ENHANCING THE USE OF COALS BY GAS REBURNING-SORBENT INJECTION

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Volume 2- Gas Reburning-Sorbent Injection at Hennepin Unit 1 Illinois Power Company

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ABSTRACT

A Clean Coal Technology (CCT) Project has been completed at a 71 MW_e (net) tangentially fired unit in Hennepin, Illinois. Energy and Environmental Research Corporation (EER) has demonstrated Gas Reburning-Sorbent Injection (GR-SI) to reduce emissions of NO_x and SO_2, by 60 and 50%, respectively. GR-SI has also been demonstrated at a cyclone fired unit in Springfield, Illinois, in the same project, as detailed in Volume 4 of this report. The primary sponsor was the Department of Energy, with co-funding provided by the Gas Research Institute and the Illinois State Department of Commerce and Community Affairs.

The host unit was Illinois Power's Hennepin Station Unit 1 which normally fires an Illinois bituminous coal containing approximately 3% sulfur. EER designed and retrofitted the GR-SI system, then evaluated its performance over a year-long demonstration. With GR-SI, natural gas is injected into the furnace above the coal burners to reduce NO_x to N_2 and dry hydrated lime sorbent is injected into the upper furnace for SO_2 capture. Natural gas is injected, at a rate corresponding to 18% of the total heat input, to form a fuel rich reducing zone in which NO_x formed in the coal zone is reduced to N_2. Overfire (burnout) air is injected at a higher point in the boiler to burnout fuel combustibles under overall fuel lean conditions. Hydrated Lime, $Ca(OH)_2$, is injected into the upper furnace cavity through front and side wall injectors, at a rate corresponding to a calcium (sorbent) to sulfur (coal) molar ratio of 1.75.

Over the year-long GR-SI demonstration the average NO_x reduction was 67%, from the 0.75 lb/10^6Btu (323 mg/MJ) coal baseline, and the average SO_2 reduction was 53%, from the 5.3 lb/10^6Btu (2280 mg/MJ) coal baseline. The average calcium utilization with Linwood hydrated lime sorbent was 24%. Low emissions of CO were maintained, with an average of 57 ppm (@ 3% O_2). Reduction of CO_2 emissions of 7%, from 15.6 to 14.5% (@ 3% O_2), was also measured. Short-term tests indicated GR-SI resulted in significant reduction in emissions of HCl (60 to 86% reduction) and HF (94 to 100% reduction). Humidification was used to effectively limit particulate matter emissions, which ranged from 0.012 to 0.025 lb/MBtu (5.2 to 10.8 mg/MJ) during GR-SI operation. Three advanced sorbents prepared by EER and the Illinois State Geological Survey showed significantly improved utilizations (31 to 38% at Ca/S of 1.75).

Under GR-SI at full load, the thermal efficiency decreased by 1.38% to 85.38%, while GR alone resulted in a reduction of 0.76% to 86.00%. The main steam temperatures were relatively constant at 995°F (535°C) during GR-SI, 994°F (534°C) during GR, and 993°F (533°C) during baseline. Other impacts of GR-SI and GR include an increase in superheat attemperation spray, a shift in the heat absorption profile, and an increase in the boiler exit gas temperature. Impacts on other areas of unit operation/performance were evaluated, with no significant deleterious impacts determined.

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LIST OF ABBREVIATIONS

ASME	American Society of Mechanical Engineers
ASME.PTC	American Society of Mechanical Engineers Performance Test Code
ASTM	American Society of Testing Materials
B&W	Babcock and Wilcox
BL	Baseline
BPMS	Boiler Performance Monitoring System
BSF	Boiler Simulator Furnace
CAAA	Clean Air Act Amendments
CCT	Clean Coal Technology
CEMS	Continuous Emissions Monitoring System
CF	Cleanliness Factor
CFLW	Coal Flow
CFR	Code of Federal Regulations
CILCO	Central Illinois Light Company
CRH	Cold Reheater
CTA	Coal Theoretical Air
CWLP	City Water Light and Power
DOE	United States Department of Energy
EA	Excess Air
EHSS	Environmental Health Safety and Socioeconomic
EER	Energy and Environmental Research Corporation
EIV	Environmental Information Volume
EMP	Environmental Monitoring Plan
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FGR	Flue Gas Recirculation
FP	Flag Point
GFLW	Gas Flow
GR-LNB	Gas Reburning-Low NO_x Burners

GR	Gas Reburning
GRI	Gas Research Institute
GR-PS	Gas Reburning-Promoted Sorbent
GR-SI	Gas Reburning-Sorbent Injection
GTA	Gas Theoretical Air
HAR	Heat Absorption Ratio
HHV	Higher Heating Value
HSAHL	High Surface Area Hydrated Lime
IEPA	Illinois Environmental Protection Agency
ISGS	Illinois State Geological Survey
LOI	Loss on Ignition
IP	Illinois Power Company
MDL	Method Detection Limit
MGD	Million Gallon per Day
MMD	Mass Mean Diameter
ND	Not Detected
NG	Natural Gas
NPDES	National Pollution Discharge Elimination System
OEM	Original Equipment Manufacturer
OFA	Overfire Air
OSHA	Occupational Safety and Health Administration
NSPS	New Source Performance Standards
PS	Promoted Sorbent
PSCo	Public Service of Colorado
PSD	Prevention of Significant Deterioration
PSH	Primary Superheater
PTC	Performance Test Code
QAMS	Quality Assurance Management Staff
QAO	Quality Assurance Officer
QAPP	Quality Assurance Project Plan
QA/QC	Quality Assurance/Quality Control

RCRA	Resource Conservation and Recovery Act
RH	Reheat
SCA	Specific Collection Area
SH	Superheat
SI	Sorbent Injection
SMD	Sauter Mean Diameter
SR	Stoichiometric Ratio
TAFLW	Total Air Flow
TDS	Total Dissolved Solids
TSP	Total Suspended Particles
TSS	Total Suspended Solids
U.S. EPA	United States Environmental Protection Agency
UT	Ultrasonic Thickness

