S, wt %		Ash, wt %[*]	Sulfur, wt %[*]	Heating Value, Btu/lb[*]	SO_2 Index, lb/10^6 Btu
3.8	Average	11.69	3.78	12876	5.88
	Standard Deviation x 2	4.10	1.45	584	2.36
	Number of Analyses	145	145	145	145
3.0	Average	10.91	2.96	12998	4.56
	Standard Deviation x 2	4.27	1.20	620	1.93
	Number of Analyses	223	223	223	223
1.6	Average	NA[1]	NA	NA	NA
	Standard Deviation x 2	NA	NA	NA	NA
	Number of Analyses	NA	NA	NA	NA

[*] Ash, sulfur, and heating value are on a dry basis.

[1] NA = Not available; since new deliveries were intermingled with stockpiled compliance coal, bunker analyses were used as the initial reference point.

TABLE 7. SUMMARY OF COAL ANALYSES - BUNKER SAMPLES (Ohio Edison Analyses)

Nominal Coal S, wt %		Ash, wt %[*]	Sulfur, wt %[*]	Heating Value, Btu/lb[*]	SO_2 Index, lb/10^6 Btu
3.8	Average	12.60	3.97	12661	6.26
	Standard Deviation x 2	2.14	0.99	426	1.62
	Number of Analyses	48	48	48	48
3.0	Average	11.04	2.89	12843	4.50
	Standard Deviation x 2	3.96	1.25	352	1.20
	Number of Analyses	60	60	60	60
1.6	Average	11.82	1.79	12855	2.78
	Standard Deviation x 2	2.25	0.52	403	0.81
	Number of Analyses	271	271	271	271

[*] Ash, sulfur, and heating value are on a dry basis.

TABLE 8. SUMMARY OF PULVERIZED COAL ANALYSES - BURNER PIPE SAMPLES (CTECo Analyses)

Nominal Coal S, wt %		Ash, wt %*	Sulfur, wt %	Heating Value, Btu/lb	SO_2 Index, lb/10^6 Btu	Carbon, wt %	Hydrogen, wt %	Nitrogen, wt %	Oxygen, wt %	Volatile Matter, wt %	Fixed Carbon, wt %
3.8	Average	12.09	3.44	12825	5.36	71.11	4.83	1.41	7.12	37.82	50.09
	Standard Deviation x 2	1.73	0.84	267	1.29	1.37	0.18	0.16	0.96	3.17	2.57
	Number of Analyses	35	35	35	35	35	35	35	35	35	35
3.0	Average	11.12	2.56	12960	3.95	72.09	4.89	1.46	7.87	36.32	52.56
	Standard Deviation x 2	1.70	0.42	445	0.63	1.49	0.23	0.13	1.00	1.94	1.74
	Number of Analyses	52	52	52	52	52	52	52	52	52	52
1.6	Average	11.57	1.45	12942	2.24	72.86	4.78	1.50	7.83	34.68	53.75
	Standard Deviation x 2	2.58	0.31	460	0.48	2.45	0.29	0.17	0.82	2.14	2.85
	Number of Analyses	212	212	212	212	212	212	212	212	212	212

* All analyses are on a dry basis.

TABLE 9. SUMMARY OF COAL SULFUR (LECO) ANALYSES - BURNER PIPE SAMPLES (Radian Analyses)

Nominal Coal S, wt %		Sulfur, wt %*
3.8	Average	3.37
	Standard Deviation x 2	0.97
	Number of Analyses	42
3.0	Average	2.62
	Standard Deviation x 2	0.40
	Number of Analyses	53
1.6	Average	1.53
	Standard Deviation x 2	0.39
	Number of Analyses	215

* Converted to a dry basis by assuming the same moisture as determined by CTECo on the composite sample.

used in the graphs for the purpose of comparing the relationship over the stoichiometry range actually tested. The nominal sulfur contents, referring to the "as delivered" rather than the "as burned" conditions, are used in discussing comparisons among the coals. A Ca/S ratio of 2.0 is similarly employed as a common reference point, unless noted otherwise.

Coal Sulfur/Inlet SO_2 Concentration

Coal sulfur content translated into inlet SO_2 loading. As the sulfur increased, the inlet SO_2 concentration seen by the LIMB sorbents increased proportionately. For 1.6, 3.0 and 3.8 percent sulfur coals corresponding to the typical analyses indicated in Table 8, the flue gas would contain approximately 1180, 2090, and 2830 ppmv (dry), respectively, at an excess air condition represented by 3.0 vol % O_2, a value which can be expected near the point of sorbent injection.

SO_2 removal by the lime sorbents at any given set of conditions increased with the sulfur content of the coal being fired. This can be seen in Figures 23 and 24 for the calcitic and ligno limes, respectively, when they were injected at the 181 ft elevation. Similar results appear in Figures 25 and 26 for the dolomitic lime at the 181 and 187 ft injection elevations, respectively. These figures show that the SO_2 reduction increased approximately seven percent absolute (at the Ca/S reference point of 2.0) when the coal being fired changed from 1.6 to 3.8 percent sulfur. Removal efficiency for the 3.0 percent sulfur coal generally fell between the removal efficiencies achieved while burning the two other coals.

The conclusion that the higher SO_2 concentrations actually led to higher removal efficiencies was not easily reached. Since earlier research had indicated such might be the case, the data was examined for evidence of the effect. As might be expected from the differences seen in the figures, no strong correlation was immediately evident. For any two sets of conditions for one sorbent, one might argue that the overlap is within experimental error. Nevertheless, the accumulated data repeatedly pointed to higher removal when the higher sulfur coals were in use. This, coupled with at least some theoretical explanation of the phenomenon,[19] led to the overall conclusion that the effect is real, at least for the limes.

This conclusion was not as easily reached for limestone, especially since data were not available for the 3.8 percent sulfur/limestone case (Figure 27). Limestone tests with both the 1.6 and 3.0 percent sulfur coals produced lower, and approximately equivalent, SO_2 reduction for this

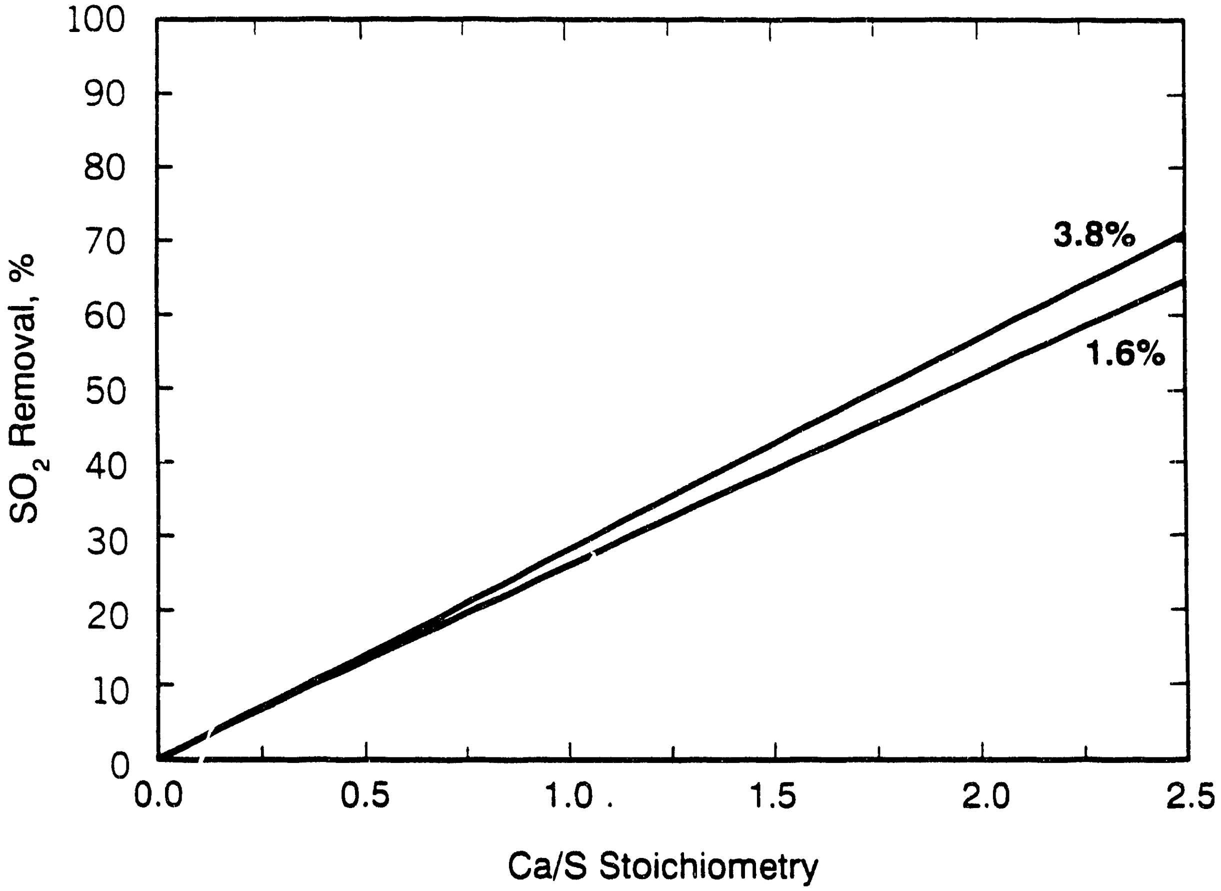


Figure 23. Effect of coal sulfur (SO_2 concentration) on SO_2 removal while injecting calcitic lime at elevation 181 ft

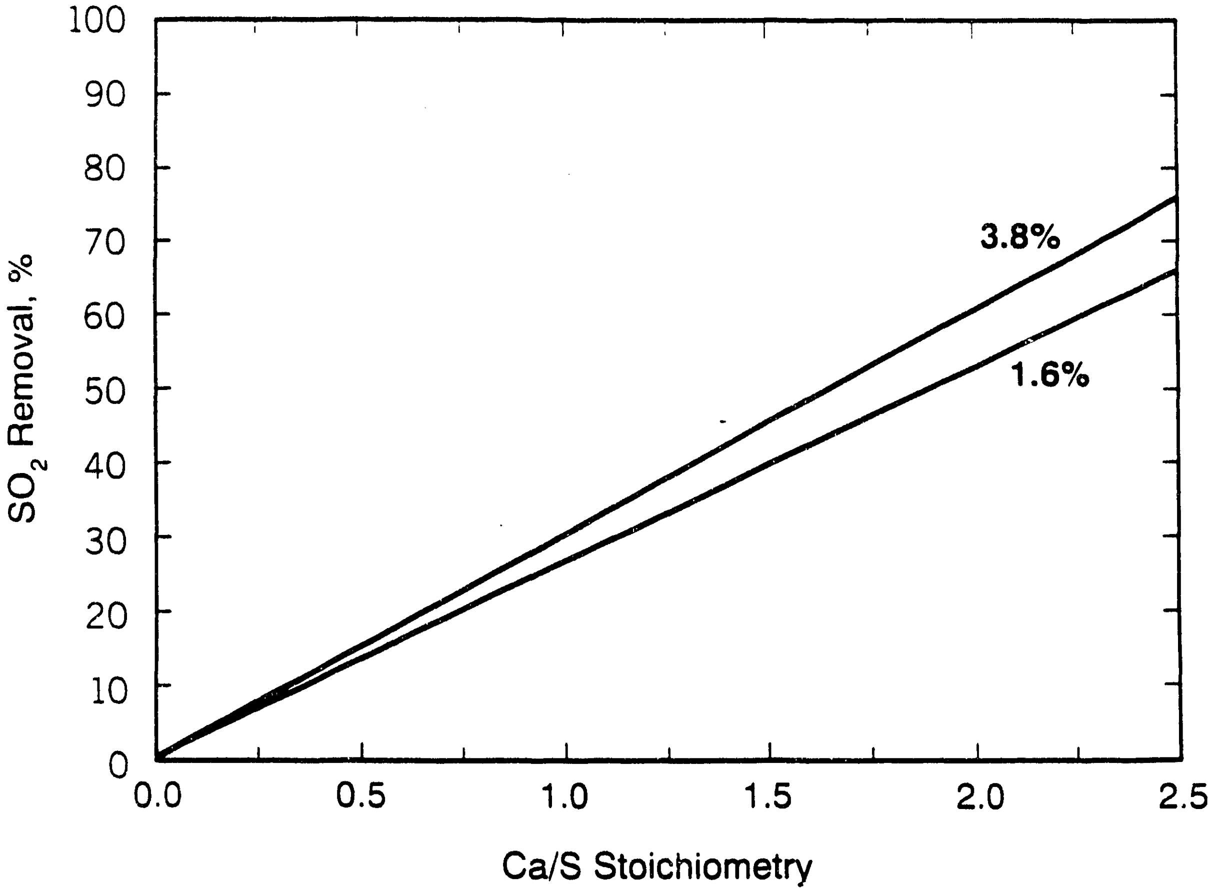


Figure 24. Effect of coal sulfur (SO_2 concentration) on SO_2 removal while injecting ligno lime at elevation 181 ft

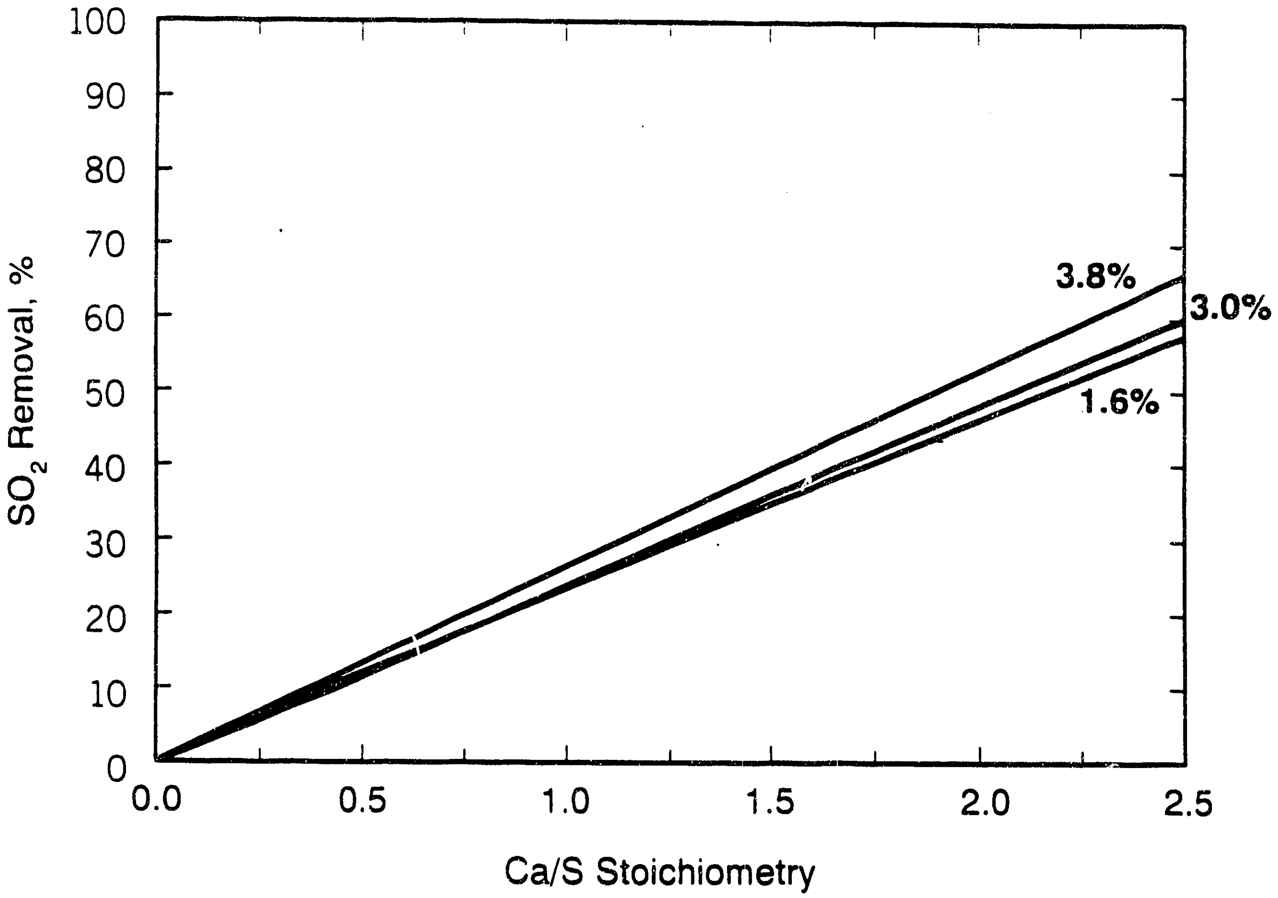


Figure 25. Effect of coal sulfur (SO_2 concentration) on SO_2 removal while injecting dolomitic lime at elevation 181 ft

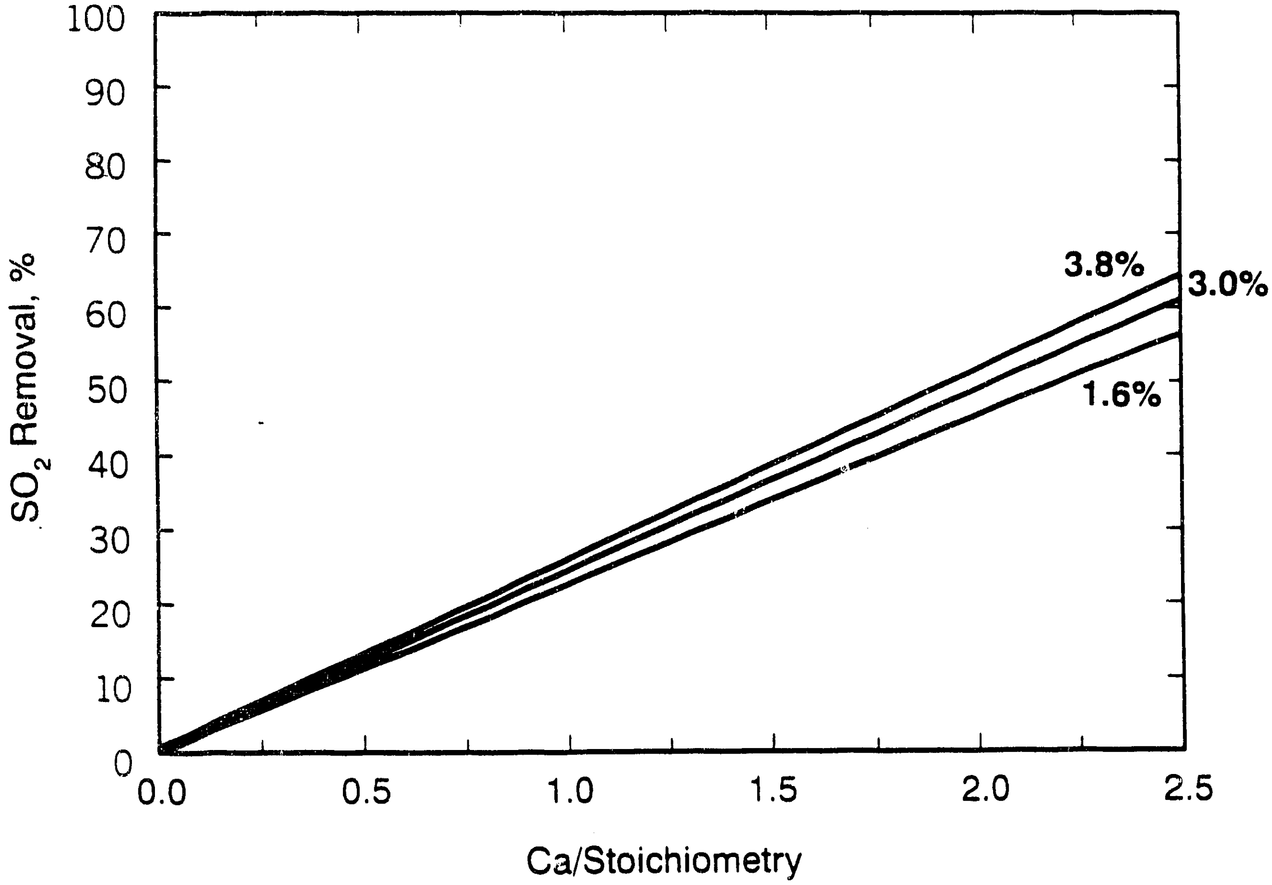


Figure 26. Effect of coal sulfur (SO_2 concentration) on SO_2 removal while injecting dolomitic lime at elevation 187 ft

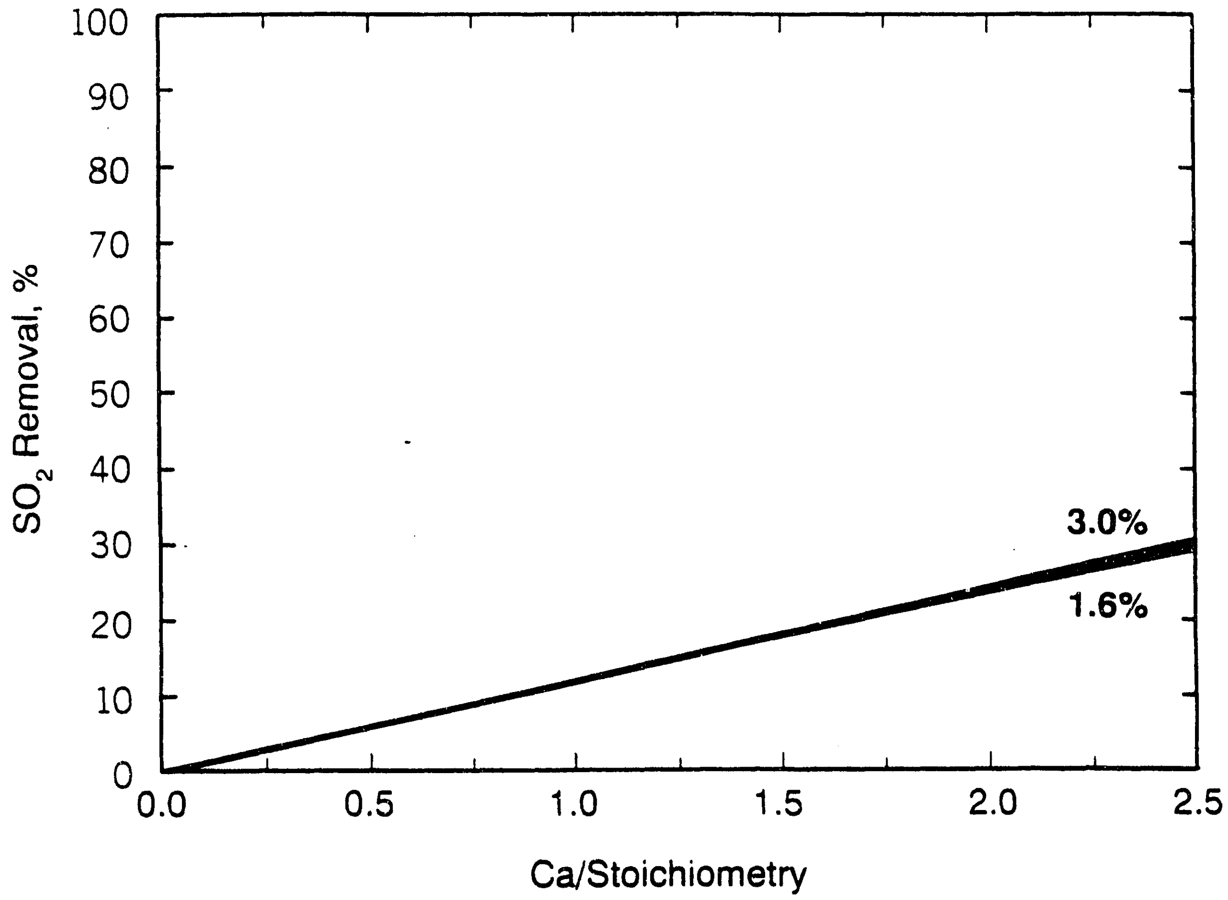


Figure 27. Effect of coal sulfur (SO_2 concentration) on SO_2 removal while injecting coarse limestone at elevation 181 ft

comparatively unreactive sorbent. Perhaps this reflected a lower sensitivity of this sorbent to the SO_2 concentration, though experimental error may just as readily be used to explain the observed results.

Sorbent Choice

The differences in reactivity obtained during the LIMB Extension are represented in Figures 28, 29, and 30 for injection of the various sorbents at elevation 181 while using the 3.8, 3.0, and 1.6 percent sulfur coals, respectively. Ligno lime had shown itself to be the most reactive sorbent during the EPA test program. During the LIMB Extension, commercial calcitic hydrated lime performed equally well, followed by type-"N" dolomitic hydrated lime. Limestone yielded the lowest removal, though more finely pulverized material increased removal as will be described in the next subsection.

Table 10 lists the SO_2 removals for each of the major types of sorbent under the specific conditions of injection at a Ca/S ratio of 2.0 at the 181 ft plant elevation, and with minimal humidification. The values obtained for the commercial calcitic hydrated and ligno limes during the EPA LIMB Demonstration while burning a 3.0 percent sulfur coal are included. Examination of the values in this table suggests that, with all else being equal, the use of dolomitic lime results in roughly six or seven percent (absolute) lower removal than when calcitic lime is injected. Limestone is even less effective with approximately 30 percent (absolute) lower removal. The values in the table also make it evident that the increase in coal sulfur from 1.6 to 3.0, and from 3.0 to 3.8, percent resulted in a three to four percent (absolute) increase in removal with each step.

TABLE 10. SO_2 REMOVAL EFFICIENCIES FOR INJECTION AT 181 ft LEVEL AT A 2.0 Ca/S RATIO WITH MINIMAL HUMIDIFICATION

	Nominal Coal Sulfur Content, wt %		
Sorbent	3.8	3.0	1.6
Ligno Lime	61	63*	53
Commercial Calcitic Lime	58	55*	51
Dolomitic Lime	52	48	45
Limestone (80% < 44μm)	NT†	25	22

* Determined during the EPA LIMB Demonstration.

† NT = Not tested.

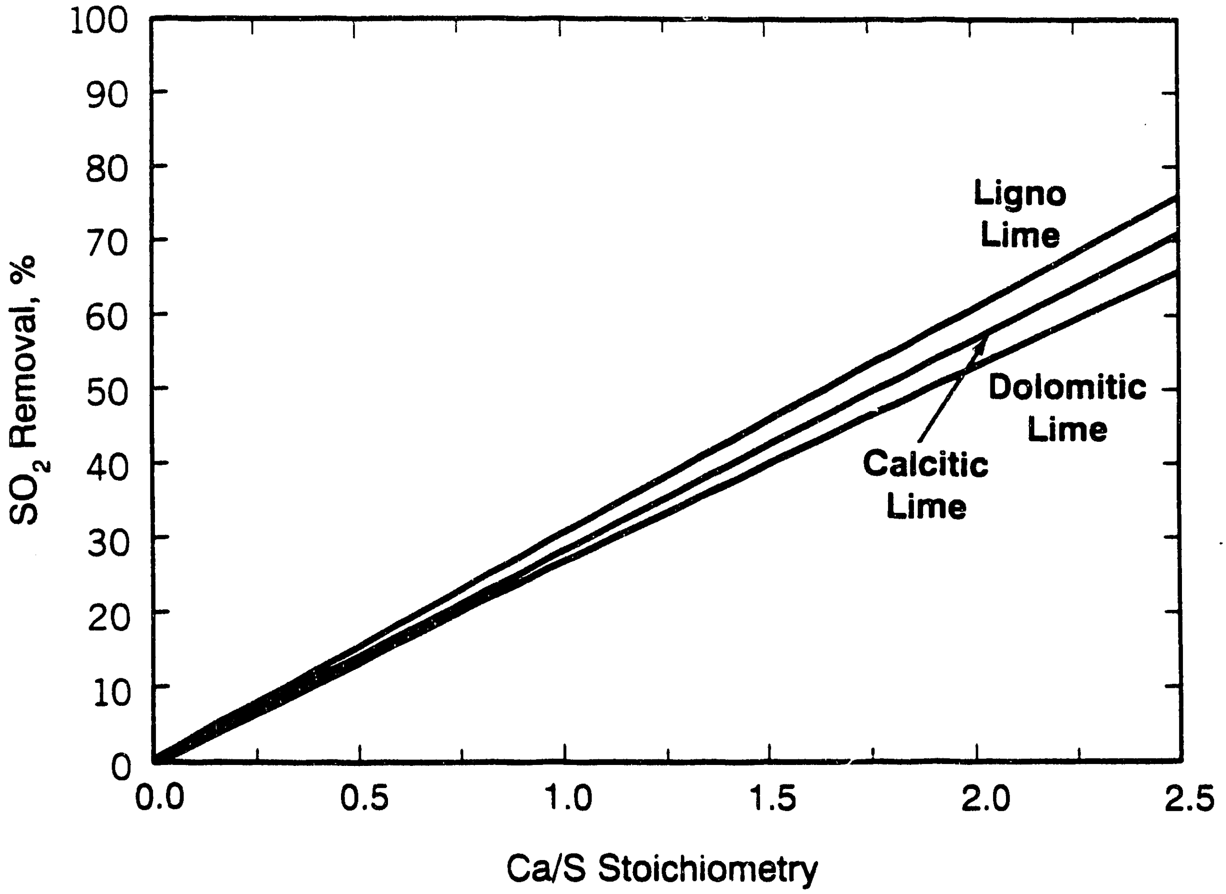


Figure 28. Effect of different sorbents on SO_2 removal while burning 3.8 weight percent sulfur coal and injecting at elevation 181 ft

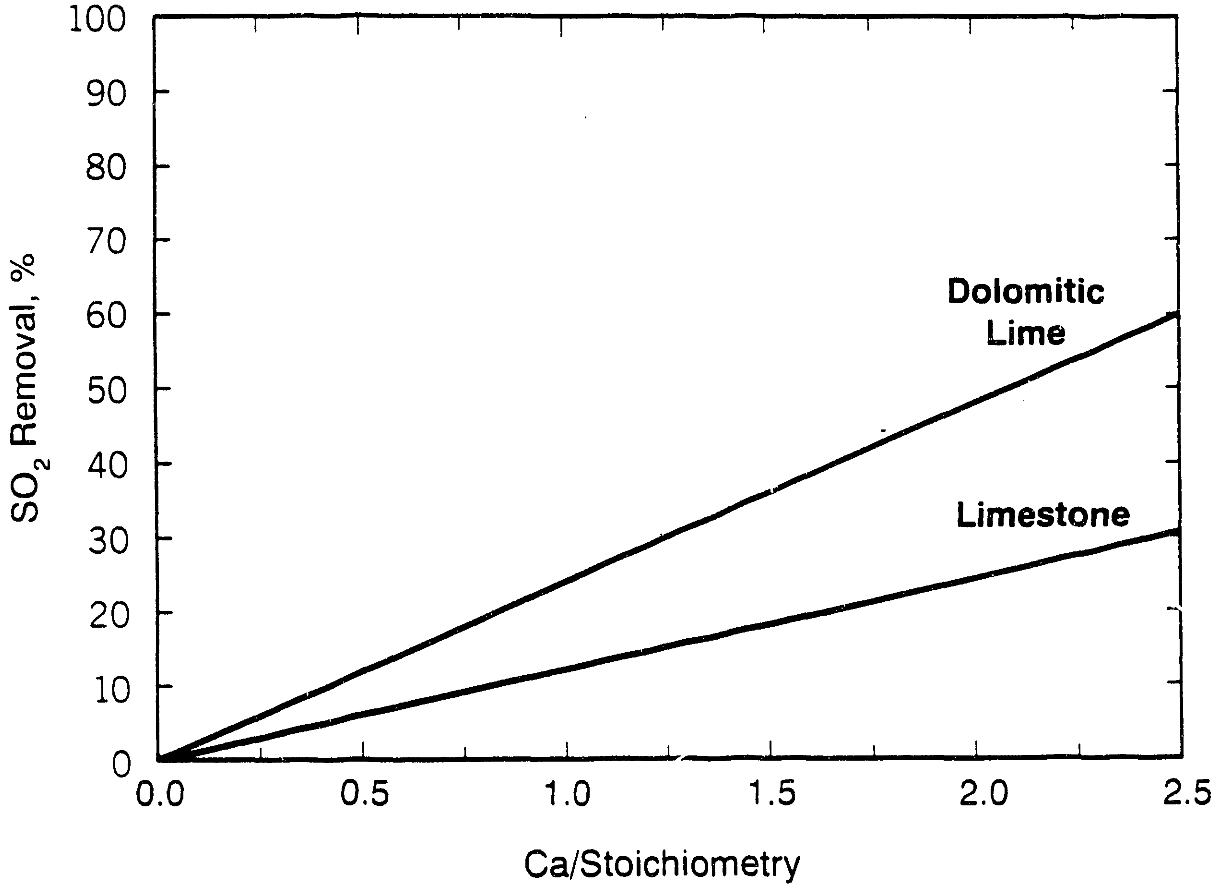


Figure 29. Effect of different sorbents on SO_2 removal while burning 3.0 weight percent sulfur coal and injecting at elevation 181 ft

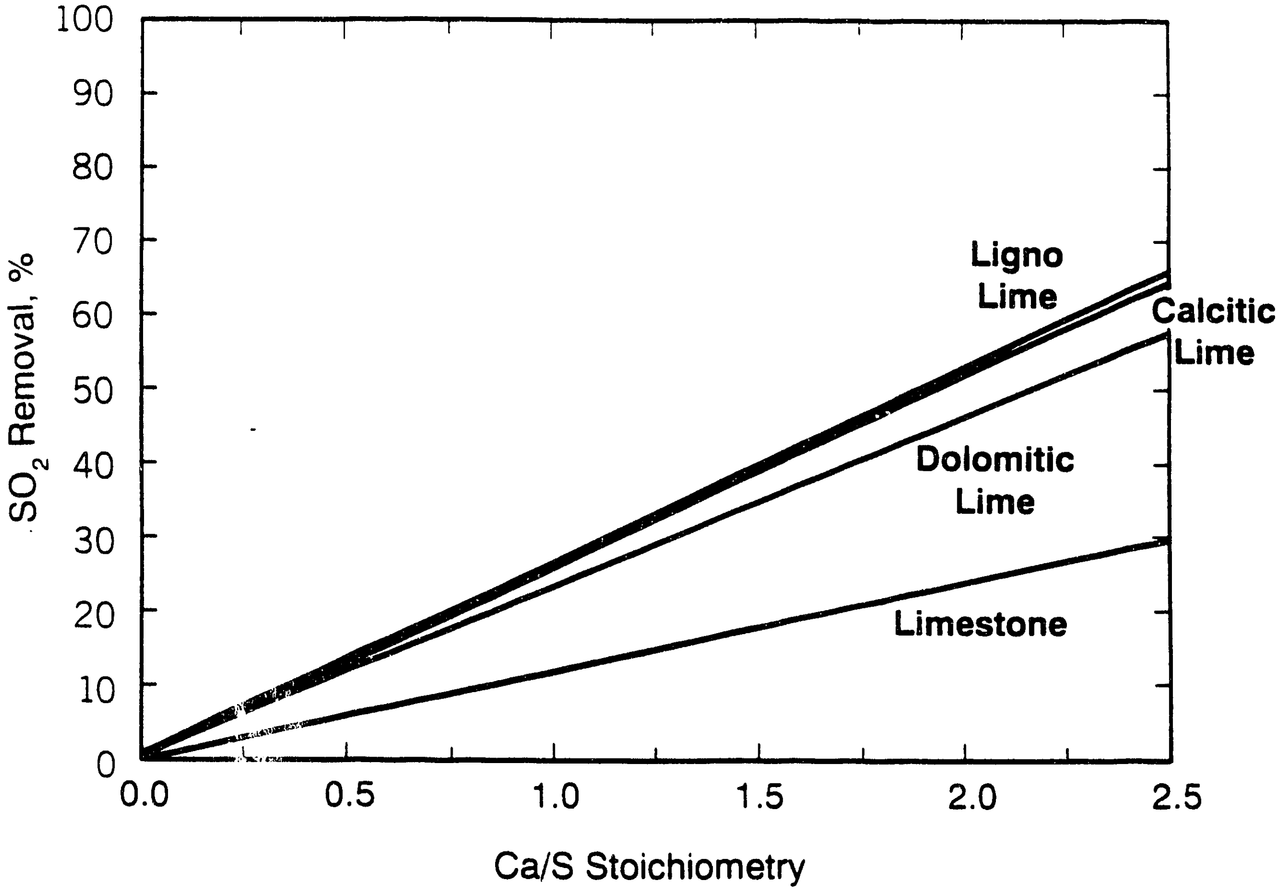


Figure 30. Effect of different sorbents on SO_2 removal while burning 1.6 weight percent sulfur coal and injecting at elevation 181 ft

The 3.0 percent sulfur coal/ligno lime combination was run early during the LIMB Extension to verify system performance when the equipment was returned to a configuration for furnace injection following the Coolside duct injection tests. The runs made indicated performance on the order of 60 to 65 percent at a stoichiometry of 2.0. Since this was quite comparable to that found during the EPA LIMB Demonstration, testing of the 3.0 percent sulfur/limestone combination began soon thereafter in May 1990. Ligno lime was not used again until February 1991 when tests were conducted while burning the 1.6 percent sulfur coal. By this time, the lower sulfur coal was expected to produce a reduced removal efficiency, though the 53 percent obtained was somewhat less than expected. Potential reasons for the differences were investigated, but none were identified. Subsequent tests with the 3.8 percent sulfur coal at the 2.0 stoichiometry yielded about 61 percent SO_2 removal, several percent lower than might otherwise have been expected.

There are several possible explanations for the apparent difference in performance of the ligno lime between the LIMB Demonstration and the LIMB Extension, none of which have been proven. They are described here because some are already the subject of on-going research, while others might be explored in the future. One possible reason is that there were subtle changes in porosity and/or surface area of the sorbent, both of which are known to be quite important in reaction kinetics. Another may be that the lower efficiency was related to a variation in the calcium lignosulfonate used to prepare the ligno lime. Variations in composition and/or concentration may have altered its intended effect. No readily implemented analytical techniques have been developed for either the raw material or for determining its actual concentration in a lime sample. There was no substantial difference evident in the chemical analyses or particle size distributions of the sorbent samples taken during this period.

A third possible explanation for the lower-than-expected SO_2 removal with the ligno lime is mechanical in nature. The tests run while burning the 3.8 and 1.6 percent sulfur coals were completed using the solids pump installed downstream of the feeders. The tests run while burning the 3.0 sulfur coal were completed using the original rotary valve configuration downstream of the feeders. It is envisioned that the solids pump would have a greater tendency to agglomerate the lime physically. Since there was no opportunity to try to observe a similar effect with the other limes, this question remains unresolved. One final explanation is simply that the relatively small number of tests during the original demonstration produced an average that would have been a few percentage points lower had more tests been run. This could only have been answered definitively at the time of the original demonstration.

Limestone Particle Size Distribution

Tests with a commercial, pulverized, calcitic limestone as the sorbent were first run in May 1990. The material used at the time had a particle size distribution such that 80 weight percent was less than 44µm (325 mesh; Figure 20). This stone had been chosen because it was representative of readily available material from commercial suppliers, and was similar to what some utilities have used in wet FGD applications. SO_2 removal efficiencies on the order of 22 percent were obtained while injecting this sorbent at a stoichiometry of 2.0, and burning 1.6 percent sulfur coal. Although pilot plant studies had produced a fairly broad band of efficiencies, a reduction of approximately 35 percent had been expected.[3,4] The reason was not readily apparent at the time since there were any of a number of differences among the various pilot studies and the full-scale unit which could have produced the effect either individually or in combination with each other.

Of the various parameters which might have caused the low removal with limestone, only a significant change in particle size distribution was considered worth trying at full scale because of its inherent simplicity. The opportunity to test a finer grind of limestone occurred in January 1991. A pulverized limestone with 100 weight percent of the particles less than 44µm (325 mesh; Figure 21) generated removal efficiencies of approximately 32 percent at a stoichiometry of 2.0. This indication of the importance of size on SO_2 removal efficiency led to the selection of an even finer material for further tests.

The sorbent selected was one for which the size distribution showed virtually all particles to be less than 10µm (Figure 22). For this limestone, the removal efficiency was about 40 percent for the conditions specified above. The relationships between Ca/S stoichiometry and SO_2 reduction for each of the different grinds of limestone are presented in Figure 31 and clearly show how the finer materials improve efficiency. This increased removal is attributed in part to the greater surface area available as the size decreases. It is noted that the finest grind of limestone is almost as fine as any of the lime sorbents tested (Figures 17 to 19), indicating that the reactivity of the limes is not due to particle size alone, even though they produce a calcine of the same chemical formula. A reduced tendency of the limes toward sintering has been suggested as the reason.[20,21]

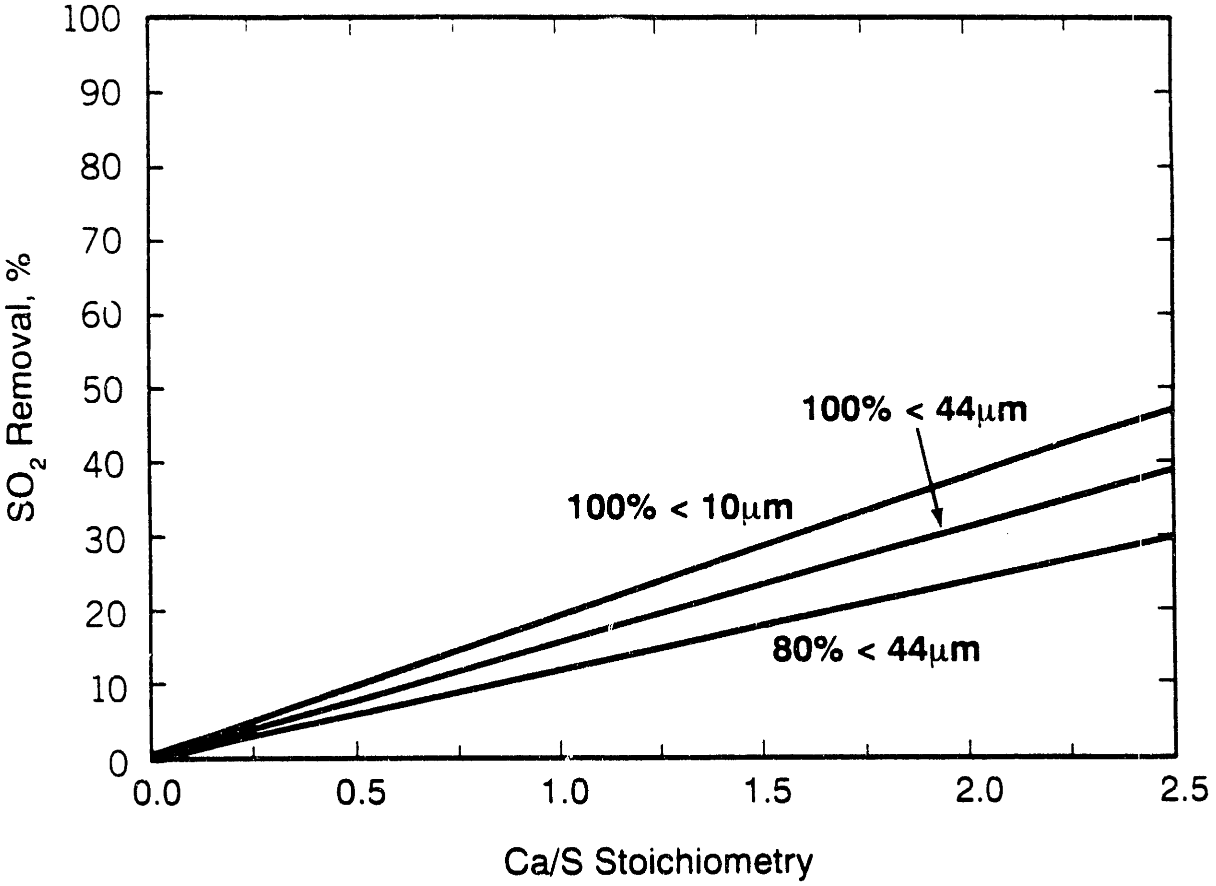


Figure 31. Effect of limestone grind on SO_2 removal while burning 1.6 weight percent sulfur coal and injecting at elevation 181 ft

All limestones used were obtained in truckload quantities, with the two more coarse materials being approximately equal in cost. The very fine material was the finest found available in this large a quantity. This fine a limestone, however, may not be considered a viable alternative for LIMB application at this time. Its cost, on a truckload basis, is on the order of four times that of the other two. Long term contracts for larger quantities may make the economics more competitive, though the gap is considered substantial at present.

Injection Level

A preface to this subsection on the effect of injection level is necessary, as the effect is really due to the combined effects of differences in temperature and in the degree of mixing and dispersion of sorbent within the flue gas. Since neither could be rigorously quantified on a routine basis in the full-scale unit, a short review of issues considered during the original design phase of the EPA project provides some insight worth remembering during the discussion of the results.

The fact that pilot studies had all shown the existence of a sulfation temperature window of approximately 2300 to 1600°F for the various sorbents was fundamental to the design of the LIMB system. Temperature and flue gas velocity measurements at full load in the Edgewater boiler indicated that the window roughly corresponded to that area of the upper furnace between the nose and the secondary superheater. In addition, the complex gas flow patterns that result as the gas passes the nose into the upper furnace cavity, while at the same time cooling as it turns to enter the convective pass, were all taken into account. To a lesser extent, operation at lower loads, changes in excess air, and/or placing specific burners in service were also recognized as having potential effects on temperatures and mixing.

The final design included provision for injection ports located at the three plant elevations of 181, 187, and 191 ft as shown in Figure 5, with elevation 181 ft corresponding to the upper end of the sulfation temperature window at full load. The lower two levels were initially recommended, with the ports at elevation 191 ft added in light of concern that a lower temperature might still be desirable, even though mixing and dispersion were more difficult to achieve at this level. Longer residence times were thought to compensate for lower temperatures associated with either operation at lower loads or injection at the uppermost elevation. While it was impractical to measure the actual temperatures at the upper two locations, a drop of approximately 200°F in the average temperature was estimated across each of the two gaps between elevations.

In order to make the installed system at least somewhat adjustable to the conditions that would be encountered, the injection nozzles were designed for manual tilting through a 30° arc. However, tests during the EPA LIMB Demonstration revealed that the tilting feature did not lead to any significant changes in the performance realized. For this reason, no tests were conducted during the LIMB Extension on the effects of nozzle tilt.

In comparison to the LIMB Extension, the relatively small amount of data obtained during the EPA LIMB Demonstration tests had shown that injection at elevation 181 ft resulted in greater SO_2 removal than that achieved at elevation 187 ft. Although the same general assessment is derived from the more extensive data obtained for the limes in this project, the evidence is not regarded to be as conclusive as originally had been anticipated for the reasons described above. Moreover, the results with the limestone perhaps show that the middle elevation is favored for that sorbent.

The first series of tests at the three injection elevations during the LIMB Extension were conducted with coarse limestone sorbent and 3.0 percent sulfur coal (Figure 32). These tests appeared to show that injecting at elevation 187 ft produced the highest removal, elevation 191 ft the lowest, and 181 ft an intermediate value. This was not unexpected in light of the pilot tests that showed limestone to be more prone to sintering. Subsequent tests while burning 1.6 percent sulfur coal indicated comparable results at elevations 181 and 191 ft (Figure 33). Unfortunately, circumstances required that the tests move on to dolomitic lime before tests with limestone could be conducted at elevation 187 ft. At the time this was not a concern, since it was thought that there would be another opportunity to test this condition. The later decision not to pursue tests with the coarse limestone because of its overall low reactivity leaves one with the conclusion from the one set of tests with the 3.0 percent sulfur coal indicating that the 187 ft elevation was optimal. Nevertheless, experience with the other sorbents, as described below, suggests that this conclusion be considered subject to further investigation.

As the tests with the limes were in progress, differences among the elevations, particularly between elevations 181 and 187 ft, were not immediately obvious, though removals achieved from injection at elevation 191 ft always appeared lower. Once all the data were plotted, however, the general trend pointed to slightly, though consistently, higher removals for injection at elevation 181 ft (Figures 34 to 38) when compared to that at elevation 187 ft. The only exception to this appears in Figure 34 for dolomitic lime injection while burning the 3.0 percent sulfur coal. The

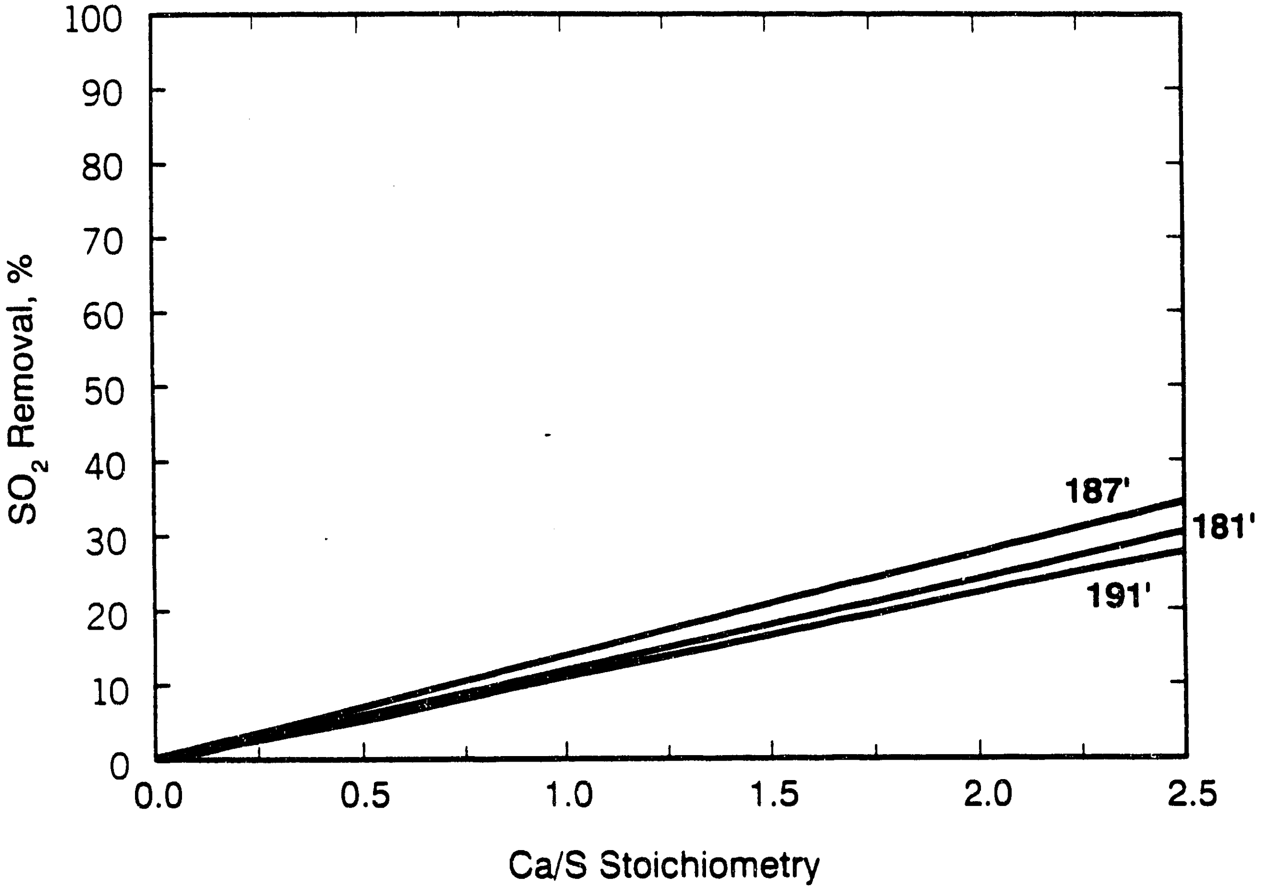


Figure 32. Effect of injection level on SO_2 removal while burning 3.0 weight percent sulfur coal and injecting coarse limestone

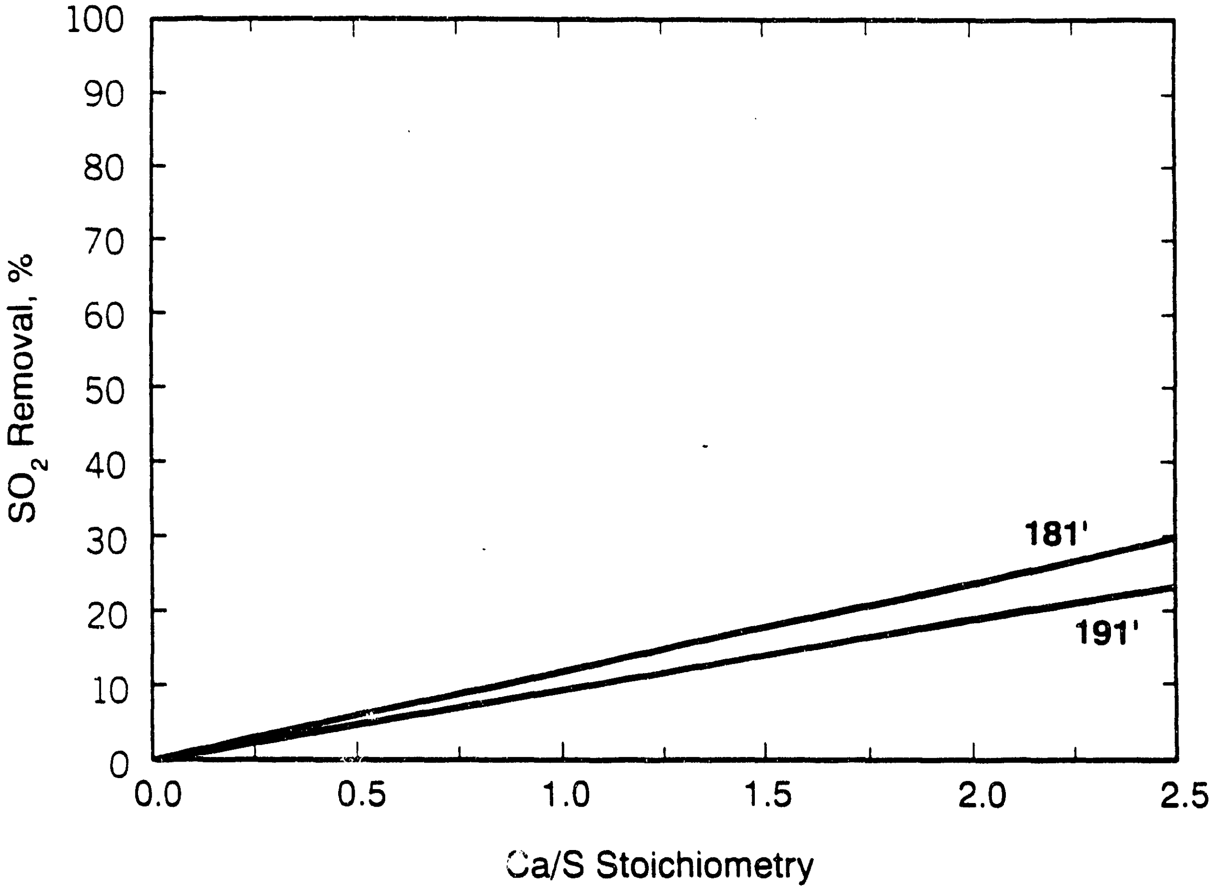


Figure 33. Effect of injection level on SO_2 removal while burning 1.6 weight percent sulfur coal and injecting coarse limestone