LIST OF UNITS

acf	Actual Cubic Foot
acfm	Actual Cubic Foot per Minute
Btu/hr ft^3	British Thermal Unit per Hour per Cubic Foot
Btu/kWh	British Thermal Unit per Kilowatt-Hour
Btu/scf	British Thermal Unit per Standard Cubic Foot
°C	Degree Celcius
cm	Centimeter
db	Decibel
dscfm	Dry Standard Cubic Foot per Minute
°F	Degree Fahrenheit
ft^2	Square Foot
ft^2/1000 acfm	Square Foot per Thousand Actual Cubic Feet per Minute
ft^3	Cubic Foot
ft/s	Foot per Second
g	Gram
g/s	Gram per Second
g/cm^3	Gram per Cubic Centimeter
g/dscm	Gram per Dry Standard Cubic Meter
gpm	Gallon per Minute
gr/dscf	Grain per Dry Standard Cubic Foot
HP	Horsepower
in	Inch
kg/m^3	Kilogram per Cubic Meter
kg/s	Kilogram per Second
kJ/kWH	Kilojoule per Kilowatt-Hour
klb/hr	Thousand Pounds per Hour
kPa	Kilopascal
KVA	Kilovolt-Ampere
kVDC	Kilovolt Direct Current

lb/ft^3	Pound per Cubic Foot
lb/hr	Pound per Hour
lb/min	Pound per Minute
$lb/10^6Btu$	Pound per Million British Thermal Units
l/s	Liter per Second
μ/m^3	Microgram per Cubic Meter
m	Meter
m^2	Square Meter
$m^2/ m^3/s$	Square Meter per Cubic Meter per Second
m/s	Meter per Second
mA	Milliampere
$10^6Btu/hr$	Million British Thermal Units per Hour
mgd	Million Gallons per Day
mg/l	Milligram per Liter
mg/m^3	Milligram per Cubic Meter
mg/MJ	Milligram per Megajoule
mil	Onethousandth Inch
MJ/s	Megajoule per Second
mld	Megaliter per Day
mm	Millimeter
MW_e	Megawatt Electric
Nm^3/s	Normal Cubic Meter per Second
MSCF	Thousand Standard Cubic Feet
ohm-cm	Ohm-Centimeter
psig	Pound per Square Inch (Gauge)
ppm	Part per Million
scfh	Standard Cubic Foot per Hour
scf/lb	Standard Cubic Foot per Pound
scfm	Standard Cubic Foot per Minute
scf/scf	Standard Cubic Foot per Standard Cubic Foot
ton/yr	Ton per Year

tonne/a	Metric Ton per Year
V	Volt
'	Foot
"	Inch
%	Percent

LIST OF SYMBOLS

Ag	Silver
Al_2O_3	Aluminum Oxide (Alumina)
As	Arsenic
B	Boron
Ba	Barium
C	Carbon
Ca	Calcium
$CaCO_3$	Calcium Carbonate
$CaCl_2$	Calcium Chloride
CaF_2	Calcium Fluoride
CaO	Calcium Oxide
$Ca(OH)_2$	Calcium Hydroxide
Ca/S	Calcium (Sorbent) to Sulfur (Coal) Molar Ratio
$CaSO_3$	Calcium Sulfite
$CaSO_4$	Calcium Sulfate
Cd	Cadmium
CH_4	Methane
C_2H_6	Ethane
C_3H_8	Propane
C_4H_{10}	Butane
C_5H_{10}	Pentane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Cr	Chromium
Fe	Iron
Fe_2O_3	Ferric Oxide
H_2	Hydrogen (Molecular)
HC	Hydrocarbon
HCl	Hydrogen Chloride

HF	Hydrogen Fluoride
Hg	Mercury
H_2S	Hydrogen Sulfide
H_2O	Water
$Mg(OH)_2$	Magnesium Hydroxide
Mn	Manganese
N_2	Nitrogen (Molecular)
NO_x	Nitrogen Oxide
N_2O	Nitrous Oxide
Pb	Lead
O_2	Oxygen (Molecular)
O_3	Ozone
S	Sulfur
SiO_2	Silicon Dioxide (Silica)
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide

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1.0 EXECUTIVE SUMMARY

The Energy and Environmental Research Corporation (EER) has conducted a project to evaluate Gas Reburning-Sorbent Injection (GR-SI) at a 71 MW_e (net) tangentially fired utility boiler. The GR-SI process involves injection of reburning fuel into the furnace above the coal burners for reduction of nitrogen oxides (NO_x) and injection of dry sorbent into the upper furnace for capture of sulfur dioxide (SO_2). The goals of the project were to reduce emissions of NO_x and SO_2 by 60 and 50%, respectively. The host unit was Illinois Power Company's Hennepin Station Unit 1, which normally fires an Illinois bituminous coal containing approximately 3% sulfur. The project was conducted in three phases in which EER designed and retrofitted a GR-SI system, conducted short-term (optimization) and long-term (one year) demonstration testing, and evaluated the impacts of GR-SI operation on various areas of host unit performance and on the local environment. The project was part of the U. S. Department of Energy (DOE) Round 1 Clean Coal Technology (CCT) Program. The primary sponsor was the DOE, the Gas Research Institute (GRI) and the Illinois Department of Commerce and Community Affairs co-funded the project.

GR-SI requires the injection of natural gas, corresponding to 18% of the total heat input, into the furnace above the coal burners. Sub-stoichiometric combustion of the natural gas results in formation of hydrocarbon fragments and free radicals, which reduce the NO_x formed in the coal combustion zone to molecular nitrogen (N_2). To complete fuel combustion, overfire air (OFA) is injected above the natural gas injection point, resulting in burnout of combustibles under overall fuel-lean conditions. The process also involves injection of a calcium sorbent, such as hydrated lime (calcium hydroxide), into the upper furnace cavity for reaction with SO_2. The sorbent and SO_2 react to form mostly $CaSO_4$, a dry powder, which is entrained in the boiler flue gases and is captured in ash hoppers and the electrostatic precipitator (ESP).

In this CCT project, GR-SI systems have been designed and evaluated at two units, Hennepin Unit 1 and at a 33 MW_e (gross) cyclone fired unit, Lakeside Station Unit 7. Lakeside Unit 7 is owned and operated by City Water, Light and Power Company, the municipal utility of Springfield, Illinois. The program at Hennepin Unit 1 was conducted from June 1987 to October 1992. The program at Lakeside Unit 7 was completed in June 1994. A third GR-SI program at Central Illinois Light Company's Edwards Station Unit 1, a 117 MW_e (net) wall fired unit, was discontinued after the design phase due to the high cost of upgrading the small ESP (SCA of 137 ft^2/1000 acfm [27.0 m^2/ m^3/s]) to accommodate sorbent injection (SI).

1.1 Testing at Hennepin Unit 1

The evaluation of the Hennepin GR-SI system was initiated with GR and GR-SI optimization (parametric) testing. It was continued with a year-long GR-SI demonstration and was concluded with an evaluation of alternate (advanced) sorbents. Gas/Coal Cofiring and Gas/Gas Reburning, which entail cofiring of coal and natural gas in the burner zone and Gas Reburning (GR) in addition to gas firing in the burner zone, respectively, were also evaluated. Hennepin Unit 1 has warm-up guns and main gas burners capable of firing 100% natural gas at full load.