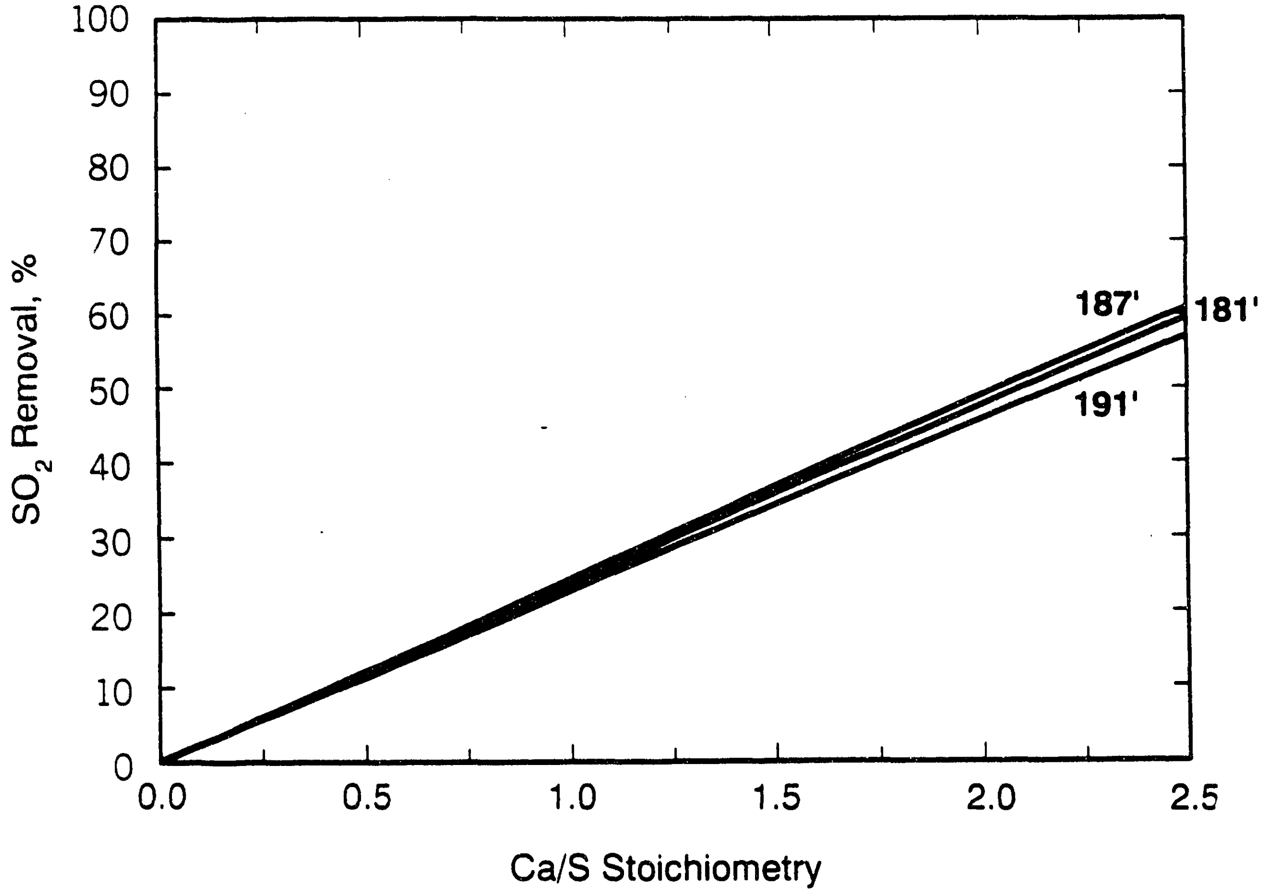


Figure 34. Effect of injection level on SO_2 removal while burning 3.0 weight percent sulfur coal and injecting dolomitic lime

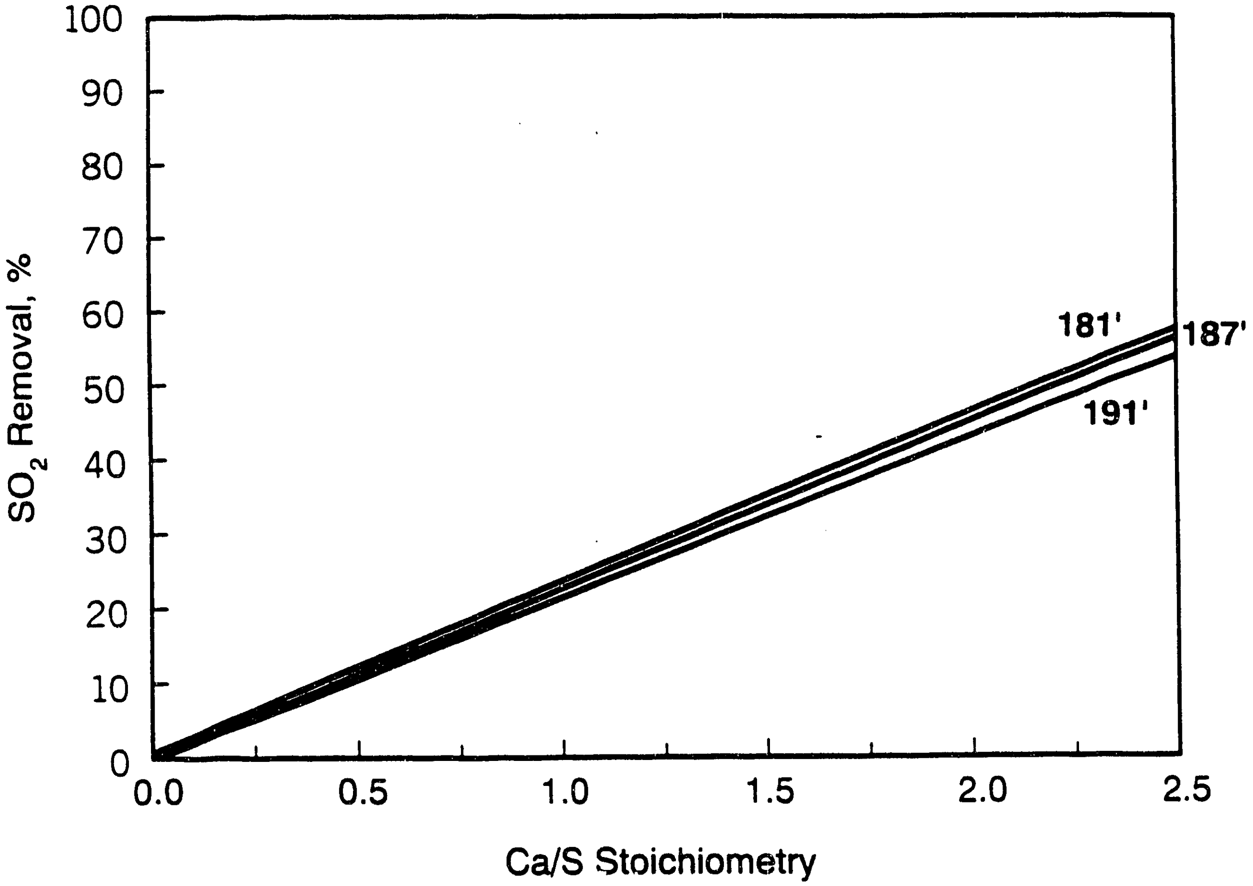


Figure 35. Effect of injection level on SO_2 removal while burning 1.6 weight percent sulfur coal and injecting dolomitic lime

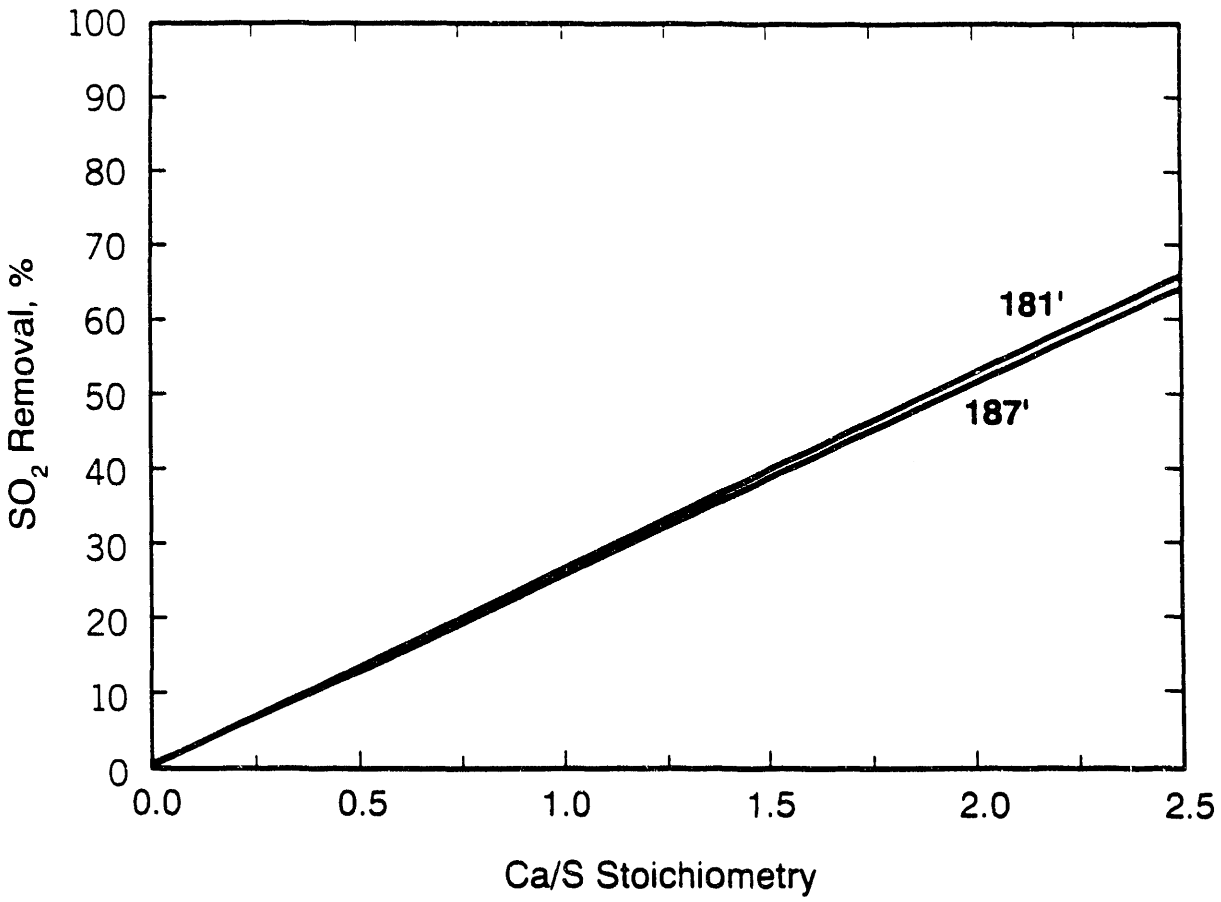


Figure 36. Effect of injection level on SO_2 removal while burning 3.8 weight percent sulfur coal and injecting dolomitic lime

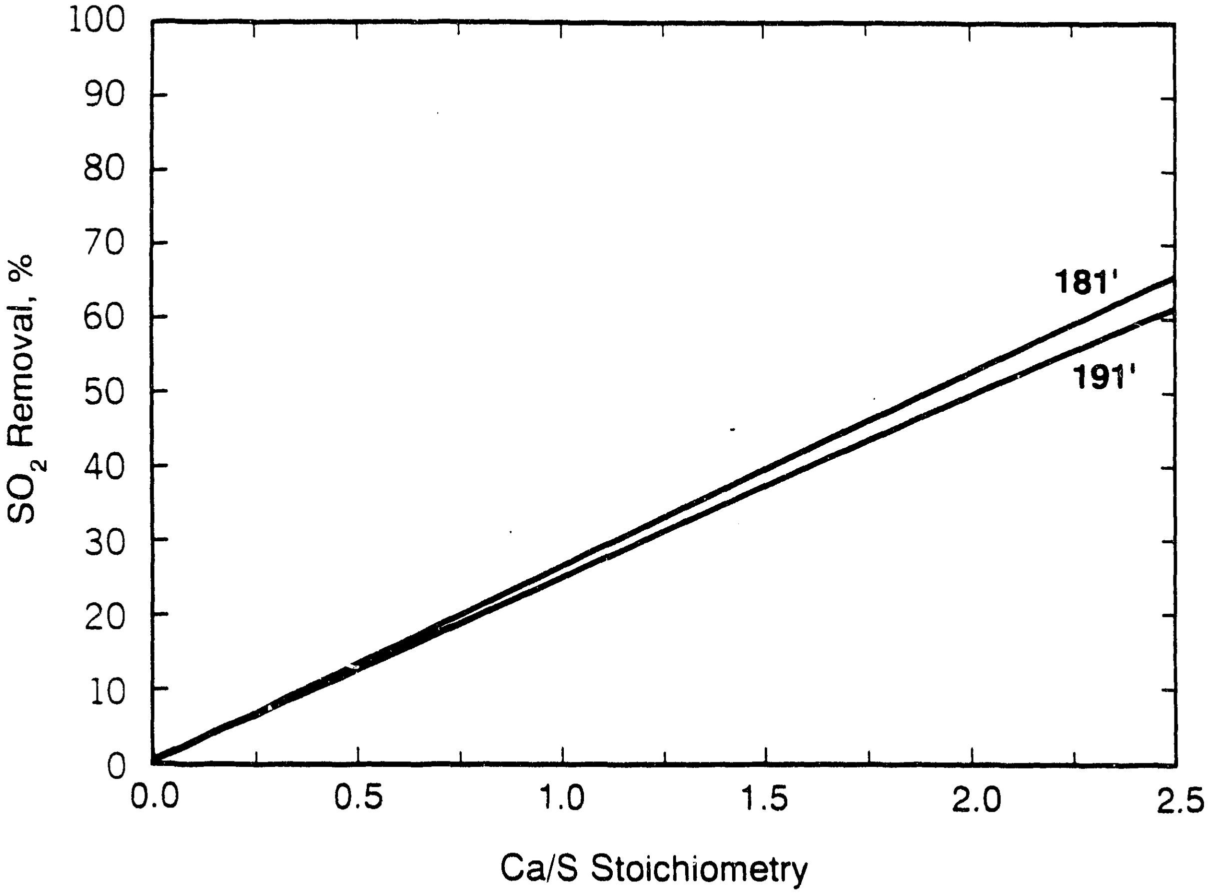


Figure 37. Effect of injection level on SO_2 removal while burning 1.6 weight percent sulfur coal and injecting ligno lime

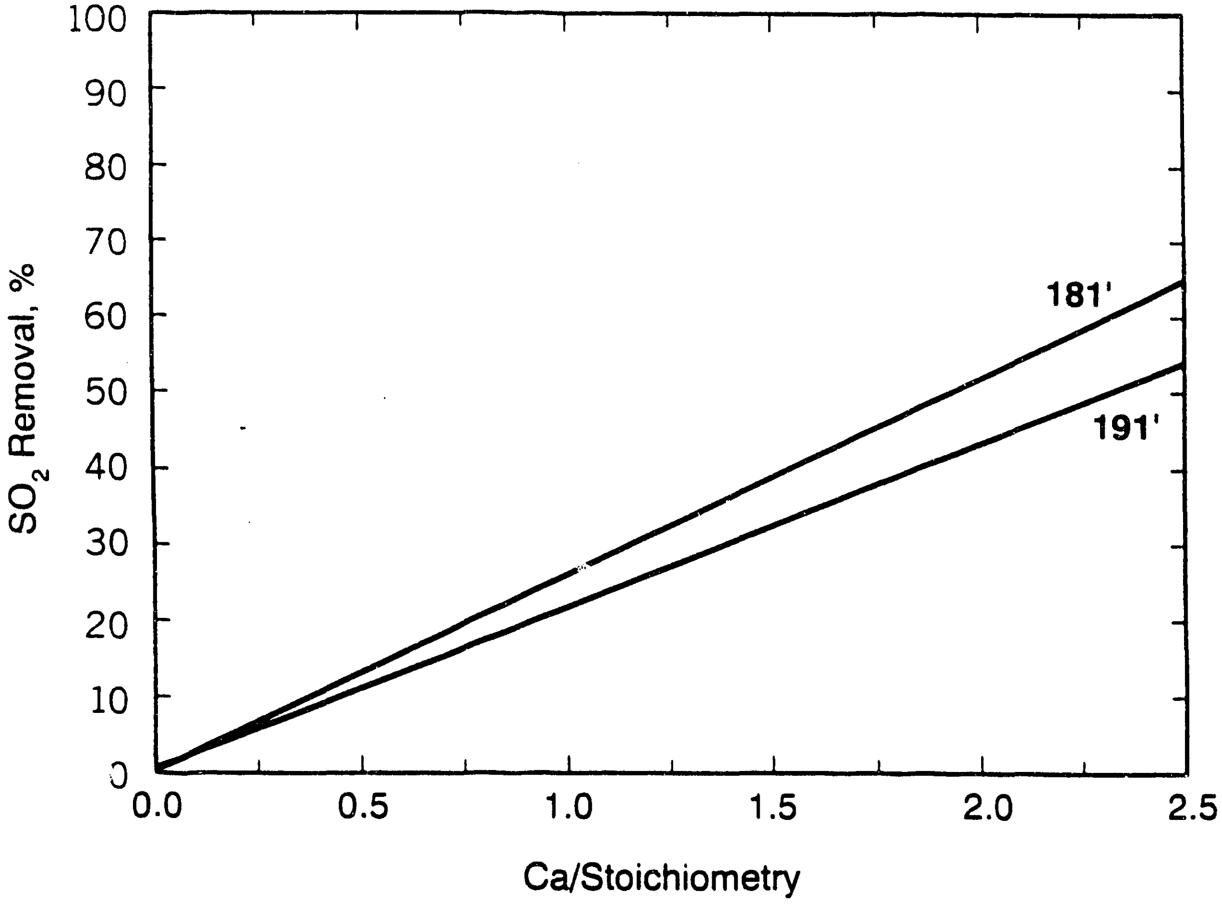


Figure 38. Effect of injection level on SO_2 removal while burning 1.6 weight percent sulfur coal and injecting calcitic lime

differences in removal between the two levels are regarded as real, though probably insignificant when compared to the difference between either and that obtained at elevation 191 ft. At this elevation, temperatures several hundred degrees cooler and flue gas flow patterns unfavorable for adequate dispersion of the sorbent combine to result in decreased SO_2 removal efficiency. Beyond this, the relative importance of the individual variables that constitute "injection level" cannot be determined from the data at hand.

Humidification

The installation of the humidification chamber capable of achieving a 20°F approach to the adiabatic saturation temperature of the flue gas provided the opportunity to enhance SO_2 removal of the LIMB system and to permit demonstration of the Coolside process. Since the flue gas saturation temperature for the coals used during the LIMB Extension was approximately 125°F, "close approach" operation typically meant controlling the humidifier outlet (ESP inlet) flue gas temperature at approximately 145°F. The humidifier was also frequently run in a "minimal humidification" mode where the outlet temperature was usually set in the 250 to 275°F range, depending on the identity and feed rate of the sorbent, as required to maintain ESP performance.

Close approach tests were run with the majority of the coal/sorbent combinations tested. The most extensive tests were run using the ligno lime sorbent injected at the 181 ft elevation while burning 1.6 percent sulfur coal. Figure 39 presents the stoichiometry/SO_2 removal data obtained at close approach with comparable results with minimal humidification. These plots give rise to an approximate 17 percent absolute increase in SO_2 removal efficiency at a stoichiometry of 2.0. Similarly derived summary data for all the tests run are presented in Table 11 which shows the increase in efficiency predicted at that common reference condition for all the coal/sorbent combinations tested at close approach. As a result of the statistical nature of the reduction, the values in this table perhaps represent a somewhat broader range than might otherwise be expected. In actual practice the loss of enhancement realized by simply closing the valve to reduce humidification water flow, typically resulted in the immediate loss of about 10 percent in removal efficiency for most of the conditions tested. About the same performance was observed during the original EPA demonstration.

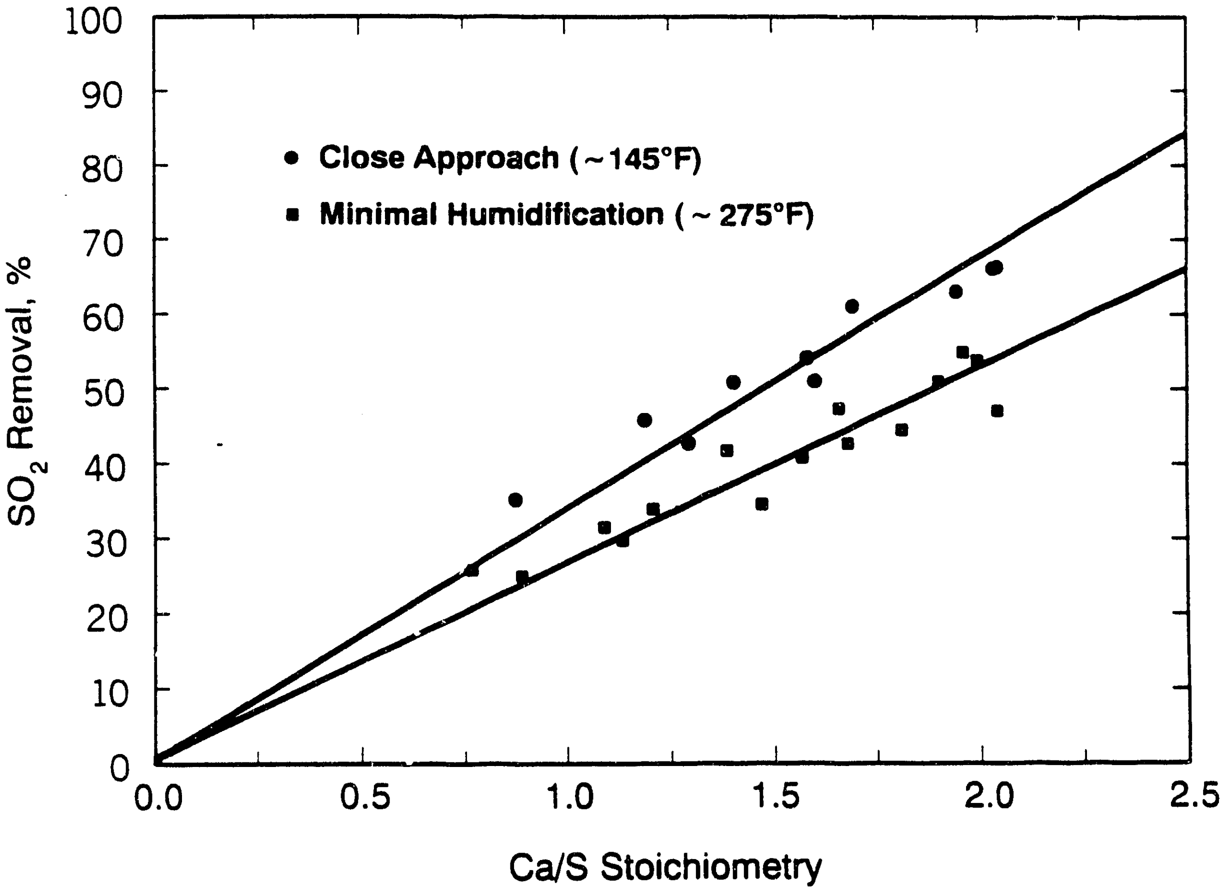


Figure 39. Effect of humidification on SO_2 removal

TABLE 11. INCREASE IN ABSOLUTE SO_2 REMOVAL EFFICIENCY POSSIBLE WITH HUMIDIFICATION TO CLOSE APPROACH TO SATURATION[*]

Sorbent	Nominal Coal Sulfur, wt % 1.6	3.0	3.8
Calcitic Hydrated Lime	NT[†]	10[‡]	NT
Ligno Lime	17	9	10
Dolomitic Hydrated Lime	17	10	NT
Limestone (80% < 44μm)	7	NT	NT

[*] Sorbent injection at elevation 181 ft at a Ca/S ratio of 2.0.

[†] NT = Not tested.

[‡] Determined during the EPA LIMB Demonstration.

NO_x EMISSION CONTROL

During the LIMB Extension, plant personnel operated the B&W DRB-XCL™ burners in the same manner as would be typical at any commercial facility. The twelve burners installed replaced circular burners that produced NO_x emissions of 0.79 to 0.94 lb/10^6 Btu at full load during baseline tests conducted in 1986 for the original LIMB Demonstration.[1] As was the case during that project, the NO_x and O_2 analyzers in the CEMS provided the concentrations of these gases that were used to convert the emissions to a lb/10^6 Btu basis as described in Section 5.

Close to the 0.48 lb/10^6 Btu NO_x emission average observed during the original LIMB Demonstration, the overall average value of 0.43 lb/10^6 Btu continued to surpass the original performance goal of 0.5 lb/10^6 Btu. This simple average represents the whole range of boiler operating conditions during the entire LIMB Extension. As was true in the earlier work, no evidence could be found that sorbent injection had any effect on NO_x emissions. More detailed evaluations took the form both of weighted averaging of all this data and of attempts to correlate some specific, shorter term NO_x emission variations with operational parameters.

As a weighted rolling average is commonly required for compliance reporting, both 24-hour and 30-day averages were calculated from the individual 10-minute averages stored in the System 140™. Coal firing rate was used as the weighting factor. A series of graphs present the progression from the individual 10-minute averages used as "raw" data from the CEMS (Figure 40), through the 24-hour weighted rolling average (Figure 41), to the 30-day weighted rolling average (Figure 42). (While the weighted rolling averages are plotted for the entire LIMB Extension period,

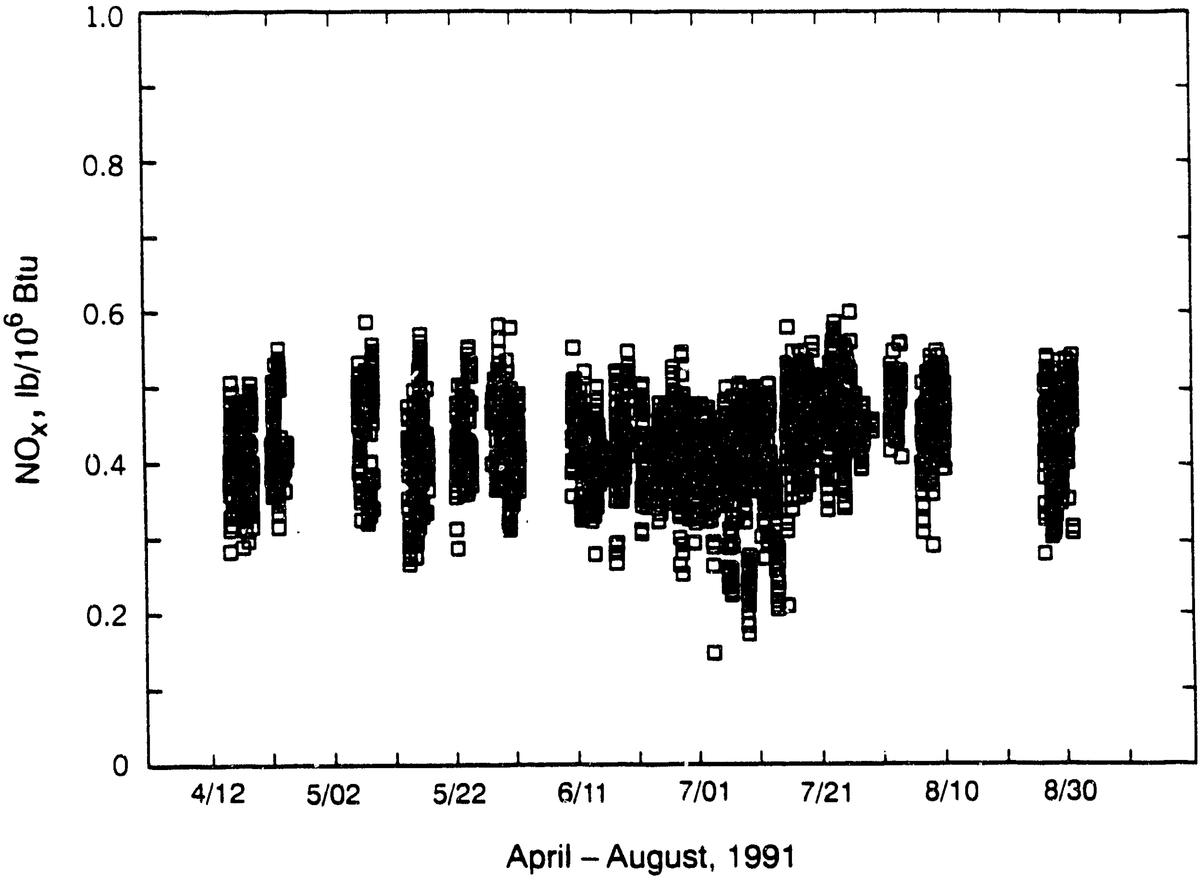


Figure 40. 10 min average DRB-XCL™ burner NO_x emissions, April 13, 1991 to August 30, 1991

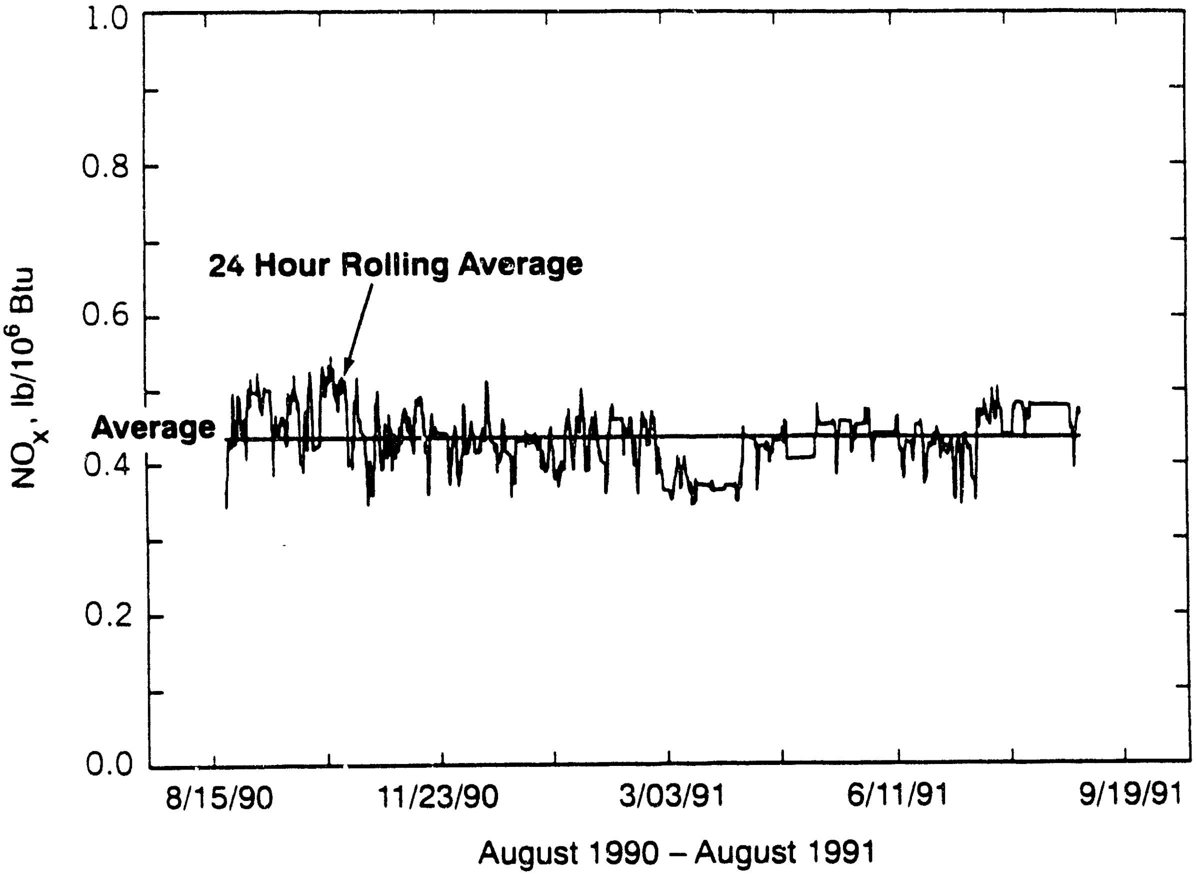


Figure 41. 24 hr Rolling average DRB-XCL™ burner NO_x emissions, August 15, 1990 to August 30, 1991

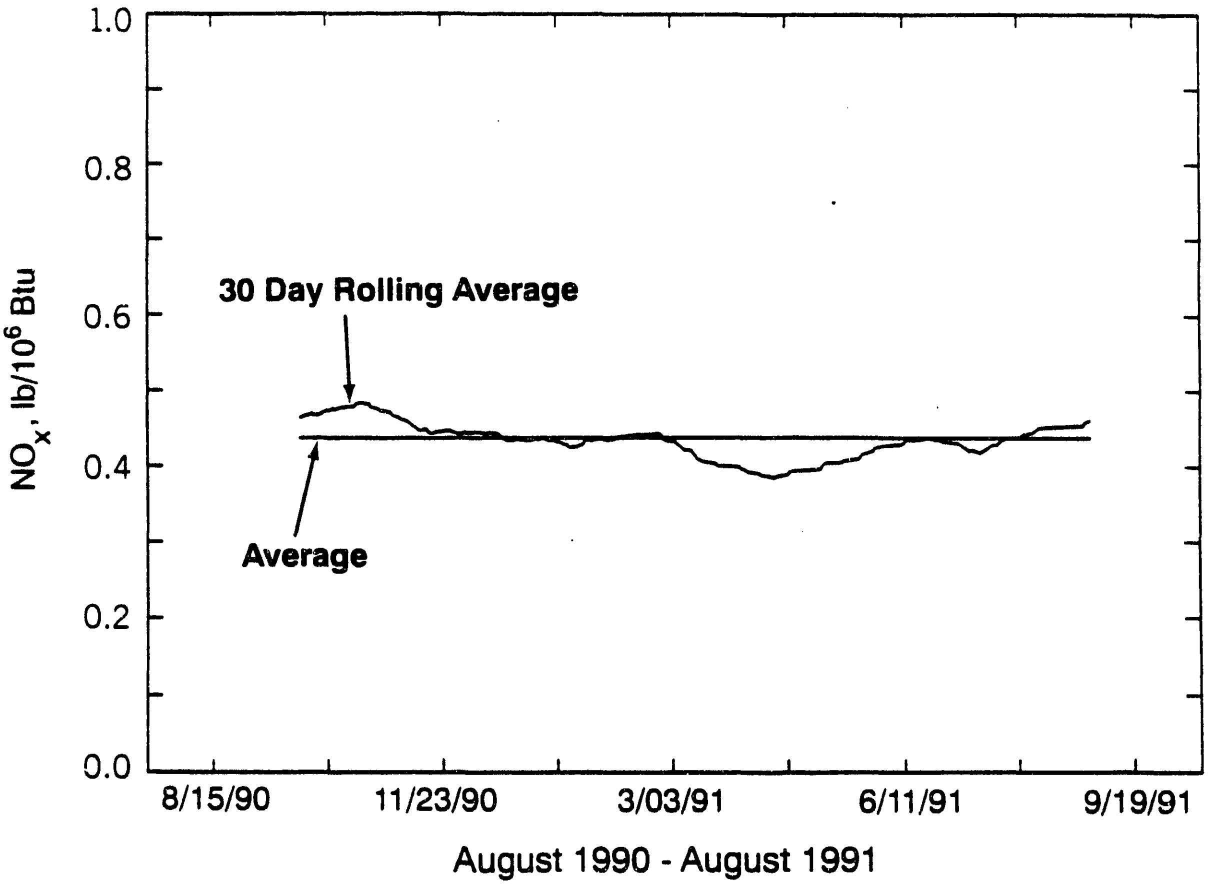


Figure 42. 30 day Rolling average DRB-XCL™ burner NO_x emissions, August 15, 1990 to August 30, 1991

computer memory limitations made it impossible to place all of the individual 10-minute averages in one graph. The April to August 1991 shown is representative of the data from earlier operation.) Both the 24-hour and 30-day weighted rolling averages determined during the Extension themselves averaged 0.44 lb/10^6 Btu. These compare to values of 0.47 and 0.49 lb/10^6 Btu, respectively, found during the original demonstration.

During the EPA LIMB Demonstration, there appeared to be somewhat regular variations in the individual NO_x emissions that suggested further reduction might be possible if the controlling variable could be identified. Pilot tests of an individual burner have typically shown that NO_x emissions vary with load and excess combustion air, as reflected in flue gas O_2 concentration. At the time of the original demonstration, the stack emission resulting from the array of DRB-XCL™ burners appeared to be insensitive to these two operating factors. There was, however, some variation within the scatter that suggested control might be possible if the cause could be determined. Such variation continued during the LIMB Extension and provided an opportunity to explore potential sources with much more data. This took the form of attempts to correlate NO_x emissions, not only with load and flue gas O_2 concentration, but also with the identity of pulverizers/burners in service, coal fineness, and even what can be a related dependent variable, carbon monoxide (CO) emissions. Unfortunately, no consistent relationship could be found between NO_x emissions and any of these variables.

PARTICULATE EMISSION CONTROL

As was found early in the EPA LIMB Demonstration, sorbent injection can dramatically affect particulate emission control by an ESP for three reasons. These include the increased particulate loading caused by the sorbent introduced, the finer size of this material, and the higher resistivity of the resultant ash. All three factors tend to degrade ESP performance.[13] Although the large (612 $ft^2/10^3$ ACFM) SCA of the ESP had been expected to permit adequate performance and meet emissions and opacity requirements, such was not the case in the first trials in September 1987, primarily because the high resistivity of the LIMB ash gave rise to a back corona condition which rendered the ESP virtually incapable of dust collection. Fortunately, planning for humidification had already begun and included a realization of the potential benefits for ESP performance.

During the balance of the EPA project and continuing into the DOE LIMB Extension, humidification of the flue gas proved to be a very effective method of maintaining ESP performance. Opacity was generally in the one to three percent range during injection of each of the sorbents, similar to what had been observed during the EPA project. Only two differences were noted, the first being that the calcitic limestone did not seem to require as much humidification. This is thought to be due either to its larger particle size making particulate collection easier, and/or to the fact that the cooler air heater outlet flue gas temperature required relatively little humidification water to maintain the temperature of the gas entering the ESP. The second difference was noted when the injection of dolomitic lime seemed to require a somewhat lower humidifier outlet temperature setpoint (250°F *vs.* 275°F) to maintain the desired opacity. This was thought to be due at least in part to the higher particulate loading associated with this sorbent for an equivalent Ca/S stoichiometry.

Particulate emission control was continuously monitored during the LIMB Extension by the opacity monitor located between the ID fan downstream of the ESP and the stack. The System 140™ took a signal from this monitor once a minute in the same way as it did other signals from the CEMS. When used for actual compliance purposes by Ohio Edison, much more frequent readings are required. Nevertheless, the large number of individual data collected, representing the full range of boiler operating conditions, are considered to be at least a semiquantitative indication of the particulate emission control realized during LIMB operation, especially when compared to similarly-gathered opacity measurements taken when no sorbent injection was taking place.

There were several reasons for relying on opacity measurements to characterize particulate emission control. One of these is that ESP technology is regarded as a mature technology for which the effects of changing the independent variables are well established. Another is that the costs of maintaining steady-state conditions for the one to two weeks required to develop truly meaningful data became prohibitive. This was particularly true when viewed against the emphasis on characterizing the SO_2 removal with much more frequent change in operating conditions. Continuous opacity data was considered to be a reasonable alternative as an indicator of the general impact of the technology on particulate emissions.

Table 12 summarizes the results obtained from averaging the opacity values over representative periods of the project, both with and without sorbent injection. The average opacity indicated is the average of all the ten-minute averages scanned over the designated time periods, both when sorbent was being injected and when it was not. As can be seen, sorbent injection appears to have no effect on opacity. This, of course, is intimately related to an appropriate degree of flue gas humidification, especially when the lime sorbents were in use.

Perhaps the most important data in the table are the maximum ten-minute average values for each of the periods of sorbent use and non-use. These data, along with the average values, suggest that there was little difference between the two in opacity, and therefore particulate emissions, over both short and extended periods of time. Compliance under normal operating conditions requires that a six-minute average opacity value be less than 20 percent, although higher values can be permitted under certain transient conditions such as occur during start-up and pulverizers going in and out of service (trips). As can be seen in the table, the number of instances of high opacity is extremely low relative to the number of averages included. The single highest ten-minute average recorded during sorbent injection within these periods was 12.27 percent while ligno lime was in use. Even this value may not be totally associated with injection, since the opacity monitor does not distinguish among types of particulate. Of the seven occurrences when the ten-minute average value exceeded 10 percent opacity, including the two over 20 percent, all were associated with three instances of a pulverizer coming on-line.

TABLE 12. OPACITY WHILE INJECTING DIFFERENT SORBENTS

Sorbent	Time Period (Full days without data within period)*	Injection	Average Opacity, %	Standard Deviation x 2	Number of Ten-minute Averages*	Number of Ten-minute Averages with Opacity		Maximum Ten-minute Average Opacity, %
						>10 %	>20 %	
Calcitic Hydrated Lime	07/09/91 - 08/29/91	On	1.87	1.81	1481	0	0	3.53
	(20)	Off	1.27	2.01	1976	0	0	4.09
Ligno Lime	03/22/91 - 05/29/91	On	1.25	2.04	1518	2	0	12.27
	(39)	Off	1.78	2.96	1417	5	2	25.24
Dolomitic Hydrated Lime	08/20/90 - 10/07/90	On	2.90	1.92	426	0	0	5.02
	(17)	Off	3.21	2.51	2268	0	0	5.96
Limestone (80% < 44μm)	06/29/90 - 07/06/90	On	1.41	0.66	603	0	0	7.16
	(0)	Off	1.54	1.21	207	0	0	8.73

* Averages were, of course, calculated only from data taken while the boiler and instrumentation were on-line. Weekend shutdowns and outages account for a significant portion of the time not reflected in the "Number of Ten-minute Averages".

SECTION 7
OPERATING RESULTS

The sorbent injection and humidification equipment operated throughout the LIMB Extension without any major problems, though the use of previously untested sorbents and/or more extensive tests did have notable effects on plant operations. Injection of large quantities of the lime sorbents continued to cause elevated temperatures at the air heater outlet. When the more coarse limestone was being injected, the increase in air heater temperatures was negligible. At equivalent stoichiometries, the higher proportion of quicklime in the ash produced by the limestone sorbents caused more steam to be produced at the ash unloading facility than did the lime sorbents. Dolomitic lime could require larger storage and transfer capacities, due to the unreactive MgO component that must be handled during delivery, use, and ash unloading. Each of these aspects are discussed more completely in the following subsections.

FURNACE

The greatest impact of sorbent injection into the furnace is decreased heat transfer caused by increased ash build-up on convective tube surfaces. The material that does accumulate is easily removed by sootblowing. Limitations arise, however, when the sootblowing system is unable to handle the increased ash loading caused by sorbent injection. The system's inability to handle this increased loading can be related to inadequate coverage of affected tube areas, and/or to insufficient capacity of the system for the frequency of blows necessary to keep the tubes clean.

The original sootblowing system on the Unit 4 boiler at the Edgewater Station used compressed air as the blowing medium. For the EPA LIMB Demonstration, analysis of the sootblower system led to the decision to install four new steam sootblowers near the reheat and primary superheat banks of the convective pass. Other areas appeared to be well covered. Despite these additions, air heater outlet temperatures consistently ran in the 350°F range while lime sorbents were being injected at the higher stoichiometries. Because the sootblowers had to operate in an almost continuous cycle to maintain this temperature, it was concluded that capacity, rather than location, was the more important limiting factor of the compressed air system .

In light of the apparent capacity limitation of the existing system, all but the four air heater sootblowers were converted to steam before beginning the LIMB Extension project. The air-to-steam conversion was done in an effort to maintain a more normal air heater outlet temperature of about 300°F. These sootblowers had a design requirement of 5,700 lb/hr of steam if operated in a continuous sequence. Actual steam consumption would vary depending upon the degree of sootblowing required which, in turn, varied with load, sorbent feed rate, sorbent type, and other considerations not readily quantified, most of which had to do with operator preferences regarding what was required for the overall safe and efficient operation of the boiler . After the conversion, the sootblowers could be cycled five to six times a shift, where previously it had been once or twice per shift with the compressed air system. Unfortunately, the air heater outlet temperature remained well above 300°F whenever the lime sorbents were injected at Ca/S ratios greater than about 1.5. As a result, future LIMB applications should address even more thoroughly both the capacity and effective coverage of the existing or expanded sootblower system to be used.

As noted earlier, injection of the more coarse limestone sorbent had almost no effect on the air heater outlet temperature. It typically remained near 300°F, even when the higher stoichiometries were employed. Attempts to uncover why this was the case have been unsuccessful. Since there was perhaps some evidence of increasing temperatures in the convective pass while the very fine limestone was being injected, some sort of particle size effect is suspected. No definitive conclusion is claimed, however, since only very limited amounts of this material were used. Although a somewhat greater quantity of the fine limestone was used, temperature increases were not readily apparent.

The tests run were designed primarily to characterize SO_2 removal, rather than to establish a quantitative relationship between sorbent injection and air heater outlet temperature. To accomplish the latter, much more stringent controls would have to have been placed on achieving equilibrium starting temperatures throughout the unit. In addition, a much more well-defined sootblowing regimen, taking into account such considerations as the differences in molecular weights and the order and frequency with which individual units blow, would have been required to assure the use of equivalent, reproducible conditions. While desirable in theory, such criteria were beyond practical implementation in the full-scale unit.

In spite of these difficulties, Table 13 is presented to provide at least some indication of the upper end of the range of air heater outlet gas temperatures experienced at Edgewater. The data are taken from tests representing each sorbent injected at elevation 181 ft at a Ca/S stoichiometry of 2.0 while burning 1.6 percent sulfur coal. Since the highest lime feed rates were used while

TABLE 13. AIR HEATER GAS OUTLET TEMPERATURES, °F, DURING SORBENT INJECTION*

Sorbent	1.6 % S Coal Temperature	1.6 % S Coal Number of Ten-minute Averages	3.8 % S Coal Temperature	3.8 % S Coal Number of Ten-minute Averages
Calcitic Hydrated Lime	334	4	352	6
Ligno Lime	324 321	23 5	344	3
Dolomitic Hydrated Lime	370	17	376 371	11 12
Limestone (80% < 44μm)	307	13	NT†	NT
Limestone (100% < 44μm)	310	14	NT	NT
Limestone (100% < 10μm)	308	16	NT	NT

* See text for description of the operating conditions.
† NT = Not tested.

burning the 3.8 percent sulfur coal, temperature data are included for these conditions as well. The main steam flow for the selected tests is about 600,000 lb/hr (approximately 80 to 85 MWe). The reason for this is that this was the one load for which data was available for all the sorbent combinations with the high and low sulfur coal cases under somewhat comparable conditions. While sootblowing was generally kept in "continuous" operation during the tests with the limes, individual operator preferences imposed some variation on the degree of continuity employed. Since the system capacity had been greatly increased by the conversion to steam, the high air heater outlet temperatures suggest that the limitation of the sootblowing system was not so much the capacity, as it was the number and location of the sootblowers themselves.

BOILER TUBE THICKNESS TEST RESULTS

Ultrasonic Testing Description

As part of the original LIMB project, plans included provision for ultrasonic testing (UT) to examine the effects of furnace sorbent injection and use of the low-NO_x burners on the boiler's internal water tubes. UT is a nondestructive technique based on the transmission of sound waves through a material and is routinely used to measure metal thickness in the industry. The increased particulate loading presented the possibility for accelerated erosion of the tubes' exterior surfaces, while the tendency of the burners to form longer flames increased the potential for a less oxidizing environment which might lead to tube corrosion on the north (rear) wall of the relatively shallow furnace. The test plan therefore sought first to determine the pre-LIMB thickness of the metal tubes in those areas of the boiler most likely to have the highest potential for erosion and/or corrosion. UT was then to be repeated at the end of the LIMB program to determine abnormal wear by comparison with the earlier data.

The UT program began in August 1986 when scaffolding permitted extensive baseline measurements on the furnace water-wall and convective pass tubes. In June 1989, "sky climbers" suspended from the furnace roof were used to allow measurement of tube thicknesses only on the furnace water-wall opposite the burners during the relatively brief outage between the EPA and DOE projects. The specific locations for these measurements were chosen to match those of the 1986 locations as closely as possible. Finally, scaffolding installed again in October 1991 at the conclusion of the LIMB Extension permitted the collection of more extensive UT data throughout the boiler.

Measurements were generally made on that portion of each tube directly facing the flue gas flow or, in the case of the furnace wall tubes, the furnace cavity. A predetermined portion of all the tubes at any given location were chosen for measurement. Table 14 summarizes the areas of the boiler where measurements were made during each UT period. The table also provides the percentages of the total number of tubes tested each time.

Results and Discussion of Tube Thickness Measurements

The results obtained from the 1986, 1989, and 1991 UT programs are presented and compared in terms of the average thicknesses determined for the various areas (Table 15) and locations (Table 16) in the boiler. A more detailed comparison, for example, on individual tubes, is not warranted as it was virtually impossible to repeat readings at precisely the same, small UT points on each of the hundreds of tubes from one test period to the next. Nevertheless, most repeat test locations are thought to be within a few inches of the earlier measurement(s). This is particularly true for the waterwall tubes where elevation measurements could be made more easily, especially during the 1986 and 1991 test programs when scaffolding was installed throughout the furnace.

Most of the comparisons are made on the data collected in the 1986 and 1991 test periods. As originally planned, the measurements were intended to provide a data base in case

TABLE 14. BOILER TUBE ULTRASONIC TESTING LOCATIONS AND PERCENTAGE OF TUBES TESTED

UT Area	UT Location	Total No. of Tubes at Location	Tubes Tested, % 1986	1989	1991
North Furnace Wall	Elevation 115 ft	121			100
	Elevation 123 ft	121			100
	Elevation 129 ft	121	33	17	100
	Elevation 132 ft	121	33	17	
	Elevation 135 ft	121	33	17	100
	Elevation 138 ft	121	33	17	
	Elevation 144.5 ft	121	33	17	
	Elevation 147 ft	121	33	17	100
	Elevation 150 ft	121	33	17	
	Elevation 153 ft	121	33	17	100
	Elevation 156 ft	121	33	17	100
	Elevation 172 ft	121			100
Side Furnace Walls (East and West)	Elevation 129 ft	88	33		100
	Elevation 132 ft	88	33		
	Elevation 135 ft	88	33		100
	Elevation 138 ft	88	33		
	Elevation 144.5 ft	88	33		
	Elevation 147 ft	88	33		100
	Elevation 150 ft	88	33		
	Elevation 153 ft	88	33		100
	Elevation 156 ft	88	33		100
	Elevation 172 ft				100
South Furnace Wall	Elevation 115 ft	121			100
	Elevation 172 ft	121			100
Pendant Secondary Superheater	259 in above slope	30	50		100
	192 in above slope	30	50		100
	48 in above slope	30	50		
	43 in above slope	30			100
Outlet Reheater Bank	200 in above slope	60			100
	103 in above slope	60	50		100
	43 in above slope	60	50		
	3rd row above weld				100
Inlet Reheater Bank	31 in above slope	60	50		
Horizontal Secondary Superheater	33 in from wall	90	50		
	15 in from wall	90	50		
	Below sootblower	90			100
Primary Superheater	24 in from wall	90	50		
Economizer	18 in from west wall	50	50[*]		
	91.75 in from west wall	50	50[*]		
	183.5 in from west wall	50	50[*]		
	275.25 in from west wall	50	50[*]		
	394 in from west wall	50	50[*]		
	Below east sootblower	50			50
	Below west sootblower	50			50

[*] Thickness was also measured at points 45° to the left and right of the center point facing the gas flow.

TABLE 15. ULTRASONIC TESTING AREA AVERAGES

UT Area	Average Tube Thickness, mil 1986	 1989	 1991	Design Tube Thickness, mil
North Furnace Wall	272 ± 15*	279 ± 14	260 ± 28	265 ± 27
West Furnace Wall	271 ± 15	NT	257 ± 19	265 ± 27
East Furnace Wall	270 ± 16	NT	259 ± 21	265 ± 27
South Furnace Wall	NT†	NT	252 ± 24	265 ± 27
Pendant Secondary Superheater	334 ± 55	NT	307 ± 63	≥300
Outlet Reheater Bank	243 ± 46	NT	207 ± 100	≥220
Inlet Reheater Bank	225 ± 17	NT	NT	≥203
Horizontal Secondary Superheater	351 ± 32	NT	342 ± 28	≥300
Primary Superheater	256 ± 24	NT	NT	≥240
Economizer	257 ± 20	NT	258 ± 17	≥240

* Variation is twice the standard deviation of the measured thickness, and the allowable tolerance in the design thickness.
† NT = Not tested.

extensive erosion/corrosion occurred. This was not the case, however, as most of the 1991 averages appear to be only slightly less than the 1986 averages. This is what might be expected as a result of five years of additional operation.

The precision of measurements within a test period is lower for the convective pass UT locations. This is true for both the baseline and concluding test periods for several reasons. The pendant secondary superheat and reheat banks, in particular, are exposed to the highest temperatures and pressures in this area of the boiler. Because of this, tubes in these areas are most prone to failure, repair, and replacement. This made measurements more susceptible to variations, since test engineers were occasionally forced to modify test locations up or down a few inches across the planned elevations. In addition, the limited accessibility and complexity of these tube banks generally make it more difficult to take readings in these areas.

The limitations of UT for assessing long term wear are evident when comparisons are made with the 1989 data, which appear to show an impossible increase in tube thickness. The use of similar, though not identical, test equipment by different personnel at slightly different points, are thought to be responsible, at least in part, for the variation in the data among the three test periods, even though instrument calibrations were thought to reduce this to being a negligible

TABLE 16. ULTRASONIC TESTING LOCATION AVERAGES

UT Area	UT Location	Average Tube Thickness, mil 1986	 1989	 1991
North Furnace Wall	Elevation 115 ft	NT	NT	243 ± 33
	Elevation 123 ft	NT	NT	249 ± 29
	Elevation 129 ft	270 ± 16	270 ± 16	263 ± 19
	Elevation 132 ft	273 ± 18	273 ± 18	NT
	Elevation 135 ft	272 ± 19	272 ± 19	270 ± 18
	Elevation 138 ft	272 ± 13	272 ± 13	NT
	Elevation 144.5 ft	273 ± 14	273 ± 14	NT
	Elevation 147 ft	271 ± 16	271 ± 16	268 ± 16
	Elevation 150 ft	271 ± 10	271 ± 10	NT
	Elevation 153 ft	274 ± 10	274 ± 10	263 ± 13
	Elevation 156 ft	273 ± 18	273 ± 18	264 ± 17
	Elevation 172 ft	NT	NT	254 ± 19
West Furnace Walls	Elevation 129 ft	271 ± 13	NT	260 ± 14
	Elevation 132 ft	269 ± 15	NT	NT
	Elevation 135 ft	271 ± 14	NT	257 ± 21
	Elevation 138 ft	269 ± 16	NT	NT
	Elevation 144.5 ft	271 ± 15	NT	NT
	Elevation 147 ft	274 ± 12	NT	261 ± 16
	Elevation 150 ft	271 ± 15	NT	NT
	Elevation 153 ft	271 ± 15	NT	266 ± 19
	Elevation 156 ft	269 ± 15	NT	258 ± 21
	Elevation 172 ft	NT	NT	261 ± 21
East Furnace Wall	Elevation 129 ft	270 ± 16	NT	263 ± 17
	Elevation 132 ft	272 ± 19	NT	NT
	Elevation 135 ft	270 ± 18	NT	262 ± 19
	Elevation 138 ft	271 ± 13	NT	NT
	Elevation 144.5 ft	268 ± 10	NT	NT
	Elevation 147 ft	269 ± 13	NT	259 ± 22
	Elevation 150 ft	272 ± 16	NT	NT
	Elevation 153 ft	269 ± 17	NT	269 ± 19
	Elevation 156 ft	269 ± 15	NT	259 ± 23
	Elevation 172 ft	NT	NT	264 ± 17
South Furnace Wall	Elevation 115 ft	NT	NT	239 ± 24
	Elevation 172 ft	NT	NT	258 ± 18
Pendant Secondary Superheater	269 in above slope	328 ± 41	NT	303 ± 27
	182 in above slope	321 ± 68	NT	282 ± 59
	48 in above slope	353 ± 25	NT	NT
	43 in above slope	NT	NT	335 ± 43
Outlet Reheater Bank	200 in above slope	NT	NT	210 ± 111
	103 in above slope	234 ± 60	NT	237 ± 29
	43 in above slope	252 ± 12	NT	NT
	3rd row above weld	NT	NT	198 ± 90
Inlet Reheater Bank	31 in above slope	225 ± 17	NT	NT
Horizontal Secondary Superheater	33 in from wall	357 ± 34	NT	NT
	15 in from wall	344 ± 23	NT	NT
	Below sootblower	NT	NT	342 ± 28
Primary Superheater	24 in from wall	258 ± 24	NT	NT
Economizer	18 in from west wall	252 ± 17	NT	NT
	91.75 in from west wall	258 ± 29	NT	NT
	183.5 in from west wall	259 ± 14	NT	NT
	275.25 in from west wall	259 ± 16	NT	NT
	394 in from west wall	258 ± 16	NT	NT
	Below east sootblower	NT	NT	264 ± 18
	Below west sootblower	NT	NT	262 ± 13

[*] Variation is twice the standard deviation of the measured thickness.

[†] NT = Not tested.

factor. Unfortunately, there was no way of determining which set of data was more likely to contain the error if there was one. The fact that the values in all three periods generally fall within each other's 95 percent confidence intervals (defined by twice the standard deviation) suggests that tube wear was nowhere nearly as bad as had been thought possible in the early stages of the project. This is supported by the finding that the measurements in all but the pendant secondary superheater and reheater were very close to, and sometimes exceeded, the original design tube thicknesses even after all these years of service. Quantifying finer distinctions, such as the extent to which tube loss was due to "normal" wear, increased particulate loading, or increased sootblowing, of course, turned out to be impossible.

In summary, the UT conducted on the boiler water tubes in 1986, 1989, and 1991 demonstrated that no significant tube erosion or corrosion took place during the period in which lime and limestone sorbents were injected into the furnace. The data also indicate that the general condition of the tubes remains excellent, and that no abnormal tube replacement or repair has been necessary as the result of using LIMB technology. Moreover, the favorable results of the 1991 tests of the north furnace water-wall, in particular, supported Ohio Edison's decision to continue use of the DRB-XCL™ burners at the Edgewater Station after the demonstration concluded.

ASH HANDLING

As long as an appropriate level of humidification was used, the conservatively designed (SCA of 612 $ft^2/10^3$ ACFM) ESP at the Edgewater facility was capable of collecting the increased particulate loading that resulted from sorbent injection. For the nominal 10 percent ash coals burned, there was up to a two- to threefold increase in ash loading depending on the stoichiometric ratio and the specific sorbent being used. When upsets or problems occurred in the precipitator ash removal system, however, it was common to reduce or sometimes interrupt sorbent injection. Since the types of leaks and plugs were no different than those found in conventional ash systems, they were not a reflection of the operability of LIMB technology. It was just that instances of plugged hoppers or vacuum leaks, with the additional quantity of ash, began to strain the overall capacity of the existing system, leaving little, if any, margin for error.

ASH UNLOADING

Fly ash collected in the Unit 4 ESP at Edgewater is pneumatically conveyed to the storage silo as described in Section 4. Water is added to the ash in a pug mill situated beneath the silo and over a truck bay in order to provide dust control in the ash unloading and disposal process. For the LIMB system, this operation was expected to result in steam evolution as a result of the highly exothermic reaction of water with the quicklime component of the ash. Since no large scale byproduct use could be arranged at the time, dry ash disposal was rejected from a safety standpoint, and there was no water source readily available for alternative treatment at the disposal site, the plan for the original, one-year LIMB Demonstration called for use of the existing system. This consisted of increasing the water pumping capacity, addition of a large, reversible fan that was expected to draw or blow the condensing billows of steam out of the truck bay, and other relatively minor upgrades equipment. The wetted LIMB ash discharged from the pug mill drops into a truck waiting below.

During the LIMB Extension, the amount of steam generated depended primarily on the sorbent being used and the stoichiometry at which it was injected. While it was effectively impossible to determine the amount of water lost as steam accurately, qualitative observations were made. Ash from the limestone sorbents seemed to steam worse than that from the lime sorbents. This was attributed to the lower utilization of the limestone, resulting in a higher concentration of reactive CaO in the ash. Ash from the dolomitic lime, on the other hand, appeared to steam less than the other limes, presumably because the MgO component does not hydrate appreciably at atmospheric conditions. It also appeared that ash generated during close approach operation produced less steam as the result of the rehydration reaction taking place in the humidifier.

In actual practice, the steam evolved made it difficult to fill the trucks properly because it obstructed the operator's line of sight. As a consequence, early operations were characterized by under- and overfilled trucks. The latter caused the additional problem of ash spills which raised the pH of the water sent to the drain when the area was washed down. A neutralization system installed and upgraded during the original LIMB Demonstration adequately adjusted the pH of the water sent to the ash pond.

After failure of attempts to make the fan originally installed work, one moderately effective method of dealing with the difficulty consisted of lowering a hanging thermocouple to the desired fill level of the truck. The unloader would be stopped when the thermocouple readout showed that the hot ash had reached the desired level in the truck bed. While this worked for dump trucks with smaller beds, this procedure could not be used on larger trucks with tarpaulin supports spaced along the bed. These supports would have caught the thermocouple and its support wire whenever the truck was repositioned under the pug mill discharge chute during the filling process.

A multiple component exhaust system employing two large fans and three blowers was eventually used during the latter portions of the LIMB Extension to keep the operator's sight path clear. These were definitely more effective than the single fan system, though large amounts of steam combined with certain wind conditions in the vicinity of the bay occasionally required that a second operator assist in unloading.

Finally, it is noted that the steaming never stopped sorbent injection. Much of the difficulty stemmed from the site-specific conditions at Edgewater, particularly since it was decided early on that the relatively short term demonstration did not justify the expense that would have incurred by installing a known technology. A more permanent system would likely consist of dry unloading and transport to the disposal site, where installation of a water line and a radial stacking system would easily have avoided the difficulties caused by steaming altogether.

SORBENT STORAGE AND FEED SYSTEM

This system worked very well following modifications made mostly during the original LIMB Demonstration. Discussed in detail in Section 4, these included increasing the size of the baghouse on top of the feed silo and changing the filter medium of the bags, resheaving the solids pump below the storage silo, and installation of a solids pump to replace a rotary valve downstream of the differential weight loss feeders. There was also a redesign of the injection system that included removal of all dense phase air lines and related equipment, increasing line sizes both from the pick-up point to the distribution bottle, and from the distribution bottle to the injection nozzles. The result was a system that, except for some routine mechanical problems, provided the capabilities expected of it.

On those occasions when lines between the distribution bottle and the injection nozzles plugged, more frequently than not it seemed to occur upon restart of the system after a shutdown of a few hours or more. Many times the pluggage was ascribed to incomplete purging of the lines as part of the shutdown process. Whatever the cause, service air connections installed in each line between the distribution bottle and the injectors provided a simple solution. This connection was used to attach a service air line to blow out the accumulated material quickly and effectively.

There were a couple of instances of sorbent line failures. The most significant of these involved one of the 4 in ID rubber hoses between the feeder discharge and the distribution bottle. When it was decided to change to the larger diameter lines, the original carbon steel pipe was changed to hose because it could be quickly and inexpensively installed. The failure was believed to have been due to a combination of wear and pressure. The hose was spliced back together and the system restarted, though the spliced connection itself failed less than a day later. Replacement of the hose solved the problem for the balance of the demonstration. Commercial installations would normally use carbon steel pipe, and use hose only as a temporary measure as was done at Edgewater. There were no failures of any carbon steel pipe during the demonstration.

The only other significant equipment failure occurred once when the baghouse on top of the feed silo plugged during the transfer of sorbent from the storage silo. Caused by a failure of the silo weigh cell, the silo overfilled and the baghouse had to be cleaned out manually. After the weigh cell was recalibrated and another interlock added, there were no further overfills of the silo.

HUMIDIFIER

In spite of the potential for major problems associated with the formation of large deposits as had been observed in similar technologies, the humidifier presented few difficulties in the course of the LIMB Extension. The humidifier was cleaned out three times during the 16 months of total elapsed time. In all but one of these cases, the build-up was fluffy ash that was easily removed by an industrial vacuum truck. For the one remaining occasion, a large deposit formed in the chamber after a period of extended operation with poor water atomization. As one might expect, the build-up grew exponentially on itself once unevaporated water droplets began impacting at the wet/dry interface. This build-up was hard enough that it first had to be broken up before it could be vacuumed out.

The formation of this one large deposit points to the need to monitor humidification performance carefully. Data indicated that before the build-up was found, some of the diagnostic thermocouples in the chamber had been running "cool" and very close to the saturation temperature. The poor atomization was traced to a combination of a small amount of a scale that had slowly and imperceptibly formed over preceding months in the atomization air and water supply lines. Moreover, the "scale" only became a more significant problem after a more lengthy shutdown for an outage, during which it dried out. The suspected cause is the formation of a "hard water" type scale which may have been aggravated by the use of caustic during the Coolside tests several months earlier. Upon restart of the system, the now dry and cracked material slowly began to spall off, plugging the small passageways in the atomization nozzles. In the ensuing week or two of operation, the atomization quality slowly deteriorated, forming the deposit from the outlet end of the humidifier with gradual growth toward the inlet. This was unlike the few early difficulties where, for example, an improperly assembled nozzle would leak and immediately form an easily observed deposit which could then go on to cause coalescence of droplets and further deposit formation in the vicinity of the spray zone. Thorough flushing of both the air and water piping cleared the pluggages. In the ten remaining months of operation, this kind of build-up never occurred again.

The two fluid atomizing nozzles themselves were maintained to assure continued acceptable performance. When the boiler was down and time permitted, the faces of the nozzles were cleaned with wire brushes to remove any wet/dry build-up that had started to grow on them. Their atomization performance was also checked on the same boiler outage basis. Occasionally, an individual nozzle would have to be removed from a lance and cleaned. This process was not complicated, involving removal and a check for the plugged orifice(s). When pluggage was found, it usually was in the form of very small pieces of scale or rust that had fallen off from inside the air line and blocked or partially blocked an opening. Although almost all of the air lines were stainless steel, there was one carbon steel piece in the lance assembly downstream of any filters because there was no alternate available at the time. This would not be the case in a permanent, commercial installation.

SECTION 8
MAINTENANCE AND RELIABILITY

The LIMB process is easy to operate and maintain. No major maintenance or reliability problems were encountered during the LIMB Extension. In the following discussion on maintenance and reliability, the reasons for forced outages are separated according to whether they were mechanical or process-related. Similarly, availability of the LIMB and humidification systems are categorized separately.

The LIMB system at Edgewater operated over the 16-month period with relatively few occurrences of process-related downtime. Such downtime was considered acceptable, as it caused the LIMB system to be unavailable less than two percent of the time. LIMB Extension tests commenced on April 27, 1990 and ended on August 30, 1991. Over that time, a total of 11,784 possible hours, the boiler operated 7,709 hours or 65 percent of the time. Sorbent was injected into the boiler 46 percent of the time the boiler was on-line (3,521 total hours). The LIMB injection equipment was available over 95 percent of the time, and the humidifier and related equipment were available over 96 percent of the time. The percent time available relates to the total time the boiler was on-line. If the boiler was off-line and work was being done on the LIMB system, LIMB was not considered unavailable. Basically, LIMB and humidification were considered unavailable whenever the boiler was operating and they could not.

The LIMB system, which includes the sorbent storage and feed subsystems, was unavailable for a total of 344 hours. If the humidifier was out of service, and humidification was necessary to inject sorbent, this counted toward both LIMB and humidifier unavailability. For the purpose of this discussion, the LIMB system being unavailable relates to the inability to inject sorbent into the furnace. When low sulfur coal was being burned, there was no need to inject sorbent to maintain emission limits. On these days, the equipment was operated for the sole purpose of obtaining test data. The off-time during these periods is not counted as unavailable time since the equipment was, in fact, available, but not being run to conserve sorbent for test purposes.

PROCESS-RELATED UNAVAILABILITY

The downtime most critical to the success of the demonstration was the process-related downtime which refers to time when the system was unavailable due to failures such as plugging of sorbent lines or humidifier clean-up. The two percent of the boiler operating time noted earlier equated to 149 hours of process-related downtime over the course of the project. These 149 hours are further broken down as follows:

- 99.5 hr of downtime associated with the humidifier. Clean-up crews worked no more than 12 hr per day, but if they had to come back the next day, all 24 hr were counted. The humidifier needed to be cleaned three times in the 16 month period, the worst of which was described in more detail in the preceding section.

- 33 hr of forced outages due to plugged sorbent lines. Most of the six occurrences had to do with lines between the distribution bottle and the nozzles. Service air connections to blow pluggage out were installed about half way through the project. After that time, there was only one pluggage in these lines which required about 1.5 hr downtime.

- 16.5 hr of unavailability to balance humidification lance flows. After the humidifier was cleaned out the second time, one day was spent balancing lance flows to produce an even temperature profile throughout the humidifier. The whole 16.5 hr is attributable to this one occurrence.

MECHANICALLY-RELATED UNAVAILABILITY

Mechanical problems are inherent with any equipment or process. Although counted toward unavailability, the downtime associated with mechanical problems was not LIMB-specific. It includes outright equipment failures unless they could be directly attributed to the process. A more detailed listing of these mechanical failures is as follows:

- 138.5 hr of unavailability caused by the compressor that supplied the atomizing air for the humidifier.

- 99.5 hr of downtime due to the sorbent feed pump. This solids pump was purchased secondhand, which may have contributed to this downtime as there was no downtime attributable to a larger size of the same pump used to transfer sorbent from the storage to the feed silo.

- 48 hr caused by problems with the weigh cell on the feed silo. As noted in the preceding section, malfunction of this device caused the silo to overfill with sorbent, plugging the baghouse. A redundant high level transmitter was added to shut down the transfer equipment on alarm.

- 16 hr of unavailability due to hose failures. This would not be a problem in a commercial installation with carbon steel piping.

- The balance of the downtime was attributable to minor electrical and mechanical problems with the various pieces of both LIMB and humidification equipment.

MAINTENANCE AND RELIABILITY SUMMARY

The numbers presented in this subsection would tend to be higher than expected for a commercial unit operating to maintain air quality. When a piece of equipment failed, no more than eight hours per day were spent on the problem, and there was little if LIMB equipment maintenance done on weekends. If a piece of equipment could not be fixed in an eight hour day, 24 hours of unavailability were still attributed to the problem. This was true as the objective of the demonstration focused on obtaining operating data, while minimizing the amount of money spent on equipment repairs.

Appendix E contains a complete log of the hours of unavailability and what caused them. As previously stated, if the humidifier was down for any reason and this halted sorbent injection, both the LIMB and humidifier systems were labelled unavailable as well. Also contained in this appendix is a log of the time the boiler and LIMB system were on-line.

SECTION 9
ECONOMICS

INTRODUCTION

This section addresses the economic comparison of SO_2 removal with the LIMB, Coolside, and LSFO FGD technologies. The evaluation is based on the capital and annual levelized costs for each of the three. Technical and economic premises were developed utilizing the DOE Program Opportunity Notice (PON) DE-PS01-88FE61530, EPRI's *TAG™ Technical Assessment Guide,*[22] the design and operating experience from the LIMB project, CONSOL's topical report on the Coolside process,[2] and a review of state-of-the-art technology being utilized in the design of wet limestone FGD systems.

The base LIMB system evaluated is an optimized commercial system utilizing hydrated calcitic lime as the sorbent to achieve 60 percent SO_2 removal efficiency. No credit is taken for NO_x emission control with LIMB, and no costs are included for burners and associated hardware. Equivalent NO_x emissions are assumed in the economic evaluations, and only the costs associated with SO_2 removal are used in the analysis. The Coolside system evaluated is an optimized commercial system utilizing commercial hydrated calcitic lime to achieve an SO_2 removal efficiency of 70 percent. The LSFO system evaluated is a typical commercial system utilizing commercial limestone to achieve 95 percent SO_2 removal.

The goal of this analysis is to provide a comparison of the three FGD processes over the range of the economic and technical premises chosen. The analysis reviews the economics of the three processes for power plants with generating capacities from 100 to 500 MWe, while they burn coals with sulfur contents ranging from 1.5 to 3.5 weight percent. The results of this analysis is intended to assist utility and industrial boiler owners in deciding how to comply with current emission control legislation.

In the following discussion it is important to keep in mind that the LIMB and Coolside processes were conceived as low capital cost technologies for moderate levels of SO_2 removal. As such, they are generally targeted for use on relatively small, older plants for which wet scrubbers would be especially hard to justify. This is in contrast to LSFO FGD which normally is designed for high levels of SO_2 reduction. Guaranteed removals of 95 percent or more have been common for the state-of-the-art LSFO technology since passage of the CAAA in 1990. Its higher capital cost with notably greater reagent utilization make it the choice usually preferred for newer, larger plants burning higher sulfur coals. At least as importantly, site-specific considerations influence the economics of all three processes, as is commonly recognized in the industry.

For the reasons above, direct comparisons of LIMB and Coolside with LSFO FGD must be interpreted with care. Several alternatives were evaluated in order to try to overcome the inherent differences. One included operation of the LSFO system at lower levels of performance, essentially equal to that of the other two technologies. Another examined partial flue gas bypass for the overall removal desired, while still operating the LSFO process at 95 percent removal efficiency. Arguments against making such assumptions were thought to be at least as valid as presenting each technology in its own realm of applicability. The end result was a decision to present each of the technologies in its own best light. When viewed in the light of the caveats in the preceding paragraph, the limitations of comparison with the LSFO process are readily apparent.

Since the differences between LIMB and Coolside are less pronounced, greater significance may be placed on their comparative economics. Nevertheless, site-specific considerations become especially important. Whereas Coolside demands humidification to a close approach to the flue gas saturation temperature, LIMB can require little to none depending on the nature and quantity of sorbent injected. Enhanced SO_2 removal is, of course, possible under close approach conditions. The site-specific concern arises out of the greater amount of space required to permit essentially complete evaporation to achieve close approach operation. The other fundamental difference between these two technologies, sorbent injection in the furnace for LIMB, and in a downstream location for Coolside, becomes a matter of preference for the individual operating utility.

ECONOMIC EVALUATION RESULTS

For base load boiler operation (65% plant capacity factor) the Coolside and LIMB processes, with design SO_2 removal requirements of 70 and 60 percent, respectively, were found to be competitive with a LSFO FGD process on a $/ton of SO_2 removed basis. Examined under sets of operating conditions described later in this section, the LIMB and Coolside technologies appeared to be generally applicable for three coals of varying sulfur content (1.5, 2.5, and 3.5 weight percent), fired in the following unit sizes:

Coal Sulfur, wt %	Coolside	LIMB
1.5	≤ 500 MWe	≥ 500 MWe
2.5	≤ 220 MWe	≤ 450 MWe
3.5	≤ 100 MWe	≤ 240 MWe

In comparison with LSFO, Coolside and LIMB economics also become increasingly favorable with both decreasing plant capacity factor and book life. As might be expected, variations in reagent cost have a much greater effect on LIMB and Coolside than on LSFO because of the lower utilization realized as stoichiometry increases. Conversely, the availability of a low cost reagent supply can significantly improve LIMB and Coolside economics.

BASIS OF EVALUATION

Similar technical and economic assumptions were used to provide as common a basis for the three fundamental process designs in order to make comparisons as valid as possible. Four reference plant capacities of 100, 150, 250, and 500 MWe were selected. Eastern bituminous coals were chosen which essentially differed only in that they had different sulfur contents of 1.5, 2.5, and 3.5 weight percent. An economic evaluation, effectively consisting of a budgetary estimate targeted to be accurate to within 10 to 20 percent, was then made for each FGD process for each reference plant/coal sulfur combination. This type of accuracy is expected to result from the detailed design-estimate efforts used as outlined in *TAG*™. These resulted in twelve separate evaluations for each FGD process, or a total of thirty-six separate evaluations.

The basic LIMB system design is assumed to use commercial calcitic hydrated lime as the sorbent. Use of other sorbents in the process can have a substantial effect on annual levelized costs, as is discussed later in this section. While capital costs that result from the differences in molecular weight and/or bulk densities would be affected somewhat, the differences are expected to be within the accuracy of the estimates. The major impact on annual levelized costs due to changing sorbent is the result of lower utilization in the case of limestone, and the unreactive MgO component in the case of dolomitic lime. There would also be an effect on ash disposal costs, but this would be expected to have an even lower impact on the levelized costs. The costs for LIMB operation at close approach to saturation are considered to be close to those for similar application of the Coolside technology.

The Process Engineering Group of B&W's Environmental Equipment Division (EED) generated the material balances for the 12 LIMB and 12 LSFO cases, while CONSOL's Research and Development Group developed those for the 12 Coolside cases. These material balances were used to size the equipment necessary for each design case. The equipment included silos, tanks, vessels, pumps, fans, compressors, buildings, and the related process equipment and structures required for each FGD system. Structural steel, electrical, instrumentation, and control requirements were developed in B&W's mechanical and electrical engineering departments.

Costs were then estimated for each design case. Budgetary vendor quotes were obtained for the process equipment. EED's Mechanical Engineering and Estimating Groups determined the costs for silos, tanks, absorbers, structures, and accessory equipment. B&W's Electrical Engineering Group determined costs for the electrical equipment, wiring, instrumentation, and controls. CONSOL's Research and Development Group assembled cost information from appropriate suppliers for those portions of the Coolside process humidifier and sodium addition systems not covered by B&W. Construction cost factors were developed from B&W's Construction Company's experience in the installation of FGD and power plant equipment.

REFERENCE POWER PLANT DESIGN

The economics presented are based on reference plants with nominal capacities of 100, 150, 250, and 500 MWe (net). The plants are base loaded (65 percent capacity factor) and located in the state of Ohio near the Ohio River. Other pertinent design and performance assumptions are listed in Table 17. The site plan is assumed to be similar to those in the DOE PON noted earlier in this section. For the purposes of the LIMB, Coolside, and LSFO process layouts, all boiler sizes are assumed to be equipped with two parallel air heaters, each of which handles half of the flue gas flow. The flue gas exits each air heater and flows through parallel ducts to separate ESPs. Table 18 presents the fuel specifications for each of the eastern bituminous coals containing 1.5, 2.5, and 3.5 weight percent sulfur, as received.

The potential application of the LIMB and Coolside technologies to other coals such as lignites and western subbituminous fuels is not considered to have a significant enough impact on costs to warrant separate evaluation. The primary effect would be one associated with the generally lower sulfur content of such coals, and as such, is represented in the 1.5 weight percent sulfur case here. While the ash of these coals is frequently high in alkaline components that provide some degree of inherent SO_2 capture, the effect is again one which can be thought of as relating to an "effective sulfur content" for the purposes of process design. In similar fashion, the generally higher moisture and ash content of such coals would be taken into account in the design stage. Such differences would tend to lead to slightly lower costs, but ones that do not appear to warrant separate treatment in this analysis.

Flue gas compositions and rates depend on boiler design, fuel composition, and operating conditions. The assumed flue gas compositions and rates used in this report are based on combustion of pulverized coal with 40% excess air, reflecting the higher degree of air infiltration that might be expected in an older unit. This includes excess air to the boiler and air in-leakage from the duct and air heaters. The flue gas compositions and rates are also presented in Table 18. This information is included since the flue gas flow rate, moisture content, and temperature define the humidification water flow requirements for the LIMB and Coolside processes, as well as the evaporation water requirements for the LSFO process. The flue gas flow rate, SO_2 concentration, and required Ca/S mole ratio define the hydrated lime rate for the LIMB and Coolside processes, and the scrubber tower diameter, recycle pump capacity, and limestone feed rate for the LSFO system.

TABLE 17. REFERENCE PLANT DESIGN INFORMATION

Plant location		Ohio, near the Ohio River			
Plant elevation		500 ft above sea level			
Seismic zone		1			
Boiler type		Pulverized coal-fired, radiant boiler			
Capacity factor		65 percent			
ESP:	Emission rate	0.1 lb/10^6 Btu			
	Specific collection area	400 $ft^2/10^3$ ACFM			
ID fans:	LIMB	Adequate			
	Coolside	Adequate			
	LSFO	Supplemental fans required			
Plant retrofit factors:	LIMB	1.0			
	Coolside	1.3 for the humidifier, 1.0 for other equipment			
	LSFO	1.3			
Plant size, MWe (net)		100	150	250	500
Coal flow rate, lb/hr		82,000	123,000	205,000	410,000
Main steam flow, lb/hr		634,000	951,000	1,585,000	3,170,000

TABLE 18. DESIGN FUEL AND FLUE GAS SPECIFICATIONS

Fuel type	Eastern Bituminous		
Coal sulfur, wt % (as received)	1.5	2.5	3.5
High heating value (HHV), Btu/lb (as received)	11,872	11,872	11,872
Proximate analysis, wt % (as received)			
Moisture	8.01	8.01	8.01
Volatile matter	31.65	31.65	31.65
Fixed carbon (by difference)	49.57	49.57	49.57
Ash	10.77	10.77	10.77
Ultimate analysis, wt % (dry basis)			
Carbon	72.15	71.71	71.27
Hydrogen	4.82	4.82	4.82
Nitrogen	1.52	1.52	1.52
Sulfur	1.63	2.72	3.80
Chlorine	0.14	0.14	0.14
Oxygen (by difference)	8.03	7.39	6.74
Ash	11.71	11.71	11.71
HHV	12,906	12,906	12,906
Flue gas composition			
H_2O, vol %	7.7	7.7	7.7
CO_2, vol %[*]	12.1	12.0	11.9
O_2, vol %	5.6	5.6	5.6
SO_2, ppmv	1022	1700	2375
Flue gas flow rate, ACFM[†]			
100 MWe	347,274	348,059	348,793
150 MWe	520,911	522,088	523,175
250 MWe	868,184	870,147	871,958
500 MWe	1,736,369	1,740,295	1,743,916

[*] ≤ 1 % of coal carbon lost to carbon in ash and flue gas CO.

[†] At 1 atm and 300 °F.

FGD SYSTEM DESIGN

Commercial designs were developed for each of the three FGD processes utilizing the most current technology considered applicable. Detailed system descriptions, technical premises, equipment scope of supply lists, and process flow schematics are presented in the following sections for each of the three FGD processes. A comparison of the major process and equipment design parameters is shown in Table 19. The designs were kept as similar as possible in order to provide as fair a comparison as possible among the three processes. For example, the drainage sumps for all cases compared are the same size and have the same sump pumps and mixers. This was done even though it is realized that scale-up of certain operations and equipment from the 100 to the 500 MWe size would necessitate design changes for economic and/or practical reasons. Thus, for the purposes of the evaluation, assuming truck delivery of lime for all four plant sizes was considered preferable to trying to account for cost differences for rail or barge delivery for the larger size plants. Individual LIMB, Coolside, and LSFO system design criteria are summarized in Tables 20, 21, and 22, respectively.

TABLE 19. FGD PROCESS/EQUIPMENT DESIGN ASSUMPTIONS

	LIMB	Coolside	LSFO
SO_2 removal, %	60	70	95
Sorbent	Calcitic hydrated lime	Calcitic hydrated lime and soda ash	Limestone
Ca/S Stoichiometry, mol Ca/mol S inlet	2.0	2.0	NA[*]
Ca/S Stoichiometry, mol Ca fed/mol S removed	NA	NA	1.05
Na/Ca Stoichiometry, mol/mol	NA	0.2	NA
Total system ΔP, in WC	Negligible	1.5	10
ID fans	Adequate	Adequate	Supplemental fans required
Flue gas reheat	No	No	No
Flue gas by-pass	NA	Yes, 100 %	Yes, 100 %
Isolation dampers	NA	5	3
New wet stack	No	No	Yes
Total sorbent storage, day	7	7	31
Waste product components	Fly ash, lime, gypsum	Fly ash, lime, calcium and sodium sulfites and sulfates	Disposable gypsum[†]
System outlet temperature, °F	275	145	125
Total additional operating manpower required	0	4	16

[*] NA = Not applicable.

[†] As opposed to wallboard-quality gypsum.

TABLE 20. LIMB FGD SYSTEM DESIGN CRITERIA

SO_2 removal efficiency, %	60
Ca/S Stoichiometry, mol Ca/mol S inlet	2.0
Total system ΔP, in WC	Negligible
Furnace injection point temperature, °F	2300
Humidification cooling requirement, °F	25
Humidifier atomizing air, lb air/lb water	0.45
Humidifier duct gas velocity, ft/sec	50
Reactive lime purity, wt %	93
Total lime storage, day	7
ESP collection efficiency, %	99.6
ESP particulate emission, lb/10^6 Btu	0.1
ESP SCA, $ft^2/10^3$ ACFM sorbent storage, day	400
Materials of construction for flue gas contact:	
Humidifier spray lances	316L stainless steel

TABLE 21. COOLSIDE FGD SYSTEM DESIGN CRITERIA

SO_2 removal efficiency, %	70
Ca/S Stoichiometry, mol Ca/mol S inlet	2.0
Na/Ca Stoichiometry, mol/mol	0.2
Ash recycle ratio, lb ash/lb fresh lime:	
1.5 % S coal	2.59
2.5 % S coal	0.71
3.5 % S coal	0.00
Total system ΔP, in WC	1.5
Humidification cooling requirement	To 20°F ΔT_{as}*
Humidifier atomizing air, lb air/lb water	0.45
Humidifier duct gas velocity, ft/sec	20
Humidifier residence time, sec	3
Reactive lime purity, wt %	93
Total lime storage, day	7
ESP collection efficiency, %	99.6
ESP particulate emission, lb/10^6 Btu	0.1
ESP SCA, $ft^2/10^3$ ACFM sorbent storage, day	400
Materials of construction for flue gas contact:	
Humidifier inlet and outlet ducts	Carbon steel
Humidifier	Carbon steel
Humidifier spray lances	316L stainless steel

* ΔT_{as} = Approach to the adiabatic saturation temperature of the flue gas.

TABLE 22. LSFO FGD SYSTEM DESIGN CRITERIA

SO_2 removal efficiency, %	95
Ca/S Stoichiometry, mol Ca fed/mol S removed	1.05
O_2 Stoichiometry for 99 percent oxidation, mol O_2 fed/mol S removed	1.5
Total system ΔP, in WC	10
Absorber:	
Design type	Tray tower
Number of modules	One 100 % capacity
Flue gas velocity, ft/sec	10
Reaction tank solids concentration, wt %	15
Reaction tank residence time, sec	8
Liquid-to-gas (L/G) ratio, gal/10^3 actual ft^3	
For 1.5 wt % S coal	88
For 2.5 wt % S coal	100
For 3.5 wt % S coal	120
Reactive limestone purity, wt %	90
Total limestone storage, day	31
Limestone slurry storage tank capacity, hr	12
Limestone particle size	95 % < 325 mesh (44μm)
Waste slurry tank capacity, hr	16
Reclaim water storage tank capacity	Equal to water volume of waste slurry tank
Primary dewatering:	
Number of hydroclone clusters	Two 50 % capacity
Hydroclone underflow solids concentration, wt %	35
Secondary dewatering:	
Number of vacuum filters	Two 100 % capacity
Vacuum filter cake solids, wt %	85
Upstream ESP collection efficiency, %	99.6
Materials of construction for flue gas contact:	
Inlet duct	Carbon steel
Bypass duct	Carbon steel
Absorber entrance nozzle	Alloy C-276
Absorber module	Rubber-lined carbon steel
Outlet duct	317LMN stainless steel

Commercial LIMB System Design

The scope for the LIMB system begins with truck delivery of dry hydrated calcitic lime to the site and ends with removal of a water-conditioned LIMB ash in trucks. The design consists of four process areas: the lime unloading, storage, and feed system; the furnace injection system; the humidification system; and the ash collection, storage, and removal system. A listing of the scope of equipment and a LIMB system schematic are presented after the detailed descriptions in Table 23 and Figure 43, respectively.

Lime Unloading, Storage, and Feed System--

Lime is delivered to the site by pneumatic trucks, two of which can unload lime into the storage silo at the same time. The silo can hold a seven-day supply of lime when the unit is operating at its maximum continuous rating (MCR). A baghouse is located on top of the silo to prevent lime from escaping to the atmosphere during unloading. A mechanical level detection device is provided to prevent overfilling the silo.

Lime discharge at the conical bottom of the silo is aided by internal air slides on the sloping sides. A fluidizing air system consisting of a fluidizing air blower, air dryer, and the interconnecting piping, valves, and instruments is provided to supply air to the air slides. A 100 percent spare fluidizing air blower is included. The air dryer can be by-passed when maintenance is being performed.

There are two discharge points on the bottom of the silo, each of which can be isolated with a manual slide gate. From each discharge point, lime can be fed to a variable speed rotary feeder, whose speed can be controlled to supply the required amount of lime to the system. The rotary feeder prevents flooding and feeds at a controlled rate into a solids pump. Sorbent is compacted as it is pushed through the pump barrel by the screw, sealing against the transport line back-pressure. The lime is then fed into the pump mixing chamber where it is fluidized with transport air and conveyed to the distribution bottle through the transport line. Transport air is provided by one of two 100 percent air blowers. The lime is split at the distribution bottle into several smaller streams and continues on to the furnace injection system.

Furnace Injection System--

Based on furnace gas temperature ranges, lime is injected into the upper furnace, generally at a level close to the screen tubes and entrance to the superheater. Here the hydrated lime reacts with the SO_2 in the flue gas to form $CaSO_4$. An array of equally spaced injection nozzles, similar to the Edgewater design, penetrate the front wall carrying air-transported hydrated lime from the lime distribution bottle. Additional "booster" air is injected through annular openings surrounding the lime nozzles to aid penetration and mixing with furnace gases. Booster air is supplied by a centrifugal fan located as close to the injection points as possible, to reduce the distribution ductwork. The booster air fan and ductwork is insulated for noise protection. A video camera and monitor system is provided for continuous observation of the lime flow into the furnace by the boiler control room operators.

Humidification System--

The humidifier for the LIMB process as described here is designed to provide gas conditioning sufficient to restore ESP performance. This represents an approximate 25°F reduction in the air heater outlet temperature. Humidification takes place in the flue after the air heater, and ahead of the ESP. Humidification lances would be installed in an existing, preferably vertical, duct, between the air heater outlet(s) and the ESP inlet, with the longest possible length of straight duct after them. High pressure air is used in dual-fluid atomizing nozzles to produce very fine water droplets which evaporate quickly and cool the flue gas.

An enclosed heated, ventilated, and insulated platform is required on each side of the duct to monitor the operation and maintain the spray lances. These enclosures would contain atomization air and water headers, distribution piping, and the associated valves, filters, and instruments. It would not be necessary to enclose these platforms in warmer climates.

Compressed air and water for humidification would require new equipment, which, if space is available, would be located as close to the humidifier as possible. For the purposes of this comparison, it will be assumed that space is not available, and that the equipment will be located in a building under the lime storage silo described below. Air compressors (spared), water pumps (spared), duplex water strainers, an air receiver, and a water tank would be supplied along with the associated piping, valves, instruments, and controls.

Costs to perform flow model testing for optimization of the final humidification system design are also included. This would be necessary because each installation would be unique.

Ash Collection/Storage/Removal System--

LIMB ash fall out/collection will occur in three areas, namely, the air heater, economizer, and ESP hoppers. It was found at Edgewater that only a minimal amount of LIMB ash falls out in the air heater and economizer hoppers. The majority of the LIMB ash is collected by the ESP and falls out in the ESP hoppers. It is assumed that the existing ESP has sufficient SCA, transformer/rectifier (T/R) set capability, and rapping capability to handle the increased LIMB ash loading. The existing ESP equipment must be evaluated under the increased loading conditions to determine if stack particulate emission limits can be maintained. No modifications were necessary to the Edgewater ESP which had a design SCA of 612 $ft^2/10^3$ ACFM to achieve 99.38 percent particulate removal efficiency.

For the conditions studied, the application of LIMB to a boiler can increase the total ash collected in the ESP by a ratio up to about 3:1 when operating at 2.0 Ca/S ratio. For this evaluation it has been assumed that, similar to the Edgewater installation, the existing ash removal system can collect and transport the additional ash by more frequent emptying of both the ESP hoppers and those under the air heater and convection pass. The ash storage silo capacity is assumed to be adequate and capable of storing four days's production of LIMB ash, as was the case at Edgewater. Costs are provided for upgrading the system to handle the increased solids flow better. It is noted, however, that some plants would not have this margin available, and would find it necessary to increase the capacity of all or part of the ash handling system.

Ash Collection and Storage System--The existing ash collection system is assumed to be the dry vacuum type, which utilizes either a hydraulic exhauster or mechanical exhausters to effect the flow of conveying air. For the purposes of this comparison, it will be assumed that the reference plants utilize mechanical exhausters. An existing primary cyclone type collector and a secondary pulse jet bag filter, both mounted on the top of the ash silo, collect the conveyed ash and empty it into the silo through double-dump discharge gates. This existing system will be upgraded in order to handle the increased solids flow as follows:

- The vacuum source will be replaced with one of greater capacity source.

- The pulse jet bag filter will be replaced with a greater capacity bag filter(s) fitted with Gore-Tex™ bags.

Ash Removal System--It is assumed that the reference plants presently utilize an ash conditioning/unloading system consisting of ash silo fluidizers, an ash discharge slide gate, a rotary feed valve, and a paddle-type ash conditioner which wets the ash for discharge into trucks for transport to a landfill. In order to handle the increased LIMB ash loading, this system would be upgraded as follows:

- A new variable speed rotary feed valve of double the original capacity would be installed.

- A new plastic-lined, paddle-type ash conditioner of double the original capacity would be installed.

- A new plastic-lined discharge chute would be installed and fitted with wash-out capability.

- The water feed to the unloader would be made adjustable.

- The truck unloading bay would be fitted with four reversible exhaust fans to prevent the steam generated by wetting the LIMB ash with water from disrupting the unloading operator's view of the truck filling process.

The operation of the ash discharge slide gate, rotary feeder, ash conditioner, and water supply would be automatically sequenced, with ash and water rates manually adjustable from a panel. The loaded trucks would normally wait about 15 min for the steaming to subside, and then proceed to the plant scales and on to the disposal site.

LIMB Equipment Enclosure--

Those items and groups of equipment that could not be located in the existing boiler building and associated structures would be brought together and housed in a single separate structure, called the "LIMB equipment enclosure". This enclosure would be located below the lime storage silo and would support and/or enclose:

- The lime storage silo truck unloading, bin discharge, and feed equipment

- Atomization water tank, feed pumps, and two sets of strainers

- The atomization air compressors, air receiver, and instrument air conditioning equipment

- A room for electrical switchgear and motor control centers

- Noise abatement enclosures for the centrifugal air compressors.

Pipe Rack--

The design includes a 150 ft long pipe rack for supporting pipe runs between the LIMB equipment enclosure and the boiler structure. The support elevation will be 20 ft above grade to clear roadways. The rack will carry interconnecting piping, and electrical wiring in cable trays.

Instrumentation and Controls--

The LIMB system will be controlled from the boiler control room by the boiler operators. Subsystem, and individual equipment, start/stop operations would be from the boiler control room. Local start/stop capability will also be provided for the rotating equipment. The design includes computerized process control and an operator interface console. Required instrumentation for local or remote status indication is included, with recording and alarms for critical conditions. Annunciation of trouble spots are highlighted on computer graphics. It is assumed that the plant will have a CEMS in place. It is recognized that each plant will have its own control philosophy, and that any final design would have to make accommodations for its unique facilities and requirements.

Electrical Equipment--

It is assumed that the plant can provide a power lead from its 4160 VAC bus. The design would include the necessary transformer and switchgear to power the LIMB equipment. The electrical equipment room is located in the LIMB equipment enclosure and will house the 4160 and 480 VAC load centers, motor control centers, and lighting panel. A grounding grid, 120 VAC utility outlet and control power system, electrical heat tracing, and indoor and outdoor lighting are also included. The interconnecting wire, conduit, and cable trays between the LIMB equipment and the electrical equipment room is included. The 4160/480 transformer is located just outside the LIMB enclosure.

Sootblowers--

For the purposes of the economic evaluation, new steam sootblowers were added in the convection pass. These, plus more frequent blowing cycles, are expected to keep the pendant section and convection pass surfaces clean when injecting lime. The existing controls will be upgraded to add the new blowers in the blowing sequence. Although the need to take into account the combined effect of capacity and more effective coverage were not as well understood early enough for the Edgewater system, it is believed that proper placement of sootblowers with adequate capacity will result in maintaining air heater outlet temperatures close to a more normal 300°F. It is also noted that additional sootblower requirements will be especially site-specific.

Heating, Ventilation, and Air Conditioning--

The LIMB equipment enclosure and the humidification enclosures will be heated and ventilated. The electrical equipment room will be heated and air conditioned to support the control system hardware.

Miscellaneous--

A sump is located in the LIMB equipment enclosure to collect ash and lime truck spill wash-down water, atomization water tank overflow, and miscellaneous drip and floor drains, but not including sanitary, roof downspouts, or storm drains. Two 100 percent vertical sump pumps will pump the ash/lime waste water into a disposal system by others. A mixer will be located in the sump to provide off-bottom suspension of solids.

Both LIMB ash and lime truck spill wash-down water will be highly alkaline. It will, therefore, be necessary to neutralize this alkaline water before pumping it to disposal. A neutralization system consisting of two pH meters, a sulfuric acid tank in containment, and an acid metering control valve is included. The acid tank will be located just outside of the LIMB enclosure, as close to the sump as possible. The pH meters will monitor sump water pH and forward the signal to the control system which will maintain the sump pH at 7.0 by gravity addition of sulfuric acid to the sump.

An instrument air conditioning system will be included to dry, filter, and condition a portion of the atomization air for use as instrument air throughout the LIMB system. The plant's existing instrument air system will be a back-up to this system.

LIMB Operating Manpower--

Based on the experience at Edgewater, it is expected that no additional operating manpower would be required to start, operate, control, and shut down a commercial LIMB system. Lime truck unloading is performed unsupervised by the truck drivers. The boiler control room operator will start/stop remotely operated equipment, set process flow control conditions, monitor process operation, and respond to alarm conditions. The boiler auxiliary equipment operator will start/stop locally operated equipment, walk down and monitor equipment operation, and respond to alarm and upset conditions as requested by the boiler control room operator. Ash hopper evacuation will proceed in the same manner as before LIMB, although more frequent evacuation will be required. Ash unloading to trucks will also proceed in the same manner as before LIMB, and will be performed more frequently and/or a greater number of trucks will be filled during each unloading operation.

TABLE 23. COMMERCIAL LIMB SYSTEM SCOPE OF EQUIPMENT

Lime Storage and Feed System	
Lime silo	Lot
Lime truck unloading equipment	2
Lime silo baghouse	1
Fluidizing air blower	2
Fluidizing air dryer	1
Lime silo discharge air slides	Lot
Variable speed rotary feeder	2
Lime solids pump	2
Transport air blower	2
Interconnecting piping, valves, and instruments	Lot
Furnace Injection System	
Lime distribution bottle	Lot
Injection nozzles	Lot
Booster air fan	1
Fan ductwork with insulation	Lot
Interconnecting piping, valves, and instruments	Lot
Video camera and monitor system	1
Humidification System	
Humidification spray lances	Lot
Lance rapper system	Lot
Air and water distribution headers	Lot
Humidification platforms with enclosure	2
Atomization air compressors	2
Air compressor cooling water booster pump	2
Air receiver	1
Water tank	1
Duplex water strainers	3
Atomization water pumps	2
Interconnecting piping, valves, and instruments	Lot
Flow model testing	Lot
Ash Collection System	
Mechanical exhausters	Lot
Pulse jet bag filter with Gore-Tex™ bags	Lot
Variable speed rotary feed valve	1
Ash conditioner/unloader (pug mill)	1
Ash discharge chute	1
Interconnecting piping, valves, and instruments	Lot
Reversible exhaust fans	4
LIMB Enclosure and Electricals	
LIMB equipment enclosure	Lot
Foundations and concrete work	Lot
Support steel, stairways, and platforms	Lot
Heating, ventilation, and air conditioning	Lot
4160 VAC transformer	1
480 VAC load centers	Lot
Motor control centers	Lot
Lighting panel	1
Control power system including back-up power	1
Heat trace panel and heat tracing	1
120 VAC utility panel	1
Communication equipment	Lot
Grounding grid	Lot
Hoists and trolleys	Lot
Interconnecting wire, conduit, and cable trays	Lot
Miscellaneous	
Pipe rack	150 ft
Computerized control system	Lot
Operator interface console	1
Sootblowers	Lot
Sootblower control upgrade	Lot
Instrument air system	Lot
Sump	1
Sump pumps	2
Mixer	1
pH meters	2
Acid tank	1
Acid tank containment	1
Eyewash/safety showers	Lot
Fire protection systems	Lot
Interconnecting piping, valves, and instruments	Lot

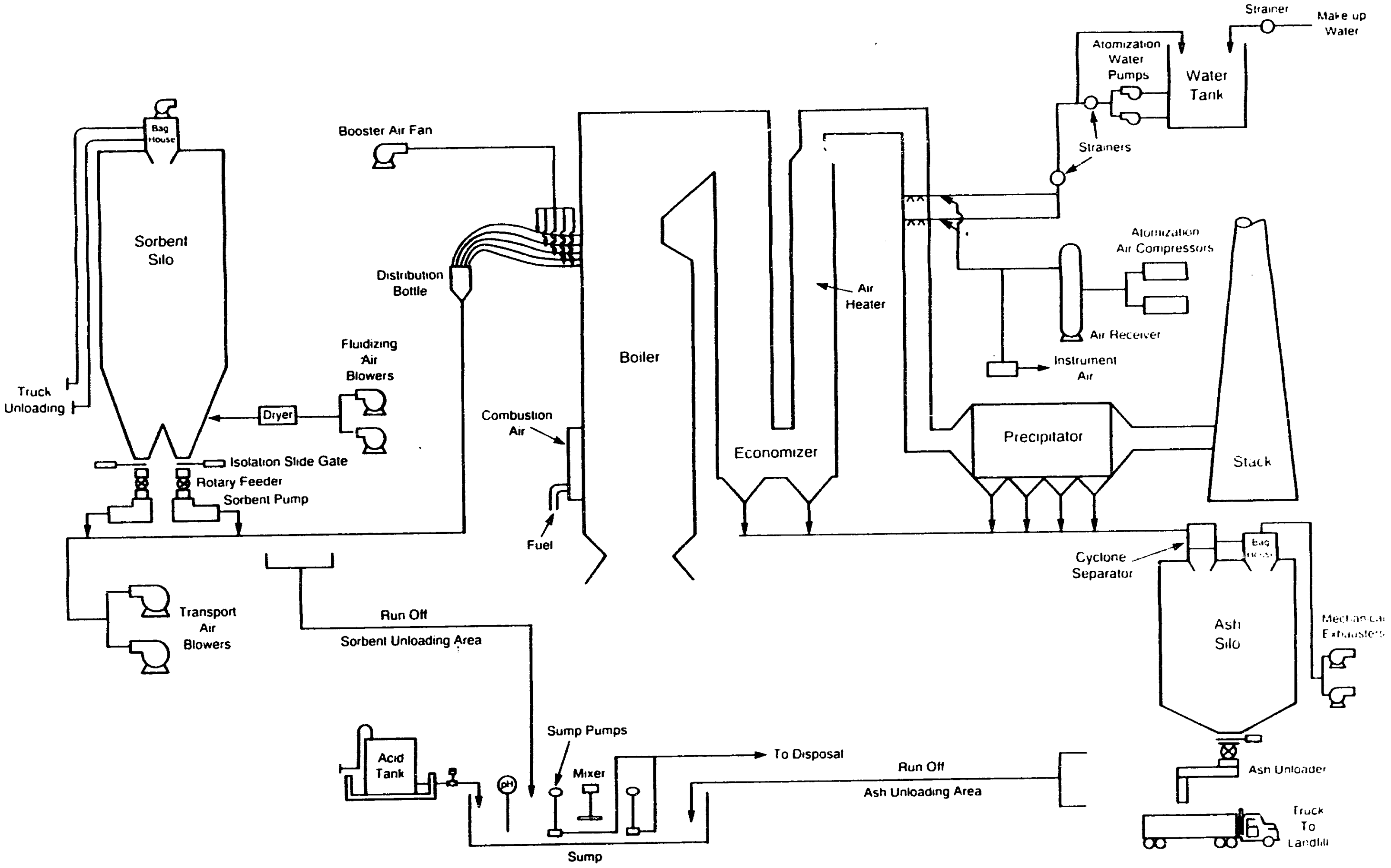


Figure 43. Commercial LIMB system schematic

Commercial Coolside System Design

The Coolside process design is based on current FGD industry practice and the results of the Edgewater Coolside process evaluation. The scope for the Coolside system begins with truck delivery of dry hydrated calcitic lime to the site and ends with removal of a water conditioned Coolside ash in trucks. The design consists of four process areas: the lime unloading, storage, and feed system; the sodium addition system; the humidification system; and the ash collection, storage, recycle, and removal system. A listing of the scope of equipment and a Coolside system schematic are presented after the detailed descriptions in Table 24 and Figure 45, respectively.

Lime Unloading, Storage, and Feed System--

Lime is delivered to the site by pneumatic trucks, two of which can unload lime into the storage silo at the same time. The silo can hold a seven-day supply of lime when the unit is operating at MCR. A baghouse is located at the top of the silo to prevent lime from escaping to the atmosphere during lime truck unloading. A mechanical level detection device is provided on the silo.

Lime discharge at the conical bottom of the silo is aided by internal air slides on the sloping sides. A fluidizing air system consisting of a fluidizing air blower, air dryer, and interconnecting piping, valves, and instruments is provided to supply fluidizing air to the air slides. A 100 percent spare fluidizing air blower is included. The air dryer can be by-passed when maintenance is being performed.

There are two discharge points on the bottom of the lime silo, each of which can be isolated with a manual slide gate. From each discharge point, lime can be fed to a variable speed rotary feeder whose speed can be controlled to supply the required amount of lime to the system. The rotary feeder prevents flooding and feeds at a controlled rate into a solids pump. Sorbent is compacted as it is pushed through the pump barrel by the screw sealing against the transport line back-pressure. The hydrated lime is then fed into the pump mixing chamber where it is fluidized with transport air and then conveyed to the distribution bottle through the transport line. Transport air is provided by one of two 100 percent air blowers.

The hydrated lime is split at the distribution bottle into several smaller streams. The hydrated lime is then distributed into the humidifier through an array of injector pipes located in the plane of the humidification nozzles. In the humidifier, the hydrated lime reacts in the presence of high humidity with the SO_2 in the flue gas to form calcium sulfite and some calcium sulfate.

Sodium Addition System--

The Coolside process uses sodium compounds to increase SO_2 removal and lime utilization. In the design shown, the sodium is stored as an aqueous solution. Dry soda ash is pneumatically unloaded from trucks into a 30-day, wet soda ash storage and supply system. The soda ash feed system is a packaged unit which maintains a saturated solution of sodium carbonate. The saturated soda ash solution is metered, dependent upon the hydrated lime feed rate and the Na/Ca molar ratio setpoint, to an in-line mixer in the humidification water supply line. The soda ash supply system comes with a small dust scrubber to control dust emissions during unloading operations.

Flue Gas Humidifier--

Boiler flue gas from the air heater(s) is conveyed to a single humidification chamber. In the humidifier, water containing the sodium additive is fed to an array of atomizing nozzles. High pressure air is used in dual-fluid atomizing nozzles to produce very fine water droplets which evaporate virtually completely and quickly cool the flue gas. The rate of water addition is controlled to maintain a design humidifier outlet temperature 20°F above the adiabatic saturation temperature of the flue gas.

The atomizers selected for the Coolside process design are B&W Mark XII nozzles or the equivalent. Each nozzle is designed to operate at 0.8 to 1.0 gpm throughput with an atomizing air-to- humidification water ratio of 0.45 lb/lb.

Two key humidifier design parameters are the humidifier residence time and the inlet flue gas temperature. Based on the Edgewater demonstration, the flue gas humidifier residence time was chosen to be three seconds. To minimize the humidifier length, the humidifier cross-sectional area is set to maintain a 20 ft/sec flue gas velocity in the humidifier. To minimize the potential for solids buildup within the humidifier, the design is vertical downflow as shown in Figure 44. A hopper is provided at base of the humidifier to collect and remove any wall scale, atomizer deposit debris, and ash which may drop out of the flue gas. The design incorporates turning vanes in all ductwork bends to minimize pressure drop and to insure a uniform gas flow profile at the humidifier inlet.

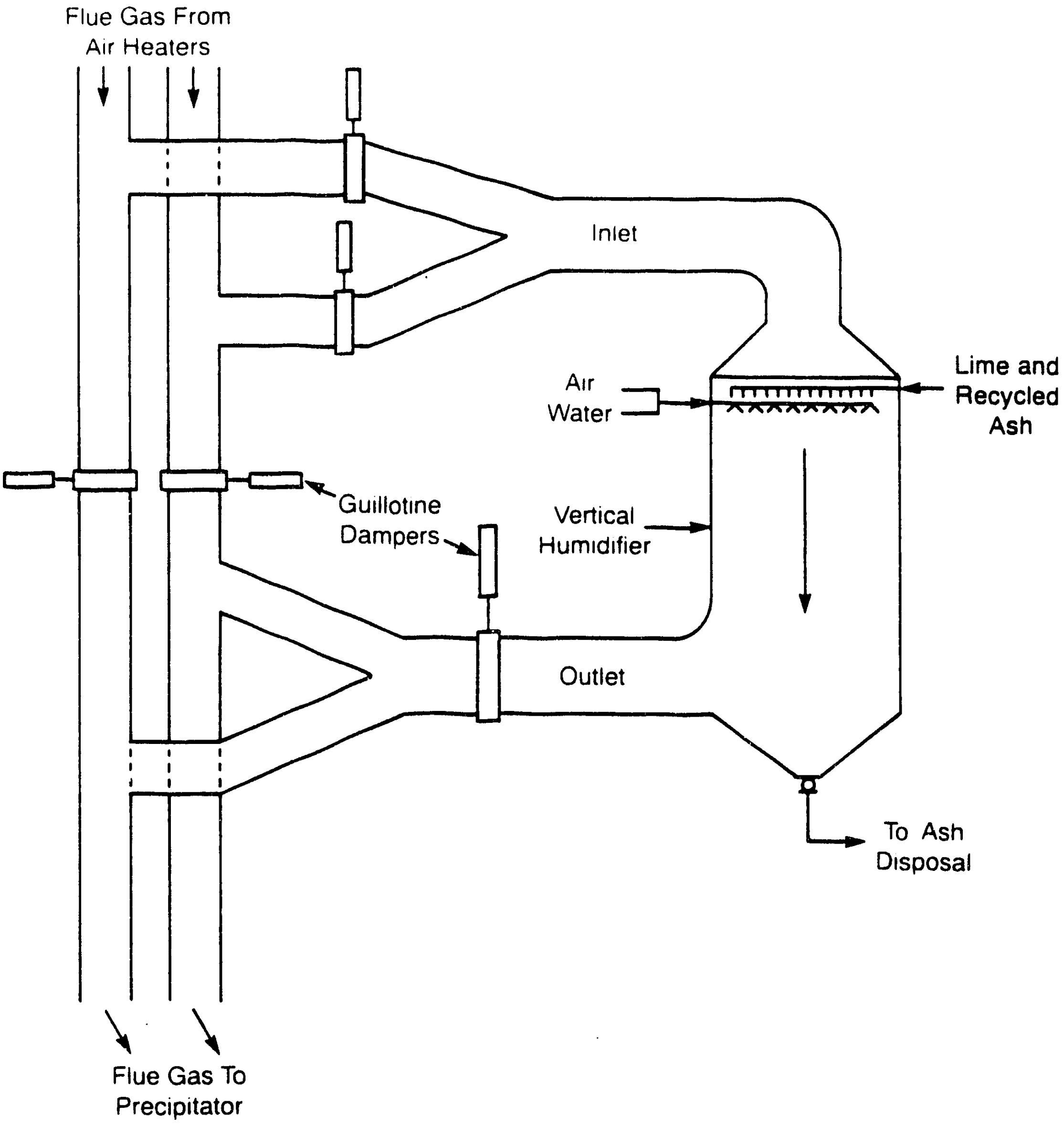


Figure 44. Vertical humidifier conceptual design for a commercial Coolside system

An enclosed, heated, ventilated, and insulated platform is required on each side of the humidifier to monitor the operation and maintain the spray lances. These enclosures would contain atomization air and water headers, distribution piping, and associated valves, filters, and instruments. It would not be necessary to enclose these platforms in warmer climates.

Compressed air and water for humidification would require new equipment, which would be located as close to the humidifier as possible. Because a relatively large area is required, it will be assumed that space is not available for the purposes of this comparison. The equipment will therefore be located in an equipment building under the lime storage silo described below. Air compressors (spared), water pumps (spared), duplex water strainers, an air receiver, and a water tank would be supplied along with associated piping, valves, instruments, and controls.

Other equipment includes five guillotine dampers supplied to isolate the humidifier from the existing flue gas duct. A rotary lump grinder is also supplied at the discharge of the humidifier hopper to grind any large material before sending it to the ash removal system.

Costs to perform flow model testing for optimization of the final humidification system design are likewise included. This would be necessary to assure proper design of the humidifier for operation at close approach to saturation.

Ash Collection, Storage, Recycle, and Removal System--

Coolside ash fall out/collection will occur in the humidifier hopper and the ESP hoppers, although only a minimal amount is expected to accumulate in the former. Most is collected by the ESP and falls into the ESP hoppers. It is assumed that the existing ESP has sufficient SCA, T/R set capability, and rapping capability to handle the increased Coolside ash loading. The existing ESP equipment must be evaluated under the increased loading conditions to determine if stack particulate emission limits can be maintained. No modifications were necessary to the Edgewater ESP which had a design SCA of 612 $ft^2/10^3$ ACFM to achieve a particulate removal efficiency of 99.38 percent. [Post-Coolside inspection of the Edgewater precipitator revealed doughnut-shaped ash build-up on many wires of the first field of the ESP, however, this was attributed to several upset conditions which occurred during the early stages of testing.]

For the conditions studied, the application of Coolside can increase the total ash collected in the ESP by a ratio up to about 3:1 when operating at 2.0 Ca/S ratio (recycle was assumed to be employed to a lesser extent as the coal sulfur content increased). For this evaluation, it has been assumed that, similar to the Edgewater installation, the existing ash removal system can collect and transport the additional ash by more frequently emptying of the ESP hoppers. The ash storage silo capacity is assumed to be adequate and capable of storing about four days' production of Coolside ash, as was the case at Edgewater. Costs are provided for upgrading the system to handle the increased solids flow. It is noted, however, that some plants would not have this margin available and would find it necessary to consider increasing the capacity of all or selected parts of their ash handling system.

Ash Collection and Storage System--The existing ash collection system is assumed to be the dry vacuum type, which utilizes either a hydraulic exhauster or mechanical exhausters to effect the flow of conveying air. For the purposes of this comparison, it will be assumed that the reference plants utilize mechanical exhausters. An existing primary cyclone type collector and a secondary pulse jet bag filter, both mounted on the top of the ash silo, collect the conveyed ash and empty it into the silo through double-dump discharge gates. This existing system will be upgraded in order to handle the increased solids flow as follows:

- The humidifier hopper will be tied into the existing plant fly ash vacuum system.
- The vacuum source will be replaced with one of greater capacity.
- The pulse jet bag filter will be replaced with a greater capacity bag filter(s) which has been fitted with Gore-Tex™ bags.