GR was optimized with respect to several parameters which had a potential to impact NO_x formation/reduction, including: primary (coal) zone stoichiometric ratio, reburning zone stoichiometric ratio, burnout (exit) zone stoichiometric ratio, boiler load, mills in service, burner tilt angle, flue gas recirculation (FGR) flow rate and reburning fuel injector tilt. The principal parameters used to evaluate the GR process are the stoichiometric ratios which indicate an excess or deficiency of air due to firing of coal and natural gas and injection of primary/secondary and overfire air. The other significant parameters are the mills in service, burner and reburning fuel injector tilt angles and FGR flow. Following the GR optimization tests, SI and GR-SI optimization testing was conducted. The significant parameters evaluated in these tests were: load, calcium/sulfur molar ratio (the ratio of sorbent calcium to coal sulfur), injection velocity, injection configuration and sorbent reactivity. The Hennepin SI system has two injection configurations, SI nozzles at the IFA ports and at the boiler nose plane, for use during low and high loads, respectively. Testing of SI was conducted to determine the impact of GR on sorbent reactivity. The parametric test results were analyzed to determine the appropriate set-points to achieve 60% NO_x and 50% SO_2 emissions reductions for the one-year technology demonstration. The GR-SI demonstration testing was conducted with the unit under dispatch operation to meet station power requirements and at specific loads. The primary sorbent evaluated in GR-SI parametric testing and over the demonstration period was Linwood hydrated lime; Marblehead hydrated lime was also briefly evaluated. Following the one-year GR-SI demonstration, three alternate sorbents containing promoting agents were tested.

1.2 Emissions Reductions

The optimization testing data were analyzed to determine a design point for the best overall balance of emissions control and boiler performance. The results showed that reduction in NO_x emissions in excess of 60%, from the "as found" baseline of 0.75 lb/10^6Btu (323 mg/MJ), and reduction in SO_2 emissions in excess of 50%, from 5.3 lb/10^6Btu (2,280 mg/MJ), may be obtained under the following conditions:

Percent Reburning Fuel	18.0
Primary Zone Stoichiometric Ratio	1.08
Reburning Zone Stoichiometric Ratio	0.90
Burnout Zone Stoichiometric Ratio	1.18
Ca/S Molar Ratio	1.75
Injection Configuration for SI	Upper - 6 Nozzles

The load following long-term demonstration was conducted from January to October 1992, generally under these set-point conditions. Over the long-term demonstration period the average NO_x emissions were 0.246 lb/10^6Btu (106 mg/MJ), corresponding to a reduction of 67.3%, while the average SO_2 emissions were 2.51 lb/10^6Btu (1,079 mg/MJ), corresponding to a reduction of 52.7%. The NO_x emissions ranged from a low of 0.179 lb/10^6Btu (77 mg/MJ) to a high of 0.312 lb/10^6Btu (134 mg/MJ), and showed significant dependence as the natural gas input, primary and reburning zone stoichiometric ratios, mills in service, and coal burner tilt angle were varied by the operators.

The long-term demonstration results also indicate that the GR-SI system achieves the target NO_x and SO_2 emission reduction as well as modest reduction in CO_2 and significant reductions in HCl and HF. Short-term tests of HCl and HF emissions were conducted during the demonstration period. Emissions of CO were maintained at acceptable levels and N_2O emissions were insignificant. The range of operating parameters, species emissions, and reductions from baseline emissions are listed below.

	Range	Average
Gas Heat Input (%)	12.1 - 19.7	18.2
Ca/S Molar Ratio	1.42 - 2.07	1.76
NO_x emissions reduction (%)	58.4 - 76.1	67.3
SO_2 emissions reduction (%)	42.6 - 62.0	52.7
Calcium utilization (%)	16.5 - 32.5	24.1
CO_2 emissions reduction (%)	4.5 - 10.3	7.1
HCl emissions reduction (%)	60.4 - 85.5	73.0
HF emissions reduction (%)	94.3 - 99.7	97.0
CO emissions (ppm @ 3% O_2)	13 - 254	57
N_2O emissions (ppm @ 3% O_2)	0.5 - 4.3	1.9

At full load, NO_x reductions with 10% and 18% gas heat input were 55% and 67%, respectively. NO_x emissions were reduced when operating at low primary and reburning zone stoichiometric ratios, with the top mill out of service and when the coal burners were tilted downward. Under low load operation, removing the top mill from service resulted in greater staging of the coal combustion. The NO_x reduction process was most effective when the coal burners were tilted downward, due to effective separation of the primary combustion and the reburning zone.

Emissions of SO_2 ranged from 2.01 to 3.04 lb/10^6Btu (864 to 1,307 mg/MJ), with an average of 2.51 lb/10^6Btu (1,080 mg/MJ). These results, obtained primarily with Linwood hydrated lime, correspond to an average reduction of 52.7% from the baseline. Reductions in CO_2 emissions result from replacement of coal, which theoretically produces CO_2 at a rate of 205 lb/10^6Btu (88.2 mg/MJ), with natural gas which produces CO_2 at a level of 115 lb/10^6Btu (49.5 mg/MJ). The measured CO_2 emissions decreased from a baseline of 15.6% (@ 3% O_2) to 14.5% under GR operation with 18% natural gas heat input. The reduction of HCl and HF is due in part to fuel switching, since natural gas is free of halides. Most of the reduction is due to the reaction with sorbent to form calcium halides. The measured emissions were in the range 9.29×10^{-3} to 24.6×10^{-3} lb HCl/10^6Btu (3.99 to 10.6 mg/MJ) and 1.14×10^{-5} to 19.1×10^{-5} lb HF/10^6Btu (4.90×10^{-3} to 82.1×10^{-3} mg/MJ). Emissions of CO were maintained below 100 ppm in most cases, with an average of 57 ppm (@ 3% O_2) over the long-term demonstration. CO emissions were below 50 ppm at full load, but reached above 100 ppm at reduced loads due to reduced gas temperatures, upward tilting of the coal burners, and reductions in overfire air velocity below the optimum for rapid mixing with furnace gases. N_2O emissions under GR and GR-SI operation were in the 0.5 to 4.3 ppm range, indicating that the processes do not result in unacceptable N_2O emissions.

Gas/Coal Cofiring and Gas/Gas Reburning resulted in significant NO_x reductions from the uncontrolled levels. Gas/Coal cofiring with 34% gas heat input resulted in NO_x reductions of 35 to 45% from the 100% coal baseline and Gas/Gas Reburning with 18 to 20% gas heat reburning fuel resulted in NO_x reductions of 60 to 65% from the 100% gas baseline.

Three alternate sorbents, prepared by EER and the Illinois State Geological Survey (ISGS) Department, were also evaluated. Two sorbents containing agents to facilitate sulfation, designated PromiSORB™ A and PromiSORB™ B, were prepared through an EER-Petroleos de Venezuela joint venture. At a nominal Ca/S molar ratio of 1.75, PromiSORB™ A injection resulted in SO_2 capture of 53%, corresponding to a calcium utilization of 31%, while PromiSORB™ B resulted in SO_2 capture of 66% and calcium utilization of 38%. At the same Ca/S, the ISGS High Surface Area Hydrated Lime (HSAHL) injection resulted in

SO_2 capture of 60% and a calcium utilization of 34%. PromiSORB™ B injection resulted in a maximum SO_2 capture of 81.2% at a Ca/S of 2.59. These improved utilizations allow the SO_2 reduction to be achieved at lower SI rates; alternatively, for the same SI rate, higher SO_2 capture can be achieved.