Ash Removal System--It is assumed that the reference plants presently utilize an ash conditioning/unloading system consisting of ash silo fluidizers, an ash discharge slide gate, a rotary feed valve, and a paddle-type ash conditioner which wets the ash for discharge into trucks for transport to a landfill. In order to handle the increased Coolside ash loading this system would be upgraded as follows:

- A new variable speed rotary feed valve of double the original capacity will be installed.
- A new plastic-lined, paddle-type ash conditioner will be installed to handle the increased capacity.

- A new plastic-lined discharge chute will be installed and fitted with wash-out capability.

- The water feed to the unloader will be made adjustable.

The operation of the ash discharge slide gate, rotary feeder, ash conditioner, and water supply will be automatically sequenced, with ash and water rates manually adjustable from a panel.

Coolside Ash Recycle System--To increase the sorbent utilization, a portion of the collected solids is recycled. Coolside ash is discharged from the ash silo to a variable speed rotary feeder controlled to supply the required amount of recycle ash to the system. The rotary feeder prevents flooding and feeds at the desired rate into a solids pump. Recycle ash is compacted as it is pushed through the pump barrel by the screw sealing against the transport line back-pressure. The Coolside ash is then fed into the pump mixing chamber where it is fluidized with transport air and conveyed to the distribution bottle through the transport line. Transport air is provided by one 100 percent air blower. The Coolside ash is split at the distribution bottle into several smaller streams, and then directed to an array of injector pipes located in the plane of the humidification nozzles. The ash recycle equipment is not spared because loss of this system would only affect lime utilization, and not the capability of the Coolside system to meet emission requirements.

Coolside Equipment Enclosure--

Those items and groups of equipment that do not fit in the existing boiler building and associated structures will be brought together and housed in a single separate structure called the "Coolside equipment enclosure". Located below the lime storage silo, it will support and/or enclose:

- The lime storage silo truck unloading, bin discharge, and feed equipment

- Atomization water tank, feed pumps, and two sets of strainers

- The atomization air compressors, air receiver, and instrument air conditioning equipment

- A room for electrical switchgear and motor control centers

- Noise abatement enclosures for the centrifugal air compressors.

Pipe Rack--

The design includes a 150 ft long pipe rack for supporting pipe runs between the Coolside equipment enclosure and the boiler structure. The support elevation will be 20 ft above grade to clear roadways. The rack will carry interconnecting piping, and electrical wiring in cable trays.

Instrumentation and Controls--

The Coolside system will be controlled from the boiler control room by the Coolside operator. Subsystem and individual equipment start/stop operations would be from the boiler control room. Local start/stop capability will also be provided for the rotating equipment. The design includes computerized process control and an operator interface console. Required instrumentation for local or remote status indication is included with recording and alarms for critical conditions. Annunciation of trouble spots are highlighted on computer graphics. It is assumed that the plant will have a CEMS in place. It is recognized that each plant will have its own control philosophy, and any final design would have to make accommodations for the plant's unique facilities and requirements.

Electrical Equipment--

It is assumed that the plant can provide a power lead from its 4160 VAC bus. The design would include the necessary transformer and switchgear to power the Coolside equipment enclosure and Coolside equipment. The electrical equipment room is located in the Coolside equipment enclosure and will house the 4160 and 480 VAC load centers, motor control centers, and lighting panel. A grounding grid, 120 VAC utility outlet and control power system, electrical heat tracing, and indoor and outdoor lighting are also included. The interconnecting wire, conduit, and cable trays between the Coolside equipment and the electrical equipment room are included. The 4160/480 transformer is located just outside the Coolside equipment enclosure.

Heating, Ventilation, and Air Conditioning--

The Coolside equipment enclosure and the humidification enclosures will be heated and ventilated. The electrical equipment room will be heated and air conditioned to support the control system hardware.

Miscellaneous--

A sump is located in the Coolside equipment enclosure to collect water from ash and lime truck spill wash-down water, atomization water tank overflow, and miscellaneous drip and floor drains, but not including sanitary, roof downspouts, or storm drains. Two 100 percent vertical sump pumps will transfer the ash/lime waste water into a disposal system by others. A mixer will be located in the sump to provide off-bottom suspension of solids.

Both Coolside ash and lime truck spill wash-down water will be highly alkaline. Therefore, it will be necessary to neutralize this water before pumping it to disposal. A neutralization system consisting of two pH meters, a sulfuric acid tank, a tank containment, and an acid metering control valve is included. The acid tank will be located just outside of the Coolside enclosure as close to the sump as possible. The pH meters will monitor sump water pH and forward the signal to the control system which will maintain the sump pH at 7.0 by the gravity addition of sulfuric acid.

An instrument air system will be included to dry, filter, and condition a portion of the atomization air for use as instrument air throughout the Coolside system. The plant's instrument air system will be the back-up to this system.

Coolside Operating Manpower--

It is expected that four additional operators would be required to start, operate, control, and shut down a commercial Coolside system. Lime truck unloading is performed unsupervised by the lime truck drivers. One Coolside control room operator per shift will start/stop remotely operated equipment, set process flow control conditions, monitor process operation, and respond to alarm conditions. The boiler auxiliary equipment operator will start/stop locally operated equipment, walk down and monitor equipment operation, and respond to alarm and upset conditions as requested by the Coolside operator in the control room. Ash hopper evacuation will proceed in the same manner as before Coolside, however, more frequent evacuation will be required. Ash unloading to trucks will also proceed in the same manner as before Coolside, and will be performed more frequently and/or a greater number of trucks will be filled during each unloading process.

TABLE 24. COMMERCIAL COOLSIDE SYSTEM SCOPE OF EQUIPMENT

Item	Quantity
Lime Storage and Feed System	
Lime silo	1
Lime truck unloading equipment	2
Lime silo baghouse	1
Fluidizing air blower	2
Fluidizing air dryer	1
Lime silo discharge air slides	Lot
Variable speed rotary feeder	2
Lime solids pump	2
Transport air blower	2
Lime distribution bottle	2
Injector pipes	Lot
Interconnecting piping, valves, and instruments	Lot
Sodium Addition System	
Soda ash storage tank	1
Tank containment	1
Truck unloading system	1
Dust scrubber	1
Heater	1
Recycle pump	2
Feed pump	2
In-line mixer	1
Interconnecting piping, valves, and instruments	Lot
Humidification System	
Humidification chamber	1
Humidification spray lances	Lot
Lance rapper system	Lot
Air and water distribution headers	Lot
Humidification platforms with enclosure	2
Atomization air compressors	2
Air receiver	1
Water tank	1
Duplex water strainers	3
Atomization water pumps	2
Outlet hopper	1
Support steel	Lot
Tie-in ductwork	Lot
Guillotine dampers	6
Rotary lump grinder	1
Interconnecting piping, valves, and instruments	Lot
Flow model testing	Lot
Ash Collection System	
Humidifier hopper tie-in	Lot
Mechanical exhausters	Lot
Pulse jet bag filter with Gore-Tex™ bags	Lot
Variable speed rotary feed valve	1
Ash conditioner/unloader (pug mill)	1
Ash discharge chute	1
Interconnecting piping, valves, and instruments	Lot
Ash Recycle System	
Variable speed rotary feeder	1
Solids pump	1
Transport air blower	1
Distribution bottle	1
Injector pipes	Lot
Interconnecting piping, valves, and instruments	Lot
Coolside Enclosure and Electricals	
Coolside equipment enclosure	Lot
Foundations and concrete work	Lot
Support steel, stairways, and platforms	Lot
Heating, ventilation, and air conditioning	Lot
4160 VAC transformer	1
480 VAC load centers	Lot
Motor control centers	Lot
Lighting panel	1
Control power system including back-up power	2
Heat trace panel and heat tracing	1
120 VAC utility panel	1
Communication equipment	Lot
Grounding grid	Lot
Hoists and trolleys	Lot
Interconnecting wire, conduit, and cable trays	Lot
Miscellaneous	
Pipe rack	160 ft
Computerized control system	Lot
Operator interface console	1
Instrument air system	Lot
Sump	1
Sump pumps	2
Mixer	1
pH meters	2
Acid tank	1
Acid tank containment	1
Eyewash/safety showers	Lot
Fire protection systems	Lot
Interconnecting piping, valves, and instruments	Lot

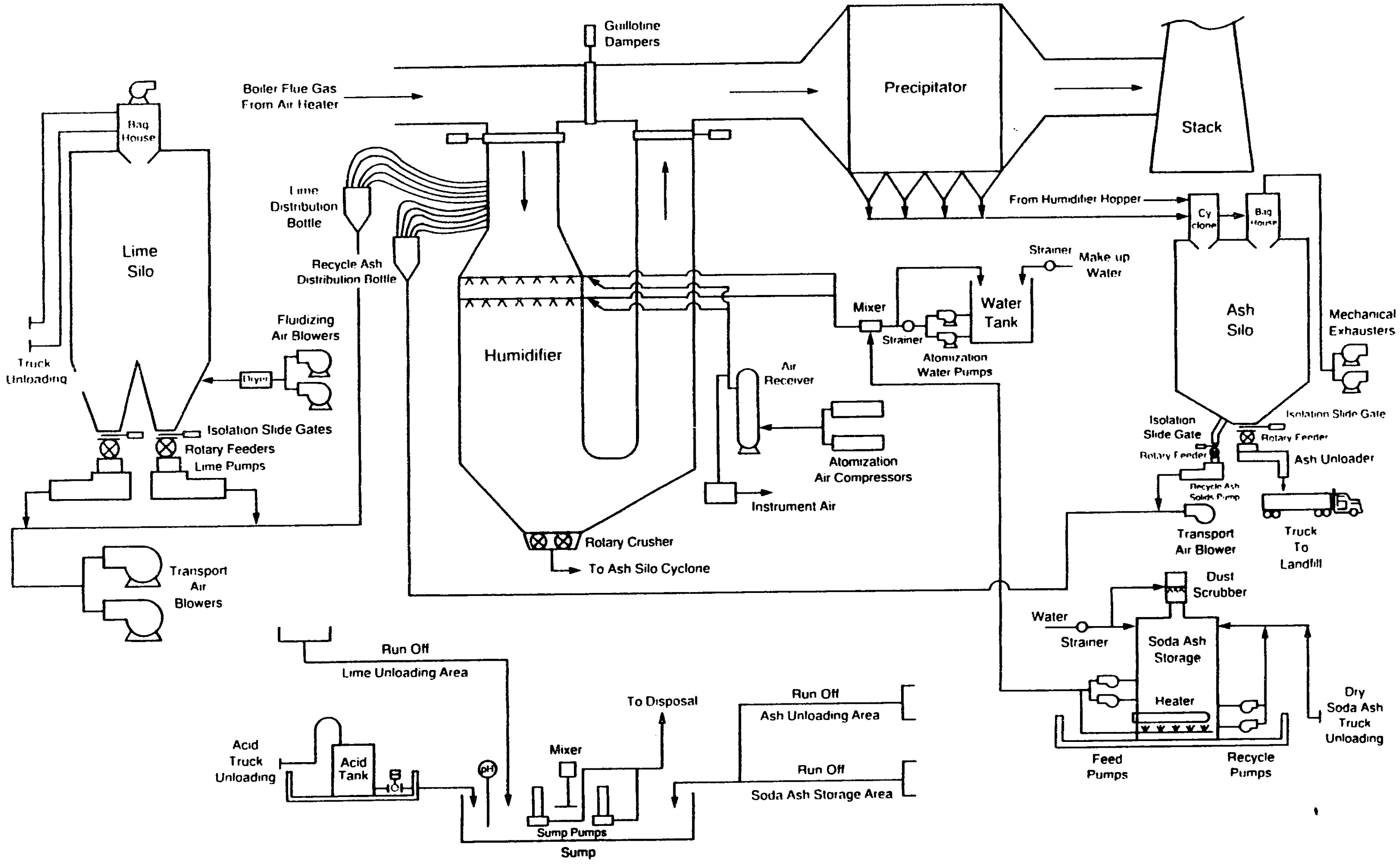


Figure 45. Commercial Coolside system schematic

Commercial Limestone Forced Oxidation FGD System Design

The LSFO FGD process was selected for comparison with LIMB and Coolside FGD Systems because its design is considered to be the state-of-the-art wet scrubbing system that would be purchased by an electric utility to meet current and future stack emission requirements. The design consists of four process areas: the limestone storage and preparation system; fans and ductwork; the absorber system; and the dewatering system. It is assumed that the existing ID fans are not of great enough capacity to overcome the additional pressure drop of the LSFO system, and new supplemental ID fan(s) will be required. Rubber-lined carbon steel was chosen as the material of construction for the absorber tower, although it is realized that varying chloride concentrations and other site-specific conditions may dictate the use of stainless steel alloys or other materials. A gas distribution/SO_2 absorption tray is utilized in the absorber tower in this evaluation. A design without a tray would require an additional spray level(s) and a greater liquid-to-gas ratio (L/G). In this design the gypsum product is considered to be of disposal grade, rather than being washed to a higher quality for use as wallboard. Flue gas reheat is not included as there is provision for a new wet stack. A listing of the scope of equipment and a LSFO FGD system schematic are presented after the detailed descriptions in Table 25 and Figure 46, respectively.

Limestone Storage and Preparation System--

Limestone is delivered to the site by trucks which unload into a receiving bin located near the limestone bulk storage facility. A conveyor elevates the limestone into this facility which holds a 31 day supply of limestone for the unit operating at MCR. A transfer conveyer elevates limestone from the bottom of the bulk storage facility to the limestone day silo which holds a 24 hr supply of limestone. The limestone bulk storage facility is enclosed for weather protection. The limestone day silo has two discharge points, each of which is fitted with a manual slide gate for isolation, and with a vibrating bin bottom to facilitate the flow of limestone to the limestone preparation system. From each discharge point, limestone can be fed to a weigh belt feeder which is controlled to supply the required amount of limestone to a wet ball mill. There are two 100 percent capacity, rubber-lined ball mills supplied. The mills grind the limestone to a particle size of 95 percent passing 325 mesh (44 μm). The resulting 30 percent solids limestone/water slurry is fed to the its storage tank which has a 12 hr storage capacity at MCR.

Each ball mill has one mill product tank with a mixer, two 100 percent mill product pumps, cyclone classifiers (spared), two bearing lubrication oil systems, and a gear lubrication system included. The limestone slurry storage tank has one mixer and two 100 percent feed slurry pumps which pump fresh slurry to the absorber system. The limestone slurry preparation equipment is located in an enclosure which contains the necessary stairways and platforms for access to the equipment, heating and ventilation, lighting, control panel, overhead maintenance hoists, an electric roll-up equipment access door, and a drainage sump. The sump is fitted with two 100 percent sump pumps and a mixer.

Fans and Ductwork--

Flue gas exiting the existing ESP is directed to two 50 percent ID fans by a section of carbon steel ductwork. The ID fans are sized to overcome the pressure drop of the absorber module and the ductwork. From the ID fan outlets, a carbon steel duct directs the flue gas to the absorber module entrance nozzle. The absorber module entrance nozzle is constructed of 3/16 in thick C-276 alloy. After exiting the absorber tower, the flue gas is directed to the stack by a 3/16 in thick 317 LMN stainless steel outlet duct. A carbon steel 100 percent absorber bypass and three guillotine isolation dampers are included.

Absorber System--

Flue gas from the ID fan outlet is directed to the SO_2 absorber system, which utilizes a single 100 percent capacity carbon steel, rubber-lined absorber module to remove 95 percent of the SO_2. Removal is accomplished by a countercurrent spray absorption process occurring in the absorber module. By spraying limestone slurry into the flue gas, calcium carbonate ($CaCO_3$) reacts with SO_2 in the flue gas to form hydrates of calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$). The reacted slurry collects in the absorber module recirculation tank. Air is blown into the recirculation tank through a sparge ring at a stoichiometric ratio of 1.5 mol O_2/mol SO_2 absorbed to convert 99 percent of the sulfite to sulfate. The recirculation tank is sized for 8 min retention time. Mixers provide off-bottom suspension of the slurry solids. Large slurry pumps take suction from the recirculation tank with each feeding an individual spray header. A perforated tray, located below the spray zone, acts as a gas distribution device. A froth of recycled slurry develops on the tray as flue gas passes through it, assuring optimum gas/liquid contact and promoting the absorption of SO_2.

Before exiting the absorber module, the flue gas passes through two sets of mist eliminators where entrained slurry droplets are removed. A mist eliminator wash system periodically removes any collected solids from the mist eliminator. The pH of the recirculation tank slurry is monitored, with fresh limestone slurry added to maintain the optimal pH for the SO_2 absorption/oxidation reactions. The density of the recycle slurry is controlled by the addition of reclaim water to the recirculation tank. Spent recirculation slurry is pumped to the dewatering system, as required, to maintain proper level in the recirculation tank. The cleaned flue gas exiting the absorber tower is exhausted through a new wet stack.

Dewatering System--

The spent slurry is dewatered to a concentration of 35 percent solids by two 50 percent capacity hydroclone clusters. Each cluster consists of several cyclones (spared) with carbon steel housings and snap-in rubber liners. The thickened underflow slurry is collected in a rubber-lined launder and fed by gravity to a waste slurry tank. The waste slurry tank is sized for 16 hr storage and fitted with an off-bottom mixer. One of two 100 percent waste slurry feed pumps directs waste slurry to the vacuum filters. The overflow from the hydroclones is directed to a clarifier for removal of the fine solids. A polymeric flocculant added to the clarifier assists the gravity settling of fines. The solids settle to a discharge cone at the center of the clarifier where one of two 100 percent clarifier underflow pumps directs the solids to the waste slurry tank. Clarified reclaim water overflows the clarifier and is directed to a reclaim water storage tank which is sized to equal the clear water content of the waste slurry tank. One of two 100 percent reclaim water pumps returns reclaim water to the absorber, limestone preparation system, and other process equipment.

Two 100 percent capacity rotary drum vacuum filters dewater the waste slurry to an 85 percent solids filter cake. The filtrate is directed to the clarifier for removal of the fine solids. Conveyors transport the gypsum filter cake to the stack-out area where it is stored until it can be trucked to a disposal site. For this evaluation, the disposal site is assumed to be an unlined landfill located one mile from the gypsum stack-out area.

Absorber Area Enclosure--

An enclosure will be located at the base of the absorber tower. It will support and/or enclose:

- The absorber recirculation pumps
- The oxidation air blowers
- The absorber tank mixers
- The absorber area sump

- pH and density monitoring equipment
- Heating and ventilation
- Hoists and monorails
- Water strainers
- A control room with heating, ventilation, and air conditioning (HVAC)
- A room for electrical switchgear and motor control centers with heating and ventilation
- Equipment access roll up doors
- An instrument air system
- Restroom facilities
- Lighting
- Heat trace panels
- Elevator.

Vacuum Filter Enclosure--

The vacuum filters and related process equipment will be located in an enclosure which contains the necessary stairways and platforms for access to the equipment, heating and ventilation, lighting, a control panel, overhead maintenance hoists, an electric roll-up equipment access door, and a drainage sump fitted with two 100 percent sump pumps and a mixer.

Pipe Racks--

The design includes two 150 ft pipe racks for supporting pipe runs between the limestone preparation system and the absorber system, and between the vacuum filter system and the absorber system. The support elevation will be 20 ft above grade to clear roadways. The rack will carry interconnecting piping, and electrical wiring in cable trays.

Instrumentation and Controls--

The absorber system will be controlled and monitored from the scrubber control room located in the absorber enclosure by scrubber operators. Absorber area equipment start/stop and process control operations will be from the scrubber control room. The limestone preparation system and the vacuum filter system will be started from local control panels. These systems will be monitored from the scrubber control room where full start/stop capability will also exist. The control system design includes computerized process control and an operator interface console. System process status and annunciation of trouble spots are highlighted on computer graphics. It is assumed that the plant will have a CEMS in place. It is recognized that each plant will have its own control philosophy and that any final design would have to make accommodations for the plant's unique facilities and requirements.

Electrical Equipment--

It is assumed that the plant can provide a power lead(s) from its 4160 VAC bus. The design would include the necessary transformer(s) and switchgear to power the LSFO system equipment. The electrical equipment room is located in the absorber area enclosure and will house the 4160 and 480 VAC load centers, motor control centers, and lighting panel. A grounding grid, 120 VAC utility outlet and control power system, electrical heat tracing, and indoor and outdoor lighting are also included. The interconnecting wire, conduit, and cable trays between the LSFO system equipment and the electrical equipment room are included.

Heating, Ventilation, and Air Conditioning--

The absorber area, limestone preparation system, and vacuum filter enclosures will be heated and ventilated, as will the electrical equipment room. The control room will be heated, ventilated, and air conditioned.

Miscellaneous--

Two 50 percent instrument air systems complete with air dryers, filters, and air receivers are included. Eyewash/safety showers are provided throughout the system as required. A seal water system is provided. Service water and service air stations will be provided as required throughout the system. It is assumed that the plant will be able to supply seal water, service water, and service air to the LSFO system.

LSFO FGD System Operating Manpower--

Additional operating manpower will be required to start, operate, control, monitor, and shut down the LSFO system. One control room operator per shift will start/stop remotely operated equipment, set process flow conditions, monitor process operations, and respond to alarm conditions. One outside operator per shift (two on day shift) will start/stop locally operated equipment, walk down and monitor equipment operation, and respond to alarm and upset conditions as requested by the control room operator. One full-time laboratory technician will monitor scrubber chemistry and critical process parameters such as limestone quality, pH, density, and fresh slurry grind size. Two full-time instrumentation and control (I&C) technicians will troubleshoot and maintain the LSFO system controls and instruments. Four full-time mechanics will perform maintenance on the system equipment. One full-time yard equipment operator will operate a front end loader to fill gypsum disposal trucks and move limestone into the unloading bin. One full-time supervisor will have responsibility for the optimum operation of the LSFO system and provide supervision for the operating personnel. These requirements are summarized as follows:

Job Description	Coverage	No. Required
LSFO system supervisor	Day shift-5 day/wk	1
Control room operator	24 hr-7 day/wk	4
Outside operator	24 hr-7 day/wk	4
Outside operator	Day shift-7 day/wk	2
Lab technician	Day shift-5 day/wk	1
I&C technician	Day shift-5 day/wk	2
Mechanics	Day shift-5 day/wk	4
Yard equipment operator	Day shift-5 day/wk	1

TABLE 25. COMMERCIAL LSFO FGD SYSTEM SCOPE OF EQUIPMENT

Limestone Storage and Preparation System	
Limestone receiving bin	1
Bulk storage transfer conveyor	1
Limestone bulk storage area enclosure	1
Limestone bulk storage transfer bin	1
Day silo transfer conveyor	1
Limestone day silo	1
Vibrating bin bottom	2
Weigh belt feeder	2
Ball mill feed chute	2
Ball mill	2
Mill product tank	2
Mill product tank mixer	2
Mill product pumps	4
Cyclone classifiers	2
Lubrication oil systems	4
Gear lubrication systems	2
Limestone slurry storage tank	1
Limestone slurry storage tank mixer	1
Feed slurry pumps	2
Drainage sump	1
Sump mixer	1
Sump pumps	2
Interconnecting piping, valves, and instruments	Lot

Fans and Ductwork	
Booster ID fans: for 100 and 150 MWe cases	1
for 250 and 500 MWe cases	2
ID fan outlet duct	Lot
By-pass duct	Lot
Absorber entrance nozzle	1
Absorber outlet duct	1
Guillotine dampers	3
Support steel, stairways, and platforms	Lot
Insulation and lagging	Lot
Foundations and concrete work	Lot

Absorber System	
Absorber module with integral reaction tank	1
Absorber headers, spray nozzles, and tray	Lot
Mist eliminators	Lot
Mixers	3
Absorber recirculating pumps	Lot
Absorber recirculating pump, piping, and valves	Lot
Mist eliminator wash tank	1
Mist eliminator wash pumps	2
Mist eliminator wash water strainer	1
Waste slurry blowdown pumps	2
Oxidation air compressors	2
Sparge ring	1
Sump pumps	2
Sump mixer	1
Interconnecting piping, valves, and instruments	Lot
Support steel, stairways, and platforms	Lot
Flow model testing	Lot

Absorber Area Enclosure	
Absorber enclosure	Lot
Foundations and concrete work	Lot
Support steel, stairways, and platforms	Lot
Heating, ventilation, and air conditioning	Lot
Lighting	Lot
Drainage sump	1
Hoists and trolleys	2
Control room	1
Electrical equipment room	1
Restroom facilities	Lot
Roll-up door	2
Elevator	1

Limestone Area Enclosure	
Limestone area enclosure	1
Support steel, stairways, and platforms	Lot
Heating and ventilation	Lot
Lighting	Lot
Control panel	Lot
Hoists and trolleys	2
Roll-up door	1
Drainage sump	1
Foundations and concrete work	Lot

Dewatering System	
Hydroclone clusters	2
Waste slurry tank	1
Waste slurry tank mixer	1
Vacuum filter feed pump	2
Clarifier	Lot
Flocculent feed system	1
Clarifier underflow pump	2
Reclaim water storage tank	1
Reclaim water pumps	2
Vacuum filter with pumps, receiver, and air separator	2
Collecting conveyor	1
Forwarding conveyor	1
Radial stacker	1
Gypsum stack out area	Lot
Sump pumps	2
Sump mixer	1
Interconnecting piping, valves, and instruments	Lot

Dewatering Area Enclosure	
Vacuum filter enclosure	Lot
Foundations and concrete work	Lot
Support steel, stairways, and platforms	Lot
Heating and ventilation	Lot
Lighting	Lot
Drainage sump	1
Hoists and monorails	2
Control panel	1
Roll-up door	1

Electrical Equipment	
4160 VAC transformer	2
480 VAC load centers	Lot
Motor control centers	Lot
Lighting panel	3
Control power system including back-up power	1
Heat trace panel	3
Heat tracing	Lot
120 VAC utility panel	3
Grounding grid	Lot
Outdoor lighting	Lot
Communications system	Lot
Interconnecting wire, conduit, and cable trays	Lot

Miscellaneous	
Pipe rack	300 ft
Computerized control system	Lot
Operator interface console	2
Instrument air system	2
Seal water system	Lot
Service water system	Lot
Service air system	Lot
Fire protection system	Lot
Eyewash/safety showers	Lot
Wet stack	1
Stack foundation	1

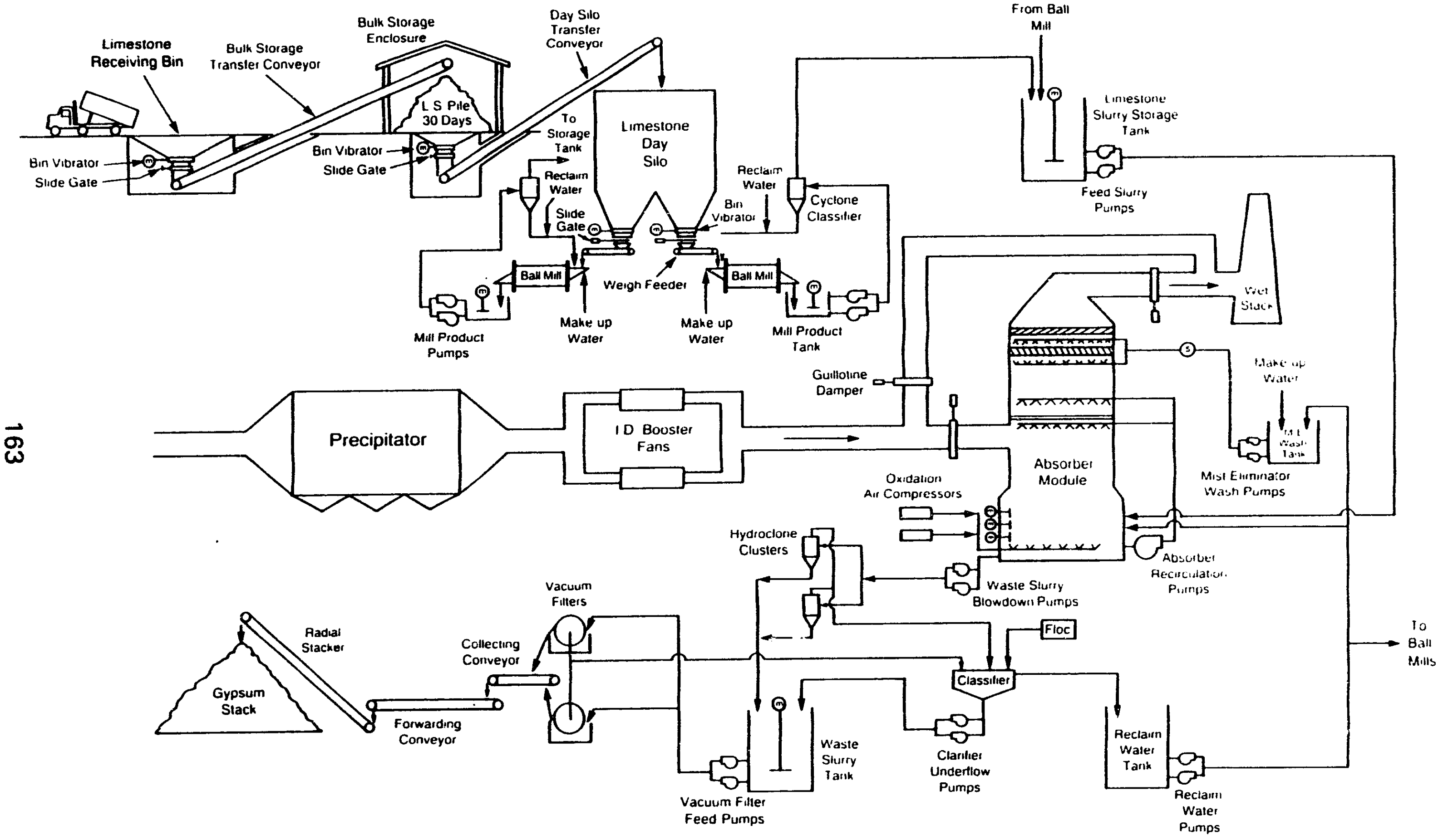


Figure 46. Commercial LSFO FGD system schematic

ECONOMIC EVALUATION

Following on the design, installation, operation, and technical evaluation of the LIMB and Coolside technologies, the economic analysis is the last step of the demonstration projects. In keeping with the project goal to show generic applicability, the analysis attempts to present a comprehensive summary for both processes. The perspective is one developed by those who both participated in each of the preceding steps and have direct access to corresponding information on the LSFO technology with which the two are compared.

The costs of the LIMB, Coolside, and LSFO processes for each of the three coals and four plant sizes used the same overall approach. Wherever possible, this included a level of engineering typical of that used to provide actual budgetary estimates to customers in commercial applications. Although the number of cases examined precluded absolutely unique analysis of each, individual material balances established the basis for sizing and developing equipment lists. Whenever necessary, new vendor quotations were obtained to supplement the current B&W equipment cost data base which reflects costs on utility systems sold within the past year or two after passage of the CAAA in late 1990. The reference plant and process design information included earlier in Tables 17 through 22 established the bases for the scopes of equipment in Tables 23 through 25 from which costs were individually determined. Because it probably reflects the most widely accepted methodology, EPRI's *TAG*™ was used as a guide for the analysis, with the vendor quotations or pertinent costs from the current data base being inserted whenever they were considered to be more representative than more generic estimating techniques.

The discussion to follow tries to present the analysis in a format that a utility might use in determining the applicability of the processes as part of an overall compliance strategy, rather than as a detailed listing of all the specific assumptions and costs made for each and every case. Such an approach recognizes the uncertainty that arises from any of a number of site-specific considerations that require individual analyses in the final decision-making process. General, rather than explicit, justification is used for choosing various factors for such things as construction and maintenance because these factors are usually closely coupled with site-specificity. The summary curves permit the individual reader to superimpose his or her own immediate concerns and make a preliminary judgment regarding feasibility of a potential application.

Costs are divided into the three major categories of capital cost, variable costs, and fixed operating and maintenance (O&M) costs. The capital costs, or total capital requirement (TCR), consist of the total plant investment (TPI), preproduction costs, inventory, land, and interest during construction (IDC). Variable costs include major consumables and disposal costs. Maintenance costs for both labor and materials, operating manpower costs, and administration and overhead costs constitute the fixed O&M costs. Annual levelized requirements, expressed in terms of \$/ton SO_2 removed, and operating costs, expressed in units of mill/kWh, were also determined. A constant dollar levelization technique, as outlined in *TAG*™, was used on the capital carrying charges and operating costs in order to account for only real, and not inflationary, escalation. Table 26 summarizes the economic premises. The costs for consumables, utilities, labor, and disposal were derived from *TAG*™ and converted to 1992 dollars.

Capital Costs

The installed equipment costs (IEC) are calculated using the individual equipment costs (EC) and construction factors (CF). The latter are discrete multipliers for each item in the scope of supply and represent that percentage of each EC needed to cover both direct and indirect construction costs. Direct construction costs include such things as field labor, factory equipment, and field materials and supplies. Indirect construction costs are for such items as supervision, payroll burden, tools, field engineering, and facilities. The construction factors were derived from B&W Construction Company's historical information, and are based on their wide range of experience installing FGD and power plant equipment. As applied here, the construction factors include so-called retrofit and site-factors and varied according to the specific requirements of installing each piece of equipment.

The TPI is the sum of the IEC, engineering, general facilities, and process and project contingencies costs. Engineering costs include the costs of engineering and home office overhead. A factor of ten percent of the IEC is used, as this is the amount considered representative of the FGD industry.

General facilities costs are the funds used to construct the general facilities, including roads, buildings, shops, and laboratories. A factor of 5 percent of the IEC, at the low end of the 5 to 20 percent range found in *TAG*™, is used since the cost for all of the buildings associated with

TABLE 26. PREMISES FOR THE ECONOMIC EVALUATIONS

	LIMB	Coolside	LSFO
Reference date of cost estimate	April 1992	April 1992	April 1992
Unit book life, yr	15	15	15
Tax life, yr	15	15	15
Levelizing factor for 15 yr carrying charges	0.139	0.139	0.139
Construction period, yr	1	1	2-3*
<u>Indirect costs as percent of total direct capital</u>			
General facilities	5	5	5
Engineering	10	10	10
Project contingency	18	18	15
Process contingency	5	5	2.5
<u>Consumables, utilities, labor, and disposal costs</u>			
Water, $\$/10^3$ gal	0.69	0.69	0.69
Lime, $/ton delivered	64	64	-
Limestone, $/ton delivered	-	-	17
Soda ash, $/ton delivered	-	157	-
Sulfuric acid (93 %), $/ton delivered	102.40	102.40	-
Coal cost, $/ton	34.09	-	-
Replacement power, ¢/kWh	5.8	5.8	5.8
Steam, $\$/10^3$ lb	6.19	-	-
Solids disposal, $/ton (dry)	9.26	9.26	9.43
Fly ash credit, $/ton (dry)	9.28	9.26	-
Labor rate, $/hr	-	23.15	23.15
Land, $/acre	-	-	7410

* The construction period is dependent upon plant size.

each of the processes was included in the IEC already.

The process contingency factor takes into account the capital costs associated with the uncertainty inherent in a new technology. *TAG*™ values span the range of 0 to a high of 10 percent for processes that are in the commercial phase. A factor of 5 percent is assumed here for the LIMB and Coolside processes, and a factor of 2.5 percent for the LSFO process. Process contingency cost is calculated by multiplying this factor by the sum of the IEC, engineering, and general facilities cost.

The project contingency cost is similarly calculated according to the *TAG*™ procedures to cover possible cost deficiencies caused by a less-than-final design/estimate. The project contingency factor is multiplied by the sum of the IEC, engineering, general facilities, and process contingency costs to arrive at the project contingency cost. The factor itself can range from 5 to 50 percent, corresponding to a design/estimate ranging from finalized through preliminary to simplified. Those prepared in this study fall into the preliminary category, which generally are assigned values of 15 to 30 percent. Since the LSFO design/estimate satisfied all of the criteria for a preliminary rating, the 15 percent factor was used. An 18 percent factor was chosen for LIMB and Coolside since slightly less detail was used in developing these designs.

Once the TPI has been determined, the costs for preproduction, inventory, land, and IDC are added to arrive at the TCR. In the case of LSFO FGD, the cost of land was also added since this technology is known to have certain space requirements. Those for LIMB and Coolside, on the other hand, are regarded as insignificant. The procedure used to arrive at the costs for preproduction, inventory, and IDC follow those outlined in *TAG*™.

Variable Costs

Variable operating costs are those associated with the major consumables and the disposal of waste products. These costs are dependent on flow rates and plant operating time. To arrive at the yearly cost for any given consumable, the full-load, hourly rate of consumption is multiplied by the unit cost, the plant capacity factor, and 8,760 hr/yr. The cost of disposal of waste products is calculated in an equivalent manner from the feed rates and removal efficiencies. The total represents the annual variable operating cost. Appendix F contains a summary table of consumable usage and waste disposal quantities for all the cases, as well as motor lists specifying the quantity of each, the horsepower rating of the motors, and the associated operating power in kW.

Fixed Costs

Fixed costs are those associated with operating labor, maintenance, and administrative overhead. Operating labor costs are determined by multiplying the number of jobs required to operate the plant by the average hourly labor rate and by 8,760 hr/yr. Annual maintenance costs are calculated as the product of the TPI and a maintenance factor related to the severity of the service environment. The range in *TAG*™ runs from 1 percent for abrasive conditions to over 10 percent for very corrosive conditions. In this study, a common value of 4 percent was selected based on the assumption that the potential for abrasive conditions in LIMB and Coolside is no more expensive than the potential for corrosion in LSFO. Forty percent of the total is ascribed to maintenance labor and the balance to maintenance materials. Administrative and overhead costs are assumed to be 30 percent of the maintenance labor and operating labor costs.

Appendices G, H, and I contain examples of the detailed summaries resulting from the economic analyses of the LIMB, Coolside, and LSFO processes, respectively. The data are presented for the 150 MWe cases with 1.5, 2.5, and 3.5 weight percent sulfur coals and using commercial hydrated calcitic lime as the LIMB sorbent.

ECONOMIC COMPARISON OF LIMB, COOLSIDE, AND LSFO FGD

The comparison of LIMB, Coolside, and LSFO capital and annual levelized costs are summarized in Tables 27 and 28, respectively, for each of the 36 cases evaluated. The same information is presented in a series of figures, discussed in sets of three, which depict the costs as a function of size expressed in terms of the unit's nominal generating capacity. The effect of increasing coal sulfur content from 1.5 to 2.5 to 3.5 weight percent is shown within each set of three graphs. Total capital required is expressed on a \$/kW basis. The annual levelized cost, calculated in terms of \$/ton SO_2 removed with a basic assumed book life of 15 yr, accounts for the operating and maintenance costs associated with each case. Operating costs in particular are also presented on a mill/kWh basis.

TABLE 27. CAPITAL COST COMPARISON, \$/kW

Coal Sulfur, wt %	100 MWe			150 MWe			250 MWe			500 MWe		
	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
1.5	93	150	413	66	116	312	46	96	228	31	69	163
2.5	95	154	421	71	122	316	50	101	235	36	76	169
3.5	102	160	425	73	127	324	54	105	240	40	81	174

TABLE 28. ANNUAL LEVELIZED COST COMPARISON, $/ton SO_2 removed*

Coal Sulfur, wt %	100 MWe			150 MWe			250 MWe			500 MWe		
	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
1.5	791	943	1418	653	797	1098	549	704	831	480	589	623
2.5	595	706	895	520	624	692	456	567	539	416	502	411
3.5	525	629	665	461	570	527	419	526	413	392	482	321

* 15 yr book life assumed.

Following the discussion of the basic capital and levelized costs, the concluding portion of this economics section presents figures depicting the sensitivities of the LIMB and Coolside costs to changes in those conditions most likely to affect costs in actual applications. These sensitivities include the effects of plant capacity factor, unit book life, and reagent cost. LIMB-specific sensitivities to sorbent choice and sootblowing requirements conclude the discussion of economics.

Capital Cost Comparison

The capital costs of the optimized LIMB, Coolside, and LSFO processes for coal sulfur contents of 1.5, 2.5, and 3.5 weight percent appear in Figures 47, 48, and 49, respectively. The plots reflect the economy of size, dropping quickly between the 100 and 250 MWe cases, and then leveling off between boilers capable of 250 and 500 MWe. As would be expected, the LSFO capital costs are significantly higher than those of LIMB and Coolside in all cases, primarily because of the amount of equipment required.

For the cases studied, LSFO capital costs are 4.3 to 5.4 times LIMB capital costs, and 2.3 to 2.8 times Coolside capital costs. Coolside capital costs are 1.6 to 2.3 times LIMB capital costs, mainly because of the humidification requirement. A LIMB system designed for operation at close approach to the adiabatic saturation temperature of the flue gas would have costs similar to those of Coolside. Overall, capital cost economics favor the LIMB and Coolside processes for those applications where high SO_2 removal efficiency is not required.

Annual Levelized Cost Comparison

Corresponding to the capital cost comparisons above, Figures 50, 51, and 52 show the

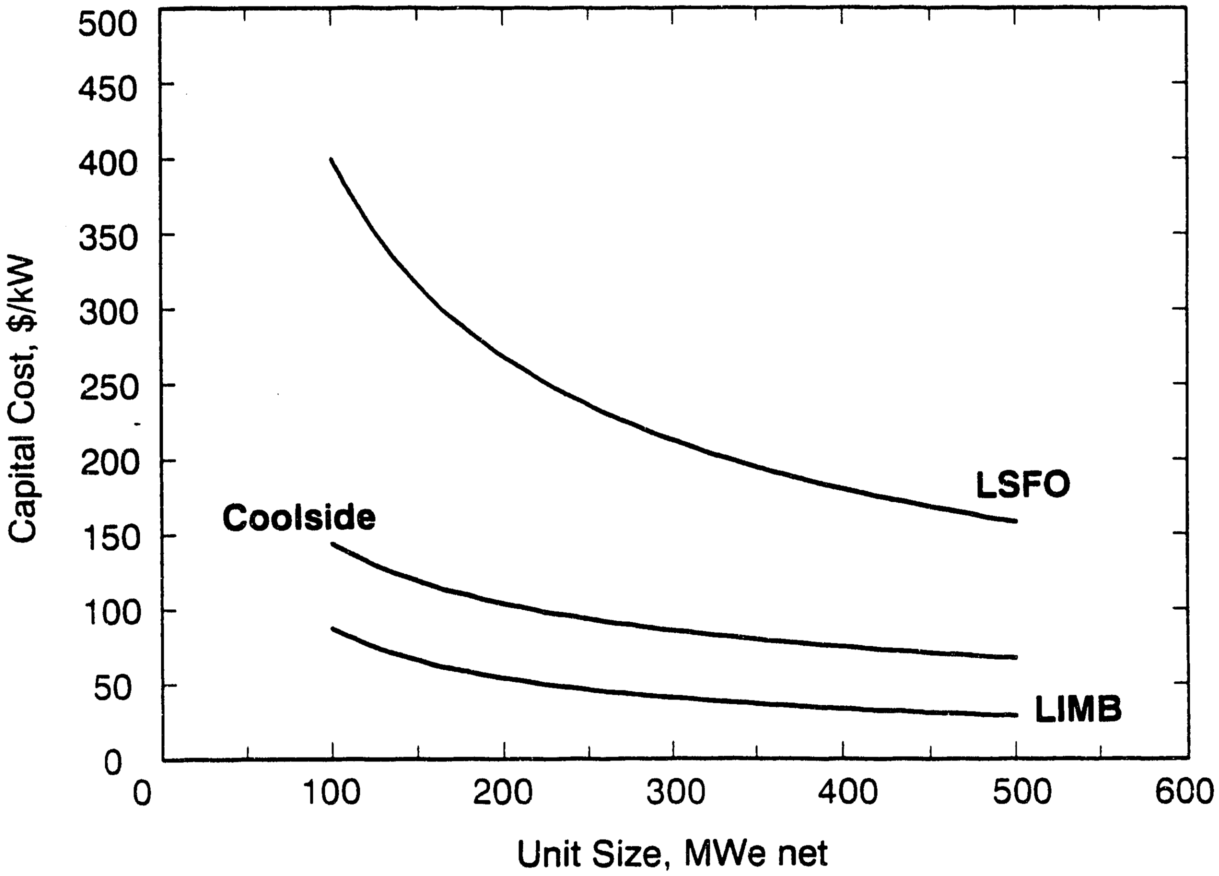


Figure 47. Capital cost sensitivity of LIMB, Coolside, and LSFO to unit size for 1.5 weight percent sulfur coal

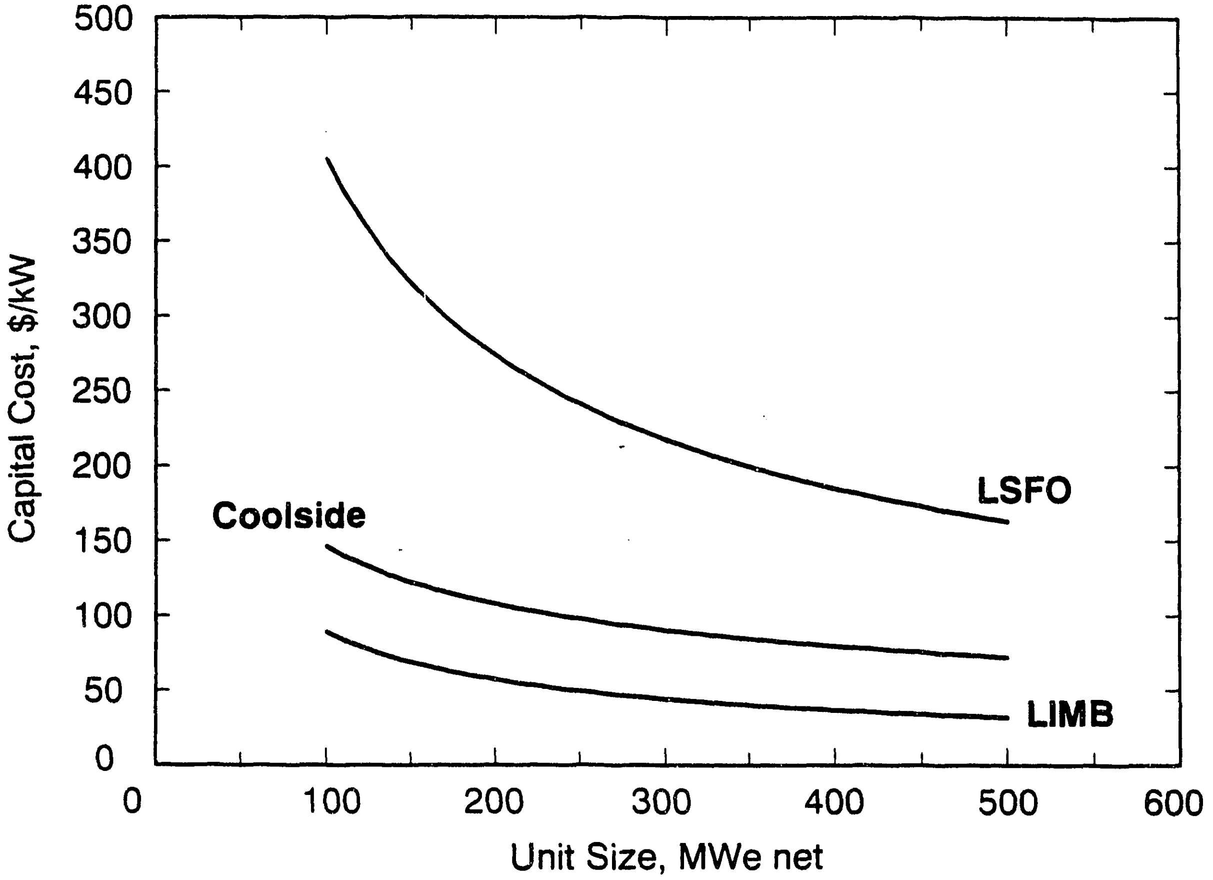


Figure 48. Capital cost sensitivity of LIMB, Coolside, and LSFO to unit size for 2.5 weight percent sulfur coal

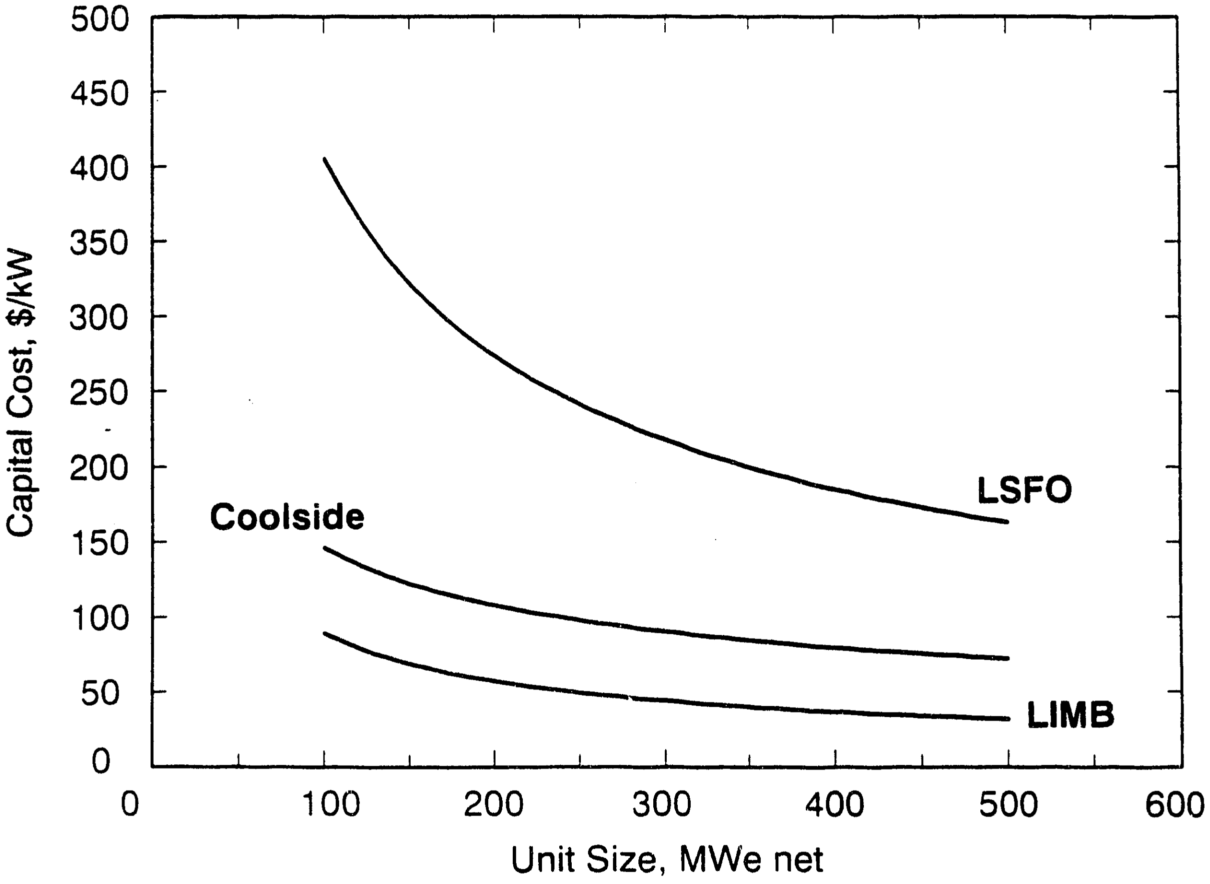


Figure 49. Capital cost sensitivity of LIMB, Coolside, and LSFO to unit size for 3.5 weight percent sulfur coal

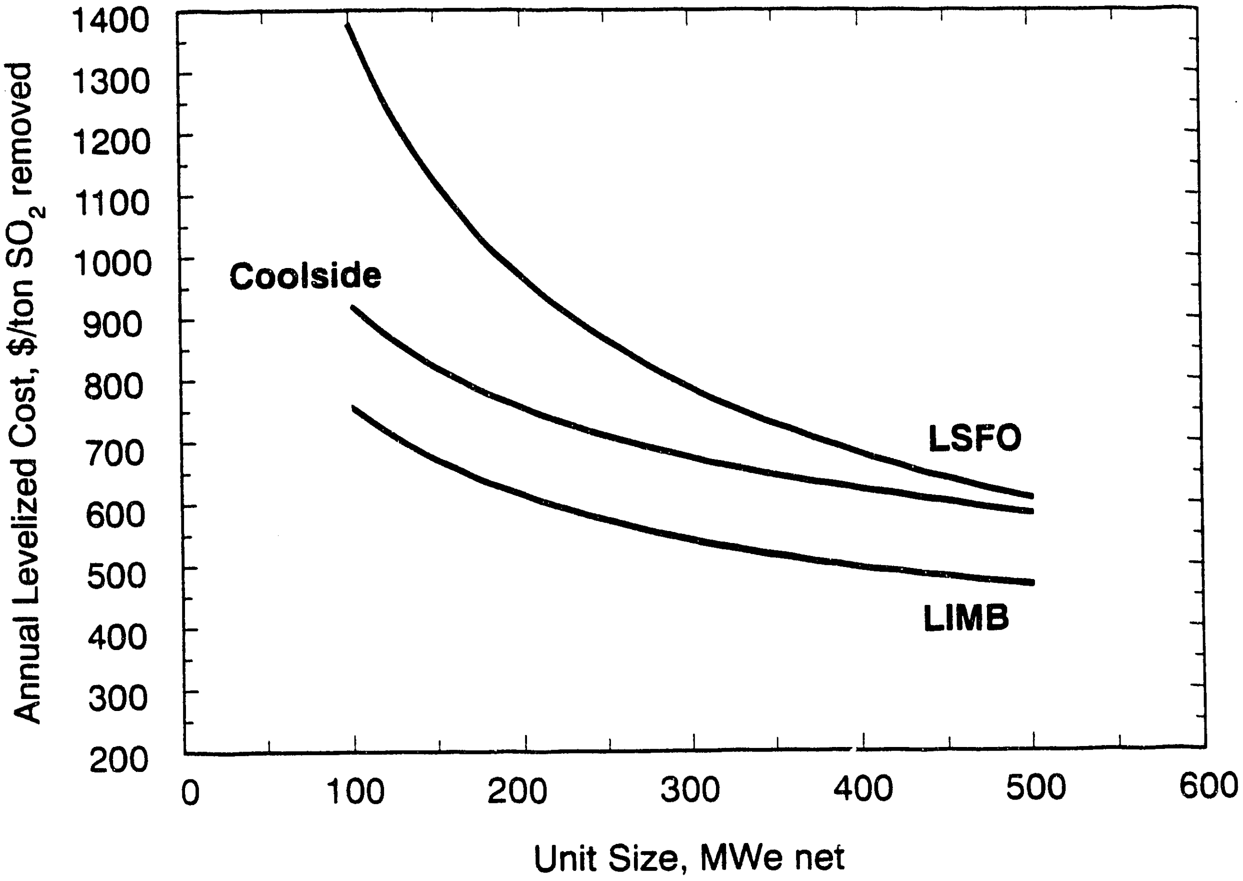


Figure 50. Annual levelized cost sensitivity of LIMB, Coolside, and LSFO to unit size for 1.5 weight percent sulfur coal

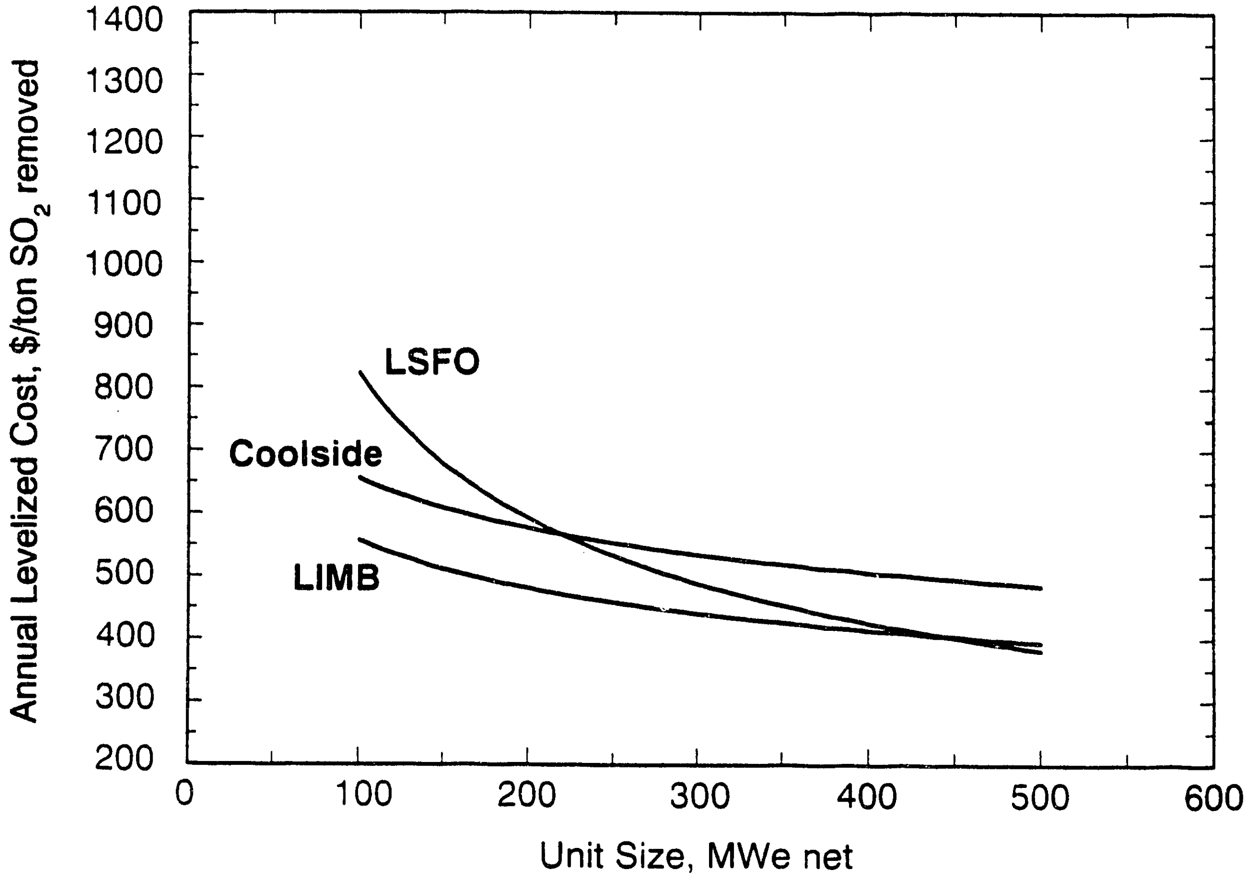


Figure 51. Annual levelized cost sensitivity of LIMB, Coolside, and LSFO to unit size for 2.5 weight percent sulfur coal

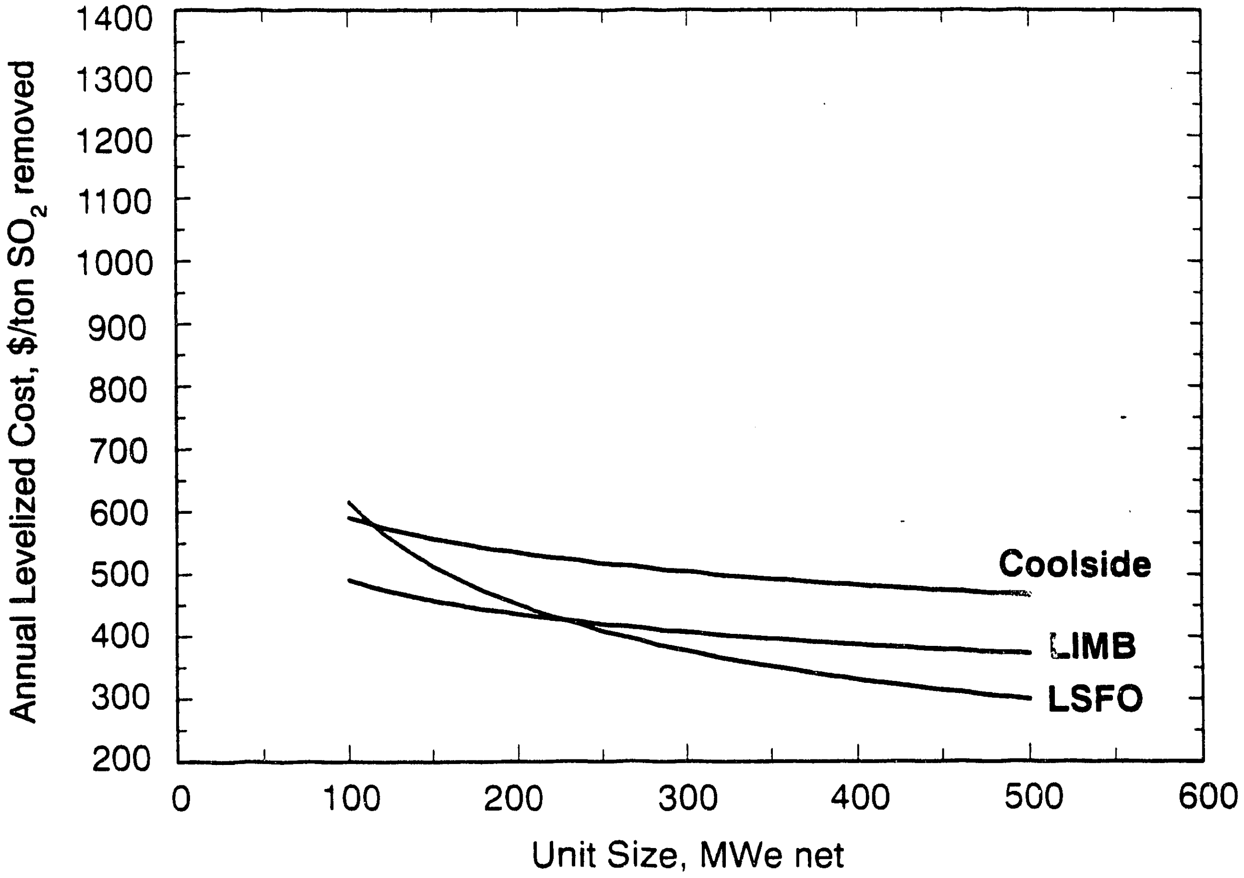


Figure 52. Annual levelized cost sensitivity of LIMB, Coolside, and LSFO to unit size for 3.5 weight percent sulfur coal

annual levelized costs in terms of \$/ton of SO_2 removed. These graphs again depict a drop in cost as the unit size increases, with the greatest decrease occurring between the 100 and 150 MWe sizes. For the cases studied, the annual levelized costs of LIMB and Coolside were found to decrease as the coal sulfur increases, even though operating costs (discussed in the next subsection) increase. However, the lower utilization of sorbent with these technologies causes the difference to become less pronounced as the size increases.

For the 1.5 weight percent sulfur coal case, both LIMB and Coolside show favorable economics compared to LSFO for all unit sizes examined. The fact that LIMB economics are lower than those of Coolside for all cases is again attributed to a significant extent to the cost of humidification to a close approach temperature. For the 500 MWe case, LSFO costs are nearly equal to those of Coolside, indicating that LSFO economics begin to become favorable for units this large and larger, even for the relatively low sulfur coal. For the 2.5 weight percent sulfur coal, LIMB maintains favorable economics in comparison to those of LSFO up to about 450 MWe, and Coolside up to about 220 MWe. LIMB continues to show favorable economics in comparison to Coolside for all cases, though the reader is reminded that site-specific circumstances might easily make the difference less significant. For the 3.5 weight percent sulfur coal, LSFO is the preferred choice over Coolside except for the 100 MWe case, and over LIMB for units larger than about 240 MWe in size. LIMB economics remain lower than those of Coolside over the whole range for the same reasons mentioned above.

Operating and Maintenance Cost Comparison

Since the annual levelized costs represent the overall combined costs, utility personnel find it instructive to examine the operating costs alone on a mill/kWh basis. Table 29 contains this information for all 36 cases. Fixed and variable operating costs are separately listed, along with the total of the two. The costs presented are first-year costs and are based on net kWh and a 65 percent capacity factor. As noted earlier in this section, the fixed operating costs include operating labor, maintenance labor and materials, and administration and overhead. The variable operating costs include reagents, power, water, and steam usage, and waste disposal costs.

Because these operating costs constitute a substantial portion of the levelized costs, they exhibit the same types of trends, except that lower utilization drives up the cost per kilowatt-hour as coal sulfur increases for a given unit size. LIMB and Coolside operating costs are generally lower

TABLE 29. FIRST YEAR OPERATING COSTS, mill/kWh

Coal Sulfur, wt %	100 MWe			150 MWe			250 MWe			500 MWe		
	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
	Fixed Operating Costs*											
1.5	0.68	1.57	4.37	0.48	1.16	3.18	0.33	0.89	2.20	0.22	0.60	1.42
2.5	0.69	1.58	4.42	0.51	1.20	3.20	0.35	0.91	2.24	0.25	0.64	1.45
3.5	0.73	1.61	4.45	0.51	1.22	3.26	0.37	0.93	2.28	0.27	0.66	1.49
	Variable Operating Costs†											
1.5	2.82	2.88	2.11	2.67	2.85	2.02	2.54	2.81	1.94	2.51	2.77	1.86
2.5	4.30	4.80	2.72	4.15	4.77	2.56	4.03	4.75	2.51	3.99	4.70	2.41
3.5	5.81	7.11	3.29	5.66	7.09	3.19	5.52	7.05	3.12	5.49	7.02	2.98
	Total Operating Costs											
1.5	3.50	4.45	6.48	3.15	4.01	5.20	2.87	3.70	4.14	2.73	3.37	3.28
2.5	4.99	6.38	7.14	4.66	5.97	5.76	4.38	5.66	4.75	4.24	5.34	3.86
3.5	6.54	8.72	7.74	6.17	8.31	6.45	5.89	7.98	5.40	5.76	7.68	4.47

* Includes operating labor, maintenance labor and material, and administration and overhead.

† Includes reagents, power, water, and steam usage, and waste disposal costs.

than those for LSFO for smaller units burning the lower sulfur coals. As boiler size and coal sulfur content increase, the LSFO operating costs gradually swing the economics in favor of this technology.

COST SENSITIVITIES

Effect of Plant Capacity Factor

The base case economics discussed above assumed a 65 percent unit capacity factor, a figure used in *TAG*™ for a base-loaded plant. The LIMB and Coolside technologies are viewed as being particularly applicable in retrofit situations for smaller, older plants. Since this population of boilers undoubtedly operate over range of capacity factors, cost sensitivity to this variable is thought to be especially pertinent. As a result, the economics at 40 and 75 percent capacity factors were also determined. Figures 53, 54, and 55 present the annual levelized costs for all cases at a plant capacity factor of 40%. The results show that lowering the plant capacity factor shifts the economics toward LIMB and Coolside. Coolside is favored over LSFO for the 1.5 weight

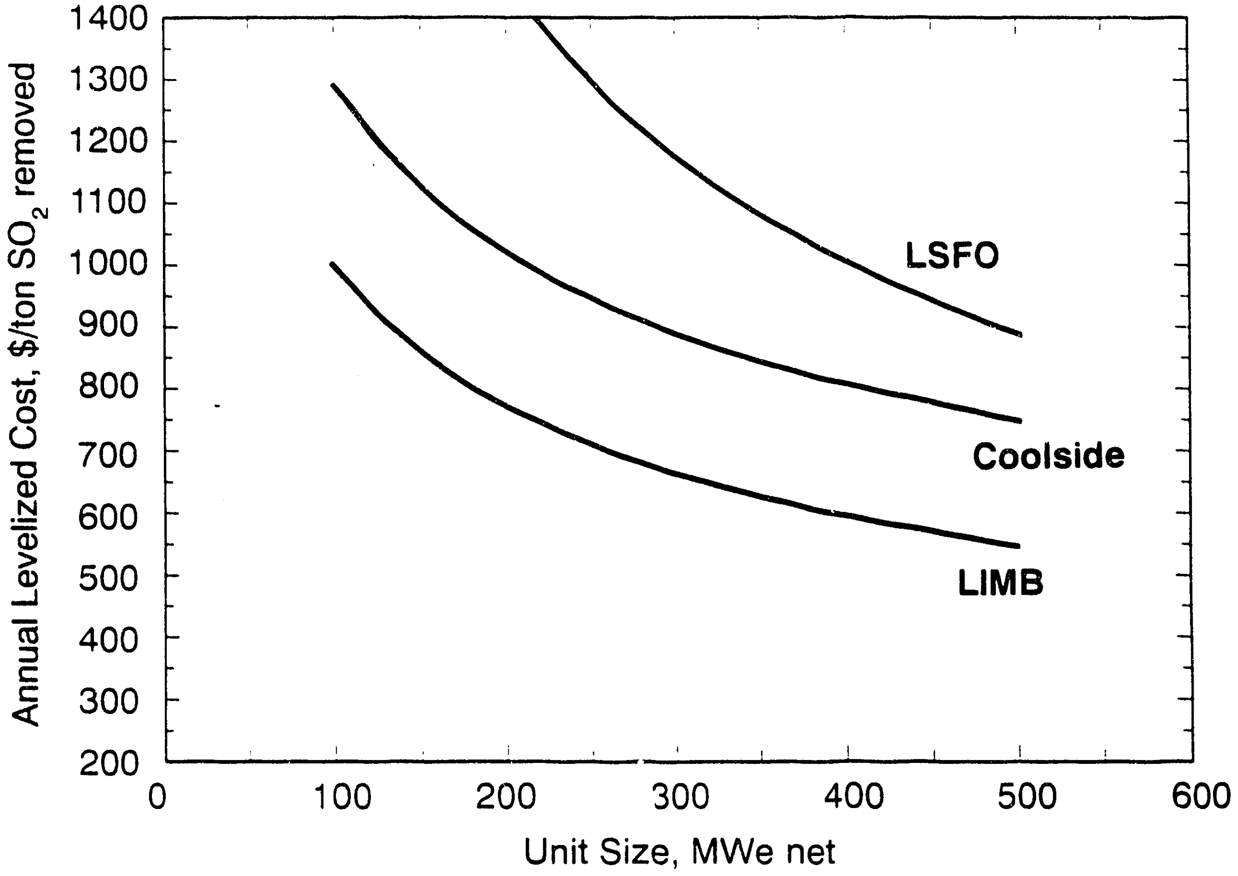


Figure 53. LIMB, Coolside, and LSFO annual levelized cost sensitivity to unit size with 40 % capacity factor and 1.5 weight percent sulfur coal

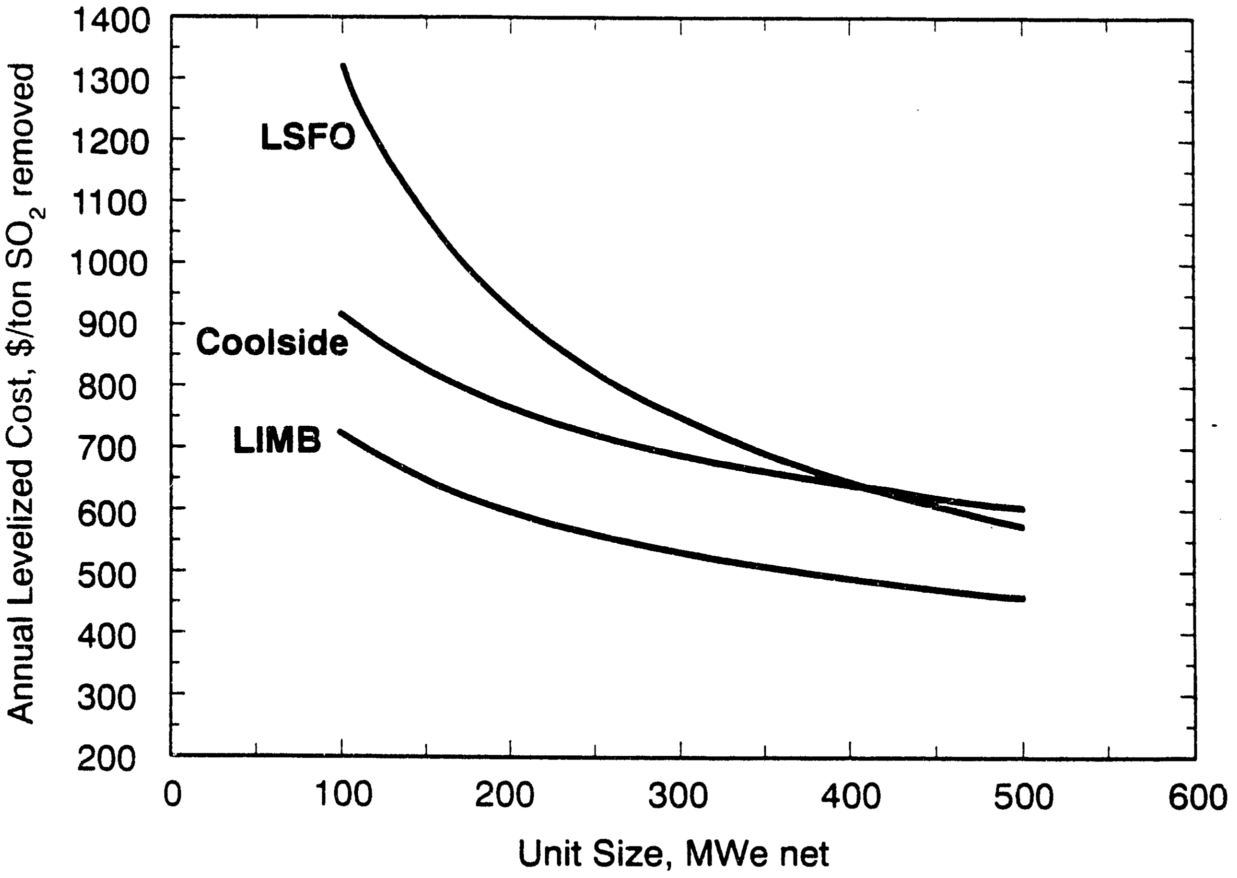


Figure 54. LIMB, Coolside, and LSFO annual levelized cost sensitivity to unit size with 40 % capacity factor and 2.5 weight percent sulfur coal

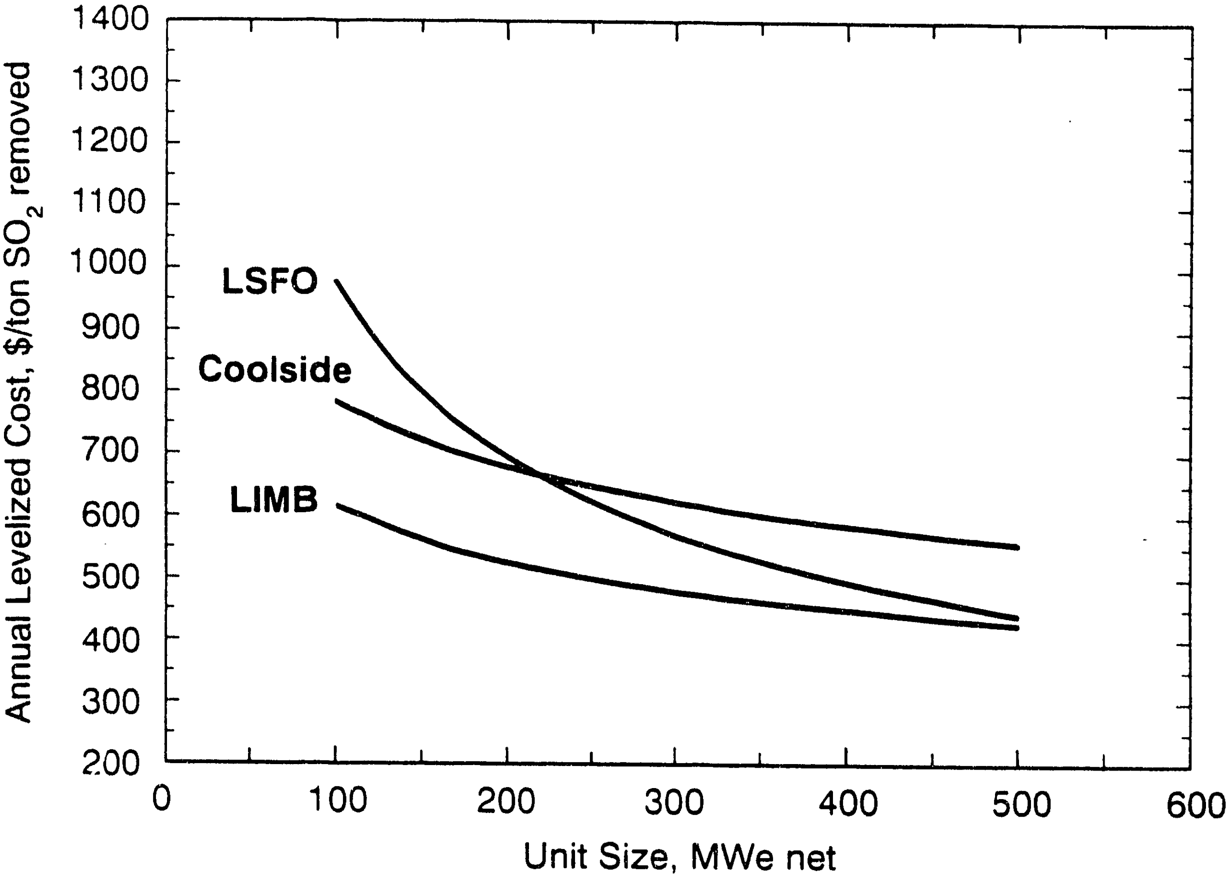


Figure 55. LIMB, Coolside, and LSFO annual levelized cost sensitivity to unit size with 40 % capacity factor and 3.5 weight percent sulfur coal

percent sulfur coal case, up to about 400 MWe for the 2.5 weight percent sulfur coal case, and up to approximately 210 MWe for the 3.5 weight percent sulfur coal case. LIMB is favored over LSFO in all 1.5 and 2.5 weight percent sulfur coal cases, and up to about 500 MWe in the 3.5 coal sulfur case. LIMB is favored over Coolside in all cases. Including provision for operating a LIMB system close to the saturation temperature to improve SO_2 removal would be expected to minimize or eliminate this advantage.

Figures 56, 57, and 58 present the annual levelized costs for all cases at the higher plant capacity factor of 75 percent. As would be expected, the results show that increasing the plant capacity factor limits the applicability the LIMB and Coolside processes in comparison to LSFO. Under this assumption, Coolside is favored over LSFO up to about 450 MWe for the 1.5 weight percent sulfur coal case, and up to 180 MWe for 2.5 weight percent sulfur coal case. The advantage goes to LSFO for the 3.5 weight percent sulfur coal case for all unit sizes. LIMB is favored over LSFO in all cases for the 1.5 weight percent sulfur coal case, up to 340 MWe for the 2.5 weight percent sulfur coal sulfur case, and up to 175 MWe for the 3.5 weight percent sulfur coal case. The unit sizes favored by the technologies are summarized in Table 30.

TABLE 30. UNIT SIZES (MWe) FAVORING LIMB AND COOLSIDE AS A FUNCTION OF CAPACITY FACTOR - RELATIVE TO LSFO ECONOMICS

	Unit Capacity Factor, %		
Coal Sulfur, wt %	40	65	75
	LIMB vs. LSFO		
1.5	LIMB favored*	LIMB favored*	LIMB favored*
2.5	LIMB favored*	≤450	≤340
3.5	≤500	≤240	≤175
	Coolside vs. LSFO		
1.5	Coolside favored*	≤500	≤450
2.5	≤400	≤220	≤180
3.5	≤210	≤100	LSFO favored*

* Indicates the technology is generally favored up to at least the maximum of 500 MW evcluated.

Effect of Unit Book Life

Base case economics were determined with an assumed 15-yr plant book life. For actual

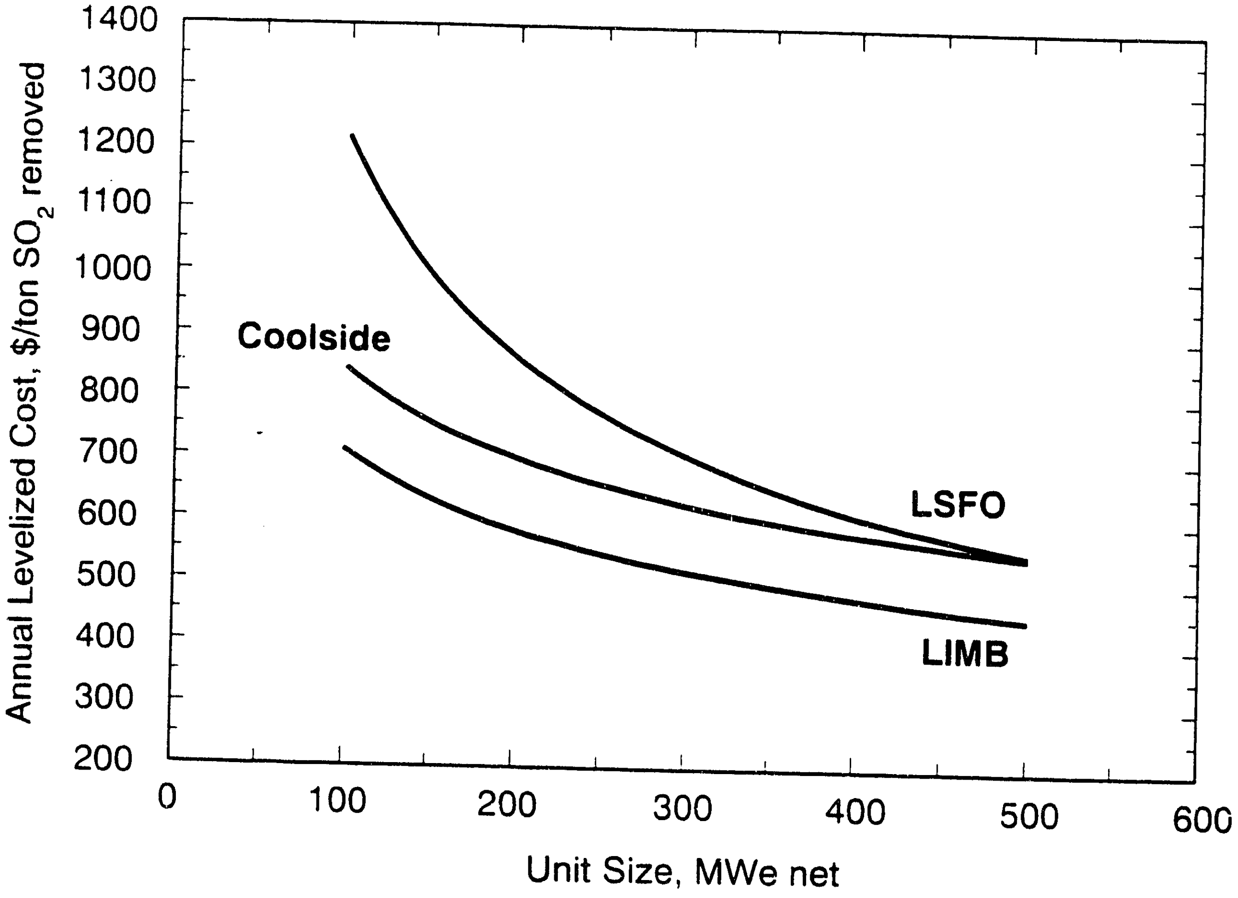


Figure 56. LIMB, Coolside, and LSFO annual levelized cost sensitivity to unit size with 75 % capacity factor and 1.5 weight percent sulfur coal

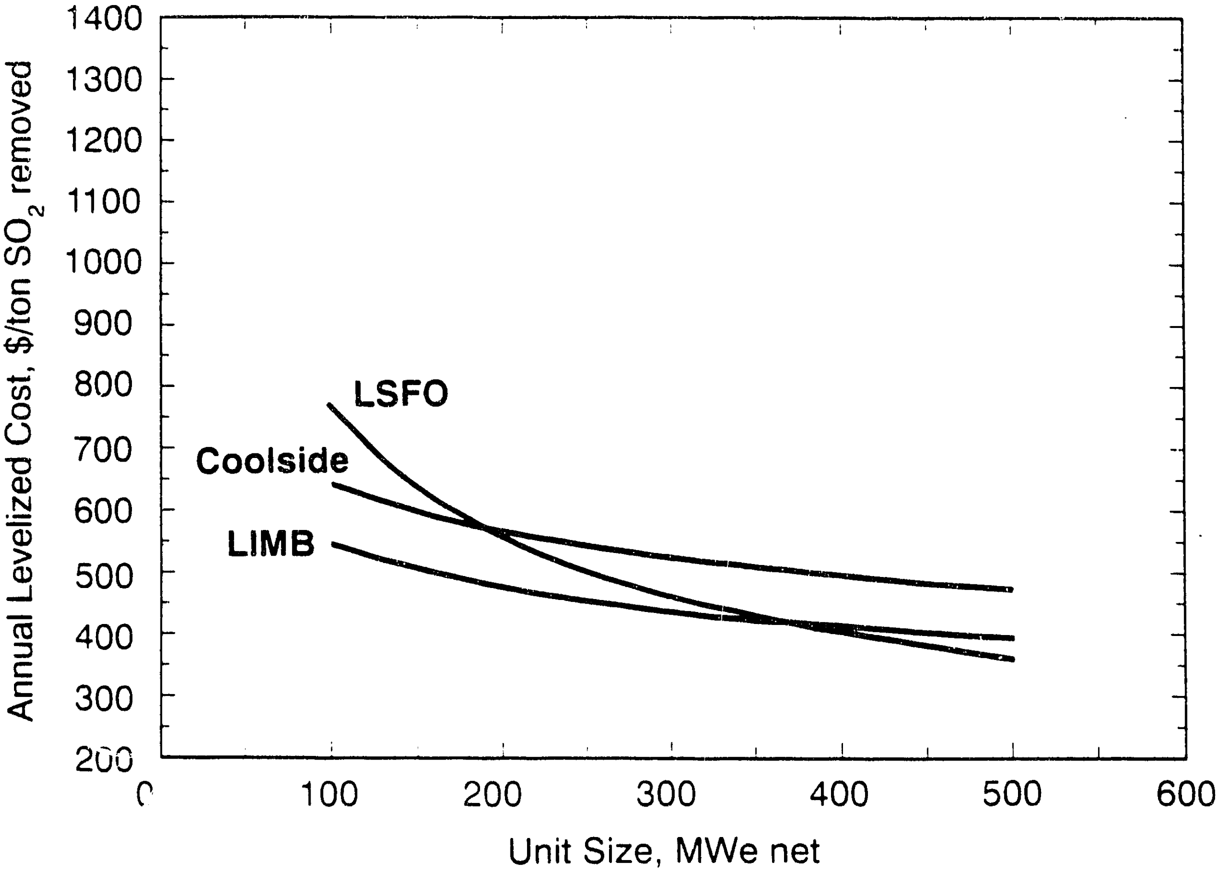


Figure 57. LIMB, Coolside, and LSFO annual levelized cost sensitivity to unit size with 75 % capacity factor and 2.5 weight percent sulfur coal

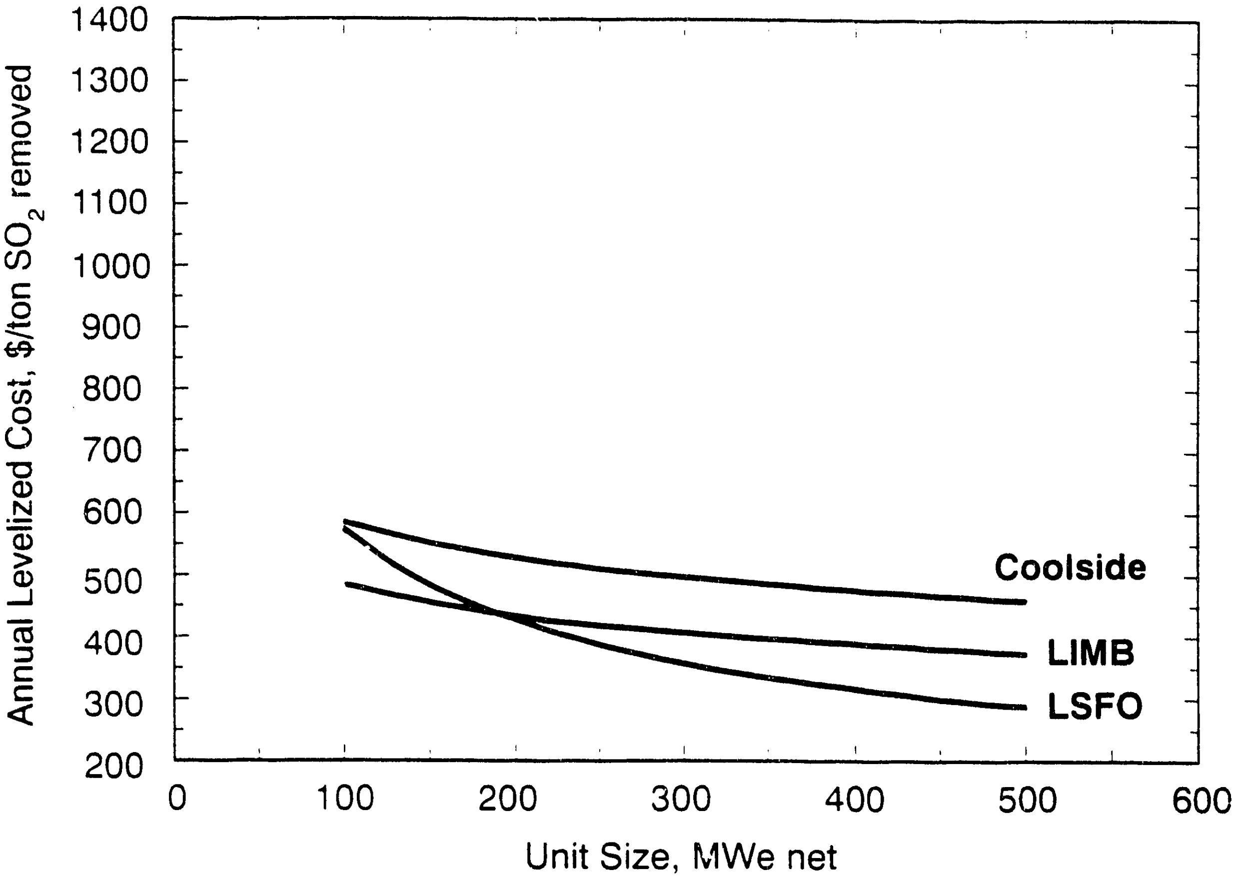


Figure 58. LIMB, Coolside, and LSFO annual levelized cost sensitivity to unit size with 75 % capacity factor and 3.5 weight percent sulfur coal

retrofit installations, this may vary significantly or change as time passes. In order to provide some estimate of the effect on the economic analysis, additional annual levelized costs were determined for each case for book life spans of 5, 10, 20, and 30 yr. The results presented in Table 31 show that LIMB and Coolside tend to have the economic advantage over LSFO as the plant book life is lowered. Reducing the book life favors the lowest capital cost option because capital costs increase proportionally for each case, while the operating expenses remain constant. As a result, older plants will tend to be sites where application of the lower capital cost LIMB and Coolside processes will be favored.

TABLE 31. EFFECT OF UNIT BOOK LIFE ON ANNUAL LEVELIZED COSTS, \$/ton SO_2 removed

		Unit Book Life, yr											
		5			10			20			30		
Unit Size, MWe	Coal Sulfur, wt %	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
100	1.5	1093	1356	2257	865	1044	1623	758	897	1326	726	854	1238
100	2.5	779	960	1408	640	768	1020	575	678	838	556	652	785
100	3.5	666	818	1036	559	676	756	509	608	624	495	589	586
150	1.5	867	1118	1732	706	875	1253	629	761	1027	607	728	962
150	2.5	658	826	1077	564	673	786	505	602	650	491	581	610
150	3.5	561	720	809	485	606	596	450	553	496	440	537	467
250	1.5	699	970	1294	585	769	944	532	675	780	516	647	732
250	2.5	552	734	825	479	608	609	445	648	507	435	531	478
250	3.5	494	651	622	437	557	464	411	513	390	403	500	368
500	1.5	583	781	966	505	636	704	469	568	586	458	548	552
500	2.5	485	628	616	433	533	461	408	488	388	401	475	366
500	3.5	447	578	473	405	505	358	386	471	304	380	461	288

Effect of Changing Reagent Cost

For the base case analysis, the hydrated calcitic lime cost was assumed to be 64 \$/ton for LIMB and Coolside, while limestone cost was assumed to be \$17/ton for LSFO. The values were costs suggested in *TAG*™ (adjusted for escalation). Reagent costs can vary significantly with geographic location, transportation methods and distances, and market demands. The effects of lower and higher reagent costs on the annual levelized costs were determined. The change in reagent cost was expressed in terms of a percentage, as shown in Figure 59. A 10 percent reduction in reagent cost effects corresponding decreases of \$4, \$18, and \$26 per ton of SO_2 removed for LSFO, Coolside, and LIMB, respectively. A 5 percent higher reagent cost results in increases of \$2, \$9, and \$14 per ton of SO_2 removed for LSFO, Coolside, and LIMB, respectively. Overall, this portion of the analysis is another indication of the greater sensitivity of LIMB and Coolside to sorbent utilization.

Effect of Sorbent Choice on LIMB Economics

Related to the effect of changing reagent cost, the choice of sorbent for LIMB applications in particular affects the annual levelized costs of this technology. Costs were examined for the three commercially available materials - hydrated calcitic lime, type-N hydrated dolomitic lime, and calcitic limestone. As mentioned early in this section, the major impact of changing sorbent is on the operating costs. Some differences in the capital cost requirements would be expected for reasons related to density or purity (*e.g.*, somewhat larger silos or transfer equipment capacities). However, these are considered minimal in comparison to the impact on operating costs.

The changes in operating costs would come about not only as a result of the cost of the sorbent itself, but also because of the tonnage that must be injected, the change in removal efficiency, and the cost of ash disposal. For the purposes of this evaluation, the delivered cost of dolomitic lime and calcitic lime are assumed to be equal at \$64/ton, and the cost of limestone to be \$45/ton delivered. The cost for lime is an escalated value from *TAG*™, and that for limestone is derived from B&W vendor information. This limestone cost was assumed for supply of pulverized (100 percent passing through 325 mesh [44 μm]) material by an outside vendor. While the possibility exists that a utility would choose to buy coarse material and grind it on site, this variation was not expected to be sufficiently likely to warrant the more detailed analysis that would be required for this one variation. Though it may be off by some amount, the \$45/ton figure is probably a reasonably equivalent cost for the utility to grind its own limestone.

The impact of choosing different sorbents on the annual levelized costs of LIMB is shown in Figures 60, 61, and 62 as a function of unit size. The SO_2 removal efficiencies for the three

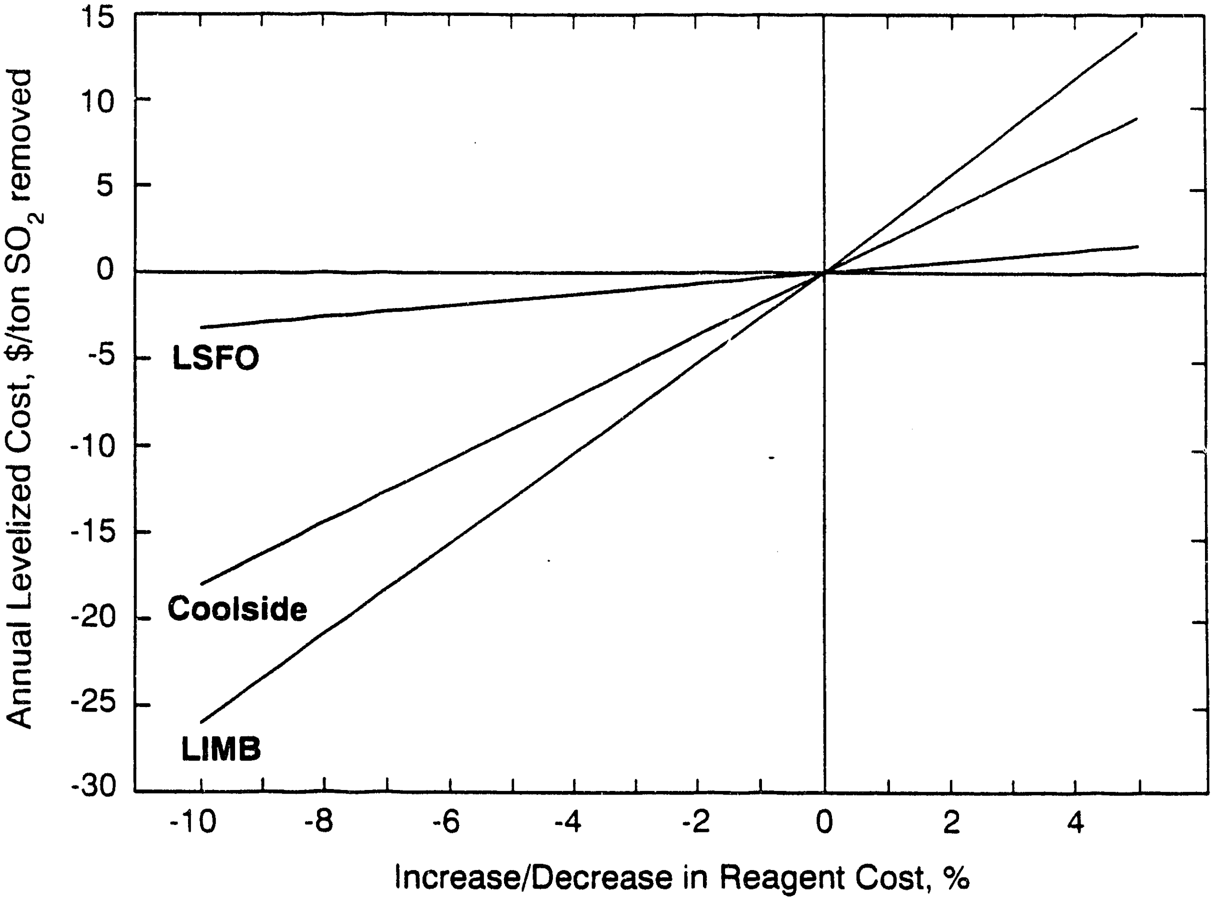


Figure 59. Sensitivity of annual levelized costs to reagent cost changes for LIMB, Coolside, and LSFO

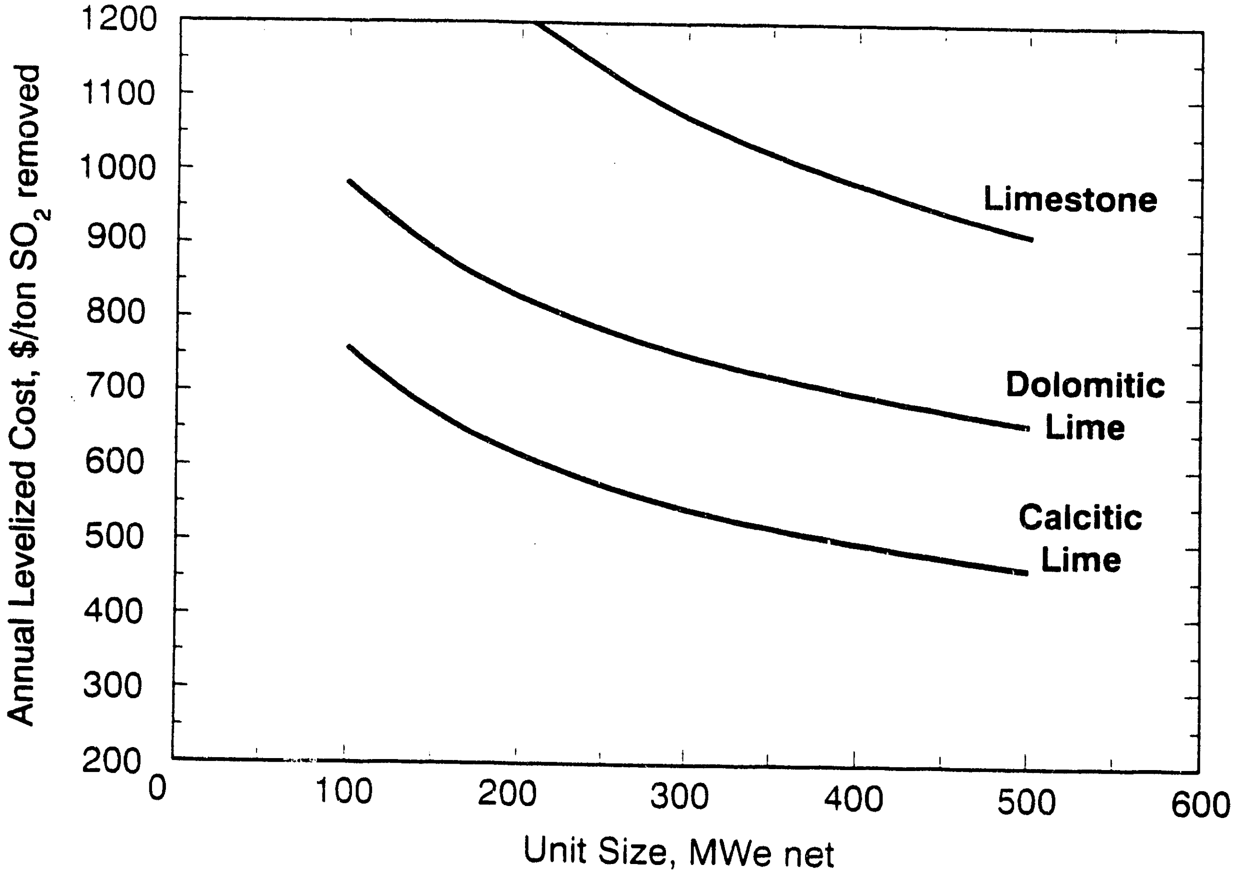


Figure 60. Sensitivity of LIMB annual levelized costs to sorbent choice and unit size for 1.5 weight percent sulfur coal

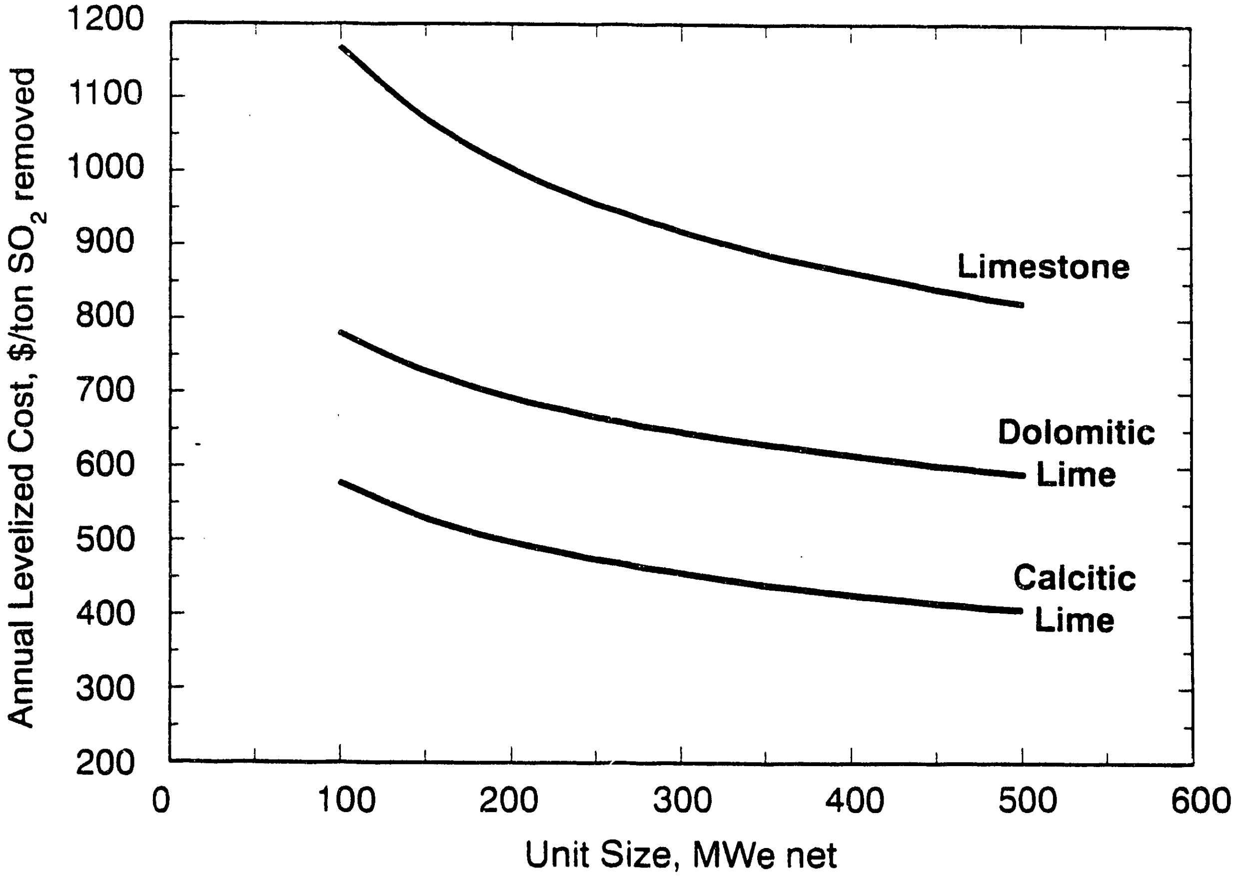


Figure 61. Sensitivity of LIMB annual levelized costs to sorbent choice and unit size for 2.5 weight percent sulfur coal

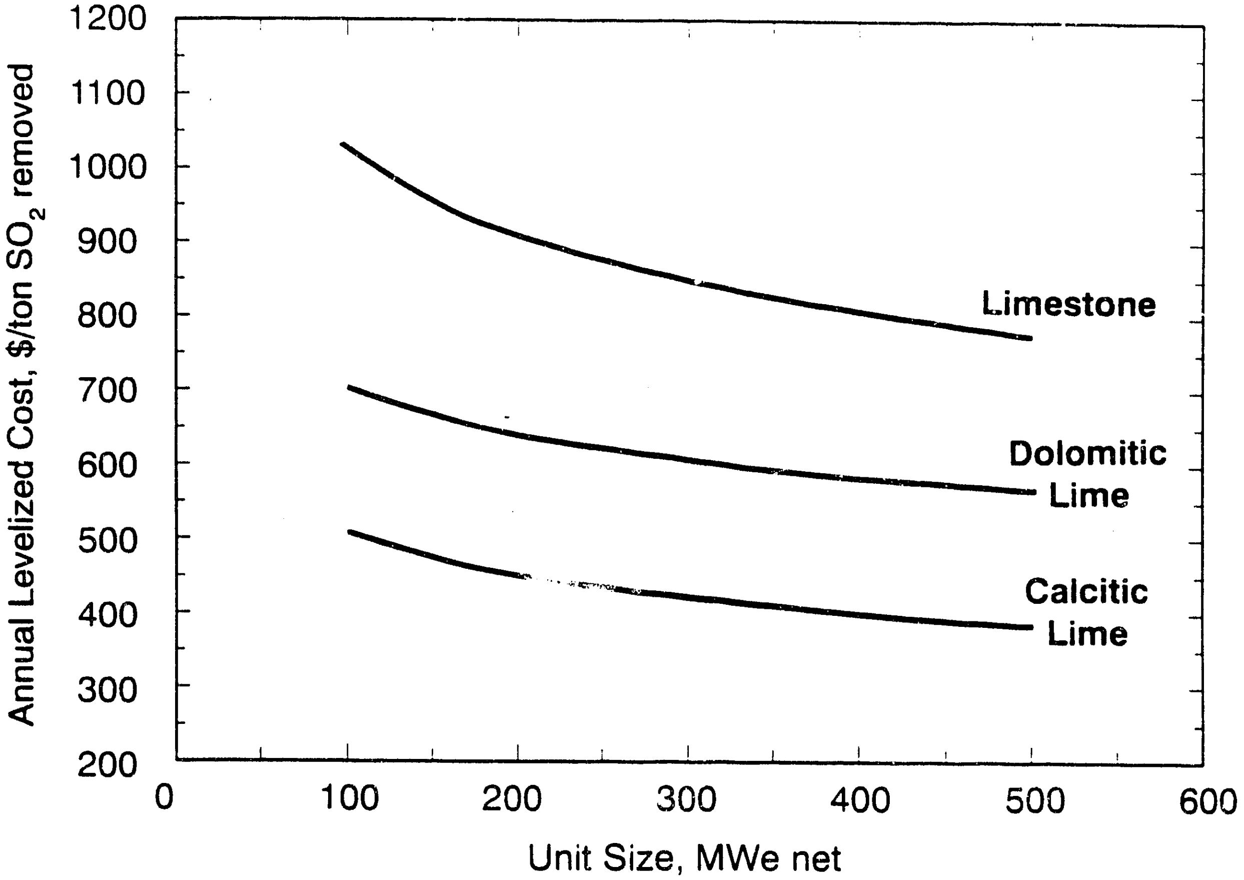


Figure 62. Sensitivity of LIMB annual levelized costs to sorbent choice and unit size for 3.5 weight percent sulfur coal

sorbents were set at 60 percent for calcitic lime, 55 percent for dolomitic lime, and 30 percent for calcitic limestone, with one plot for each of the three coals examined. For all cases, the limestone costs are higher than those for calcitic lime, with the cost difference being on the order of $450 to 600/ton SO_2 removed for any given plant size while burning any of the three coals. The calcitic lime appears to have about a $200/ton SO_2 removed advantage in the comparison with dolomitic lime for the ranges of both plant size and coal sulfur evaluated. While these figures clearly point to calcitic lime as the sorbent of choice, site-specific delivery and ash hauling costs can influence this particular segment of the economics dramatically.

Effect of Sootblowing Requirements on LIMB Economics

A key factor in maintaining boiler efficiency with the LIMB system is the proper design of the sootblowing system. It is generally expected that additional sootblowers would be required in most applications, especially in the convection pass area of the boiler. The base case economic analysis assumed the need for four additional sootblowers for the 100, 150, and 250 MWe cases, and six for the 500 MWe case. The actual number of additional sootblowers required would be very site-specific, and would depend upon the basic boiler design, coal and ash characteristics, and reagent characteristics. In anticipation of the possible variations that might be encountered, the effects on capital and annual levelized costs for the reference plants are presented in Figures 63 and 64, respectively. The results were determined per pair of sootblowers that could be added since such modifications tend to follow symmetric patterns more often than not.

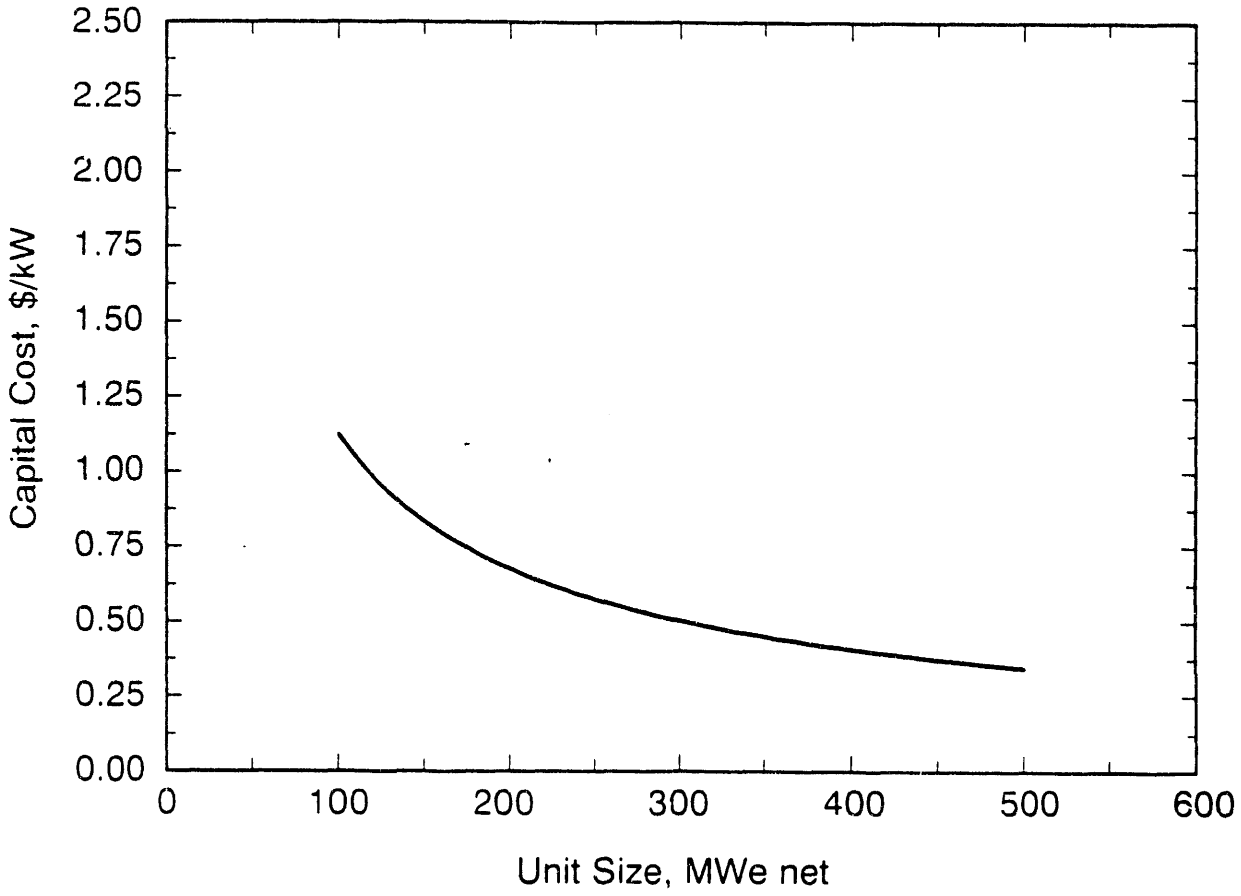


Figure 63. Capital cost associated with two additional sootblowers

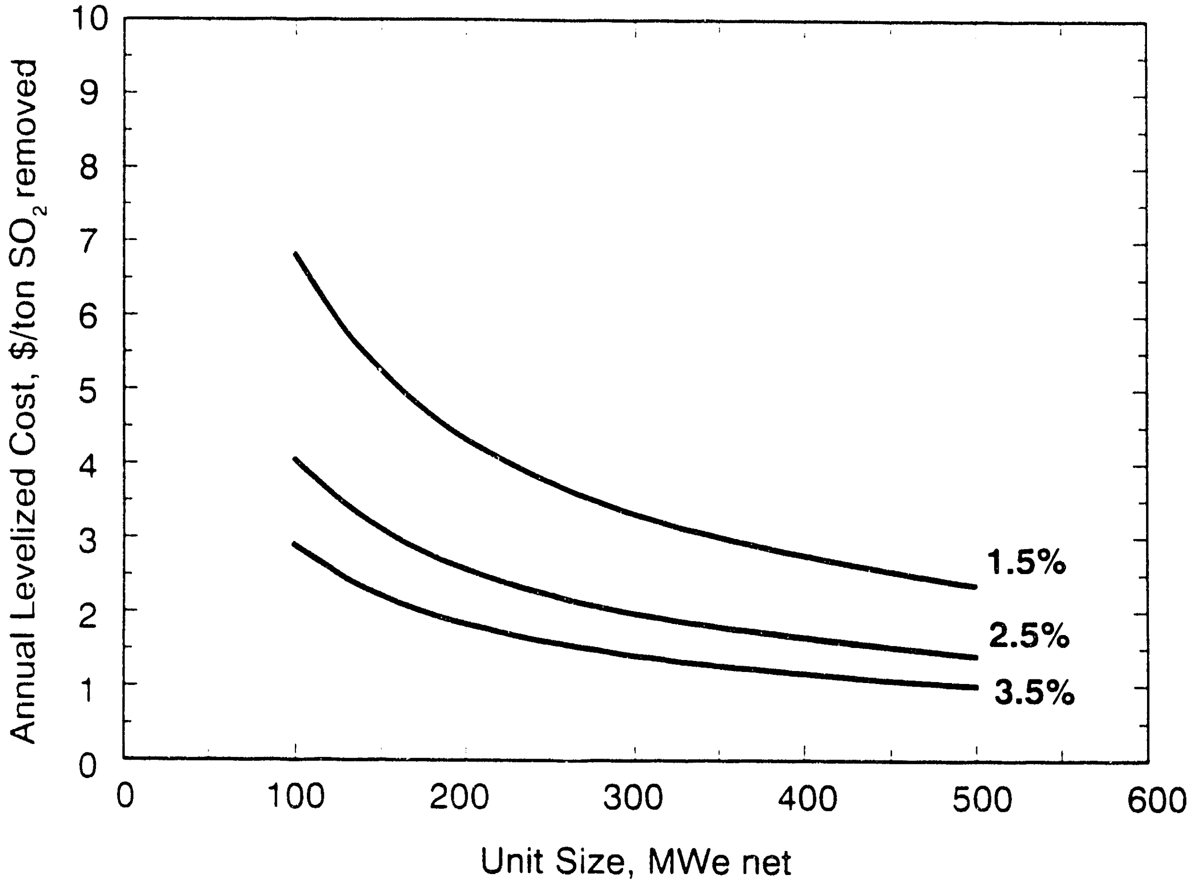


Figure 64. Annual levelized cost associated with two additional sootblowers

SECTION 10
SUMMARY AND CONCLUSIONS

The DOE LIMB Demonstration Extension Program showed that substantial reductions in SO_2 and NO_x emissions are possible, using furnace sorbent injection to reduce SO_2 and low NO_x burners to reduce NO_x. The SO_2 was reduced by as much as 70 percent while injecting ligno lime at a stoichiometry of 2.0 and humidifying to a 20°F approach to adiabatic saturation. Removal efficiencies of 61 percent were demonstrated while injecting the same sorbent at a stoichiometry of 2.0 with the humidifier operating only to maintain ESP performance. NO_x levels were reduced to an average of 0.43 lb/10^6 Btu over the demonstration, well below the goal of 0.50 lb/10^6 Btu.