1.3 Electrostatic Precipitator Performance

Flue gas humidification was applied to enhance ESP performance, permitting continued adherence to the regulatory limit of 0.10 lb particulate matter/10^6Btu (43.0 mg/MJ). GR-SI operation impacts ESP performance via several mechanisms including increased particulate loading at the ESP inlet, an increase in gas temperature and an increase in the fly ash resistivity. The humidification system was designed to reduce the gas temperature at the ESP inlet to 195°F (39°C), which corresponds to an approach to adiabatic saturation of 70°F (39°C). This requires 60 gpm (3.8 l/s) of water at full load. In practice, a 150°F (83°C) approach was sufficient to maintain low stack opacity and particulate matter emissions. Particulate matter emissions were measured at two times in the demonstration period, indicating emissions of 0.015 to 0.025 lb/10^6Btu (6.5 to 10.8 mg/MJ) during full load GR-SI operation. These correspond to collection efficiencies of 99.8 to 99.9% and required humidification water flows of 24.9 to 27.6 gpm (1.57 to 1.74 l/s). GR had a minor impact on ESP performance, due to an increase in the gas temperature at the ESP. Under full load GR operation the particulate emissions were in the 0.025 to 0.033 lb/10^6Btu (10.8 to 14.2 mg/MJ) range. These may be compared to full load baseline emissions of 0.018 to 0.035 lb/10^6Btu (7.7 to 15.1 mg/MJ).

1.4 Thermal Performance During GR and GR-SI Operation

The Hennepin unit was equipped with tilting burners to control reheat steam temperature. The tilts were automatically adjusted to achieve design point temperature within a narrow tolerance. For GR operation at full load, the burners were tilted down slightly. Under SI, the burner position was shifted upward, to a nearly horizontal or upward tilting position, to enhance heat transfer to the reheat superheater.

The Hennepin unit was equipped with spray attemperation for main steam temperature control. While GR and GR-SI affected the boiler heat absorption profile, main steam temperature could be maintained by adjusting the attemperation water flow rate. The operators typically strive to maintain steam temperature at slightly less than the design point of 1,005°F (541°C). The table below summarizes the steam temperatures and attemperation flow rates over the demonstration period.

Condition	*Steam Temperature* (°F)	*Spray Attemperation*	
		Flow Rate (lb/hr)	% of maximum
Baseline	993	6,700	8.9
GR	994	7,900	10.5
GR-SI	995	12,200	16.3

The fouling of heat transfer surfaces under GR-SI also resulted in a change in the heat absorption profile. The changes in the percentage of total heat absorbed by each heat transfer section were: 0.64% decrease by the furnace water wall, 0.93% decrease by the secondary superheater, 0.48% decrease by the reheater, 1.62% increase by the primary superheater, and a 0.43% increase by the economizer. The boiler easily accommodated these small shifts in heat transfer distribution.

GR operation resulted in a 0.76% reduction in thermal efficiency, to 86.00%. This was due to an increase in the flue gas moisture from combustion of natural gas. Under GR-SI, an increase in air heater gas exit temperature of 33°F (18°C) decreased the thermal efficiency to 85.38%.

1.5 Other Impacts of GR and GR-SI Operation

To evaluate other potential impacts of GR-SI, ash deposition, boiler durability and chimney inspections were conducted.

GR had essentially no impact on furnace or convective pass ash deposition patterns. In some cases, ash deposition around the reburning fuel injectors and overfire air ports was noted but the deposits had no observable effect on operation. Adding SI had little effect on the furnace but did increase deposits in the convective pass. The most extensive particulate matter deposits were on the cold reheater sections where there were no sootblowers and on the primary superheater elements. These deposits decreased heat absorption and increased the boiler exhaust temperature, resulting in a slight decrease in boiler efficiency as previously mentioned.

Boiler durability was assessed by both destructive and non-destructive techniques. Both methods confirmed no adverse impacts on tube wall metallurgy and no measurable increase in tube wall wastage. Sixteen tube wall samples were examined and no indication of decarburization was detected. Extensive ultrasonic thickness measurements of the tube walls were conducted at approximately 4,000 points in 1988 (prior to baseline testing), in 1990 (after baseline operation), and in 1992 after completion of the GR-SI tests. Since the normal tube wastage rates expected over this period were comparable to the accuracy of the instrument, it was recognized that it would not be possible to quantify small changes due to GR-SI. The primary objective was to determine if there was a significant increase in tube wastage. No accelerated wastage could be detected.

The chimney was inspected at the completion of the long term tests. Normally there is some ash deposited on the liner. Material buildup, upon inspection, appeared to be spent sorbent. The deposits were considered to be within the normal range and no remedial work was required.

2.0 INTRODUCTION

The Energy and Environmental Research Corporation (EER) has conducted a project entitled "Enhancing the Use of Coals by Gas Reburning-Sorbent Injection." The project objective was to demonstrate GR-SI for reduction of emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) from coal fired boilers. The specific goals were to reduce NO_x emissions by 60% and SO_2 emissions by 50%. One of the host sites for the project was Illinois Power's Hennepin Station Unit 1, which is a 71 MW_e (net) tangentially-fired balanced draft unit supplied by Combustion Engineering. The unit fires an Illinois bituminous coal containing approximately 3% sulfur. It was constructed prior to 1971; therefore, its emissions are not required to meet New Source Performance Standards (NSPS). The GR-SI system, designed by EER, was retrofitted to the unit and operated over a year-long demonstration to evaluate emissions reductions and impacts on various areas of unit performance.

2.1 Purpose of the Project Performance Report

The purpose of this report is to present GR-SI system design and performance data for Hennepin Station Unit 1. The design of the GR-SI system as well as the methodology used in finalizing the design are presented. The report contains data in the areas of emissions, thermal performance, alternate sorbent performance, environmental impacts, slagging/fouling, ESP performance and unit wear. Process capital costs and operating costs as well as an analysis of the market for the technology are not included and will be presented in a subsequent volume. This is Volume 2 of a five volume series prepared by EER to meet the requirements of its CCT Round 1 Program. The other volumes to be prepared are described as follows:

Volume	Description
Volume 1	Summary/overview of the work completed at the three sites: Edwards Unit 1, Lakeside Unit 7, and Hennepin Unit 1

Volume 3 Process/engineering design of the Edwards Unit 1 GR-SI system. Since this project was suspended after the design phase, there was no field evaluation of that system.