The demonstration of the generic applicability of LIMB technology, coupled with similar success with Coolside technology, more than met the project's objective of building upon the knowledge base gained during the original EPA LIMB demonstration. With regard to the LIMB process, system operation succeeded in characterizing system performance of the four sorbents. The LIMB Extension portion of the demonstration took place between April 1990 and August 1991, while three coals with sulfur contents of 1.6, 3.0, and 3.8 weight percent were burned in the 105 MWe boiler at Ohio Edison's Edgewater Station in Lorain, Ohio. The sorbents tested were commercial calcitic hydrated lime, the same lime with a small amount of calcium lignosulfonate added, a type-"N" atmospherically hydrated dolomitic lime, and calcitic limestone. Three increasingly finer grinds of pulverized limestone were tested. With the exception of the limestone/3.8 weight percent sulfur coal, all the basic coal/sorbent combinations were tested between the original LIMB Demonstration and the LIMB Extension projects. Tests with this one combination were not attempted because the relatively low SO_2 removal efficiency of this sorbent would have made it unnecessarily difficult to obtain data within a reasonable time period and still maintain compliance with the plant's 30-day weighted rolling average SO_2 emission limit of 3.4 lb/10^6 Btu.

RESULTS SUMMARY

The SO_2 removal capabilities of the sorbents were characterized over a range of Ca/S stoichiometries while firing each of the different coals. All of the sorbents tested were found to be capable of SO_2 removal. Ligno lime offered the greatest reduction in SO_2, followed in order by hydrated calcitic lime, hydrated dolomitic lime, and calcitic limestone. The removal efficiencies with limestone were about 30 percent, absolute, less than the calcitic lime. A summary of the SO_2 removal efficiencies obtained is presented in Table 32.

The calcitic limes were found to be somewhat more effective than the type-"N" dolomitic lime on a Ca/S basis. The unreactive MgO component of the dolomitic lime makes it necessary to feed and remove material at higher rates for any given Ca/S ratio. Site-specific conditions, particularly those related to the possibility of low-cost, local supply, may still make this sorbent economical for some applications.

Contrary to results obtained with ligno lime during the original LIMB Demonstration, tests here indicated, at best, only a slight advantage in its use as compared to the commercial hydrated calcitic lime from which it is made. The possibility exists that the apparent lack of reproducibility arose out of manufacturing or handling differences, but neither could be proven from the tests conducted.

The results also showed that the finer the limestone, the greater the reduction in SO_2 emissions. The sizes tested included 80 percent through 325 mesh (44 μm), 100 percent through 325 mesh, and 100 percent less than 10μm. At a common reference Ca/S molar stoichiometry of 2.0 while burning the 1.6 weight percent sulfur coal, the very fine material reduced SO_2 emissions by 38 percent, the midsize by 31 percent, and the coarse material by only 22 percent.

More extensive tests were run during the LIMB Extension than in the original project to determine the effect of injection level on removal efficiency. Sorbent injection points in the Edgewater boiler were located at plant elevations of 181, 187, and 191 ft. Test results indicate that SO_2 removal was about 5 absolute percent lower at 191 ft as compared to that obtained at the lowest level. Injection at elevation 187 ft appeared to fall in between the two. Given the much wider variations that had been observed in pilot tests, the results suggest that all three levels were close to optimal for this unit. It is noted, however, that the effect is intimately connected with proper mixing and dispersion of the injected sorbent into the temperature window required for maximum removal.

Humidification of the flue gas to within 20°F of its adiabatic saturation temperature continued to show about an absolute 10 percent increase in SO_2 removal with any of the sorbents tested. This is similar to what had been observed during the original LIMB Demonstration project.

TABLE 32. SUMMARY OF SO_2 REMOVAL EFFICIENCIES ACHIEVED AT A Ca/S RATIO OF 2.0 WITH INJECTION AT THE 181 ft ELEVATION

	Coal Sulfur, wt %		
Sorbent/Humidification Conditions	1.6	3.0	3.8
Calcitic Hydrated Lime without Close Approach	51	55*	58
Additional Removal with Close Approach	NT†	10*	NT
Ligno Lime without Close Approach	53	63*	61
Additional Removal with Close Approach	17	9*	10
Dolomitic Lime without Close Approach	45	48	52
Additional Removal with Close Approach	17	10	NT
Limestone (80% < 44μm) without Close Approach	22	25	NT
Additional Removal with Close Approach	7	NT	NT
Limestone (100% < 44μm) without Close Approach	31	NT	NT
Limestone (100% < 10μm) without Close Approach	38	NT	NT

* Testing took place during the EPA-sponsored project.
† Not tested.

The only other correlation found was that between removal efficiency and inlet SO_2 concentration (coal sulfur). Results indicated that higher concentration tended to result in slightly higher SO_2 removal for any given set of conditions. For the range studied, the effect is not a strong one, however.

Examination of the NO_x emission data showed that the B&W DRB-XCL™ burners continued to perform as they had during the original demonstration. The overall average NO_x emission of 0.43 lb/10^6 Btu translated into 24-hour and 30-day weighted rolling averages of 0.44 lb/10^6 Btu, where coal firing rate was the weighting factor. Attempts to correlate minor variations in NO_x emissions with load, excess air, the identity of pulverizers/burners in service, and coal fineness were unsuccessful. Since tests on individual burners have shown that each of these can affect NO_x emissions, it is suspected that the results in the full-scale furnace at Edgewater reflect a commingling of all, with the added influence of individual preferences of the operators.

Particulate emission control, as monitored in the form of continuous opacity measurements, indicated that minimal humidification was effective in maintaining ESP performance throughout the LIMB Extension. The fact that little or no humidification was needed when the coarse limestone was in use was in sharp contrast to its being essential when the limes were injected. Since air heater outlet temperatures also remained relatively low during injection of this limestone, one must question what the relative effects of size, particulate composition, flue gas water concentration (both in liquid and gas phase), and temperature are on ESP efficiency. Resolution of these effects was far beyond the scope of the project. Evaluation of the opacity data with that obtained during periods without sorbent injection became the primary means of comparison when time and cost constraints precluded the more intensive inlet/outlet loading tests that would have been necessary to assess performance directly under all the conditions tested.

OPERATIONS SUMMARY

Operation of the LIMB system over the course of 16 months showed it to be available about 95 percent of the time the boiler was operational. Roughly half of the outage time was associated with mechanical failures of the atomizing air compressor, the solids pump, and a weigh cell on the feed silo -- failures not specific to the technology. Plugged sorbent lines were a process-related problem early in the testing, though proper purging of lines before shutdown and the installation of service air connections soon reduced this to a negligible concern. The remaining downtime is primarily accounted for by two process-related incidents that included one major cleaning of harder deposits in the humidifier, and rebalancing of the humidifier lance flows following the formation of these harder deposits. The experience points to the need for careful design of the humidification system, especially when close approach to saturation temperatures is desired. In the latter case, a downflow humidifier with a hopper at the bottom would be the preferred configuration if space permits.

Reduced heat transfer, as evidenced by elevated air heater outlet temperatures, continued to be the most noticeable effect of sorbent injection on the operation of the boiler itself. The greater the rate of sorbent injection, the more heat transfer was reduced until an equilibrium condition is established with sootblowing. Fortunately, there was no indication of any substantial, adherent deposits on the tube surfaces in spite of the substantial increases in particulate loading. Sootblowing easily removed the accumulation of ash on the tubes, though the need for careful planning of both the coverage and capacity of the system was identified. Some reduction of air heater outlet temperatures was realized by increasing the capacity of the existing sootblowing system in the change from compressed air to steam. Experience gained during the LIMB Extension suggested that more effective coverage would have reduced these temperatures to normal levels.

Somewhat surprisingly, almost no effect on the air heater outlet temperature was seen during injection of the more coarse limestone sorbent. Even when higher feed rates were used, the temperature remained near 300°F. Although a particle size effect is suspected because there was some indication of increasing temperatures in the short time when the very fine limestone was injected, no specific reason(s) have been identified.

Alternate methods of unloading the quicklime-laden LIMB ash are seen as eliminating the difficulties encountered at the Edgewater facility. These stemmed from release of steam as a result of the exothermic reaction between quicklime in the ash (from excess sorbent) and water added both to rehydrate the quicklime and to control fugitive dust during disposal. At Edgewater, fans added to keep the steam from blocking the operator's line of sight proved to be less than fully effective, and at times depended on wind direction and the amount of steam being evolved. Off-site hydration with radial stacking to allow steaming to subside, though impractical for the Edgewater demonstration, would have avoided the problem entirely. Totally dry removal as a byproduct is another possibility, as on-going studies continue to evaluate the potential for byproduct use associated with the cementitious properties of the ash for such purposes as soil stabilization and use as a synthetic aggregate.

ECONOMICS SUMMARY

The economics of flue gas desulfurization by the LIMB, Coolside, and LSFO technologies were determined in the form of what essentially constitutes budgetary cost estimates for twelve cases each. Process designs were based on optimized, commercial, retrofit installations with assumed SO_2 removal efficiencies of 60, 70, and 95 percent, respectively. The basic sets of reference plants were assumed to burn 1.5, 2.5, and 3.5 weight percent sulfur coal in units of nominal 100, 150, 250, and 500 MWe capacities. Comparisons made included those of capital costs on a \$/kW basis, annual levelized costs on a \$/ton SO_2 removed basis, and fixed and variable operating costs on a mill/kWh basis. Sensitivities of the economics to capacity factor, book life, and reagent cost were determined for all three processes. The effects of sorbent choice and sootblowing on the LIMB process were examined separately because of their particular influence on the economics of this technology.

Averaged over all the cases studied, the total, installed, capital cost of LSFO was found to be roughly 2.5 times that of Coolside, and about 4.8 times that of the LIMB process. The installed, capital cost of the Coolside process was found to be approximately 1.9 times that of the LIMB process with minimal humidification. Inclusion of the capability to operate LIMB at close approach to the saturation temperature, to improve SO_2 removal, is expected to minimize or eliminate this advantage.

Similar comparison of the annual levelized costs show LIMB to be economically favored over LSFO for all unit sizes studied while burning 1.5 weight percent sulfur coal, for those up to 450 MWe while burning 2.5 weight percent sulfur coal, and for those up to 240 MWe while burning 3.5 weight percent sulfur coal. Coolside is favored over LSFO for sizes up to 500 MWe while burning 1.5 weight percent sulfur coal, for those up to 220 MWe while burning 2.5 weight percent sulfur coal, and for units up to 100 MWe while burning 3.5 weight percent sulfur coal.

The sensitivity analyses show that lower plant capacity factors favor the LIMB and Coolside processes, as does shorter book life. Varying the reagent costs has a greater effect on LIMB and Coolside economics than it does on the LSFO process economics, primarily because of lower sorbent utilization. The results of these sensitivity analyses reflect what would be expected because of the relatively higher operating costs for the LIMB and Coolside processes when compared to LSFO.

Finally, the economic analyses highlight the fact that further optimization of the technologies should focus on improving sorbent utilization. Such studies are in progress, notably within laboratories at EPA, several universities under sponsorship of OCDO, the Illinois Clean Coal Institute (formerly the Center for Research on Sulfur in Coal), and private industry. Advances in these technologies are expected to offer increasingly more cost effective options for older, smaller plants to reduce emissions simply and reliably.

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APPENDIX A: METRIC CONVERSION TABLE

To convert from	To	Multiply by
micron	m	1.000×10^{-6}
in	m	2.540×10^{-2}
ft	m	3.048×10^{-1}
mil	m	2.540×10^{-6}
mile	km	1.609
lb	kg	4.536×10^{-1}
ton	kg	9.072×10^{2}
Btu	J	1.055×10^{3}
HP	W	7.460×10^{2}
acre	m^2	4.047×10^{3}
gal	m^3	3.785×10^{-3}
ft^3	m^3	2.832×10^{-2}
ft/sec	m/s	3.048×10^{-1}
cfm (actual - acfm, standard - scfm)	m^3/s	4.719×10^{-4}
ft^2/1000 cfm	m^2/1000 m^3/s	1.968×10^{-2}
gr/dscf (68°F)	kg/m^3 (273 K)	2.288×10^{-3}
lb/ft^3	kg/m^3	1.602×10^{1}
in WC (39.2°F)	Pa	2.491×10^{2}
lb/10^6 Btu	ng/J	4.299×10^{2}

°F	C	C = (5/9)(°F-32)
°F	K	K = 273.15 + (5/9)(°F-32)
psig	Pa (absolute)	Pa = 6895 (psig + 14.7)

APPENDIX B: DETAILED SYSTEM DESIGN

Sorbent Storage and Handling System

1. Storage Silo Baghouse	
a). General Information	
Service	Storage Silo
Number of Collectors	One (1)
Type	Intermittent
Manufacturer	Fuller Company
Model	Unifilter Model #4
b). Sizing Information	
Air Flow, ACFM	1800 Nominal/2400 Maximum
Collected Material Density, lb/ft^3	75 for Limestone 30 for Hydrated Lime
Air to Cloth Ratio, ACFM/ft^2	3.0 Nominal/4.0 Maximum
Pressure Drop Across Bag, in WC	6.0 Nominal/7.1 Maximum
Operating Frequency, hr/day	Ten (10)
c). Bag Cleaning	
Type of System	Shaker
2. Storage Silo	
a). Design Information	
Design Pressures	
Maximum Positive, in WC	14.5
Maximum Negative, in WC	7.6
Design Material Density	
Structural, lb/ft^3	75
Volumetric, lb/ft^3	30
b). Sizing Information	
Storage Capacity at Design Conditions, hr	43 Hydrated Lime/73 Limestone

3. Aerator

a). General Information

Type	Aerator
Make	Fuller Company

4. Storage Silo Blower

a). General Information

Service	Storage Silo Blower
Number Supplied	One (1)
Manufacturer	Sutorbilt
Type	Rotary Positive

b). Sizing Information

Rated Transport Capacity, lb/hr	1027 (227 CFM)
Rated Discharge Pressure, psig	6
Discharge Temperature, °F	200

c). Motor Information

Manufacturer	Reliance Electric
Voltage/Phase/Cycle	460/230 / 3 / 60
Horsepower	10
Speed, rpm	1800
Enclosure Type	TEFC
Frame Size	215-T

5. Fluidizing Air Dryer

a). General Information

Service	Dry Fluidizing Air
Number Supplied	One (1)
Manufacturer	Pioneer
Type	Refrigerant

b). Sizing Information

Rated Transport Capacity, SCFM	245
Rated Pressure Drop, psig	3
Rated Outlet Dewpoint, °F	50
Rated Discharge Temperature	Within 25°F of Inlet Air
Water Flow, gpm	12

6. Storage Silo Feed Pump	
a). General Information	
Manufacturer	Fuller Company
Model Number	300M
b). Sizing Information	
Capacity, ton/hr	50 Limestone/50 Hydrated Lime
c). Motor Information	
Manufacturer	Reliance Electric
Voltage/Phase/Cycle	460 / 3 / 60
Horsepower	75
Speed, rpm	1200
Enclosure Type	TEFC
Frame Size	405-T
Service Factor	1.15
7. Storage Silo Feed Pump Compressor	
a). General Information	
Service	Transport Air to Sorbent Feed Pump
Number Supplied	One (1)
Manufacturer	Fuller Company
Type	Single Stage Rotary Vane
b). Sizing Information	
Design Transport Capacity, CFM	1230
Design Discharge Pressure, psig	15
Discharge Temperature, °F	200 - 250
Maximum Transport Distance, ft	350
c). Motor Information	
Manufacturer	Reliance Electric
Voltage/Phase/Cycle	460 / 3 / 60
Horsepower	125
Speed, rpm	600
Enclosure Type	ODP
Frame Size	449T
Service Factor	1.15

8. Feed Silo Baghouse	
a). General Information	
Service	Feed Silo
Number of Collectors	One (1)
Type	Intermittent
Manufacturer	Fuller Company
Model	Unifilter Model #3
b). Sizing Information	
Air Flow, ACFM	1200 Nominal/1600 Maximum
Collected Material Density, lb/ft^3	75 Limestone/30 Hydrated Lime
Air to Cloth Ratio, ACFM/ft^2	3.0 Nominal/4.0 Maximum
Pressure Drop Across Bag, in WC	6.9 Nominal/7.5 Maximum
Operating Frequency, hr/day	6 Limestone/3.5 Hydrated Lime
c). Bag Cleaning	
Type of System	Pulse Jet
9. Feed Silo	
a). Design Information	
Design Pressures	
Maximum Positive, in WC	61
Maximum Negative, in WC	3
Design Material Density	
Structural, lb/ft^3	75
Volumetric, lb/ft^3	30
b). Sizing Information	
Storage Capacity at Design Conditions, hr	5.2 Limestone/3.0 Hydrated Lime

Feed System

1. Feed Silo Bin Vibrator	
a). General Information	
Service	Feed Silo Hopper
Type	Vibrating Bin Discharger
Manufacturer	Vibranetics, Inc.
Model Number	VBD-3

2. Sorbent Differential Weight Loss Feeder	
a). General Information	
Manufacturer	Acrison, Inc.
Model Number	403-24000-7500-BDF4-R
Quantity	Two (2)
b). Sizing Information	
Capacity - Each, min to max ton/hr	2-11 Limestone/2-11 Hydrated Lime
3. Rotary Feeder	
a). General Information	
Service	Feed Silo to Conveying Line
Manufacturer	Beaumont Feeders, Inc.
Model Number	STT Mark II Type R2
b). Sizing Information	
Pocket Efficiency, %	50
Design Capacity, lb/hr	22,000 (Hydrated Lime)
Number of Pockets	8
Sealing Capacity, psig	45
4. Feed Silo Feed Pump	
a). General Information	
Manufacturer	Fuller Company
Model Number	200M
b). Sizing Information	
Capacity, ton/hr	2-12
c). Motor Information	
Manufacturer	Reliance Electric
Voltage/Phase/Cycle	460 / 3 / 60
Horsepower	75
Speed, rpm	1800
Enclosure Type	TEFC-XEX
Frame Size	365T
Service Factor	1.15

Conveying Air System

1. Conveying Air Compressors

a). General Information

Service	Conveying Air
Number Supplied	One (1)
Manufacturer	Sullair Corporation
Type	Rotary Screw

b). Sizing Information

Design Transport Capacity, SCFM	773
Design Discharge Pressure, psig	60
Discharge Temperature	Within 15°F of Ambient

c). Motor Information

Manufacturer	Lincoln, Inc.
Voltage/Phase/Cycle	460 / 3 / 60
Horsepower	125
Speed, rpm	1770
Enclosure Type	ODP
Frame Size	405-TS

2. Conveying Air Dryer

a). General Information

Service	Conveying Air Dryer
Number Supplied	One (1)
Manufacturer	Pure Aire, Inc.
Type	Refrigerated

b). Sizing Information

Rated Transport Capacity, SCFM	790 at 100 psig
Rated Outlet Dewpoint, °F	50

3. Conveying Air Receiver

a). General Information

Service	Conveying Air Receiver
Number Supplied	One (1)
Manufacturer	Brunner, Inc.

3. Conveying Air Receiver (continued)	
b). Sizing Information	
Design Pressure, psi	125
Volume, gal	400
4. Conveying Air Filter	
a). General Information	
Service	Conveying Air Receiver
Number Supplied	One (1)
Manufacturer	Pure Aire, Inc.
Type	Coalescing
b). Sizing Information	
Rated Transport Capacity	790 SCFM at 100 psig
Minimum Particle Size, micron	0.3

Booster Air System

1. Booster Air Fan	
a). General Information	
Service	Booster Air
Number Supplied	One (1)
Manufacturer	Garden City Fan Company
Type	Radial
Arrangement	One (1)
b). Sizing Information	
Design Transport Capacity, SCFM	11,700
Design Discharge Pressure, in WC	40
Discharge Temperature	15°F above Ambient
c). Motor Information	
Manufacturer	Siemens
Voltage/Phase/Cycle	460 / 3 / 60
Horsepower	125
Speed, rpm	1800
Enclosure Type	TEFC
Frame Size	444T

pH Control System

1. Acid Storage Tank	
a). General Information	
Height, ft	12
Diameter, ft	8.5
Tank Material	Carbon Steel
Lining	Plasite 3066
Lining Thickness, mil	6-9
Covered	Yes
Overflow	No
b). Sizing Information	
Capacity, ft^3	681
3. Acid Transfer Pump	
a). General Information	
Service	Storage Tank to Day Tank
Type	Centrifugal
Manufacturer	Chem Pump
Model	Ja 1 - 1/2K
Material	A-20
Pump Speed, rpm	3450
b). Sizing Information	
Capacity, gpm	5-50
Total Head, ft	44
c). Motor information	
Manufacturer	General Electric
Voltage/Phase/Cycle	460 / 3 / 60
Horsepower	2
Speed, rpm	3450
Enclosure Type	TE Severe Duty

4. Acid Metering Pump

a). General Information

Service	Acid Metering
Type	Metering
Manufacturer	Milton Roy
Model	FR-165-144
Material	A-20
Stroke Speed (per min)	144
Quantity	2

b). Sizing Information

Capacity, gpm	Reliance
Discharge Pressure, norm/max psig	20 / 400

c). Motor Information

Manufacturer	Reliance
Voltage	230/460
Horsepower	1/2
Speed, rpm	1725
Enclosure Type	Terro - SXE

Humidification System

1. Humidification Air Compressor

a). General Information

Service	Air Supply to Atomizers
Manufacturer	Ingersoll-Rand
Type	Centrifugal - Three Stage

b). Sizing Information

Design Transport Capacity, CFM	4500
Design Discharge Pressure, psig	15

c). Motor Information

Manufacturer	Reliance Electric
Voltage/Phase/Cycle	4000 / 3 / 60
Horsepower	1250
Speed, rpm	3600
Frame Size	E5810S

2. Atomizing Water Pump

a). General Information

Service	Water Supply to Atomizers
Manufacturer	Worthington
Model	D-1011
Size	3 x 1-1/2 x 10

b). Sizing Information

Design Transport Capacity, gpm	150
Design Discharge Head, ft	350

c). Motor Information

Manufacturer	Reliance
Voltage/Phase/Cycle	460 / 3 / 60
Horsepower	30
Speed, rpm	360
Enclosure Type	TEFC
Service Factor	1.15

Reheater System

1. a). General Information

Manufacturer	Aerofin Corporation
Airflow	Horizontal
Construction	1" OD x 0.065" Avg. Wall Welded Seamless Carbon Steel

b). Sizing Information

Design Pressure, psig	300
Design Temperature	40°F from 150°F

Coolside Caustic Feed System

1. Caustic Holding Tank with Spill Containment

a). General Information

Service	Caustic Storage
Height x Diameter, ft	8.75 x 13
Type	Carbon Steel Shell-Flat Bottom
Fabricator	Milan Steel Fabricators, Inc.

b). Sizing Information

Tank Capacity, gal	8,700
Working Capacity, hr	40 @ 2.8 gpm
Working Capacity, gal	6,700
Steel Containment	18 ft x 20 ft Area with 42 in high Wall

c). Construction

Tank Bottom Plate	0.5" Thick A235
Tank Shell and Cover	0.375" Thick A235
Steel Containment	0.25" Thick Carbon Steel Plate

2. Caustic Pump

a). General Information

Service	Caustic Supply to Atomizing Water Tank
Manufacturer	Ingersoll-Rand
Model	Voc, 2 X 1-1/2 X 8

b). Sizing Information

Design Transport Capacity, gpm	50
Design Discharge Head, ft	300

c). Motor Information

Manufacturer	Reliance
Voltage/Phase/Cycle	460 / 3 / 60
Horsepower	20
Speed, rpm	3,600
Service Factor	1.15
Enclosure Type	TEFC

Coolside Recycled Ash Feed System

1. Rotary Feeder

a). General Information

Service	Flyash Feed to Transport Hose
Manufacturer	Smoot Company
Model	FT-14
Type	Fall Through, Rotary Airlock Feeder
Quantity	2

b). Sizing Information

Capacity, lb/hr	20,000
Density of Ash, lb/ft^3	30-60
Rotor Displacement, ft^3/rev	0.96

c). Motor Information

Horsepower	1.5
Enclosure Type	TEFC

2. Transport Hose

a). General Information

Service	Ash Feed to Distribution Bottle
Manufacturer	Goodyear
Model	Tan Flextra, MKFH-20
Type	Reinforced, Inner Lined

b). Sizing Information

Inner Diameter, in	6

3. Transport Air Compressor

a). General Information

Service	Ash Transport Air
Type	Rental Compressor

APPENDIX C: QUALITY ASSURANCE/QUALITY CONTROL

INTRODUCTION

A comprehensive quality assurance (QA) and quality control (QC) program was an integral part of the LIMB and Coolside test programs and essentially consisted of a continuation of the program begun under the original EPA-sponsored LIMB Demonstration Project. Radian Corporation was again retained to provide virtually all the analytical support under the Quality Assurance Project Plan (QAPP) prepared in accordance with EPA guidelines. The goal of the QA/QC effort was to ensure that the data collected were of known accuracy and precision, and that they were as complete and representative as the instruments and procedures used would permit.

The entire scope of the QA/QC program included a wide variety of flow, temperature, and pressure measurements throughout the boiler and sorbent feed systems, in addition to those of an analytical nature. Since this report is directed primarily at emission control aspects, the focus in this summary focuses upon the analyzers that constituted the CEMS operated by Radian Corporation at the ESP outlet location.

The concentrations of SO_2, NO_x, O_2, CO_2, and CO monitored by this system were the basis for determining the results presented in the main body of the report. The balance of this appendix presents a brief description of this sampling and analytical system, followed by a summary of the main QA/QC measures employed in the course of the project.

Continuous Emissions Monitoring System

The CEMS probe was located in the 11.5 x 11.5 ft ESP outlet duct approximately 8.5 equivalent diameters downstream of the ID fan and 1.5 diameters upstream of a 90° bend. No significant SO_2/O_2 or NO_x/O_2 stratification was experienced at this location because good gas mixing occurred in the ID fan. This was verified by SO_2/O_2 and NO_x/O_2 concentration profiles determined for the ESP outlet duct during the baseline period of the original LIMB Demonstration, prior to installation of the CEMS probe. No significant stratification was found; therefore, the CEMS probe was located in the centroidal area of the duct. Stratification was considered to be a condition identified by a difference in excess of 10 percent between the average concentration in the duct and the concentration at any point more than 1.0 ft from the side of the duct.

A schematic of the CEMS sample acquisition system after the probe is shown in Figure 14 in Section 5 of the report. The sample stream for the CEMS was acquired using a heat-traced sample line maintained at a temperature of at least 120°C to prevent condensation of water in the sample line. To ensure representative measurements, all calibration and QC gases were introduced at the inlet of this sample line. A gas conditioner, consisting of a chilled knock-out trap, provided a dry gas stream for analysis. Data from the CEMS instruments were collected and recorded by the microprocessor-based data acquisition/reduction system. A hard copy of the reduced data was printed continuously and raw data was stored on disc.

Carbon Monoxide and Carbon Dioxide Analyses--

A Beckman Model 865-11 analyzer was used to measure CO concentrations in the flue gas. This instrument is a non-dispersive infrared (NDIR) analyzer which measures the concentration of CO by infrared absorption over a broad spectrum. A Beckman Model 865-23 NDIR analyzer provided CO_2 concentration data. The typical instrument ranges used were 0 to 1000 parts per million by volume (ppmv) for CO and 0 to 20 percent by volume (vol %) for CO_2.

Oxygen Analysis--

A Thermox WDG-III O_2 analyzer continuously measured flue gas O_2 concentrations. This analyzer utilizes an electrochemical cell to produce a linearized voltage signal that is proportional to the ratio of O_2 concentrations of a reference gas (usually ambient air) and the O_2 concentration of the sample. The typical range used was 0 to 25 vol %.

Nitrogen Oxides Analysis--

A Teco Model 10AR analyzer was used for NO_x measurement. This instrument determines NO_x concentrations by converting all nitrogen oxides present in the sample to nitric oxide and then reacting the nitric oxide with ozone. The reaction produces a chemiluminescence proportional to the NO concentration in the sample. The chemiluminescence is measured using a high-sensitivity photomultiplier. The typical range used was 0 to 1000 ppmv.

Sulfur Dioxide Analysis--

A DuPont Model 400 analyzer measured SO_2 concentrations during early Coolside tests, but was replaced by a Western Model 721A analyzer on September 27, 1989. This monitor was used for the balance of the Coolside demonstration and for all LIMB Extension testing. Both analyzers are based on the absorption of ultraviolet (UV) light in the 280 to 313 nanometer (nm) range. The typical concentration ranges used were 0 to 2500 and 0 to 5000 ppmv for the Dupont and Western analyzers, respectively.

SUMMARIES OF QUALITY ASSURANCE/QUALITY CONTROL MEASURES

The principal elements involved in the implementation of the QAPP consisted of an initial certification period, periodic performance and technical system audits, and daily instrument drift checks and calibrations. Each is summarized in the following subsections.

Certification Tests

The continuous NO_x, SO_2, CO_2, and O_2 monitors were certified according to procedures outlined in the Code of Federal Regulations.[*] The procedures require that the relative accuracy and calibration drift are within prescribed limits. Relative accuracy was determined by comparing the average CEMS concentrations for each gas with the concentrations measured by EPA reference methods. These manual measurements were made at the ESP outlet sampling location about 20 ft upstream of the CEMS sample probe. The tests with the DuPont SO_2 analyzer were completed in August 1989 along with the other instruments. The new Western SO_2 analyzer was certified in September 1989 prior to its replacing the DuPont equipment which had become increasingly difficult to keep in calibration. The results of the relative accuracy tests are summarized in Table C-1.

TABLE C-1. SUMMARY OF THE CEMS RELATIVE ACCURACY TEST RESULTS

Analyzer	EPA Reference Method Number	Number of Tests	Relative Accuracy, %	Relative Accuracy Limit, %
SO_2 (DuPont)	6	9	6.33	20
SO_2 (Western)	6	9	6.17	20
NO_x	7D	9	NA[*]	20
O_2	3	9	9.54	20
CO_2	3	9	3.42	20

[*] NA = Not available.

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[*] Performance Specifications 2 and 3, <u>Code of Federal Regulations</u> <u>40</u>, Part 60, Appendix B, July 1984, pp. 682-689.

The calibration drift checks were conducted over a 168 hr (7 day) certification test period. The magnitude of the drift was determined once each day at 24 hr intervals. The drift was determined at both the low- (zero) and high-level calibration gas concentrations by comparing the CEMS response with the calibrated or adjusted response recorded at the previous 24 hr calibration cycle. The differences were recorded as a percent of instrument span for the SO_2 and NO_x monitors, and as absolute percent by volume for the O_2 and CO_2 monitors. Table C-2 summarizes the results.

TABLE C-2. SUMMARY OF THE CEMS CALIBRATION DRIFT TEST RESULTS[*]

Analyzer	Mean, %	Standard Deviation, %	Maximum Positive Drift, %	Maximum Negative Drift, %	Calibration Drift Limit, %
SO_2 (DuPont)	1.88	3.42	3.88	-3.00	2.5
SO_2 (Western)	-0.10	0.53	1.18	-1.22	2.5
NO_x	-0.04	0.39	0.80	-1.00	2.5
O_2	-0.04	0.07	0.00	-0.20	0.5
CO_2	0.09	0.14	0.40	-0.10	0.5

[*] Percentages are percent of span for SO_2 and NO_x, and absolute percent by volume for O_2 and CO_2.

Systems and Performance Audits

Audits conducted during the project were of two types, a systems audit and a performance audit. A systems audit is an on-site, qualitative review of the various aspects of the total sampling and analytical system to assess its overall effectiveness. It represents an objective evaluation with respect to strengths, weaknesses, and potential problem areas. It is used to determine the adequacy of the system in providing data which are sufficient, in terms of quantity and quality, to meet project objectives. Checklists are used extensively to review and document such record keeping and data handling activities as:

- Calibration records
- Completeness of data forms and notebooks
- Data review and validation procedures
- Data storage and filing procedures
- Sample logging procedures
- Field laboratory custody procedures

- Documentation of quality control data
- Documentation of field maintenance activities
- Review of malfunction reporting procedures

Although the systems audits found occasional lapses in procedural methods and techniques, none were judged serious enough to warrant the more formal "Recommendation for Corrective Action."

A performance audit provides a quantitative assessment of data quality by challenging the instruments with representative reference standards. Most importantly for the CEMS, this consisted of comparing the analyzer responses when gases of certified (according to EPA Traceability Protocol Number 1[*]) concentrations were introduced to the sampling system. The performance audits also included checks on other analyzers used in the process evaluation, though these were not required to meet the more stringent criteria imposed on those in the CEMS. In addition, balances and dry gas meters used in the course of project execution were also subject to the audit process. With the exception of finding one dry gas meter in need of repair, and one instance of the humidification chamber's CO_2 monitor being out of calibration, the performance audits of the devices other than those in the CEMS showed all to be well within the ranges considered acceptable.

Systems and performance audits were conducted concurrently, first at the start of the project in August 1989, once during the Coolside demonstration in December 1989, and again during the LIMB Extension in September 1990. The criteria that applied to the CEMS analyzers called for the relative error of the measured values (except for the zero gases) to be within 15 percent of the certified concentrations, and for the absolute error to be less than or equal to 2.5 percent of the span value (later changed to 1.25 percent for the Western SO_2 analyzer because the span value was twice that of the DuPont monitor).

A summary of the results of the CEMS performance audits in Tables C-3, C-4, and C-5 show that the analyzers generally met the criteria. For those that did not, corrective actions were made as soon as possible, and the accuracy reestablished as part of the daily calibration procedure. The excessive values found for the CO analyzer in the two 1989 audits and the back-up Dupont

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[*] *Quality Assurance Handbook for Air Pollution Measurement Systems*, Volume III, Stationary Source Specific Methods, EPA-600/4-77-027b, August 1977.

TABLE C-3. SUMMARY OF THE RESULTS OF THE AUGUST 1989 CEMS PERFORMANCE AUDIT

Analyzer	Cylinder Number	Span and Units	Certified Value	Measured Value	Relative Error, %	Absolute Error, % of span
SO_2 (DuPont)	AAL-19029	2500 ppmv	497	511	2.8	0.56
	AAL-16310		1010	1058	4.8	1.92
	AAL-18049		1287	1321	2.6	1.36
NO	AAL-18049	1000 ppmv	538	530	-1.5	0.80
NO_2			2	NF[*]	NF	NA
NO_x			540[†]	NF	NF	NA
NO	AAL- 9966	1000 ppmv	64	63	-1.6	0.10
NO_2			22	NF	NF	NA
NO_x			86[†]	NF	NF	NA
NO	ALM- 1722	1000 ppmv	203	212	4.4	0.90
NO_2			71	NF	NF	NA
NO_x			274[†]	NF	NF	NA
O_2	AAL-19029	25 vol %	5.14	4.9	-4.7	0.96
	AAL-16310		8.75	8.5	-2.9	1.00
	ALM- 4355		9.05	9.0	-0.6	0.20
CO_2	ALM- 4355	20 vol %	7.01	7.3	4.1	1.45
	AAL-18049		10.98	11.3	2.9	1.60
	AAL- 8002		14.75	15.2	3.1	2.25
CO	AAL- 8002	1000 ppmv	266	NA[‡]	NA	NA
	AAL-17919		551	493	-10.5	5.80

[*] NF = Not functional because the analyzer's NO_2-to-NO converter was inoperative at the time of the audit.
[†] Taken as the sum of NO and NO_2.
[‡] NA = Not available because of an analyzer failure in the course of this audit.

SO_2 monitor in the December 1989 audit were more of an inconvenience, and in no way jeopardized the integrity of the SO_2 and NO_x measurements that were of primary concern. The two failures of the NO_2-to-NO converter in the NO_x analyzer is considered to have had a minimal impact since NO generally accounts for about 95 percent of the total NO_x in the flue gas. The second failure, however, did prompt the only formal "Recommendation for Corrective Action" issued in the course of the project. This resulted in a more thorough examination and repair of the catalytic conversion unit to assure more reliable operation thereafter.

Daily Calibration

The CEMS analyzers were normally calibrated on a daily basis (5 working days/week), and more frequently when test conditions made it advisable. The procedure for the SO_2, NO_x, O_2, CO_2, and CO analyzers followed the general pattern of first passing each certified QC gas (containing a mid-range concentration of each of the five gases) through the entire sampling and analytical system in order to determine QC bias (drift from the preceding value at the measured concentration). This was followed by similar use of the zero and span calibration gases to

TABLE C-4. SUMMARY OF THE RESULTS OF THE DECEMBER 1989 CEMS PERFORMANCE AUDITS

Analyzer	Cylinder Number	Span and Units	Certified Value	Measured Value	Relative Error, %	Absolute Error, % of span
SO_2 (DuPont)[*]	ALM- 1722	2500 ppmv	0	35	NA[†]	1.40
	AAL-19029		497	550	10.7	2.12
	AAL-16310		1010	1042	3.2	1.28
	AAL-18049		1287	1310	1.8	0.92
	ALM- 3043		2828	2690	-4.9	5.52
SO_2 (Western)	ALM- 1722	5000 ppmv	0	-40	NA	0.80
	AAL-19029		497	500	0.6	0.06
	AAL-16310		1010	1010	0.0	0.00
	AAL-18049		1287	1230	-4.4	1.14
	ALM- 3043		2828	2780	-1.7	0.96
NO_x	AAL-16310	1000 ppmv	0	-6	NA	0.60
NO	AAL-18049		538	552	2.6	1.40
NO_2			2	NF[‡]	NF	NA
NO_x			540[**]	NF	NF	NA
NO	AAL- 9966	1000 ppmv	64	60	-6.3	0.40
NO_2			22	NF	NF	NA
NO_x			86[**]	NF	NF	NA
NO	ALM- 1722	1000 ppmv	203	178	-12.3	2.50
NO_2			71	NF	NF	NA
NO_x			274[**]	NF	NF	NA
O_2	ALM- 1722	25 vol %	0	0.2	NA	0.80
	AAL-19029		5.14	4.9	-4.7	0.96
	AAL-16310		8.75	8.5	-2.9	1.00
	ALM- 4355		9.05	8.9	-1.7	0.60
CO_2	ALM- 1722	20 vol %	0	0	NA	0.00
	ALM- 4355		7.01	7.1	1.3	0.45
	AAL-18049		10.98	10.9	-0.7	0.40
	ALM- 3043		17.67	17.6	-0.4	0.35
CO	ALM- 1722	1000 ppmv	0	-5	NA	0.50
	AAL-17919		561	469	-14.9	9.20

[*] Analyzer served as a back-up for several months until the Western analyzer was considered proven.

[†] NA = Not applicable.

[‡] NF = Not functional because the analyzer's NO_2-to-NO converter was inoperative at the time of the audit.

[**] Taken as the sum of NO and NO_2.

determine the drift at the two calibration points. Acceptable calibration drift was defined as less than 2.5 percent of the span for SO_2, NO_x, and CO (and later 1.25 percent for the Western SO_2 analyzer), and 0.5 absolute percent by volume for the O_2 and CO_2 instruments. Adjustments were required whenever values were outside of these ranges, or when the QC bias values were in excess of 5 percent of span for SO_2, NO_x, and CO, or 1.0 absolute volume percent for O_2 and CO_2.

Examples of the adequacy of these QA/QC control procedures are presented in Figures C-1 to C-15 which record calibration data for October 1990. Used as the basis for the weekly, monthly, and quarterly reporting scheme, they represent a typical month's data. Such procedures not only permitted on-site personnel to correct for any excessive calibration drift immediately, but also identified trends that suggested the need for more than routine maintenance.

TABLE C-5. SUMMARY OF THE RESULTS OF THE SEPTEMBER 1990 CEMS PERFORMANCE AUDITS

Analyzer	Cylinder Number	Span and Units	Certified Value	Measured Value	Relative Error, %	Absolute Error, % of span
SO_2 (Western)	ALM- 1722	5000 ppmv	0	-1	NA[*]	0.02
	AAL-19029		497	491	-1.2	0.12
	ALM- 4355		0	5	NA	0.10
	AAL-18049		1287	1279	-0.6	0.16
	AAL-17919		0	-3	NA	0.06
	ALM- 3043		2828	2793	-1.2	0.70
	AAL- 9966		0	2	NA	0.04
NO_x	AAL-16310	1000 ppmv	0	-6	NA	0.60
NO	AAL-18049		538	537	-0.2	0.10
NO_2			2	NM[†]	NA	NA
NO_x			540[‡]	552	2.2	1.20
NO	AAL- 9966	1000 ppmv	64	60	-6.3	0.10
NO_2			22	NM	NA	NA
NO_x			86[‡]	75	-12.8	1.10
NO	ALM- 1722	1000 ppmv	203	178	-12.3	2.50
NO_2			71	NM	NA	NA
NO_x			274[‡]	257	-6.2	1.70
O_2	ALM- 3043	25 vol %	0	0.10	NA	0.40
	AAL-19029		5.14	5.0	-2.7	0.56
	ALM- 4355		9.05	8.9	-1.7	0.60
CO_2	ALM- 4355	20 vol %	7.01	7.5	7.0	2.45
	AAL-18049		10.98	11.2	2.0	1.10
	ALM- 3043		17.67	17.3	-2.1	1.85
CO	ALM- 4355	1000 ppmv	0	4.6	NA	0.46
	AAL-18049		0	7.2	NA	0.72
	ALM- 3043		0	14.8	NA	1.48
	AAL-17919		551	567	2.9	1.60

[*] NA = Not applicable.

[†] NM = Not measured.

[‡] Taken as the sum of NO and NO_2.

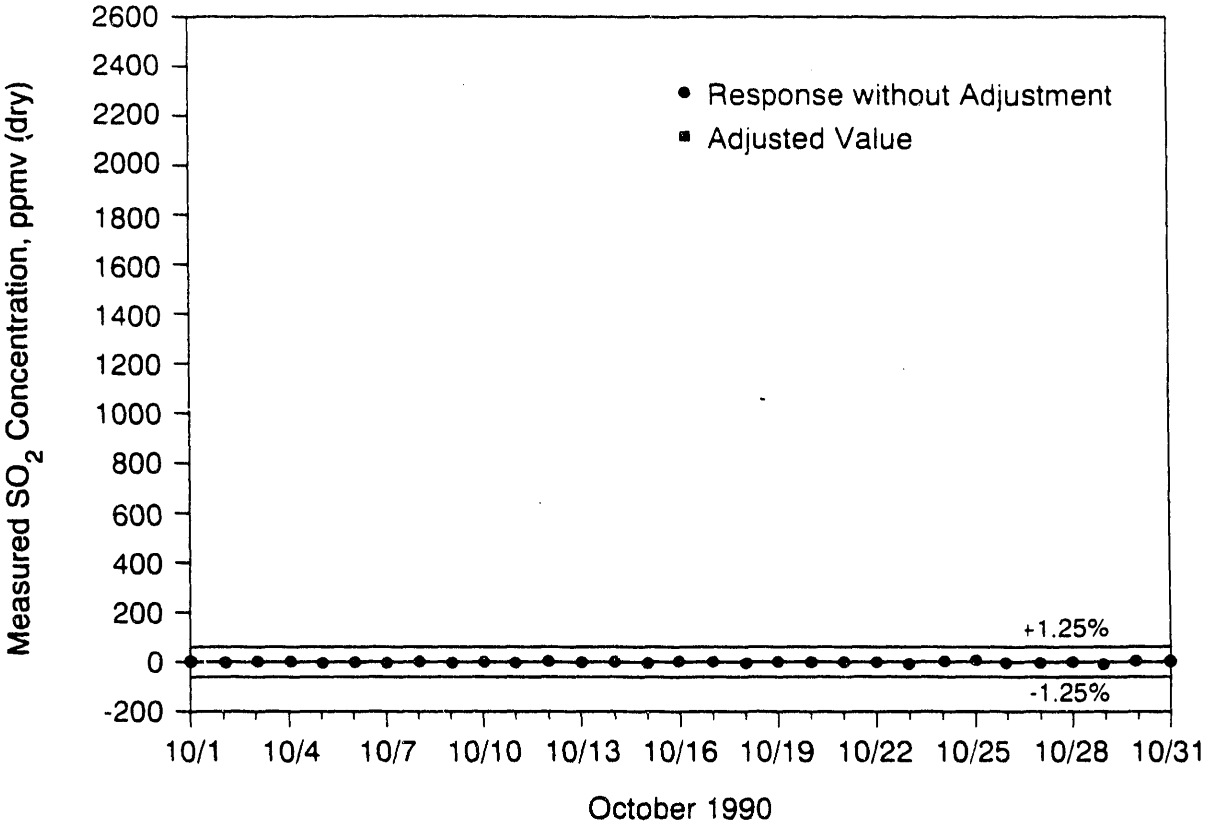

Figure C-1. SO_2 calibration data - zero response

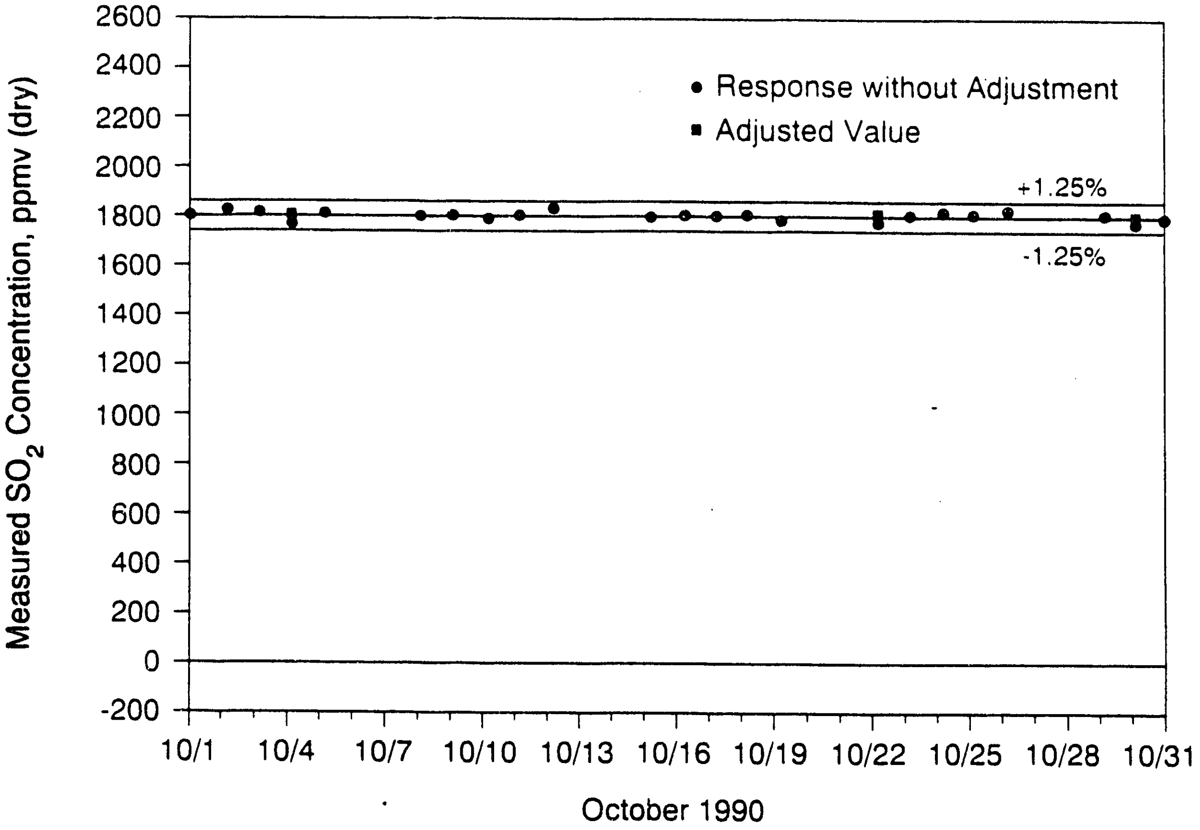

Figure C-2. SO_2 calibration data - span response

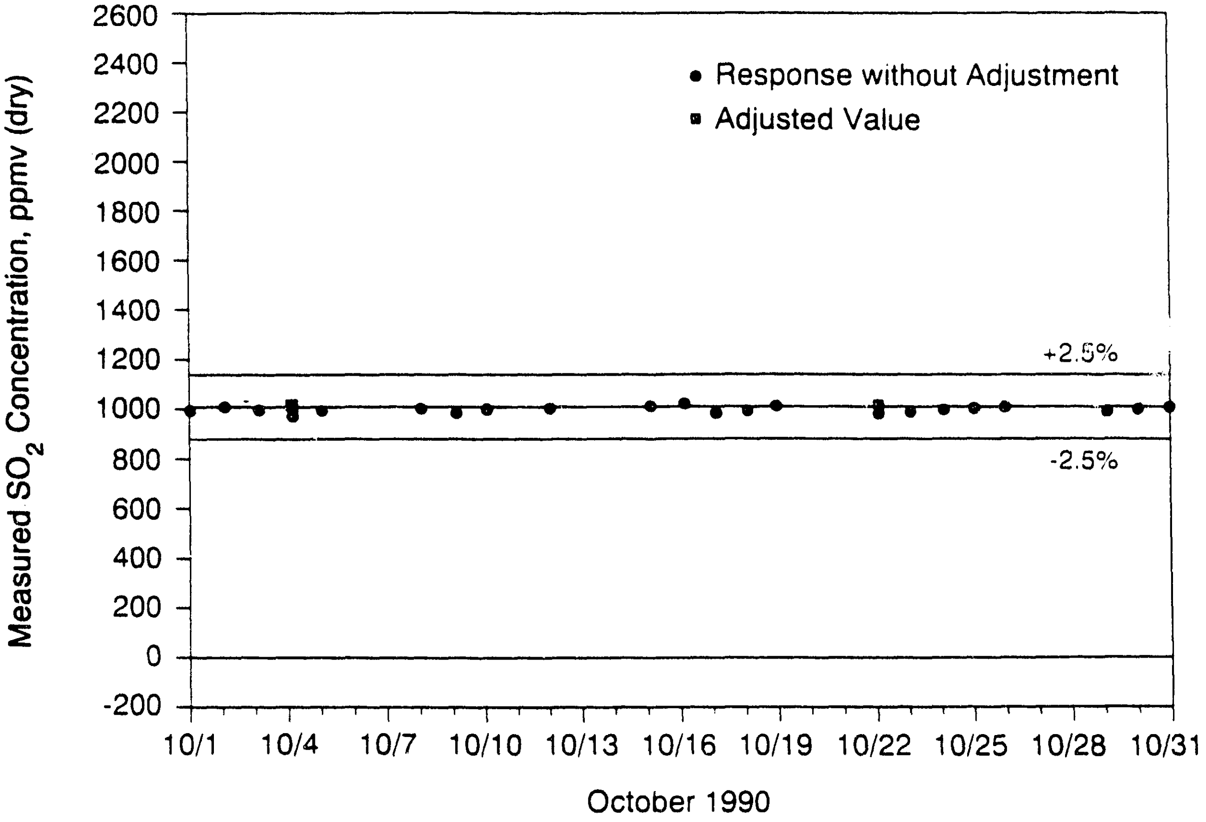

Figure C-3. SO_2 calibration data - QC response

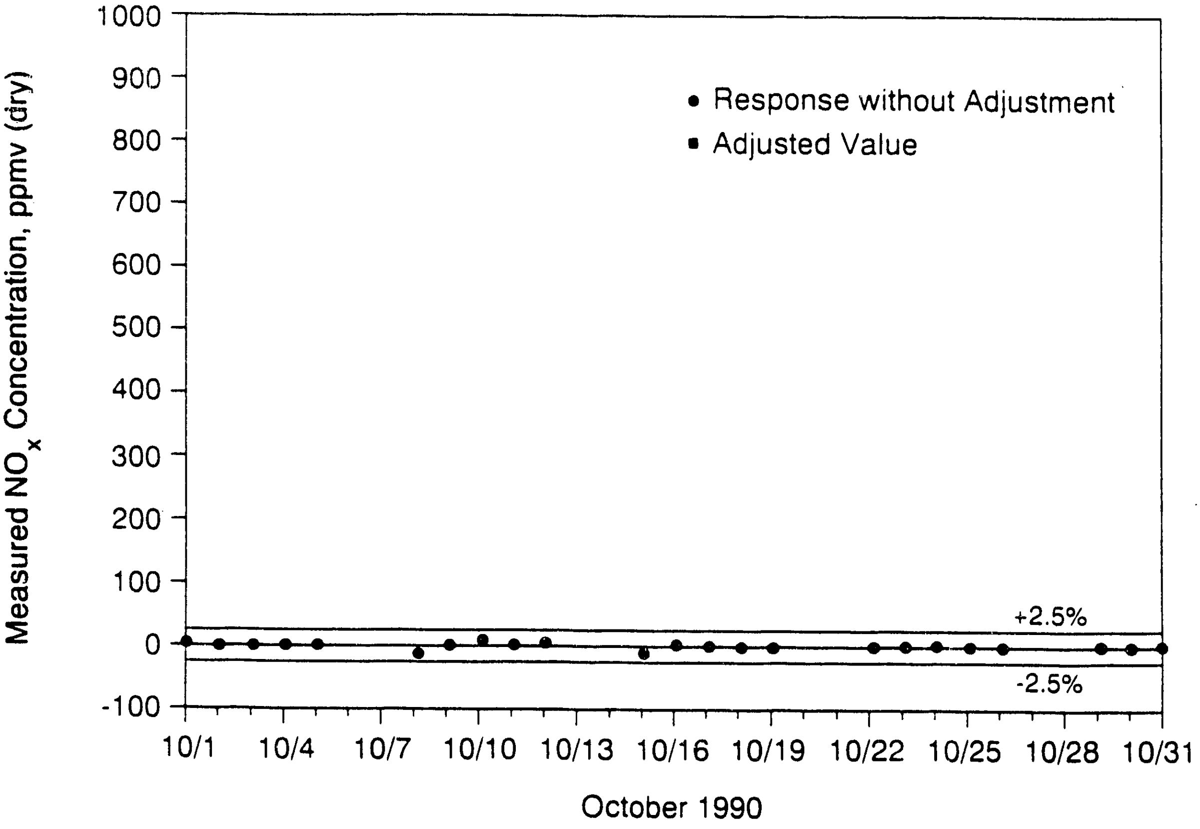

Figure C-4. NO_x calibration data - zero response

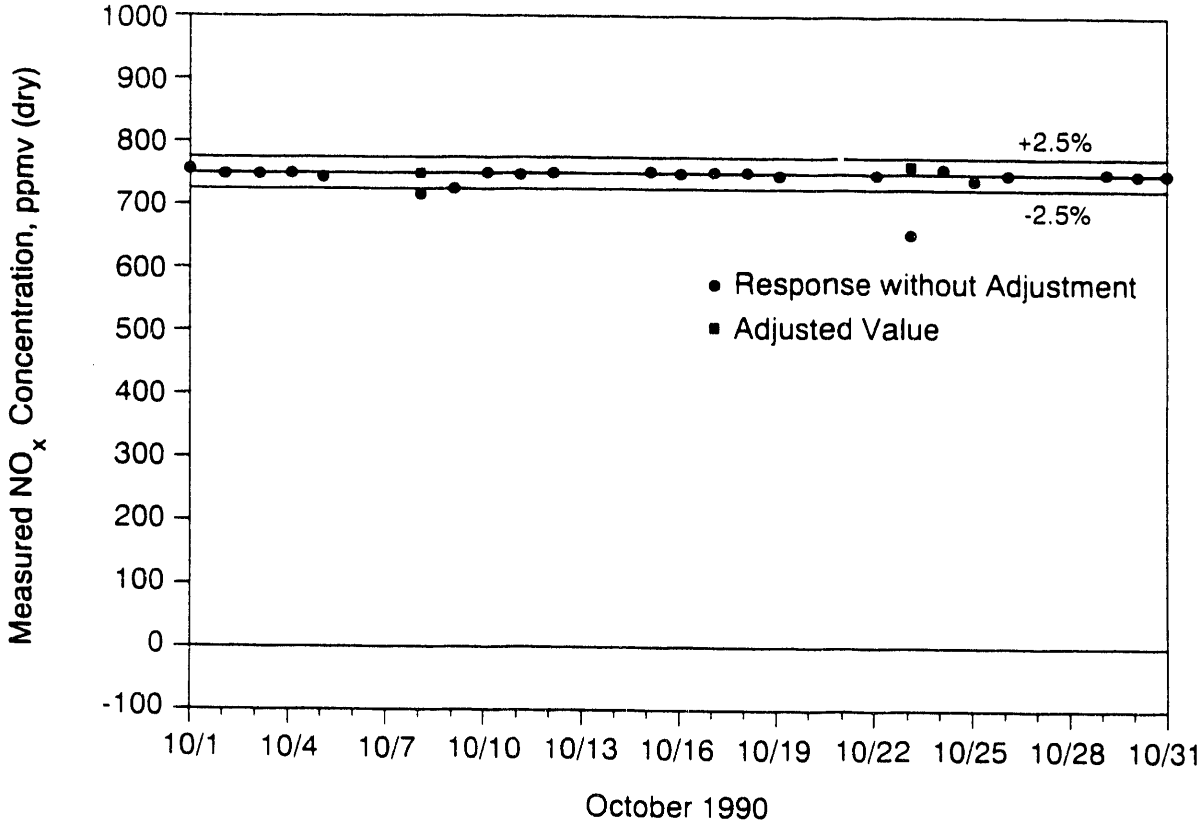

Figure C-5. NO_x calibration data - span response

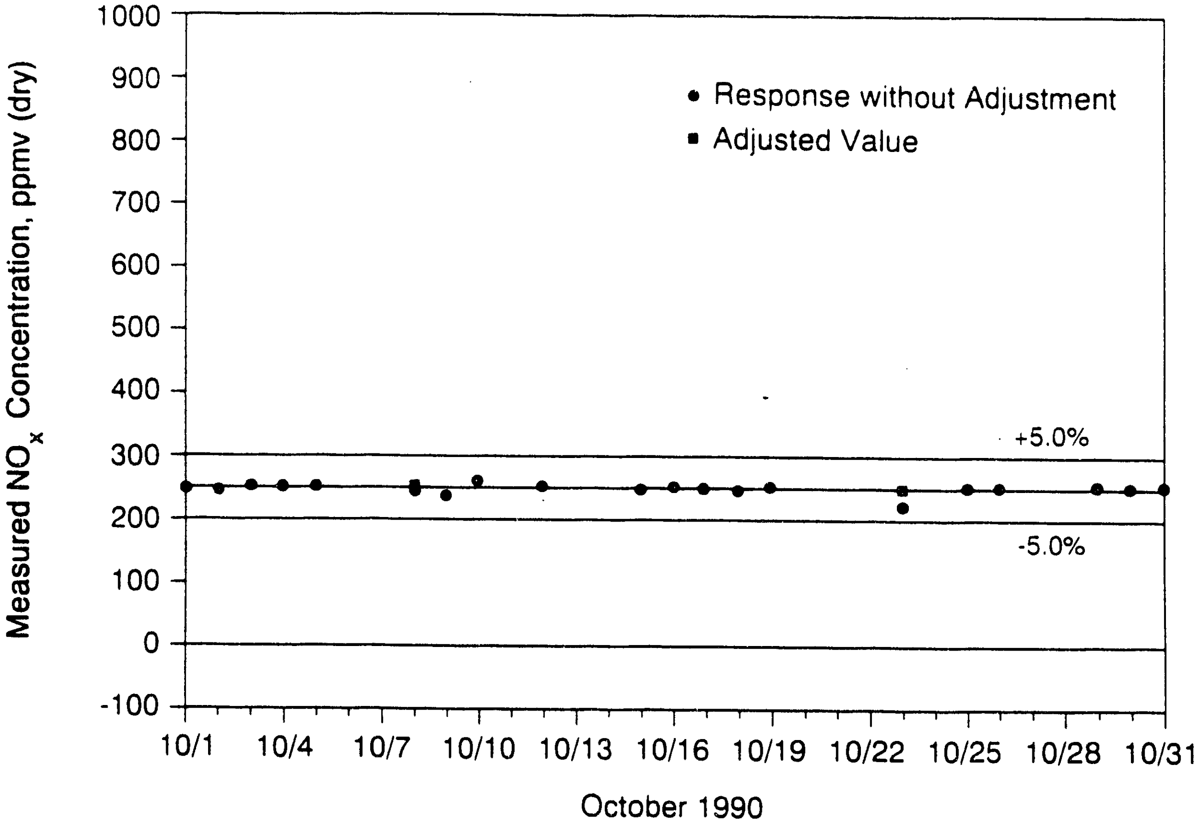

Figure C-6. NO_X calibration Data - QC response

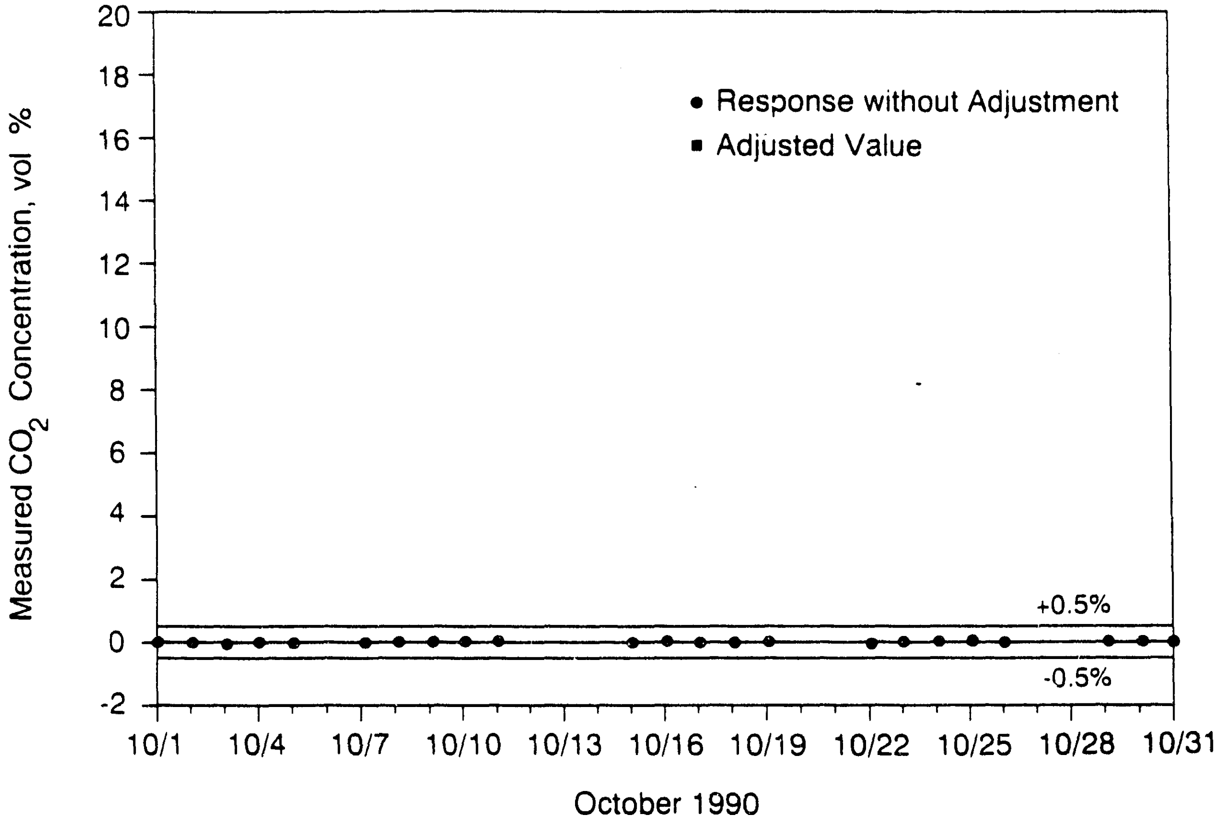

Figure C-7. O_2 calibration data - zero response

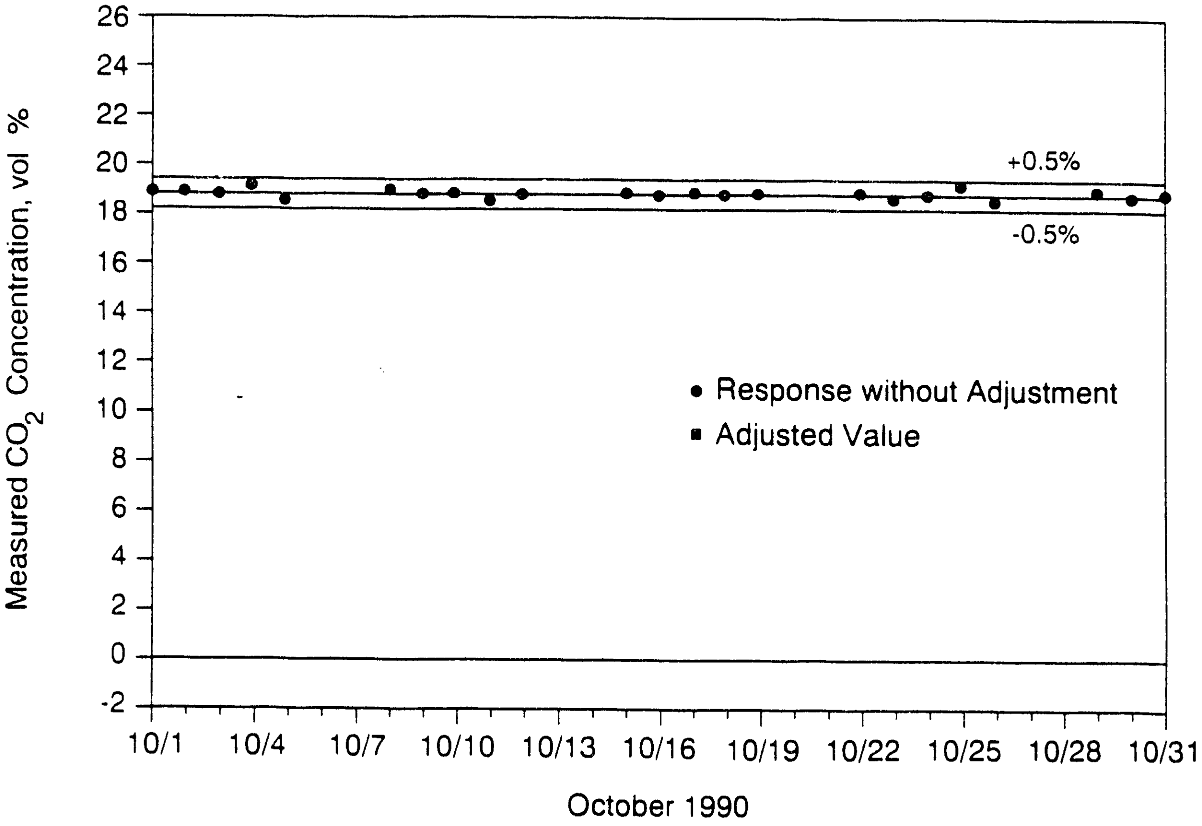

Figure C-8. O_2 calibration data - span response

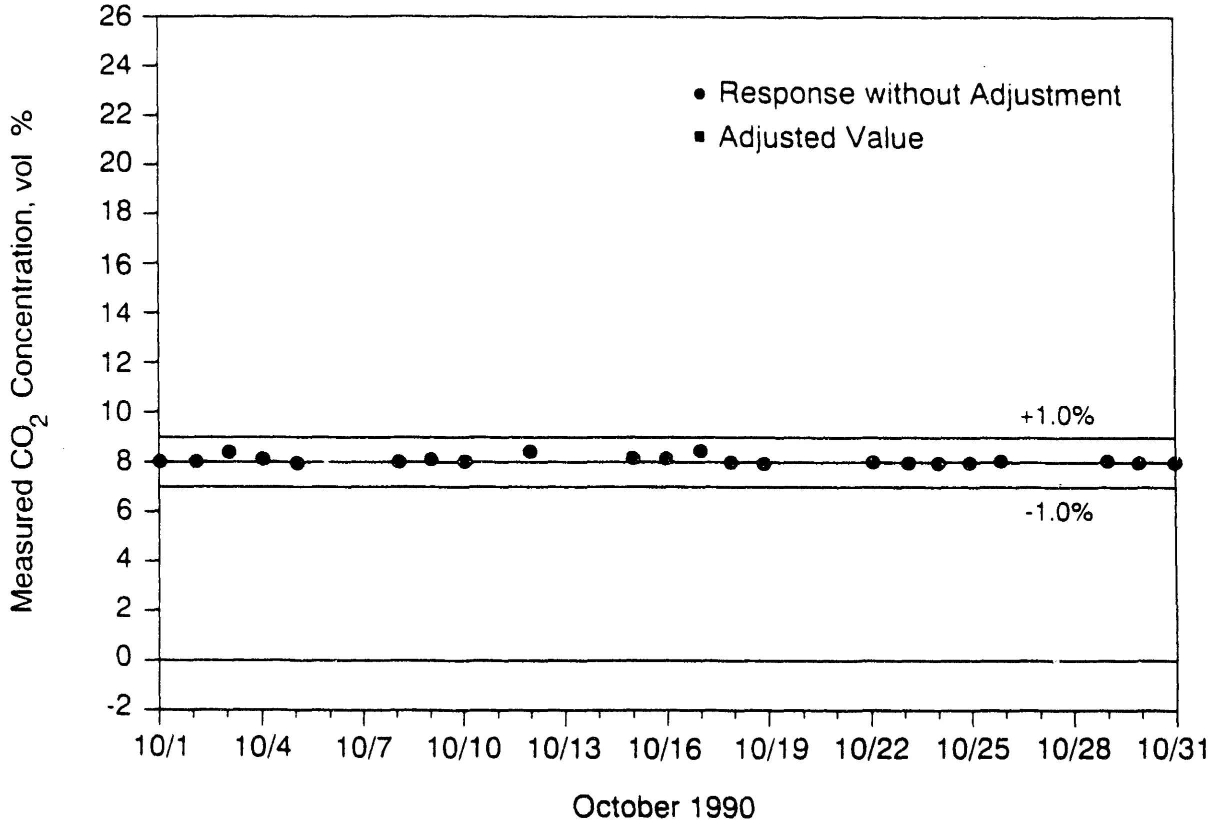

Figure C-9. O_2 calibration data - QC response

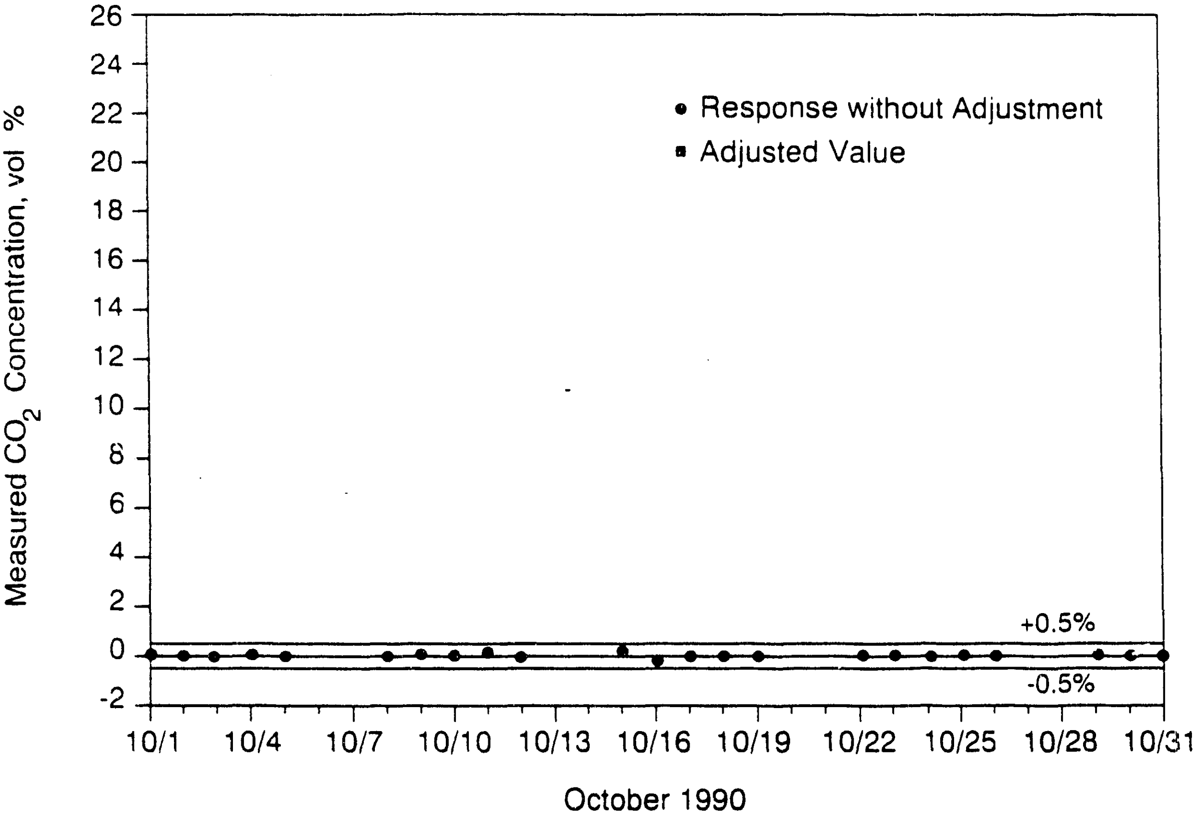

Figure C-10. CO_2 calibration data - zero response

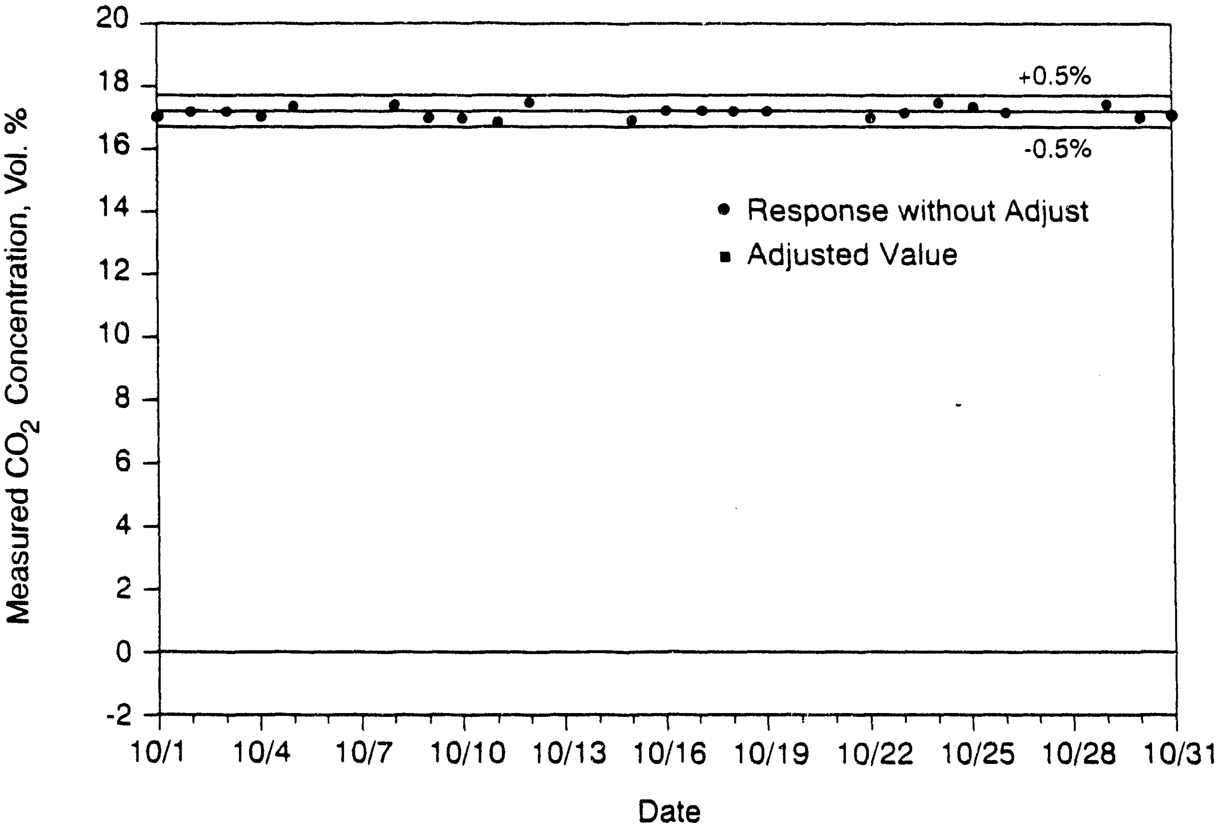

Figure C-11. CO_2 Calibration Data - Span Response

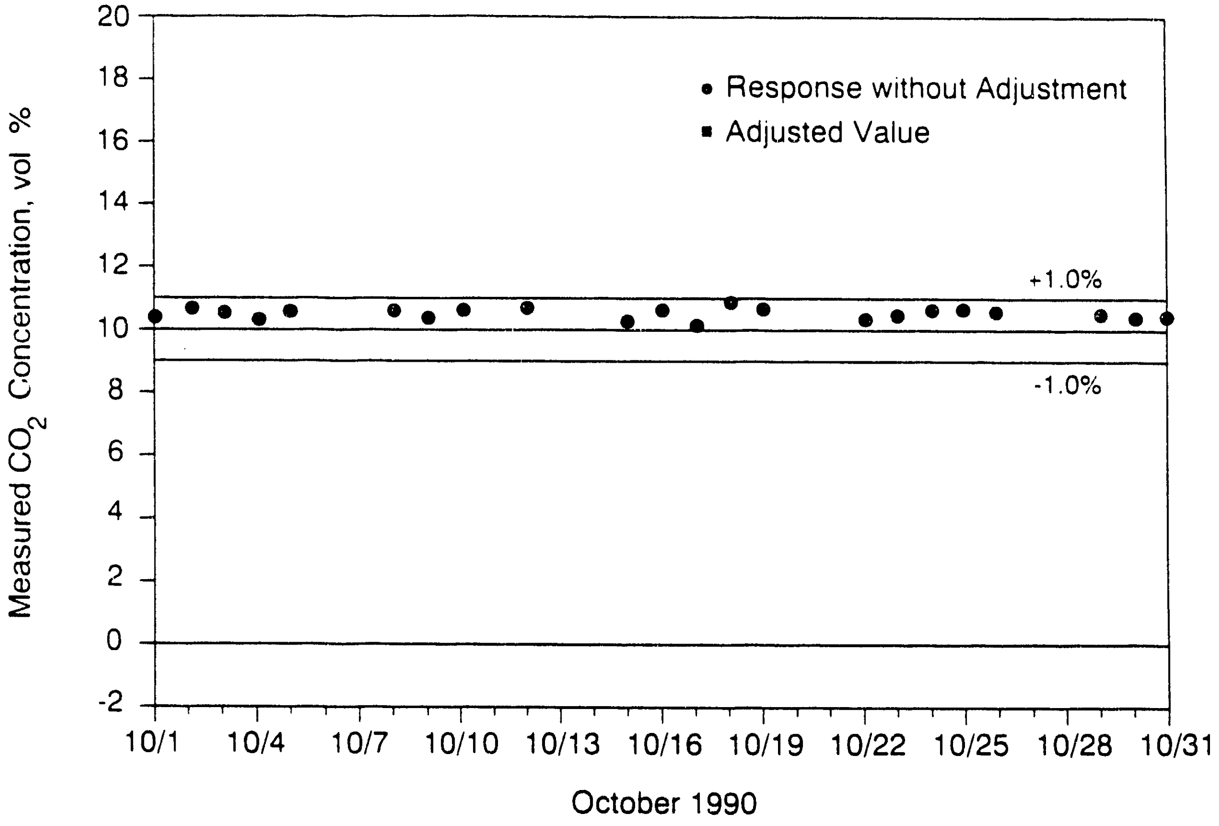

Figure C-12. CO_2 calibration data - QC response

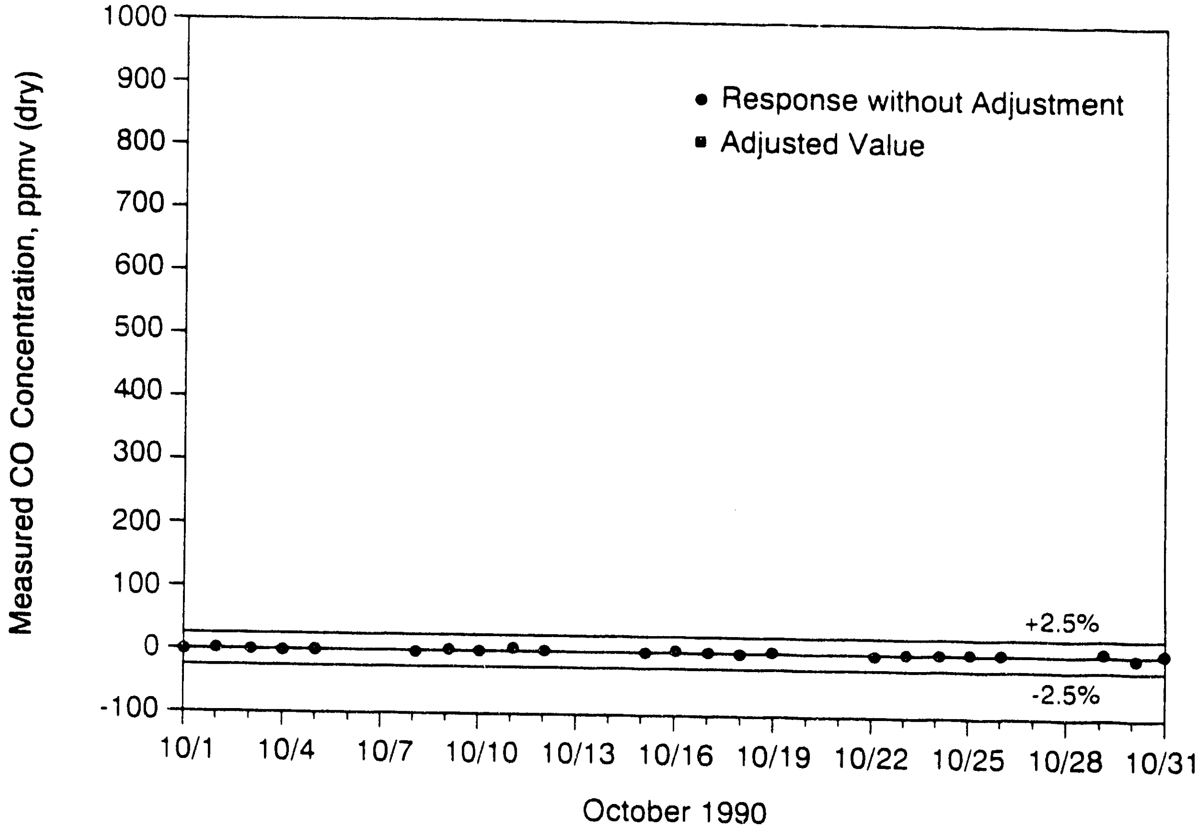

Figure C-13. CO calibration data - zero response

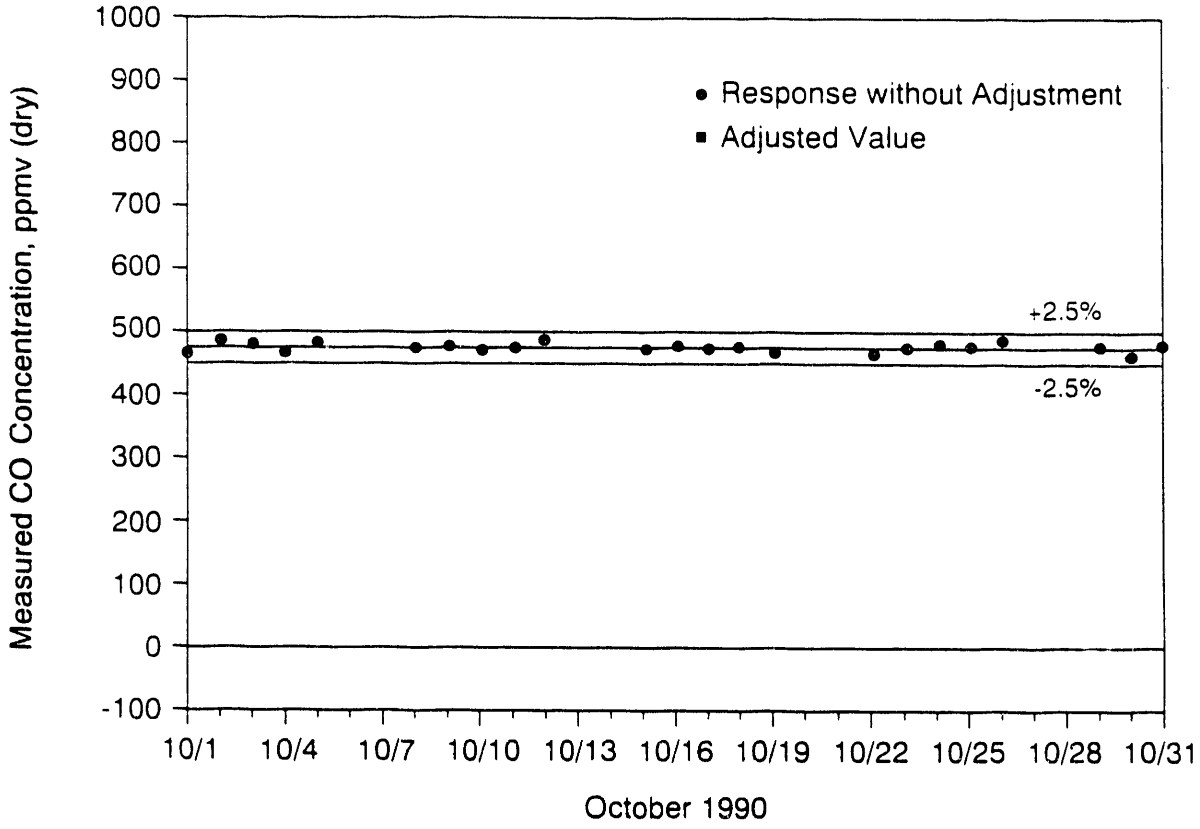

Figure C-14. CO calibration data - span response

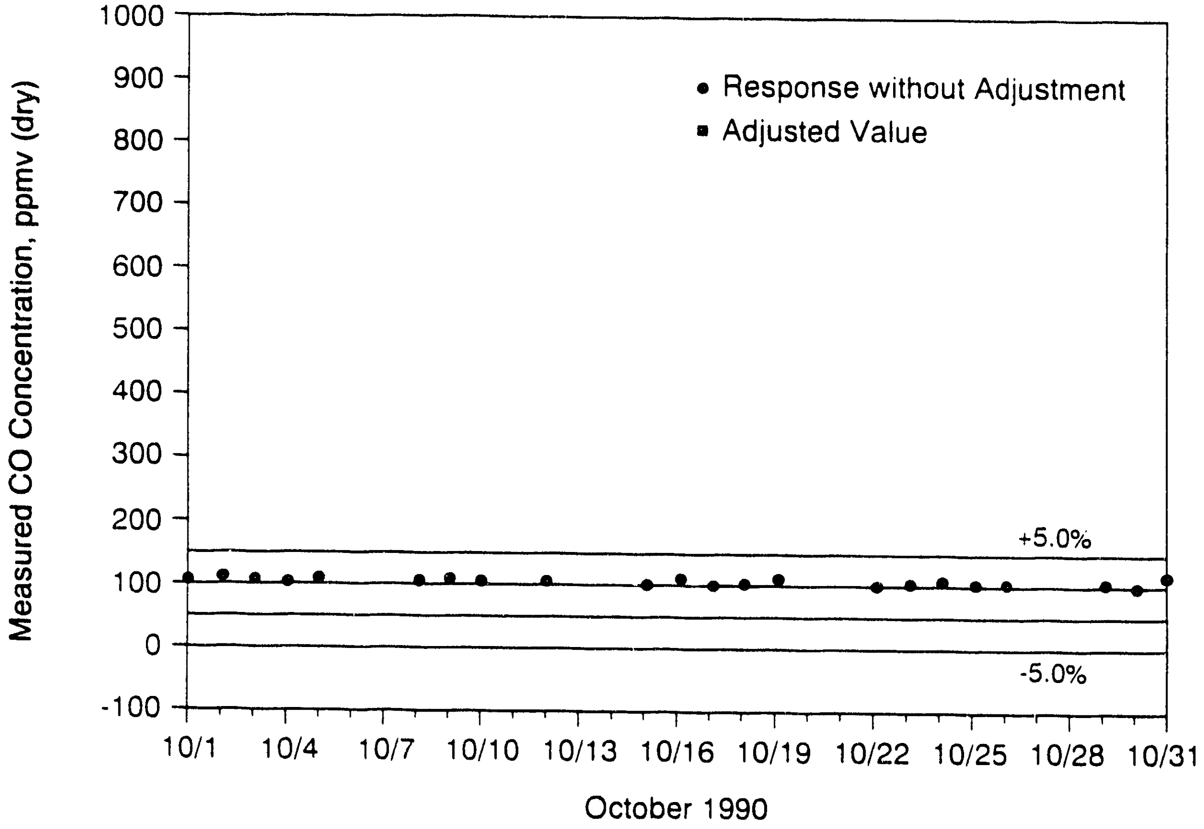

Figure C-15. CO calibration data - QC response

APPENDIX D: TEST RECORD

Test	Date	Ca/S Molar Ratio	Humid. Outlet Set Point, °F	Humid. On, Off, or Minimal	Injection Level, ft	Nominal Coal S, wt %	Sorbent	Test Used As Data Point, Yes or No	Number of Ten-minute Averages in Test	Comments
LE-1	04/27/90	1.0	275	MINIMAL	181	3.0	LIGNO	N		Mill trip at 12:00 lost zero
LE-2	05/01/90	1.3	275	MINIMAL	181	3.0	LIGNO	N		Mill change in test, zero changed
LE-3	05/02/90	1.2	275	MINIMAL	181	3.0	LIGNO	Y	7	
LE-4	05/04/90	1.5	275	MINIMAL	181	3.0	LIGNO	Y	28	
LE-4a	05/04/90	1.0	275	MINIMAL	181	3.0	LIGNO	Y	14	
LE-5	05/15/90	1.6	275	MINIMAL	181	3.0	LIGNO	N		Zero questionable
LE-6	05/17/90	0.8	275	MINIMAL	181	3.0	LIGNO	Y	11	
LE-6a	05/17/90	0.8	275	MINIMAL	181	3.0	LIGNO	Y	11	
LE-7	05/18/90	1.0	275	MINIMAL	181	3.0	LIGNO	Y	26	
LE-8	05/21/90	1.0	275	MINIMAL	181	3.0	LIGNO	N		Data not found on any LIF disk
LE-9	05/22/90	2.0	275	MINIMAL	181	3.0	LIGNO	N		Mill trip after lime start, bad test
LE-10	05/24/90	1.3	145	ON	181	3.0	LIGNO	Y	5	
LE-11	05/25/90	1.3	145	ON	181	3.0	LIGNO	Y	6	
LE-12	05/26/90	1.4	145	ON	181	3.0	LIGNO	N		Run by OE on night shift
LE-13	05/26/90	2.0	275	MINIMAL	181	3.0	LIGNO	N		LIF disk data shows zero spikes
LE-14	05/30/90	1.4	275	MINIMAL	181	3.0	LS	Y	18	
LE-15	05/30/90	1.4	275	MINIMAL	181	3.0	LS	N		Post-test zero off in the morning
LE-16	05/31/90	2.0	275	MINIMAL	181	3.0	LS	Y	32	
LE-16a	05/31/90	1.0	275	MINIMAL	181	3.0	LS	Y	10	
LE-16b	05/31/90	1.0	275	MINIMAL	181	3.0	LS	Y	4	
LE-16c	05/31/90	1.0	275	MINIMAL	181	3.0	LS	Y	4	
LE-16d	05/31/90	1.0	275	MINIMAL	181	3.0	LS	Y	30	
LE-17	06/04/90	1.9	250	MINIMAL	181	3.0	LS	Y	17	
LE-17a	06/04/90	1.9	250	MINIMAL	181	3.0	LS	Y	6	
LE-18	06/04/90	1.4	250	MINIMAL	181	3.0	LS	Y	24	
LE-19	06/04/90	1.9	250	MINIMAL	181	3.0	LS	Y	35	
LE-20	06/05/90	1.0	250	MINIMAL	181	3.0	LS	Y	31	
LE-21	06/06/90	1.4	250	MINIMAL	181	3.0	LS	N		Post-test zero off in the morning
LE-22	06/06/90	1.0	250	MINIMAL	187	3.0	LS	Y	15	
LE-22a	06/06/90	1.5	250	MINIMAL	187	3.0	LS	Y	10	
LE-23	06/06/90	1.1	250	MINIMAL	187	3.0	LS	Y	11	

Test	Date	Ca/S Molar Ratio	Humid. Outlet Set Point, °F	Humid. On, Off, or Minimal	Injection Level, ft	Nominal Coal S, wt %	Sorbent	Test Used As Data Point, Yes or No	Number of Ten-minute Averages in Test	Comments
LE-23a	06/07/90	1.0	250	MINIMAL	187	3.0	LS	Y	30	
LE-24	06/07/90	2.0	300	MINIMAL	187	3.0	LS	Y	27	
LE-25	06/07/90	2.0	300	MINIMAL	181	3.0	LS	N		Post-test zero off in the morning
LE-26	06/07/90	2.0	300	MINIMAL	187	3.0	LS	N		Post-test zero off in the morning
LE-27	06/08/90	2.0	275	MINIMAL	187	3.0	LS	N		Removal way off, post-test zero jumpy
LE-28	06/09/90	2.0	275	MINIMAL	187	3.0	LS	N		Data not on LIF disk
LE-29	06/11/90	1.0	N/A	OFF	181	3.0	LS	Y	31	
LE-30	06/11/90	1.0	N/A	OFF	181	3.0	LS	N		Post-test zero off in the morning
LE-31	06/12/90	2.0	N/A	OFF	191	3.0	LS	Y	32	
LE-32	06/12/90	2.0	N/A	OFF	191	3.0	LS	Y	19	
LE-33	06/13/90	2.4	N/A	OFF	191	3.0	LS	Y	24	
LE-34	06/14/90	2.0	N/A	OFF	191	3.0	LS	N		Removal keeps rising
LE-35	06/15/90	2.0	N/A	OFF	191	1.6	LS	Y	16	
LE-36	06/18/90	1.5	N/A	OFF	191	1.6	LS	Y	12	
LE-37	06/20/90	1.8	N/A	OFF	191	1.6	LS	Y	13	
LE-38	06/21/90	1.0	N/A	OFF	191	1.6	LS	N		No good zero
LE-39	06/21/90	2.0	N/A	OFF	181	1.6	LS	N		Coal sulfur changing, rezero at 13:30
LE-40	06/22/90	0.8	N/A	OFF	181	1.6	LS	N		Overnight zero held, removal jumpy
LE-41	06/22/90	2.0	145	ON	181	1.6	LS	N		Removal keeps climbing
LE-42	06/25/90	2.0	N/A	OFF	181	1.6	LS	Y	28	
LE-43	06/26/90	1.8	N/A	OFF	181	1.6	LS	Y	9	
LE-43a	06/26/90	1.8	145	ON	181	1.6	LS	Y	15	
LE-44	06/27/90	2.0	N/A	OFF	181	1.6	LS	N		Unit all over the place
LE-45	07/02/90	1.5	145	ON	181	1.6	LS	Y	26	
LE-45a	07/02/90	0.8	N/A	OFF	181	1.6	LS	Y	17	
LE-45b	07/03/90	0.8	N/A	OFF	181	1.6	LS	Y	11	
LE-46	07/03/90	2.0	N/A	OFF	181	1.6	LS	Y	15	
LE-46a	07/03/90	2.0	145	ON	181	1.6	LS	Y	7	
LE-47	07/05/90	1.2	N/A	OFF	181	1.6	LS	N		Coal sulfur rising
LE-48	07/10/90	1.0	N/A	OFF	181	1.6	LS	Y	19	
LE-49	07/18/90	2.0	235	MINIMAL	181	1.6	DOL	N		One port plugged all day
LE-50	07/19/90	2.0	250	MINIMAL	181	1.6	DOL	N		Good zero, removal jumpy
LE-51	08/24/90	1.3	N/A	OFF	181	1.6	DOL	Y	10	

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LE-52	08/29/90	2.7	N/A	OFF	181	1.6	DOL	Y	5	
LE-52a	08/30/90	1.1	N/A	OFF	181	1.6	DOL	Y	10	
LE-53	08/30/90	1.1	N/A	OFF	181	1.6	DOL	N		Questionable zero
LE-54	08/31/90	1.6	N/A	OFF	181	1.6	DOL	Y	13	
LE-55	09/04/90	1.4	N/A	OFF	181	1.6	DOL	Y	12	
LE-56	09/07/90	1.8	N/A	OFF	181	1.6	DOL	Y	8	
LE-57	09/11/90	3.5	N/A	OFF	181	1.6	DOL	N		Short test for feed capacity check
LE-58	09/12/90	5.0	N/A	OFF	181	1.6	DOL	N		Good zero, end test precip problem
LE-59	09/13/90	1.6	N/A	OFF	181	1.6	DOL	N		Removal dropping too much
LE-60	09/14/90	1.6	N/A	OFF	181	1.6	DOL	N		Good zero, load change during test
LE-61	09/17/90	0.8	N/A	OFF	181	1.6	DOL	N		Bad zero
LE-62	09/18/90	0.8	N/A	OFF	181	1.6	DOL	Y	16	
LE-63	09/19/90	1.0	N/A	OFF	181	1.6	DOL	Y	21	
LE-64	09/20/90	1.0	N/A	OFF	191	1.6	DOL	N		Good zero, one nozzle plugged
LE-65	09/21/90	1.2	N/A	OFF	191	1.6	DOL	Y	10	
LE-66	09/26/90	1.3	N/A	OFF	191	1.6	DOL	Y	10	
LE-67	09/27/90	1.5	N/A	OFF	191	1.6	DOL	N		Coal S changing, post-test zero off
LE-68	10/04/90	2.0	275/ 250	MINIMAL	181	1.6	DOL	N		Nozzles plugged?
LE-69	10/05/90	2.0	250	MINIMAL	181	1.6	DOL	N		Three nozzles found plugged at 11:15
LE-70	10/10/90	1.2	260	MINIMAL	181	3.0	DOL	Y	24	
LE-71	10/11/90	1.4	260	MINIMAL	181	3.0	DOL	Y	18	
LE-71a	10/11/90	1.0	250	MINIMAL	181	3.0	DOL	Y	14	
LE-72	10/12/90	1.5	250	MINIMAL	181	3.0	DOL	Y	12	
LE-73	10/16/90	2.2	260	MINIMAL	181	3.0	DOL	N		2 nozzles plugged at 14:00, unplugged at 14:30
LE-74	10/17/90	2.1	250	MINIMAL	181	3.0	DOL	Y	13	
LE-75	10/22/90	1.8	260	MINIMAL	181	3.0	DOL	N		Good zero, data missing on LIF disks
LE-76	10/23/90	1.2	250	MINIMAL	181	3.0	DOL	Y	7	
LE-76a	10/24/90	1.0	250	MINIMAL	181	3.0	DOL	Y	15	
LE-77	10/24/90	1.8	250	MINIMAL	181	3.0	DOL	Y	31	
LE-78	10/25/90	2.0	255	MINIMAL	181	3.0	DOL	N		No stoich number coming through
LE-79	10/26/90	2.1	260	MINIMAL	181	3.0	DOL	Y	19	

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LE-79a	10/28/90	1.4	260	MINIMAL	181	3.0	DOL	Y	13	
LE-79b	10/28/90	1.3	260	MINIMAL	181	3.0	DOL	Y	6	
LE-79c	10/28/90	1.4	260	MINIMAL	181	3.0	DOL	Y	10	
LE-79d	10/28/90	1.4	260	MINIMAL	181	3.0	DOL	Y	10	
LE-79e	10/28/90	1.4	260	MINIMAL	181	3.0	DOL	Y	5	
LE-79f	10/28/90	1.3	260	MINIMAL	181	3.0	DOL	Y	14	
LE-80	10/30/90	2.0	240	MINIMAL	191	3.0	DOL	Y	16	
LE-80a	10/30/90	1.3	240	MINIMAL	191	3.0	DOL	Y	10	
LE-80b	10/30/90	1.5	240	MINIMAL	191	3.0	DOL	Y	14	
LE-81	10/31/90	2.2	250	MINIMAL	191	3.0	DOL	N		Test ends abruptly as F-K pump trips
LE-82	10/31/90	2.1	250	MINIMAL	191	3.0	DOL	Y	3	
LE-82a	10/31/90	1.7	250	MINIMAL	191	3.0	DOL	Y	11	
LE-82b	11/01/90	1.0	250	MINIMAL	191	3.0	DOL	Y	19	
LE-83	11/06/90	1.0	260	MINIMAL	187	1.6	DOL	Y	20	
LE-83a	11/06/90	0.9	260	MINIMAL	187	1.6	DOL	Y	26	
LE-83b	11/06/90	0.9	260	MINIMAL	187	1.6	DOL	Y	35	
LE-84	11/07/90	1.5	260	MINIMAL	187	1.6	DOL	Y	29	
LE-84a	11/07/90	0.8	260	MINIMAL	187	1.6	DOL	Y	31	
LE-85	11/08/90	1.9	260	MINIMAL	187	1.6	DOL	Y	33	
LE-86	11/12/90	1.8	260	MINIMAL	187	1.6	DOL	N		One nozzle plugged, scrapped test
LE-87	11/13/90	1.9	260	MINIMAL	187	3.0	DOL	Y	18	
LE-87a	11/13/90	1.2	260	MINIMAL	187	3.0	DOL	Y	13	
LE-88	11/14/90	2.0	265	MINIMAL	187	3.0	DOL	Y	14	
LE-88a	11/14/90	2.0	265	MINIMAL	181	3.0	DOL	Y	6	
LE-89	11/15/90	1.6	265	MINIMAL	181	3.0	DOL	Y	7	
LE-89a	11/15/90	1.6	265	MINIMAL	187	3.0	DOL	Y	9	
LE-89b	11/15/90	0.5	265	MINIMAL	187	3.0	DOL	Y	6	
LE-89c	11/15/90	1.1	265	MINIMAL	187	3.0	DOL	Y	18	
LE-89d	11/16/90	1.1	265	MINIMAL	187	3.0	DOL	Y	21	
LE-90	11/16/90	1.9	145	ON	187	3.0	DOL	Y	4	
LE-90a	11/16/90	1.9	260	MINIMAL	187	3.0	DOL	Y	3	
LE-90b	11/16/90	1.4	145	ON	187	3.0	DOL	Y	12	
LE-91	11/16/90	1.4	145	ON	187	3.0	DOL	N		Things never steadied out
LE-92	11/20/90	1.8	260	MINIMAL	187	1.6	DOL	Y	11	

Test	Date	Ca/S Molar Ratio	Humid. Outlet Set Point, °F	Humid. On, Off, or Minimal	Injection Level, ft	Nominal Coal S, wt %	Sorbent	Test Used As Data Point, Yes or No	Number of Ten-minute Averages in Test	Comments
LE-92a	11/20/90	0.6	260	MINIMAL	187	1.6	DOL	Y	71	
LE-93	11/21/90	1.8	260	MINIMAL	187	1.6	DOL	N		Poor removal, unexplained poor data
LE-94	11/26/90	0.8	260	MINIMAL	187	1.6	DOL	N		Compressor trips
LE-95	11/28/90	1.8	260	MINIMAL	181	3.8	DOL	Y	5	
LE-96	11/29/90	1.7	260	MINIMAL	181	3.8	DOL	Y	10	
LE-96a	11/29/90	1.3	260	MINIMAL	181	3.8	DOL	Y	9	
LE-97	11/30/90	2.0	260	MINIMAL	181	3.8	DOL	Y	12	
LE-97a	11/30/90	1.3	260	MINIMAL	181	3.8	DOL	Y	34	
LE-98	12/03/90	1.6	260	MINIMAL	181	3.8	DOL	Y	17	
LE-98a	12/03/90	0.6	260	MINIMAL	181	3.8	DOL	Y	9	
LE-99	12/04/90	0.9	260	MINIMAL	181	3.8	DOL	Y	12	
LE-100	12/05/90	2.2	260	MINIMAL	181	1.6	DOL	Y	17	
LE-101	12/06/90	1.2	260	MINIMAL	181	1.6	DOL	Y	23	
LE-102	12/07/90	1.3	250	MINIMAL	181	1.6	DOL	N		Removal climbing all day long?
LE-103	12/11/90	1.7	260	MINIMAL	181	1.6	DOL	N		Things never steadied out
LE-104	12/12/90	1.7	145	ON	181	1.6	DOL	Y	11	
LE-104a	12/12/90	1.9	260	MINIMAL	181	1.6	DOL	Y	4	
LE-105	12/13/90	1.4	260/ 250	MINIMAL	181	1.6	DOL	Y	15	
LE-106	12/14/90	1.0	260	MINIMAL	181	1.6	DOL	Y	11	
LE-107	12/17/90	1.2	145	ON	181	1.6	DOL	Y	9	
LE-108	12/18/90	1.0	145	ON	181	1.6	DOL	Y	14	
LE-108a	12/18/90	0.9	250	MINIMAL	181	1.6	DOL	Y	12	
LE-109	12/20/90	1.6	250	MINIMAL	181	1.6	DOL	Y	8	
LE-110	01/07/91	2.0	260	MINIMAL	181	1.6	FINE LS	Y	25	
LE-111	01/08/91	2.0	260	MINIMAL	181	1.6	FINE LS	Y	14	
LE-112	01/09/91	1.6	260	MINIMAL	181	1.6	FINE LS	Y	9	
LE-112a	01/09/91	1.6	145	ON	181	1.6	FINE LS	Y	6	
LE-113	01/10/91	1.2	N/A	OFF	181	1.6	FINE LS	Y	24	
LE-114	01/11/91	1.7	260	MINIMAL	181	1.6	FINE LS	Y	11	
LE-114a	01/11/91	1.7	145	ON	181	1.6	FINE LS	Y	7	
LE-115	01/12/91	0.0	N/A	N/A	N/A	N/A	FINE LS	N		Never run - aborted
LE-116	01/15/91	1.4	260	MINIMAL	181	1.6	FINE LS	Y	17	
LE-117	01/17/91	1.1	N/A	OFF	181	1.6	FINE LS	Y	21	

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LE-118	01/18/91	2.2	N/A	OFF	181	1.6	FINE LS	Y	9	
LE-119	01/21/91	2.0	N/A	OFF	181	1.6	VFLS	Y	15	
LE-120	01/22/91	1.0	N/A	OFF	181	1.6	VFLS	Y	5	
LE-121	01/24/91	2.0	N/A	OFF	181	1.6	VFLS	Y	11	
LE-122	01/25/91	1.6	N/A	OFF	181	1.6	VFLS	Y	11	
LE-123	01/28/91	2.0	N/A	OFF	187	1.6	FINE LS	Y	4	
LE-124	01/29/91	1.6	N/A	OFF	187	1.6	FINE LS	Y	6	
LE-125	01/30/91	1.6	260	MINIMAL	187	1.6	FINE LS	Y	7	
LE-126	01/30/91	1.7	260	MINIMAL	187	1.6	FINE LS	Y	10	
LE-127	01/31/91	1.2	N/A	OFF	187	1.6	FINE LS	Y	9	
LE-128	01/31/91	2.2	N/A	OFF	187	1.6	FINE LS	N		Removal dropping, post-test zero low
LE-129	02/01/91	2.0	N/A	OFF	187	1.6	FINE LS	Y	30	
LE-130	02/06/91	1.9	260	MINIMAL	187	3.8	DOL	N		Possible coal sulfur change
LE-131	02/07/91	1.6	260	MINIMAL	187	3.8	DOL	Y	20	
LE-131a	02/07/91	1.2	260	MINIMAL	187	3.8	DOL	Y	11	
LE-132	02/11/91	2.2	260	MINIMAL	187	3.8	DOL	Y	13	
LE-133	02/12/91	1.1	260	MINIMAL	187	3.8	DOL	Y	7	
LE-133a	02/12/91	0.7	260	MINIMAL	187	3.8	DOL	Y	11	
LE-133b	02/12/91	1.3	260	MINIMAL	187	3.8	DOL	Y	16	
LE-133c	02/13/91	1.3	260	MINIMAL	187	3.8	DOL	Y	10	
LE-134	02/13/91	1.9	260	MINIMAL	187	3.8	DOL	Y	12	
LE-134a	02/13/91	1.5	260	MINIMAL	187	3.8	DOL	Y	8	
LE-134b	02/13/91	1.4	260	MINIMAL	187	3.8	DOL	Y	11	
LE-135	02/14/91	1.3	260	MINIMAL	187	3.8	DOL	Y	18	
LE-135a	02/18/91	0.9	260	MINIMAL	187	3.8	DOL	Y	9	
LE-136	02/18/91	1.8	250	MINIMAL	181	3.8	DOL	N		Questionable zero
LE-137	02/19/91	1.1	250	MINIMAL	181	3.8	DOL	Y	32	
LE-138	02/20/91	1.2	250	MINIMAL	181	3.8	DOL	Y	20	
LE-138a	02/20/91	1.5	240	MINIMAL	181	3.8	DOL	Y	17	
LE-139	02/21/91	2.1	240	MINIMAL	181	3.8	DOL	Y	11	
LE-140	02/25/91	1.4	275	MINIMAL	181	1.6	LIGNO	N		B mill trips
LE-140a	02/25/91	0.9	275	MINIMAL	181	1.6	LIGNO	N		Test run at night, post-test zero bad
LE-141	02/26/91	2.0	275	MINIMAL	181	1.6	LIGNO	Y	5	