Volume 4 Performance/design volume for the Lakeside Unit 7 GR-SI demonstration (similar to this report)

Volume 5 Guideline manual containing capital and operating cost information for all of the sites and a market analysis

This section contains an overview of the project at Hennepin Station Unit 1, a description of the host unit, "as found" baseline emissions, and a description of the GR-SI process. Section 3 contains a description of the GR-SI design methodology, the Hennepin Unit 1 GR-SI system process design specification, and the GR-SI system performance objectives. Section 4 contains an overview of the project and testing and Section 5 describes the test plan used to evaluate the GR-SI system and Quality Assurance/Quality Control activities. Sections 6 through 11 present the results of optimization (parametric) and long-term testing, including emissions, thermal performance, slagging and fouling, ESP performance, and environmental impacts. Sections 12 and 13 describe the design of the GR-SI system design and compare the optimized performance to the design projections. Finally, Section 14 contains project conclusions and recommendations.

2.2 Project Description

In response to growing concern regarding pollutant emissions from coal-fired power plants, the DOE initiated the Clean Coal Technology (CCT) Program. The GR-SI project at the Hennepin Station is one of several in the DOE CCT Round 1. It is one of two carried out simultaneously by EER, one at a tangentially fired unit - Illinois Power's Hennepin Station Unit 1, and the other at a cyclone fired unit - City Water, Light and Power's Lakeside Station Unit 7, in Springfield, Illinois. Another GR-SI project, at a front wall fired unit - Central Illinois Light Company's (CILCO) Edwards Station Unit 1 - was discontinued due to funding constraints. EER is also conducting a CCT Round 3 Project in which GR and Low

NO_x Burners are being evaluated at a wall fired unit - Public Service of Colorado's Cherokee Station Unit 3.

The project at Hennepin Unit 1 was conducted in three phases. Phase I consisted of design of the GR-SI system and permitting activities, construction and start-up taking place in Phase II, and Phase III consisting of operation, data collection, reporting and disposition. The unit was retrofitted with a GR-SI system designed by EER, then underwent start-up activities, optimization testing, and long-term (one-year) testing. The primary sponsor of the project was the U. S. Department of Energy (DOE). Co-funding was obtained from the Gas Research Institute (GRI) and the State of Illinois Department of Energy and Natural Resources (ENR). The two host utilities were Illinois Power Company (IP), and City Water, Light and Power Company (CWLP) the municipal utility of the City of Springfield, Illinois.

The GR-SI project goal at Hennepin was to reduce NO_x emissions by 60%, from an "as found" baseline of 0.75 lb/MBtu (323 mg/MJ) to 0.30 lb/MBtu (129 mg/MJ), and a reduce SO_2 emissions by 50%, from a baseline of 5.30 lb/MBtu (2,280 mg/MJ) to 2.65 lb/MBtu (1,140 mg/MJ). The GR-SI process consists of injection of natural gas, corresponding to 15 to 20% of the heat input, at a location above the coal burners to create a fuel-rich zone. Fuel rich combustion of natural gas results in formation of hydrocarbon fragments and other free radicals which reduce NO_x, formed in the primary (coal) zone, to molecular nitrogen (N_2). OFA is injected at a higher elevation to fully burn out the fuel combustibles under fuel lean conditions. Hydrated lime sorbent, calcium hydroxide ($Ca(OH)_2$), is injected dry into the upper furnace to react with flue gas SO_2, resulting in formation of mostly calcium sulfate ($CaSO_4$) and some calcium sulfite ($CaSO_3$). These are solids which are entrained in the boiler flue gas along with the fly ash and are captured in the particulate collection device. The fly ash/sorbent mixture is the major waste product of the GR-SI process. At Hennepin, it was mixed with water and sluiced to an on-site pond.

2.3 Roles of the DOE, GRI and ENR in the Project

This project is significant to owners/operators of existing fossil fuel fired steam electric units of all types. The Clean Air Act Amendments (CAAA) of 1990 include a broad range of regulations requiring control of both NO_x and SO_2 emissions. GR and GR-SI will find applications in meeting requirements of Titles I and IV of the CAAA. Title I requires Reasonably Available Control Technology (RACT) to be employed to reduce NO_x emissions in areas where ambient ozone levels exceed the Federal ambient air quality standards. Title IV requires both NO_x and SO_2 reductions to mitigate acid rain.

The DOE, GRI and ENR had two major roles in the demonstration of GR-SI at Hennepin Station Unit 1, as project sponsors (funding organizations) and as technical reviewers and advisor. Approximately 50% of project funds for the design, construction, and testing of the GR-SI system were received from the DOE. These organizations also played a major role in review of the GR-SI system design, construction plan, environmental monitoring plan, and testing results. Therefore, they played a key part in assessment of the GR-SI technology in each phase of the project.

The host utility also played key roles in the project. Illinois Power gave access to the unit for retrofit and testing of GR-SI. It also shared the cost of the project and provided technical review through each phase. The unit was operated by plant personnel, in accordance with a test plan prepared by EER. GR systems were retained by both utilities, Illinois Power and City Water, Light and Power, after completion long-term testing.

2.4 Significance of the Project

The GR-SI project at Hennepin Unit 1 is the first full scale demonstration of GR in a large utility boiler in the U.S. The performance of the GR system over the year-long demonstration exceeded the goals of the project, therefore the Illinois Power Company elected to retain the technology rather than to restore the unit to the pre-project configuration. The SI system performance also exceeded the project goal with the conventional sorbent. EER also developed and tested advanced sorbents, such as PromiSORB™ B, which can achieve the SO_2 capture of normal sorbents at significantly reduced sorbent inputs. PromiSORB™ B calcium utilization in some cases was nearly double that of the conventional sorbent. Flue gas humidification for ESP enhancement was evaluated and found to improve ESP performance with resulting outlet loadings at or even below baseline emissions. The successful demonstration of GR-SI has led EER to promote further commercial application of the GR technology.

SI is a viable alternative to the practice of coal switching, i.e. firing lower sulfur coals. Coal switching has had significant impacts on mining areas in midwestern states, which have large reserves of coal containing more than 3% sulfur. Therefore, the demonstration and application of the GR-SI enables utilities to fire coals which have a higher sulfur content, resulting in positive economic impacts on regions which mine medium to high sulfur coals.

2.5 Host Unit Description

The host site for this part of the program was a 71 MW_e (net) unit (unless otherwise stated all loads will be on a gross basis in this report), tangentially fired with pulverized coal. Figure 2-1 is a schematic showing the major components of the boiler and Table 2-1 contains the design specifications. The unit, which began operation in 1953, was supplied by Combustion Engineering and is owned by the Illinois Power Company. At its nominal continuous rating, the unit produces steam at a rate of 525,000 lb/hr (66.3 kg/s), at a temperature of 1005°F (541°C) and a pressure of 1500 psig (10,340 kPa). The unit reheats steam at a rate of 462,000 lb/hr (58.3 kg/s) to the same design temperature. It is tangentially fired with three elevations of coal nozzles located in each of the four corners. The burners have tilting capability to automatically control reheat steam temperature. The convective pass includes a secondary superheater, high temperature reheater, low temperature reheater, primary superheater, economizer and tubular air heater.

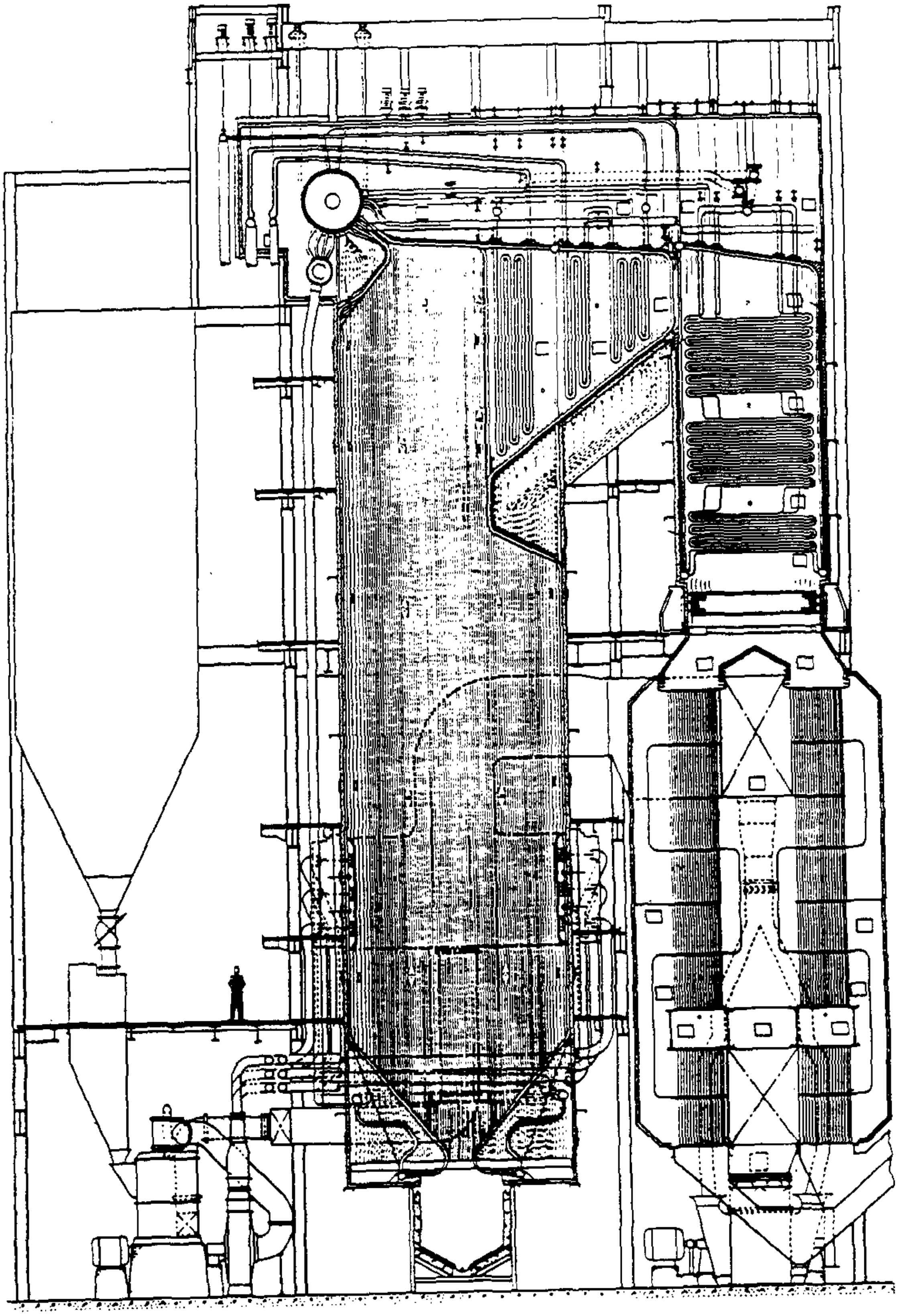


Figure 2-1. Schematic of Illinois Power's Hennepin Station Unit No. 1

TABLE 2-1. HENNEPIN UNIT 1 BOILER SPECIFICATIONS

Manufacturer	Combustion Engineering
Fuel Type	Pulverized Coal, Illinois Bituminous
Boiler Firing Configuration	Tangentially–Fired, Balanced Draft
Number of Pulverizers	3, with 3 Burner Elevations
Superheat Steam Flow Rate	525,000 lb/hr at Normal Continuous Rating
Superheat Steam Temperature	1,005°F
Steam Pressure	1,500 psig
RH Steam Temperature	1,005°F
RH Steam Flow	462,000 lb/hr
Design Efficiency	87.0 Percent
Furnace Dimensions	25'10" width x 23'11 1/4" depth
Furnace Volume	49,200 ft^3
Furnace Heat Release Rate	14,100 Btu/hr, ft^3
Heating Surface Areas	
- Furnace	9,465 ft^2
- Superheater	50,000 ft^2
- Reheater	7,830 ft^2
- Economizer	8,950 ft^2
- Air Heater	172,500 ft^2

Coal is pulverized by three Raymond bowl mills, each having a capacity of 17 tons/hr (4.29 kg/s). Operation with only one mill in service at a minimum stable operating point (mill turndown ratio of 2.5:1) corresponds to a unit power output of approximately 22 MW_e. Coal is pulverized to a specified fineness of 70% passing 200 mesh U.S.S. sieve (74 micron openings) and 98% passing 50 mesh U.S.S. sieve (297 micron openings). The coal is transported by 160°F (71°C) primary air to twelve tilting nozzles, three in each corner of the boiler, and introduced into the furnace with 450°F to 530°F (232°C to 277°C) secondary air. It is burned in a swirling combustion zone. The high temperature combustion products then pass through a superheater, reheater, economizer, and a tubular air heater before being ducted to the electrostatic precipitator.

Figure 2-2 shows the locations of the sootblowers. The boiler cleaning system is comprised of 24 sootblowers supplied by Diamond Power Specialty Company. There are 8 short retractable IR wall blowers, designated as IR by the model number, located on a single row above the top burner elevation and 16 long retractable IK sootblowers, located throughout the convective sections. Many wall boxes are present in the furnace and convective sections of the unit, where additional wallblowers may be installed.