Test	Date	Ca/S Molar Ratio	Humid. Outlet Set Point, °F	Humid. On, Off, or Minimal	Injection Level, ft	Nominal Coal S, wt %	Sorbent	Test Used As Data Point, Yes or No	Number of Ten-minute Averages in Test	Comments
LE-142	02/27/91	1.8	275	MINIMAL	181	1.6	LIGNO	Y	8	
LE-143	02/28/91	1.7	275	MINIMAL	181	1.6	LIGNO	Y	4	
LE-144	03/01/91	1.5	275	MINIMAL	181	1.6	LIGNO	Y	14	
LE-145	03/04/91	1.2	275	MINIMAL	181	1.6	LIGNO	Y	7	
LE-146	03/05/91	1.1	275	MINIMAL	181	1.6	LIGNO	Y	19	
LE-147	03/06/91	1.2	145	ON	181	1.6	LIGNO	Y	9	
LE-148	03/07/91	0.9	275	MINIMAL	181	1.6	LIGNO	Y	12	
LE-148a	03/07/91	1.6	275	MINIMAL	181	1.6	LIGNO	Y	6	
LE-149	03/08/91	0.8	275	MINIMAL	181	1.6	LIGNO	Y	7	
LE-150	03/11/91	2.0	275	MINIMAL	181	1.6	LIGNO	N		Good zero, SO_2 not steady
LE-151	03/12/91	1.3	275	MINIMAL	181	1.6	LIGNO	N		Removal still rising as test ends
LE-152	03/13/91	1.1	275	MINIMAL	181	1.6	LIGNO	Y	14	
LE-153	03/22/91	1.9	275	MINIMAL	181	1.6	LIGNO	Y	9	
LE-154	03/28/91	2.2	275	MINIMAL	181	1.6	LIGNO	N		SO_2 problems, no data
LE-155	04/01/91	2.2	275	MINIMAL	181	1.6	LIGNO	N		Test short, things never steadied out
LE-156	04/02/91	2.0	275	MINIMAL	181	1.6	LIGNO	Y	23	
LE-157	04/03/91	1.4	275	MINIMAL	181	1.6	LIGNO	Y	17	
LE-157a	04/03/91	1.7	275	MINIMAL	181	1.6	LIGNO	Y	5	
LE-158	04/04/91	1.9	275	MINIMAL	181	1.6	LIGNO	N		Removal jumpy
LE-159	04/05/91	2.0	275	MINIMAL	181	1.6	LIGNO	Y	8	
LE-160	04/12/91	2.0	275	MINIMAL	181	3.8	LIGNO	Y	16	
LE-161	04/15/91	1.4	275	MINIMAL	181	3.8	LIGNO	Y	6	
LE-162	04/17/91	2.0	275	MINIMAL	181	3.8	LIGNO	Y	29	
LE-163	04/18/91	1.0	275	MINIMAL	181	3.8	LIGNO	Y	11	
LE-163a	04/18/91	1.5	275	MINIMAL	181	3.8	LIGNO	Y	7	
LE-164	04/22/91	1.2	275	MINIMAL	181	3.8	LIGNO	Y	9	
LE-165	04/23/91	0.8	275	MINIMAL	181	3.8	LIGNO	Y	11	
LE-166	04/24/91	1.5	275	MINIMAL	181	3.8	LIGNO	Y	4	
LE-166a	04/24/91	1.5	145	ON	181	3.8	LIGNO	Y	8	
LE-167	05/06/91	2.1	275	MINIMAL	181	3.8	LIGNO	Y	7	
LE-168	05/07/91	1.5	275	MINIMAL	181	3.8	LIGNO	Y	11	
LE-168a	05/07/91	1.0	275	MINIMAL	181	3.8	LIGNO	Y	12	
LE-168b	05/07/91	1.3	275	MINIMAL	181	3.8	LIGNO	Y	20	
LE-168c	05/07/91	1.6	275	MINIMAL	181	3.8	LIGNO	Y	8	

Test	Date	Ca/S Molar Ratio	Humid. Outlet Set Point, °F	Humid. On, Off, or Minimal	Injection Level, ft	Nominal Coal S, wt %	Sorbent	Test Used As Data Point, Yes or No	Number of Ten-minute Averages in Test	Comments
LE-169	05/08/91	1.2	275	MINIMAL	181	3.8	LIGNO	Y	17	
LE-169a	05/08/91	1.7	275	MINIMAL	181	3.8	LIGNO	Y	8	
LE-169b	05/08/91	1.8	275	MINIMAL	181	3.8	LIGNO	Y	9	
LE-170	05/14/91	2.1	275	MINIMAL	181	3.8	LIGNO	Y	3	
LE-170a	05/14/91	1.6	275	MINIMAL	181	3.8	LIGNO	Y	4	
LE-170b	05/14/91	1.4	275	MINIMAL	181	3.8	LIGNO	Y	5	
LE-171	05/15/91	1.7	275	MINIMAL	181	3.8	LIGNO	Y	3	
LE-171a	05/15/91	1.7	275	MINIMAL	181	3.8	LIGNO	Y	8	
LE-172	05/16/91	1.2	275	MINIMAL	181	3.8	LIGNO	Y	4	
LE-173	05/23/91	1.6	145	ON	181	1.6	LIGNO	Y	7	
LE-174	05/24/91	1.3	145	ON	181	1.6	LIGNO	N		Coal sulfur?
LE-175	05/29/91	1.9	145	ON	181	1.6	LIGNO	Y	6	
LE-176	05/30/91	1.7	145	ON	181	1.6	LIGNO	Y	5	
LE-177	05/31/91	1.4	145	ON	181	1.6	LIGNO	Y	5	
LE-178	06/13/91	0.9	145	ON	181	1.6	LIGNO	Y	5	
LE-178a	06/13/91	2.0	145	ON	181	1.6	LIGNO	Y	7	
LE-179	06/13/91	2.2	145	ON	181	1.6	LIGNO	N		Went to two feeders at 13:50, flooding, questionable test
LE-180	06/14/91	2.2	145	ON	181	1.6	LIGNO	N		Zero no good
LE-181	06/17/91	2.0	145	ON	181	1.6	LIGNO	Y	4	
LE-182	06/18/91	1.3	145	ON	181	1.6	LIGNO	Y	11	
LE-183	06/18/91	1.6	145	ON	181	1.6	LIGNO	Y	6	
LE-184	06/24/91	2.1	275	MINIMAL	191	1.6	LIGNO	Y	5	
LE-185	06/25/91	1.6	275	MINIMAL	191	1.6	LIGNO	Y	12	
LE-185a	06/25/91	1.2	275	MINIMAL	191	1.6	LIGNO	Y	9	
LE-186	06/26/91	1.0	275	MINIMAL	191	1.6	LIGNO	Y	11	
LE-186a	06/26/91	1.7	275	MINIMAL	191	1.6	LIGNO	Y	3	
LE-187	06/28/91	1.7	275	MINIMAL	191	1.6	LIGNO	Y	19	
LE-187a	06/28/91	1.0	275	MINIMAL	191	1.6	LIGNO	Y	22	
LE-188	07/01/91	1.9	275	MINIMAL	191	1.6	LIGNO	Y	14	
LE-189	07/09/91	1.8	275	MINIMAL	181	3.8	CAL	Y	9	
LE-189a	07/09/91	1.4	275	MINIMAL	181	3.8	CAL	Y	17	
LE-190	07/10/91	1.0	275	MINIMAL	181	3.8	CAL	Y	5	
LE-190a	07/10/91	0.9	275	MINIMAL	181	3.8	CAL	Y	16	
LE-190b	07/10/91	1.3	275	MINIMAL	181	3.8	CAL	Y	18	

Test	Date	Ca/S Molar Ratio	Humid. Outlet Set Point, °F	Humid. On, Off, or Minimal	Injection Level, ft	Nominal Coal S, wt %	Sorbent	Test Used As Data Point, Yes or No	Number of Ten-minute Averages in Test	Comments
LE-191	07/12/91	1.4	275	MINIMAL	181	3.8	CAL	Y	14	
LE-192	07/12/91	1.2	275	MINIMAL	181	3.8	CAL	Y	12	
LE-193	07/15/91	2.2	275	MINIMAL	181	3.8	CAL	N		Very high coal sulfur, scrapped
LE-194	07/16/91	2.0	275	MINIMAL	181	3.8	CAL	Y	5	
LE-195	07/17/91	1.7	275	MINIMAL	181	3.8	CAL	N		Flooding
LE-196	07/18/91	1.5	275	MINIMAL	181	3.8	CAL	N		Flooding
LE-197	07/19/91	1.0	275	MINIMAL	181	3.8	CAL	N		Flooding, sulfur changed
LE-198	07/22/91	2.0	275	MINIMAL	181	1.6	CAL	N		Coal sulfur change
LE-199	07/24/91	0.8	275	MINIMAL	181	1.6	CAL	Y	15	
LE-200	07/25/91	1.8	275	MINIMAL	181	1.6	CAL	Y	9	
LE-201	08/01/91	1.0	275	MINIMAL	181	1.6	CAL	Y	8	
LE-202	08/01/91	1.2	275	MINIMAL	181	1.6	CAL	Y	16	
LE-203	08/02/91	1.4	275	MINIMAL	181	1.6	CAL	Y	8	
LE-204	08/02/91	1.6	275	MINIMAL	181	1.6	CAL	Y	13	
LE-205	08/02/91	2.0	275	MINIMAL	181	1.6	CAL	Y	4	
LE-206	08/06/91	2.2	275	MINIMAL	181	1.6	CAL	Y	18	
LE-207	08/07/91	2 0	275	MINIMAL	191	1.6	CAL	Y	12	
LE-208	08/07/91	..2	275	MINIMAL	191	1.6	CAL	Y	12	
LE-209	08/08/91	1.7	275	MINIMAL	191	1.6	CAL	Y	10	
LE-209a	08/08/91	1.4	275	MINIMAL	191	1.6	CAL	Y	8	
LE-210	08/09/91	0.9	275	MINIMAL	191	1.6	CAL	Y	10	
LE-210a	08/09/91	1.1	275	MINIMAL	191	1.6	CAL	Y	15	
LE-211	08/26/91	1.6	275	MINIMAL	191	1.6	CAL	N		Scrapped
LE-212	08/28/91	1.6	275	MINIMAL	181	3.8	CAL	N		Questionable test
LE-213	08/29/91	1.7	275	MINIMAL	181	3.8	CAL	N		Zero at -3.0%, questionable test
LE-214	08/30/91	1.7	275	MINIMAL	181	3.8	CAL	N		Coal sulfur changed

Total number of tests run	289	Shortest test in # of 10-min averages	3
		Longest test in # of 10-min averages	71
		Total number of data points	223
		Avg. length of test in # of 10-min averages	13.4

APPENDIX E: OPERATIONAL RECORD

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
04/27/90	24	21			
04/28/90	20.5	20.5			
04/29/90	0	0			
04/30/90	24	12.5			Unit coming on
05/01/90	24	18.5			
05/02/90	24	19.5			
05/03/90	13	13			
05/04/90	24	21			
05/05/90	22	22			
05/06/90	0	0			
05/07/90	0	0			
05/08/90	0	0			
05/09/90	0	0			
05/10/90	0	0			
05/11/90	0	0			
05/12/90	0	0			
05/13/90	0	0			
05/14/90	20	10	2		Hose Leak
05/15/90	24	17.5			
05/16/90	24	18			
05/17/90	24	20			
05/18/90	24	21			
05/19/90	24	24			
05/20/90	24	24			
05/21/90	24	18.5			
05/22/90	24	20			
05/23/90	24	20			
05/24/90	24	17			Change F/K pump sheave
05/25/90	24	19.5			
05/26/90	22	22			
05/27/90	0	0			
05/28/90	0	0			
05/29/90	22	15			Unit coming on

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
05/30/90	24	21.5			
05/31/90	24	20			
06/01/90	24	18	3		F/K flapper valve problems
06/02/90	22	22			
06/03/90	0	0			
06/04/90	20	12	3	3	Unit coming on, Centac compressor oil leak
06/05/90	24	19.5			
06/06/90	24	18			
06/07/90	24	20			
06/08/90	24	15.5	5		Lime hose leak
06/09/90	24	15	9		Repair same hose as yesterday
06/10/90	24	24			
06/11/90	24	20		24	Humid chamber clean out
06/12/90	24	21			
06/13/90	24	22.5			
06/14/90	24	21			
06/15/90	22	18			
06/16/90	1	1			
06/17/90	24	24			
06/18/90	24	19			
06/19/90	15	7	8		Unplug lime lines
06/20/90	18	13			Unit coming on
06/21/90	24	21.5			
06/22/90	21	16			
06/23/90	0	0			
06/24/90	0	0			
06/25/90	17	9			Unit coming on
06/26/90	14.5	6			Unit coming on
06/27/90	16	12.5			Unit coming on
06/28/90	24	18.5	1.5		Unplug lime lines
06/29/90	24	14	8		Unplug lime lines
06/30/90	23	23			
07/01/90	0	0			
07/02/90	24	8.5	8		Unit coming on, unplug lime lines
07/03/90	24	18.5			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
07/04/90	24	20			Ash transport system problems
07/05/90	24	14			
07/06/90	24	24			
07/07/90	22	22			
07/08/90	14	0	14		Plant unable to start LIMB equipment, F/K pump seized up
07/09/90	24	0	8		Pump still seized,unable to switch to spare train due to tag
07/10/90	24	4	9.5		Switched to spare train, seals blow on B-8 rotary valve
07/11/90	24	0	24		Repairing F/K pump
07/12/90	24	0	24		Repairing F/K pump
07/13/90	24	9	15		Repairing F/K pump
07/14/90	23	23			
07/15/90	1	0			Unit coming on
07/16/90	24	21			
07/17/90	24	19			Ran out of sorbent
07/18/90	24	7			
07/19/90	24	14			
07/20/90	4	4			
07/21/90	0	0			
07/22/90	0	0			
07/23/90	0	0			
07/24/90	0	0			
07/25/90	0	0			
07/26/90	0	0			
07/27/90	0	0			
07/28/90	0	0			
07/29/90	0	0			
07/30/90	0	0			
07/31/90	0	0			
08/01/90	0	0			
08/02/90	0	0			
08/03/90	0	0			
08/04/90	0	0			
08/05/90	0	0			
08/06/90	0	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
08/07/90	0	0			
08/08/90	0	0			
08/09/90	0	0			
08/10/90	0	0			
08/11/90	0	0			
08/12/90	0	0			
08/13/90	24	0			
08/14/90	19	4			
08/15/90	10	5			
08/16/90	0	0			
08/17/90	14	5			
08/18/90	0	0			
08/19/90	0	0			
08/20/90	13	13.5			Unit coming on
08/21/90	24	6.5			Ran out of sorbent
08/22/90	24	0			Waiting for dolomitic lime delivery
08/23/80	0	0			
08/24/90	14	6			
08/25/90	24	0			
08/26/90	24	0			
08/27/90	24	0			System 140™ down, no testing, LIMB available
08/28/90	24	0			System 140™ down, no testing, LIMB available
08/29/90	24	2			
08/30/90	24	3			
08/31/90	24	4.5			
09/01/90	14	0			
09/02/90	0	0			
09/03/90	0	0			
09/04/90	13	3			Ran out of sorbent
09/05/90	24	0			
09/06/90	24	0			
09/07/90	24	3			
09/08/90	0	0			
09/09/90	0	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
09/10/90	16	0			Unit coming on
09/11/90	24	1.5			
09/12/90	24	0.5			
09/13/90	24	2.5			
09/14/90	24	4			
09/15/90	22	0			
09/16/90	12	0			
09/17/90	24	4			
09/18/90	24	3.5			
09/19/90	24	4.5			
09/20/90	24	4			
09/21/90	24	2.5			
09/22/90	24	0			
09/23/90	8	0			
09/24/90	24	0			
09/25/90	24	1			
09/26/90	24	2.5			
09/27/90	24	3			
09/28/90	21	0			
09/29/90	0	0			
09/30/90	0	0			
10/01/90	16	0			
10/02/90	24	0			
10/03/90	24	3.5			Lime feed stops
10/04/90	24	13.5			Lime feed stops
10/05/90	24	11.5			
10/06/90	24	0			
10/07/90	24	0			
10/08/90	24	14			
10/09/90	24	24			
10/10/90	24	19.5			
10/11/90	24	20			
10/12/90	24	18.5			
10/13/90	24	24			
10/14/90	0	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
10/15/90	15.5	13			Unit coming on
10/16/90	23	18			
10/17/90	16	9			Unit coming on
10/18/90	20.5	20.5			
10/19/90	10	0			
10/20/90	0	0			
10/21/90	22	19			Unit coming on
10/22/90	24	20.5			
10/23/90	24	21			
10/24/90	24	21.5			
10/25/90	24	22			
10/26/90	24	21.5			
10/27/90	24	24			
10/28/90	24	24			
10/29/90	24	19			
10/30/90	24	21.5			
10/31/90	24	18.5	2		F/K pump not properly lubricated
11/01/90	24	3.5	20.5	20.5	Humid chamber clean up
11/02/90	24	0	24	24	Humid chamber clean up
11/03/90	24	0			
11/04/90	24	0			
11/05/90	24	7.5	16.5	16.5	Balance lance flows
11/06/90	24	20			
11/07/90	24	20			
11/08/90	24	12.5			Humidifier inspection
11/09/90	24	0			Humidifier inspection
11/10/90	21	0			
11/11/90	16	0			
11/12/90	24	14			Unit coming on
11/13/90	24	20.5			
11/14/90	24	20.5			
11/15/90	24	18.5	2	1	Centac trips
11/16/90	24	18.5			
11/17/90	24	16			
11/18/90	24	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
11/19/90	24	12			
11/20/90	24	21			
11/21/90	22	17.5			
11/22/90	0	0			
11/23/90	0	0			
11/24/90	0	0			
11/25/90	0	0			
11/26/90	16	10.5	3.5	3.5	Centac trips
11/27/90	24	20			
11/28/90	24	21			
11/29/90	24	20.5			
11/30/90	22	18.5			
12/01/90	15	0	15	15	Unable to start compressor
12/02/90	12	1	11	11	Unable to start compressor
12/03/90	24	19			
12/04/90	24	19			
12/05/90	24	19			Ash system problems
12/06/90	24	11			Ash system problems
12/07/90	24	17.5			
12/08/90	24	12			
12/09/90	0	0			
12/10/90	16	9.5			Unit coming on
12/11/90	24	17			
12/12/90	24	18.5			
12/13/90	24	20.5			
12/14/90	24	20			
12/15/90	21	21			
12/16/90	0	0			
12/17/90	19	11.5			Unit coming on
12/18/90	24	15	6		Acrison chute plugs
12/19/90	24	21			
12/20/90	24	21			
12/21/90	24	22			
12/22/90	0	0			
12/23/90	0	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
12/24/90	12	0			
12/25/90	24	0			
12/26/90	24	0			
12/27/90	24	0			
12/28/90	18	0			
12/29/90	0	0			
12/30/90	4	0			
12/31/90	24	0			
01/01/91	24	6		12	Booster water pump out
01/02/91	24	2	22		Feed silo baghouse plugs
01/03/91	24	7	17		Feed silo baghouse plugs
01/04/91	24	6	9		Feed silo baghouse plugs
01/05/91	24	0			
01/06/91	24	0			
01/07/91	24	5			
01/08/91	24	3			
01/09/91	24	4			
01/10/91	24	5			
01/11/91	24	6			
01/12/91	24	0			
01/13/91	24	0			
01/14/91	24	1.5			
01/15/91	24	7.5			
01/16/91	0	0			
01/17/91	17	3.5			
01/18/91	24	2.5			
01/19/91	24	0			
01/20/91	24	0			
01/21/91	24	3			
01/22/91	24	2			
01/23/91	24	0			
01/24/91	24	3			
01/25/91	24	2.5			
01/26/91	24	0			
01/27/91	24	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
01/28/91	24	3			
01/29/91	24	4.5			
01/30/91	24	5			
01/31/91	24	6.5			
02/01/91	24	13.5			Running out last of the limestone
02/02/91	14	0			
02/03/91	0	0			
02/04/91	18	7.5			Ash silo baghouse problems
02/05/91	24	11			Ash silo baghouse problems
02/06/91	24	21			
02/07/91	22	19			
02/08/91	0	0			
02/09/91	0	0			
02/10/91	0	0			
02/11/91	21	16			
02/12/91	24	21.5			
02/13/91	24	20			
02/14/91	24	21			
02/15/91	14	9			
02/16/91	24	18	4		Feeders would not refill
02/17/91	24	24			
02/18/91	24	21.5			
02/19/91	24	21.5			
02/20/91	24	21.5			
02/21/91	24	21.5			
02/22/91	24	24			
02/23/91	24	0			Ran out of sorbent
02/24/91	24	0			
02/25/91	24	11			
02/26/91	24	8			
02/27/91	24	3			
02/28/91	24	13			
03/01/91	16	8			
03/02/91	10	0			
03/03/91	0	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
03/04/91	8	1.5			Unit cycling
03/05/91	24	12			
03/06/91	24	9.5			
03/07/91	24	7			
03/08/91	24	4.5			
03/09/91	24	0			
03/10/91	24	0			
03/11/91	24	5			
03/12/91	24	9			
03/13/91	24	6			
03/14/91	24	0		16	Humid chamber clean up
03/15/91	24	0		15	Humid chamber clean up
03/16/91	17	0			
03/17/91	0	0			
03/18/91	0	0			
03/19/91	0	0			
03/20/91	0	0			
03/21/91	0	0			
03/22/91	20	3			
03/23/91	22	0			
03/24/91	0	0			
03/25/91	0	0			
03/26/91	0	0			
03/27/91	0	0			
03/28/91	14	0	6	6	Centac breaker problem
03/29/91	0	0			
03/30/91	0	0			
03/31/91	0	0			
04/01/91	20	4			
04/02/91	24	7			
04/03/91	24	8			
04/04/91	24	9			
04/05/91	19	12.5			
04/06/91	0	0			
04/07/91	0	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
04/08/91	0	0			
04/09/91	0	0			
04/10/91	9	0			
04/11/91	24	14			
04/12/91	15	13.5			
04/13/91	0	0			
04/14/91	0	0			
04/15/91	17	13			
04/16/91	24	18			
04/17/91	24	20			
04/18/91	24	20			
04/19/91	0	0			
04/20/91	0	0			
04/21/91	0	0			
04/22/91	20	13			
04/23/91	24	20.5			
04/24/91	16	13			
04/25/91	0	0			
04/26/91	0	0			
04/27/91	0	0			
04/28/91	0	0			
04/29/91	0	0			
04/30/91	0	0			
05/01/91	0	0			
05/02/91	0	0			
05/03/91	0	0			
05/04/91	0	0			
05/05/91	12	6			
05/06/91	24	20.5			
05/07/91	24	21			
05/08/91	21.5	17			
05/09/91	0	0			
05/10/91	0	0			
05/11/91	0	0			
05/12/91	0	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
05/13/91	0	0			
05/14/91	17.5	13			
05/15/91	24	19.5			
05/16/91	23.5	16			
05/17/91	8	0			
05/18/91	0	0			
05/19/91	0	0			
05/20/91	0	0			
05/21/91	0	0			
05/22/91	16	0			
05/23/91	24	4			
05/24/91	23	4			
05/25/91	0	0			
05/26/91	0	0			
05/27/91	0	0			
05/28/91	21	0			
05/29/91	24	3			
05/30/91	24	3.5			
05/31/91	24	5			
06/01/91	21	0			
06/02/91	0	0			
06/03/91	0	0			
06/04/91	0	0			
06/05/91	0	0			
06/06/91	0	0			
06/07/91	0	0			
06/08/91	0	0			
06/09/91	0	0			
06/10/91	20	0			
06/11/91	24	0	24	24	Centac problems
06/12/91	24	0	18	18	Centac problems
06/13/91	24	7			
06/14/91	24	3			
06/15/91	21	0			
06/16/91	0	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
06/17/91	20	4			
06/18/91	24	8			
06/19/91	14	0			
06/20/91	0	0			
06/21/91	9	0			
06/22/91	24	0			
06/23/91	24	0			
06/24/91	24	10.5			
06/25/91	24	13.5			
06/26/91	24	5			Centac trip, could restart but inspection tomorrow
06/27/91	24	0			Centac inspected
06/28/91	24	11			
06/29/91	24	0			
06/30/91	24	0			
07/01/91	24	13.5			
07/02/91	24	0			
07/03/91	24	0			
07/04/91	24	0			
07/05/91	24	9			
07/06/91	25	24			
07/07/91	24	24			
07/08/91	24	21			
07/09/91	24	16.5			
07/10/91	24	19			
07/11/91	24	20			
07/12/91	23	19			
07/13/91	11	11			
07/14/91	0	0			
07/15/91	15	9.5	1.5		Unit coming on, unplug lime lines
07/16/91	24	20			
07/17/91	24	19			
07/18/91	24	18.5			
07/19/91	24	12.5			
07/20/91	24	0			
07/21/91	6	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
07/22/91	24	4.5		16	Centac problems
07/23/91	24	4		24	Centac problems
07/24/91	24	3.5		16	Centac problems
07/25/91	24	5.5			
07/26/91	12	0			
07/27/91	16	0			
07/28/91	24	0			
07/29/91	8	0			
07/30/91	0	0			
07/31/91	0	0			
08/01/91	18	6			
08/02/91	24	5.5			
08/03/91	0	0			
08/04/91	0	0			
08/05/91	0	0			
08/06/91	21	5.5			
08/07/91	24	12.5			
08/08/91	24	5			
08/09/91	24	5.5			
08/10/91	22	0			
08/11/91	0	0			
08/12/91	0	0			
08/13/91	0	0			
08/14/91	0	0			
08/15/91	0	0			
08/16/91	0	0			
08/17/91	0	0			
08/18/91	0	0			
08/19/91	0	0			
08/20/91	0	0			
08/21/91	0	0			
08/22/91	0	0			
08/23/91	0	0			
08/24/91	0	0			
08/25/91	0	0			

Date	Time Boiler On, hr	Time LIMB On, hr	LIMB Time Unavailable, hr	Humid. Time Unavailable, hr	Comments
08/26/91	18.5	1.5			
08/27/91	24	9			
08/28/91	24	21			
08/29/91	24	21			
08/30/91	24	21.5			
11,784	7,709	3,521	344	265.5	Total time, hr
	–	–	4.5	3.4	Total time unavailable, % of boiler time on
	–	–	95.5	96.6	Total time available, % of boiler time on
	65.4	45.7	–	–	Total time on, % of total elapsed time

APPENDIX F: CONSUMABLES USAGE, WASTE DISPOSAL RATES, AND MOTOR LISTS

TABLE F-1. CONSUMABLES USAGE AND DISPOSAL RATES

	100 MWe			150 MWe		
Coal Sulfur, wt %	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
	Reagent Consumption, ton/yr					
1.5	17,082	12,384	12,706	25,623	18,562	19,058
2.5	23,413	23,687	20,860	42,620	35,549	31,291
3.5	39,858	37,324	29,014	59,787	56,000	43,519
	Soda Ash Usage, ton/yr					
1.5	-	1,651	-	-	2,477	-
2.5	-	3,160	-	-	4,740	-
3.5	-	4,982	-	-	7,473	-
	Waste Solids, ton/yr (dry)					
1.5	18,270	17,614	30,748	27,404	26,422	46,060
2.5	30,417	32,945	51,246	45,626	49,134	76,703
3.5	42,702	50,569	71,832	64,053	75,852	107,310
	Average Power Consumption, kW/hr					
1.5	630	1,197	2,333	642	1,726	3,265
2.5	640	1,167	2,590	672	1,689	3,465
3.5	671	1,140	2,754	722	1,689	3,877
	Water Consumption, gal/yr x 10^{-3}					
1.5	7,420	29,942	35,872	11,130	44,742	55,004
2.5	9,607	30,994	39,630	14,411	46,655	59,445
3.5	11,820	32,101	42,705	17,730	47,981	63,887
	Steam Usage, lb/yr x 10^{-3}					
1.5	25,555	-	-	31,299	-	-
2.5	25,555	-	-	31,299	-	-
3.5	25,555	-	-	31,299	-	-

continued

TABLE F-1. (continued)

	250MWe			500 MWe		
Coal Sulfur, wt %	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
	Reagent Consumption, ton/yr					
1.5	42,705	30,947	31,767	85,410	61,894	63,631
2.5	71,033	59,246	52,154	142,065	118,492	104,300
3.5	99,645	93,296	72,533	199,290	186,621	145,072
	Soda Ash Usage, ton/yr					
1.5	-	4,128	-	-	8,256	-
2.5	-	7,900	-	-	15,801	-
3.5	-	12,456	-	-	24,911	-
	Waste Solids, ton/yr (dry)					
1.5	45,673	44,321	76,641	91,346	88,359	153,072
2.5	76,043	82,079	127,616	152,087	164,158	254,885
3.5	106,756	126,136	178,555	213,511	252,557	356,672
	Average Power Consumption, kW/hr					
1.5	681	2,743	5,130	1,437	5,163	9,563
2.5	742	2,739	5,569	1,465	5,116	10,225
3.5	771	2,657	6,161	1,581	5,041	11,195
	Water Consumption, gal/yr x 10^{-3}					
1.5	18,551	74,690	91,560	37,101	149,715	183,119
2.5	24,018	77,649	99,076	48,037	154,957	198,151
3.5	29,550	80,075	108,592	59,099	160,499	213,183
	Steam Usage, lb/yr x 10^{-3}					
1.5	40,407	-	-	59,393	-	-
2.5	40,407	-	-	59,393	-	-
3.5	40,407	-	-	59,393	-	-

TABLE F-2. LIMB MOTOR LIST (150 MWe, 2.5 wt % S Coal)

Line No.	Service	Total Quantity Installed	Installed Horsepower (each)	Normal Quantity Operating	Normal Operating Time, hr	Total Operating Power, kW*
1	Lime Silo Baghouse	1	5.0	1	3	0.4
2	Fluidizing Air Blower	2	10.0	1	24	6.7
3	Fluidizing Air Dryer	1	3.0	1	24	2.0
4	Lime Feed Rotary Valve	2	2.0	1	24	1.3
5	Fuller-Kinyon Pump	2	15.0	1	24	10.1
6	Transport Blower	2	100.0	1	24	67.1
7	Booster Air Fan	1	125.0	1	24	83.9
8	Atomizing Air Compressor	2	600.0	1	24	381.1
9	Atomizing Air Compressor Cooling Water Pump	1	20.0	1	24	9.7
10	Atomizing Water Pump	2	15.0	1	24	9.7
11	Mechanical Exhauster	2	125.0	1	8	28.0
12	Ash Silo Bag Filter	1	5.0	1	8	1.1
13	Ash Silo Rotary Valve	1	1.5	1	4	0.1
14	Reversible Exhaust Fan	4	2.0	4	4	0.9
15	Sootblower	4	1.5	4	2	0.3
16	LIMB Area Sump Pump	2	20.0	1	2	1.0
17	LIMB Area Sump Mixer	1	1.5	1	2	0.1
18	Ash System Pug Mill	1	75.0	1	4	7.5
	Total					611.0
	Total, with an additional 10 percent for miscellaneous and support equipment					672.1

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[*] Normalized to a daily basis as: (Normal Quantity Operating)(Normal Operating Time, hr)(Operating Power, kW)/24 hr.

TABLE F-3. COOLSIDE MOTOR LIST (150 MWe, 2.5 wt % S Coal)

Line No.	Service	Total Quantity Installed	Installed Horsepower (each)	Normal Quantity Operating	Normal Operating Time, hr	Total Operating Power, kW*
1	Lime Silo Baghouse	1	5.0	1	2	0.3
2	Fluidizing Air Blower	2	10.0	1	24	6.7
3	Fluidizing Air Dryer	1	3.0	1	24	2.0
4	Lime Feed Rotary Valve	2	2.0	1	24	1.3
5	Fuller-Kinyon Pump	2	15.0	1	24	10.1
6	Transport Blower	2	100.0	1	24	67.1
7	Rotary Lump Grinder	1	10.0	1	4	1.1
8	Atomizing Air Compressor	2	1,750.0	1	24	1,304.2
9	Atomizing Water Pump	2	125.0	1	24	45.0
10	Mechanical Exhauster	2	125.0	1	5	17.5
11	Ash Silo Bag Filter	1	5.0	1	5	0.7
12	Ash Silo Rotary Valve	1	1.5	1	4	0.1
13	Caustic Metering Pump and Caustic Feed Pump	2	50.0	1	4	5.6
14	LIMB Area Sump Pump	2	20.0	1	2	1.0
15	LIMB Area Sump Mixer	1	1.5	1	2	0.1
16	Ash System Pug Mill	1	75.0	1	4	7.5
17	Ash Recycle Blower	1	60.0	1	24	40.3
18	Ash Recycle Rotary Valve	1	2.0	1	24	1.3
19	Ash Recycle Solids Pump	1	15.0	1	24	10.1
20	Inlet Damper Drive	2	3.5	1	0	0.0
21	Outlet Damper Drive	1	3.5	1	0	0.0
22	Isolation Damper Drive	2	3.5	1	0	0.0
23	Compressor Cooling Water Pump	1	20.0	1	24	13.8
	Total					1,535.8
	Total, with an additional 10 percent for miscellaneous and support equipment					1689.4

* Normalized to a daily basis as: (Normal Quantity Operating)(Normal Operating Time, hr)(Operating Power, kW)/24 hr.

TABLE F-4. LSFO MOTOR LIST (150 MWe, 2.5 wt % S Coal)

Line No.	Service	Total Quantity Installed	Installed Horsepower (each)	Normal Quantity Operating	Normal Operating Time, hr	Total Operating Power, kW*
1	Limestone Receiving Bin Vibrator	1	2.0	1	3	0.1
2	Bulk Storage Transfer Conveyor	1	15.0	1	3	0.8
3	Bulk Storage Transfer Bin Vibrator	1	2.0	1	12	0.6
4	Day Silo Transfer Conveyor	1	7.5	1	12	1.6
5	Day Silo Bin Vibrator	2	2.0	1	3	0.2
6	Ball Mill	2	250.0	1	24	156.6
7	Ball Mill Feeder	2	1.0	1	24	0.6
8	Mill Product Tank Mixer	2	2.0	2	24	2.2
9	Mill Product Pump	4	25.0	1	24	14.9
10	Lubrication Oil Pump	2	1.0	1	24	0.6
11	Limestone Slurry Storage Tank Mixer	1	7.5	1	24	4.5
12	Feed Slurry Pumps	2	7.5	1	24	3.7
13	Limestone Preparation Area Sump Pumps	2	20.0	1	2	1.0
14	Limestone Preparation Area Sump Mixer	1	1.5	1	24	0.6
15	ID Fans	1	3,500.0	1	24	1,916.4
16	Inlet Damper	1	11.7	1	0	0.0
17	Inlet Damper Seal Air Fan	2	20.0	1	24	11.2
18	Bypass Damper	1	11.7	1	0	0.0
19	Bypass Damper Seal Air Fan	2	20.0	1	24	11.2
20	Outlet Damper	1	11.7	1	0	0.0
21	Outlet Damper Seal Air Fan	2	10.0	1	24	5.6
22	Absorber Tank Mixers	3	40.0	3	24	78.3
23	Mist Eliminator Wash Pumps	2	25.0	1	24	16.9
24	Absorber Recirculation Pump #1	1	300.0	1	24	199.8
25	Absorber Recirculation Pump #2	1	350.0	1	24	221.5
26	Absorber Recirculation Pump #3	1	350.0	1	24	221.5
27	Absorber Recirculation Pump #4	1	350.0	1	24	239.[illegible]
28	Absorber Recirculation Pump #5	1	350.0	0	24	0.0
29	Waste Slurry Blowdown Pumps	2	20.0	1	24	11.[illegible]
30	Oxidation Air Compressor	2	350.0	1	24	223.7
31	Absorber Area Sump Pumps	2	30.0	1	2	1.3
32	Absorber Sump Mixer	1	10.0	1	24	6.0
33	Waste Slurry Tank Mixer	1	15.0	1	24	7.5
34	Vacuum Filter Feed Pump	2	7.5	1	24	3.7

continued

TABLE F-4. (continued)

Line No.	Service	Total Quantity Installed	Installed Horsepower (each)	Normal Quantity Operating	Normal Operating Time, hr	Total Operating Power, kW*
35	Flocculant Feed Pump	2	1.0	1	24	0.6
36	Clarifier Underflow Pump	2	3.0	1	24	1.1
37	Reclaimed Water Pumps	2	20.0	1	24	12.5
38	Vacuum Filter Drum Drive	2	1.5	1	24	0.6
39	Vacuum Filter Vacuum Pump	2	20.0	1	24	11.2
40	Vacuum Filter Filtrate Pump	2	7.5	1	24	3.7
41	Vacuum Filter Agitator	2	1.5	1	24	0.6
42	Vacuum Filter Cake Blower	2	3.0	1	24	1.5
43	Collecting Conveyor	1	5.0	1	24	2.4
44	Forwarding Conveyor	1	5.0	1	24	2.4
45	Radial Stacker	1	7.5	1	24	3.4
46	Dewatering Area Sump Mixer	1	1.5	1	24	0.8
47	Dewatering Area Sump Pumps	2	20.0	1	2	1.0
48	Instrument Air Compressor	2	85.0	1	24	50.7
49	Instrument Air Dryer	2		1	24	6.6
50	Elevator	1	50.0	1	2	2.5
	Total					3,464.9
	Total, with an additional 50 kW for miscellaneous and support equipment					3,514.9

[*] Normalized to a daily basis as: (Normal Quantity Operating)(Normal Operating Time, hr)(Operating Power, kW)/24 hr.

APPENDIX G: LIMB COST ESTIMATE EXAMPLE FOR 150 MWe ($ x 10^{-3} except as noted)

	1.5% S		2.5% S		3.5% S	
DESCRIPTION	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST
Lime Handling System						
Acid Tank - Lined	1		1		1	
Booster Air Ductwork	Lot		Lot		Lot	
Booster Air Fan	1		1		1	
Injection Nozzles	8		8		8	
Lime Distribution Bottle	1		1		1	
Lime Handling Equipment	Lot		Lot		Lot	
Lime Silo	1		1		1	
Lime Silo Area Sump	1		1		1	
Lime Silo Support Steel	Lot		Lot		Lot	
pH Meters	2		2		2	
Sump Mixer	1		1		1	
Sump Pumps	2		2		2	
Sump Steel and Level Transmitters	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		1215.6		1612.8		1653.8
Humidification System						
Air Receiver	1		1		1	
Air/Water Distribution Headers	Lot		Lot		Lot	
Atomization Air Compressor	2		2		2	
Atomizers	24		24		24	
Atomizing Water Pump	2		2		2	
Compressor Cooling Water Pump	1		1		1	
Duplex Water Strainer	3		3		3	
Flow Model Testing	Lot		Lot		Lot	
Humidifier Enclosure Steel	Lot		Lot		Lot	
Humidification Enclosure	2		2		2	
Lance Rapper System	Lot		Lot		Lot	
Spray Lances	8		8		8	
Water Tank	1		1		1	
Prime Contractor's Costs						
Area Subtotal		877.8		877.8		877.8

	1.5% S		2.5% S		3.5% S	
DESCRIPTION	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST
Enclosures, Site and Tract Work						
LIMB Equipment Enclosure Steel	Lot		Lot		Lot	
LIMB Equipment Enclosure	1		1		1	
Site Work, Piles, and Concrete	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		2008.9		2009.1		2009.0
Electrical Equipment						
Communication Equipment	Lot		Lot		Lot	
Electrical Work	Lot		Lot		Lot	
Heat Tracing	Lot		Lot		Lot	
Instrumentation and Controls	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		1044.0		1044.0		1044.0
Ash Handling						
Ash Handling System	Lot		Lot		Lot	
Reversible Exhaust Fan	4		4		4	
Prime Contractor's Costs						
Area Subtotal		587.4		587.4		587.4
Miscellaneous						
Assorted Piping	Lot		Lot		Lot	
Assorted Valves	Lot		Lot		Lot	
Eyewash and Safety Showers	6		6		6	
Fire Protection System	Lot		Lot		Lot	
Instrument Air System	1		1		1	
Pipe Rack	1		1		1	
Sootblowers and Controls	4		4		4	
Television System	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		583.9		583.9		583.9
Installed Equipment Cost (IEC)		6392.6		6794.7		6836.0

DESCRIPTION	1.5% S QUANTITY	1.5% S INSTALLED COST	2.5% S QUANTITY	2.5% S INSTALLED COST	3.5% S QUANTITY	3.5% S INSTALLED COST
Engineering @ 10% of Total Area Capital		639.3		679.5		683.6
General Facilities Capital @ 5% of Total Area Capital		319.6		339.7		341.8
Project Contingency @ 18% of Total Area Capital		1389.4		1476.8		1485.8
Process Contingency @ 5% of Total Area Capital		367.6		390.7		393.1
Total Plant Investment (TPI)		9108.4		9681.4		9740.2
Preproduction Costs @ 5% of Total Plant Investment		455.4		484.1		487.0
Inventory Costs @ 0.5% of Total Plant Investment, Plus One Month's Consumables		337.7		503.2		668.6
TOTAL CAPITAL REQUIREMENT (TCR)		9901.6		10668.6		10895.9
TOTAL CAPITAL REQUIREMENT, $/kW net		66.01		71.12		72.64
Fixed Operating and Maintenance Costs						
Maintenance Material		218.6		232.4		233.8
Maintenance Labor		145.7		154.9		155.8
Operating Labor		0.0		0.0		0.0
Administration and Overhead		43.7		46.5		46.8
Subtotal Fixed Operating and Maintenance Costs		408.1		433.7		436.4
Annual Variable Operating Costs for Consumables						
Water @ $0.69/10^3 gal		7.7		9.9		12.2
Steam @ $4.09/10^3 lb		128.0		128.0		128.0
Lime @ $64/ton delivered		1639.9		2727.7		3826.4
Acid @ $102.40/ton delivered		10.2		10.2		10.2
Electric cost @ $0.058/kWh		212.1		222.0		238.5
LIMB ash disposal @ $9.25/ton dry		547.2		716.4		887.5
Fly ash disposal credit @ $9.25/ton dry		-293.7		-294.4		-295.0
Cost due to 0.23% loss in boiler efficiency @ $34.09/ton coal		27.5		27.5		27.5
Subtotal Annual Consumables Cost		2278.9		3547.3		4835.3
Total Operating and Maintenance Cost		2687.0		3981.1		5271.7
Carrying Charges @ 13.9% of Total Capital Required		1376.3		1482.9		1514.5
ANNUAL LEVELIZED COST		4063.3		5464.0		6786.2
SO$_2$ Removed, ton/yr		6226		10499		14720
ANNUAL LEVELIZED COST, $/ton SO$_2$ removed		653		520		461

APPENDIX H: COOLSIDE COST ESTIMATE EXAMPLE FOR 150 MWe ($ x 10^{-3} except as noted)

	1.5% S		2.5% S		3.5% S	
DESCRIPTION	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST
Lime Handling System						
Acid Tank - Lined	1		1		1	
Lime Distribution Bottle	1		1		1	
Lime Handling Equipment	Lot		Lot		Lot	
Lime Silo	1		1		1	
Lime Silo Area Sump	1		1		1	
Lime Silo Support Steel	Lot		Lot		Lot	
pH Meters	2		2		2	
Sump Mixer	1		1		1	
Sump Pumps	2		2		2	
Sump Steel & Level Transmitters	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		1194.5		1624.5		2090.5
Humidification System						
Air Receiver	1		1		1	
Atomization Air Compressor	2		2		2	
Atomizers	159		164		166	
Atomizing Water Pump	2		2		2	
Compressor Cooling Water Pump	1		1		1	
Dampers	Lot		Lot		Lot	
Duplex Water Strainer	3		3		3	
Expansion Joints	Lot		Lot		Lot	
Flow Model Testing	Lot		Lot		Lot	
Humidifier Enclosure Steel	Lot		Lot		Lot	
Humidifier and Duct Steel	Lot		Lot		Lot	
Humidification Enclosure	2		2		2	
Humidifier and Ductwork	Lot		Lot		Lot	
Insulation and Lagging Material	Lot		Lot		Lot	
Soda Ash System	Lot		Lot		Lot	
Spray Lances	21		21		21	
Spray Lance Rappers	21		21		21	
Water Tank	1		1		1	
Prime Contractor's Costs						
Area Subtotal		5311.4		5398.2		5473.9

	1.5% S		2.5% S		3.5% S	
DESCRIPTION	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST
Enclosures and Site Work						
Coolside Equipment Enclosure Steel	Lot		Lot		Lot	
Coolside Equipment Enclosure	1		1		1	
Site Work, Piles, and Concrete	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		2171.5		2172.6		2173.6
Electrical Equipment						
Communication Equipment	Lot		Lot		Lot	
Electrical Work	Lot		Lot		Lot	
Heat Tracing	Lot		Lot		Lot	
Instrumentation and Controls	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		1234.6		1235.3		1235.9
Ash Handling						
Ash Distribution Bottle	1		1		0	
Ash Handling System	Lot		Lot		Lot	
Ash Recycle System	Lot		Lot		0	
Rotary Lump Grinders	1		1		1	
Prime Contractor's Costs						
Area Subtotal		963.3		888.2		679.0
Miscellaneous						
Assorted Piping	Lot		Lot		Lot	
Eyewash and Safety Showers	6		6		6	
Fire Protection System	Lot		Lot		Lot	
Instrument Air System	1		1		1	
Pipe Rack	1		1		1	
Assorted Valves	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		424.4		424.6		424.8
Installed Equipment Cost (IEC)		11417.3		11865.7		12203.2

	1.5% S		2.5% S		3.5% S	
DESCRIPTION	**QUANTITY**	**INSTALLED COST**	**QUANTITY**	**INSTALLED COST**	**QUANTITY**	**INSTALLED COST**
Engineering @ 10% of Total Area Capital		1141.7		1186.6		1220.3
General Facilities Capital @ 5% of Total Area Capital		570.9		593.3		610.2
Project Contingency @ 18% of Total Area Capital		2481.6		2579.0		2652.4
Process Contingency @ 5% of Total Area Capital		656.5		682.3		701.7
Total Plant Investment (TPI)		16267.9		16906.8		17387.7
Preproduction Costs @ 5% of Total Plant Investment		813.4		845.3		869.4
Inventory Costs @ 0.5% of Total Plant Investment, Plus One Month's Consumables		393.2		606.9		863.0
TOTAL CAPITAL REQUIREMENT (TCR)		17474.5		18359.1		19120.2
TOTAL CAPITAL REQUIREMENT, $/kW net		116.50		122.39		127.47
Fixed Operating and Maintenance Costs						
Maintenance Material		390.4		405.8		417.3
Maintenance Labor		260.3		270.5		278.2
Operating Labor		202.8		202.8		202.8
Administration and Overhead		138.9		142.0		144.3
Subtotal Fixed Operating and Maintenance Costs		992.4		1021.1		1042.6
Annual Variable Operating Costs for Consumables						
Water @ $0.69/10^3 gal		30.9		32.2		33.1
Lime @ $64/ton delivered		1188.0		2275.8		3584.0
Acid @ $102.40/ton delivered		10.2		10.2		10.2
Electricity cost @ $0.58/kWh		570.0		557.9		551.4
Coolside ash disposal @ $9.25/ton dry		521.4		732.1		979.6
Fly ash disposal credit @ $9.25/ton dry		-277.0		-277.6		-278.0
Na_2CO_3 cost @ $157/ton delivered		388.9		744.2		1173.3
Subtotal Annual Consumables Cost		2432.4		4074.8		6053.6
Total Operating and Maintenance Cost		3424.9		5095.9		7096.2
Carrying Charges @ 13.9% of Total Capital Required		2429.0		2551.9		2657.7
ANNUAL LEVELIZED COST		5853.8		7647.8		9753.9
SO_2 Removed, ton/yr		7345		12255		17125
ANNUAL LEVELIZED COST, $/ton SO_2 removed		797		624		570

APPENDIX I: LSFO COST ESTIMATE EXAMPLE FOR 150 MWe ($ x 10^{-3} except as noted)

	1.5% S		2.5% S		3.5% S	
DESCRIPTION	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST
Limestone Storage and Preparation System						
Limestone Receiving Bin	1		1		1	
Bulk Storage Transfer Conveyor	1		1		1	
Bulk Storage Area Enclosure	1		1		1	
Pilings for Enclosure Walls	Lot		Lot		Lot	
Bulk Storage Transfer Bin	1		1		1	
Day Silo Transfer Conveyor	1		1		1	
Limestone Day Silo	1		1		1	
Pilings for Day Silo	Lot		Lot		Lot	
Vibrating Bin Bottom	2		2		2	
Concrete Retaining Walls	Lot		Lot		Lot	
Ball Mill System	Lot		Lot		Lot	
Weigh Belt Feeders						
Ball Mill Feed Chutes						
Ball Mills and Charge						
Mill Product Tanks						
Mill Product Tank Mixers						
Mill Product Pumps/Drives						
Cyclone Classifiers						
Lubrication Oil Systems						
Gear Lubrication Systems						
Limestone Slurry Storage Tank	1		1		1	
Limestone Slurry Storage Mixer	1		1		1	
Feed Slurry Pumps	2		2		2	
Drainage Sump	With Enclosure		With Enclosure		With Enclosure	
Sump Mixer	1		1		1	
Sump Pumps	2		2		2	
Piping	Lot		Lot		Lot	
Valves	Lot		Lot		Lot	
Instrumentation	With Electricals		With Electricals		With Electricals	
Foundations for Slurry Tank	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		4130.4		4246.7		4382.0

DESCRIPTION	1.5% S		2.5% S		3.5% S	
	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST
Fans and Ductwork						
ID Fans	1		1		1	
ID Fan Outlet Duct: 1/4" A36	Lot		Lot		Lot	
Bypass Duct: 1/4" A36	Lot		Lot		Lot	
Absorber Entrance Nozzle: C-276	1		1		1	
Absorber Outlet Duct: 3/16" 317LMN	1		1		1	
Guillotine Dampers - Inlet	1		1		1	
Guillotine Dampers - Bypass	1		1		1	
Guillotine Dampers - Outlet	1		1		1	
Insulation and Lagging	Lot		Lot		Lot	
Support and Platform Steel	Lot		Lot		Lot	
Support Steel Foundations	Lot		Lot		Lot	
Expansion Joints	Lot		Lot		Lot	
Fan Foundations	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		4449.6		4450.3		4451.6
Absorber System						
Absorber Module	1		1		1	
Absorber Reaction Tank	1		1		1	
Foundations for Towers	Lot		Lot		Lot	
Pilings	Lot		Lot		Lot	
Absorber Internals:						
Spray Headers (FRP)	Lot		Lot		Lot	
Mist Eliminator Wash Headers	Lot		Lot		Lot	
Sparge Header	Lot		Lot		Lot	
Spray Nozzles	Lot		Lot		Lot	
Distribution Trays	Lot		Lot		Lot	
Supports(CS Rubber Coated)	Lot		Lot		Lot	
Mist Eliminators	Lot		Lot		Lot	
Mixers	3		3		3	
Absorber Recirculating Pumps	5		5		5	
Pilings for Absorber Recirculation Pumps	Lot		Lot		Lot	
Mist Eliminator Wash Tank/Linings	1		1		1	
Mist Eliminator Wash Tank/Foundations	1		1		1	
Mist Eliminator Wash Pumps	2		2		2	
Mist Eliminator Wash Strainer	1		1		1	

	1.5% S		2.5% S		3.5% S	
DESCRIPTION	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST
Absorber System (continued)						
Waste Slurry Blowdown Pumps	2		2		2	
Oxidation Air Compressors	2		2		2	
Overflow Pipe (FRP)	1		1		1	
Absorber Area Sump	With Enclosure		With Enclosure		With Enclosure	
Sump Pumps	2		2		2	
Sump Mixer	1		1		1	
Piping	Lot		Lot		Lot	
Valves	Lot		Lot		Lot	
Instrumentation	With Electricals		With Electricals		With Electricals	
Flow Model Testing	Lot		Lot		Lot	
Pump Foundations	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		6109.9		6188.1		6608.4
Dewatering System						
Hydroclone Clusters	2		2		2	
Waste Slurry Tank	1		1		1	
Waste Slurry Tank Foundation	Lot		Lot		Lot	
Waste Slurry Tank Mixer	1		1		1	
Vacuum Filter Feed Pump	2		2		2	
Clarifier	1		1		1	
Flocculant Feed System	1		1		1	
Clarifier Underflow Pump	2		2		2	
Reclaim Water Storage Tank	1		1		1	
Reclaim Water Storage Tank Foundation	Lot		Lot		Lot	
Reclaim Water Pumps	2		2		2	
Vacuum Filter with Vacuum Pumps, Receiver, and Air Separator	2		2		2	
Collecting Conveyor	1		1		1	
Forwarding Conveyor	1		1		1	
Radial Stacker	1		1		1	
Gypsum Stack Out - Asphalt	Lot		Lot		Lot	
Sump Pumps	2		2		2	
Sump Mixer	1		1		1	
Piping	Lot		Lot		Lot	
Valves	Lot		Lot		Lot	
Instrumentation	With Electricals		With Electricals		With Electricals	

	1.5% S		2.5% S		3.5% S	
DESCRIPTION	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST	QUANTITY	INSTALLED COST
Dewatering System (continued)						
Pump and Miscellaneous Foundations	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		2302.8		2419.7		2662.1
Dewatering Area Enclosure						
Enclosures	Lot		Lot		Lot	
Pilings	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		726.2		726.4		726.6
Limestone Area Enclosure						
Limestone Area Enclosure	1		1		1	
Concrete Slab and Trenches	With Enclosure		With Enclosure		With Enclosure	
Pilings	Lot		Lot		Lot	
Heating and Ventilation	Lot		Lot		Lot	
Lighting	With Enclosure		With Enclosure		With Enclosure	
Hoists and Trolleys	2		2		2	
Roll-up Door	1		1		1	
Drainage Sump	With Enclosure		With Enclosure		With Enclosure	
Foundations and Concrete Work	With Enclosure		With Enclosure		With Enclosure	
Prime Contractor's Costs						
Area Subtotal		1644.1		1644.3		1644.8
Absorber Area Enclosure						
Absorber Enclosure	Lot		Lot		Lot	
Pilings	Lot		Lot		Lot	
Concrete Slab and Trenches	With Enclosure		With Enclosure		With Enclosure	
Support and Platform Steel	With Enclosure		With Enclosure		With Enclosure	
HVAC Control Room/FGD Area	Lot		Lot		Lot	
Lighting	With Enclosure		With Enclosure		With Enclosure	
Drainage Sump	With Enclosure		With Enclosure		With Enclosure	
Hoists and Trolleys	With Enclosure		With Enclosure		With Enclosure	
Control Room	With Enclosure		With Enclosure		With Enclosure	
Electrical Equipment Room	With Enclosure		With Enclosure		With Enclosure	
Restroom Facilities	With Enclosure		With Enclosure		With Enclosure	

DESCRIPTION	1.5% S QUANTITY	1.5% S INSTALLED COST	2.5% S QUANTITY	2.5% S INSTALLED COST	3.5% S QUANTITY	3.5% S INSTALLED COST
Absorber Area Enclosure (continued)						
Roll-up Doors	With Enclosure		With Enclosure		With Enclosure	
Elevator	1		1		1	
Prime Contractor's Costs						
Area Subtotal		3286.9		3287.4		3288.4
Electrical Equipment						
Controls, Operating Interface/Console, and Related Equipment	Lot		Lot		Lot	
Prime Contractor's Costs						
Area Subtotal		5033.4		5034.2		5035.7
Miscellaneous						
Pipe Rack, 150 ft	2		2		2	
Instrument Air System	2		2		2	
Seal Water System	Lot		Lot		Lot	
Service Water System	Lot		Lot		Lot	
Service Air System	Lot		Lot		Lot	
Fire Protection System	Lot		Lot		Lot	
Eyewash/Safety Showers/Pipe	14		14		14	
Wet Stack	1		1		1	
Stack Foundation	1		1		1	
Prime Contractor's Costs						
Area Subtotal		3723.8		3724.4		3725.5
Installed Equipment Cost (IEC)		31653.8		31972.2		32786.0

DESCRIPTION	1.5% S QUANTITY	1.5% S INSTALLED COST	2.5% S QUANTITY	2.5% S INSTALLED COST	3.5% S QUANTITY	3.5% S INSTALLED COST
Engineering @ 10% of Total Area Capital		3165.4		3197.2		3278.6
General Facilities Capital @ 5% of Total Area Capital		1582.7		1598.6		1639.3
Project Contingency @ 15% of Total Area Capital		5596.8		5653.1		5797.0
Process Contingency @ 2.5% of Total Area Capital		910.0		919.2		942.6
Total Plant Investment (TPI)		42908.7		43340.4		44443.5
Interest during Construction (IDC) @ 3.05% of Total Plant Investment, 2 yr Construction Period		1308.7		1321.9		1355.5
Preproduction Costs @ 5% of Total Plant Investment		2145.4		2167.0		2222.2
Inventory Costs @ 0.5% of Total Plant Investment, Plus One Month's Consumables		435.4		497.1		571.2
Land		44.5		44.5		44.5
TOTAL CAPITAL REQUIREMENT (TCR)		46842.6		47370.9		48636.8
TOTAL CAPITAL REQUIREMENT, $/kW net		312.28		315.81		324.25
Fixed Operating and Maintenance Costs						
Maintenance Material		1029.8		1040.2		1066.6
Maintenance Labor		686.5		693.4		711.1
Operating Labor @ 3 per Shift		608.4		608.4		608.4
Administration and Overhead		388.5		390.5		395.8
Subtotal Fixed Operating and Maintenance Costs		2713.2		2732.5		2782.0
Annual Variable Operating Costs for Consumables						
Water @ $0.69/$10^3$ gal		37.9		41.0		44.1
Limestone @ $17/ton delivered		324.0		532.0		739.8
Electricity @ $0.058/kWh		1078.3		1144.3		1280.4
Gypsum disposal cost @ $9.43/ton dry		282.3		470.1		657.8
Subtotal Annual Consumables Cost		1722.5		2187.4		2722.1
Total Operating and Maintenance Cost		4435.7		4920.0		5504.0
Carrying Charges @ 13.9% of Total Capital Required		6511.1		6584.6		6760.5
ANNUAL LEVELIZED COST		10946.8		11504.5		12264.6
SO_2 Removed, ton/yr		9970		16618		23263
ANNUAL LEVELIZED COST, $/ton SO_2 removed		1098		692		527

END

DATE
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3 / 15 / 93