Hennepin Unit 1 is equipped with a Buell Model BA1.1X40K333-2P modular electrostatic precipitator. The precipitator was installed in 1974. It has a Specific Collection Area (SCA) of 223.4 square feet for each thousand actual cubic feet per minute (acfm) (43.97 $m^2/m^3/s$) of flue gas produced at the maximum boiler rating. It has an array of four electric fields with a total effective plate area of 64,800 square feet (6,020 m^2). A particulate collection efficiency of 99.5% and maximum outlet particulate loading of 0.01 grains per acf (0.023 g/m^3) are guaranteed.

The operating permit for Hennepin Station limits the SO_2 emissions from both Units 1 and 2 to 17,050 lb/hr (2.20 kg/s). To comply with this limit, under all operating conditions, the coal SO_2 emission potential must be less than 6.0 lb/MBtu (2,580 mg/MJ). The coal sulfur content is usually in the range of 2.8 to 3.8%.

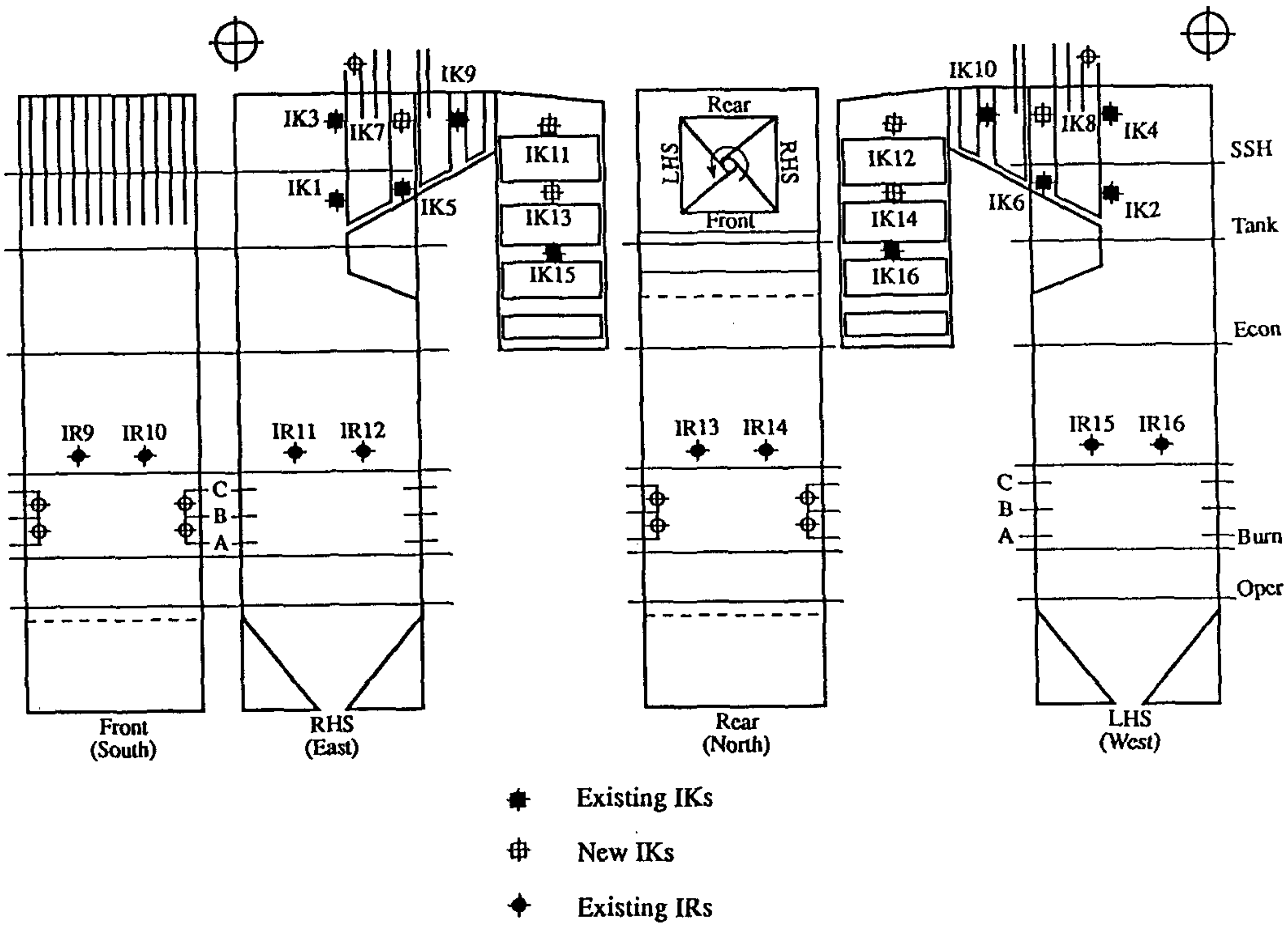


Figure 2-2. Sootblower locations at Hennepin Station Unit No. 1

Hennepin Unit 1 was constructed in 1953. The unit's capacity factor for the five-year period from 1980 to 1984 was 54.9%. The unit normally operates in cycling service, approximately 12 hours/day and 5 days/week. During the demonstration period, 1991 to 1992, the unit capacity factors were 34.09% (1991) and 32.01% (1992).

2.6 Pre-Project Baseline Emissions and Performance

Emissions measurements and unit performance data were taken during three baseline tests in Phase I of the project. Preliminary testing and data collection, used in the GR-SI system design, took place in December 1987, January 1988, and April 1988. The December 87 and January 88 tests were designed to provide input data for the initial GR-SI design including isothermal physical flow modeling and heat transfer modeling. The April 1988 tests were designed to provide additional data to be used in the GR-SI system design, more complete boiler performance and emissions data and to identify any areas which may limit or hinder the application of GR-SI to the unit. The measurements taken included furnace gas temperature and velocity, which were used to "calibrate" the heat-transfer and isothermal flow models, as well as emissions and unit operating data. The emissions and unit operating data, collected over a range of loads, include pulverizer fineness, combustibles in ash, exit particulate loading, ESP collection efficiency, and emissions of combustion products monitored with continuous gas analysis equipment.

NO_x and CO emissions, over the load range evaluated, are shown in Figure 2-3. The testing showed that the unit was operating in a smooth manner, and no problems with the GR-SI retrofit were evident. At full load, the boiler normally operates at 75 MW_e (gross). At this load and 20% excess air, the pre-project NO_x emissions were about 0.75 lb/MBtu (323 mg/MJ). NO_x emissions for loads of 60 MW_e, 50 MW_e, 45 MW_e, and 30 MW_e were 0.48 lb/MBtu (206 mg/MJ), 0.71 lb/MBtu (305 mg/MJ), 0.50 lb/MBtu (215 mg/MJ), and 0.60 lb/MBtu (258 mg/MJ), respectively. At low loads, the unit is operated at higher excess air levels to maintain steam temperatures, therefore NO_x emissions are not reduced consistently with reduction in load. Emissions of CO were in the 25 to 67 ppm range under boiler excess

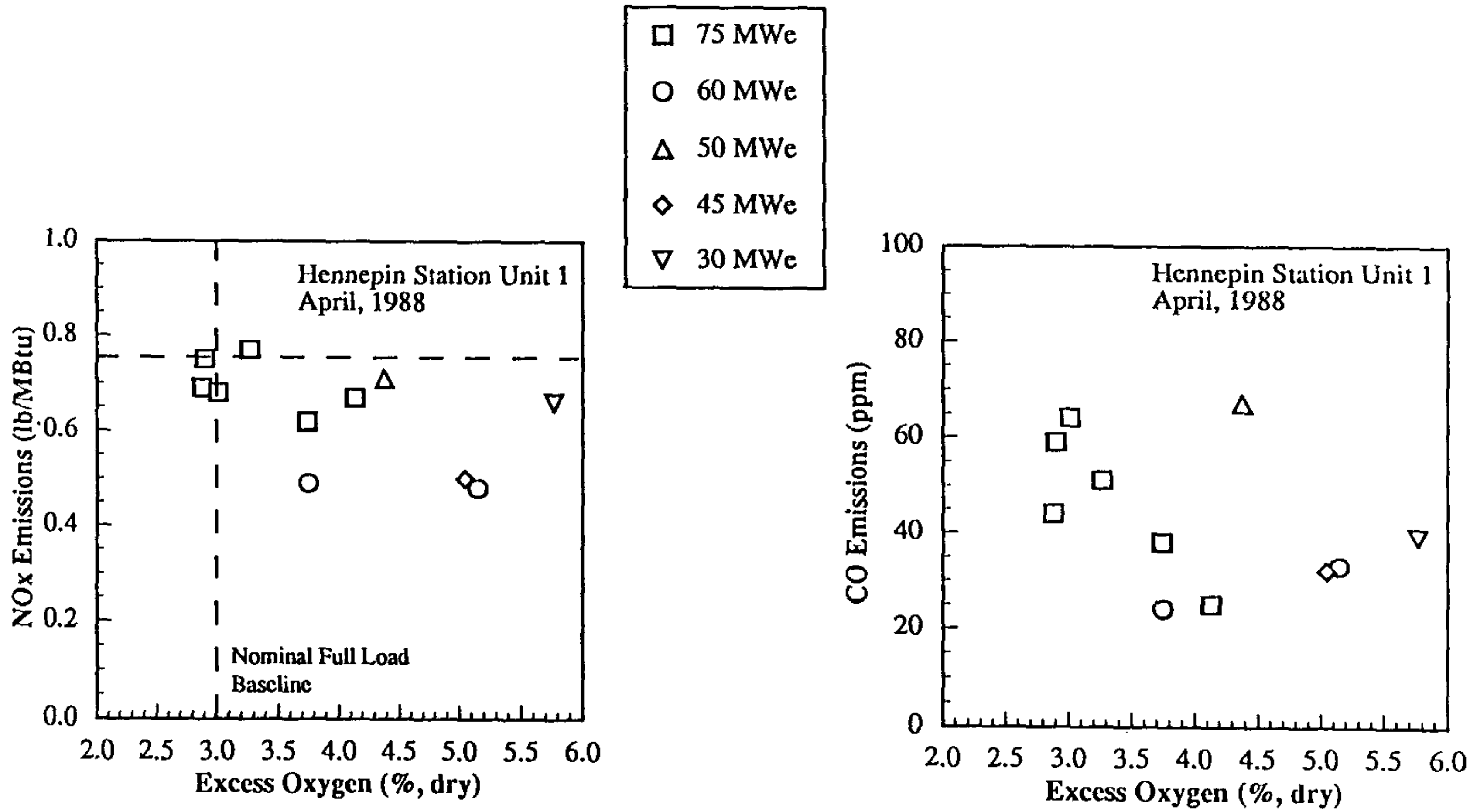


Figure 2-3. Hennepin Unit 1 NO_x and CO emissions prior to the GR-SI demonstration

O_2 of 2.88 to 5.77%.

Emissions of SO_2, based on coal sulfur content, were below the 6.0 lb/MBtu (2,580 mg/MJ) plant limit. The calculated emissions were in the 3.69 to 5.22 lb SO_2/MBtu (1,590 to 2,240 mg/MJ) range and the ash sulfur retention was 5% of the coal sulfur. The ESP collection efficiency was calculated to be 99.71%, with emissions of 0.0174 lb/MBtu (7.48 mg/MJ). Combustion efficiency losses were low, as indicated by low CO emissions and relatively low unburned carbon in ash. The steam temperature was 1000°F (538°C), which is near the design temperature of 1005°F (541°C). Without sootblowing, the maximum allowable furnace heat transfer degradation took place over a period of 8 to 10 hours. This resulted in increased superheater and reheater attemperation spray. Furnace wallblowing effectively improved furnace heat transfer, resulting in a reduction in attemperation spray requirement, but this was followed by a significant drop in steam temperature. The burner tilts then were adjusted to an upward position to increase the reheat steam temperature to the design point.

The air heater leakage was found to be 32% (air side to gas side), at full load. This is due to corrosion of the lower section of the air heater tubes. The air leakage contributed to heat loss from the unit as well as an increase in ID fan power. The increase in fan power was 99 HP over the zero air leakage case. The ID fan was at its maximum control position and power usage during full load high excess air operation.

2.7 Description of the Demonstrated Technology

The technology demonstrated at Hennepin Unit 1 is the application of two emissions control techniques: GR, for NO_x control, and SI, for SO_2 reduction. GR and SI may be applied together to achieve combined NO_x and SO_2 control in a low cost, easily retrofitted system. The GR and SI processes are complementary. Since their application does not depend on the characteristics of the primary coal combustion system, they are applicable to virtually any coal-fired boiler including stokers, cyclones, or pulverized coal-fired equipment. They can also be applied to gas and oil fired units (except that there is no need for SI on units firing a zero sulfur fuel such as natural gas). The retrofit equipment must be designed within the specific constraints of an existing furnace, requiring site-specific optimization.

Reburning for in-furnace NO_x reduction has been under development for over two decades. A flue gas NO_x incinerator using natural gas was developed and patented by the John Zink Company (Reed, 1969). Initial investigations into the fundamental processes of reburning were conducted by Shell Development. Since 1980, EER has conducted most of the U.S. GR development. Experimental studies of reburning technology have been supported by the DOE, GRI, the Environmental Protection Agency (EPA), and the Electric Power Research Institute (EPRI). Reburning for in-furnace NO_x control has been applied to coal-fired boilers in Japan (Takahashi, et al, 1981), where it is known as Mitsubishi Advanced Combustion Technology (MACT). Other recent international reburning work has been conducted in Sweden, Ukraine, and Italy.

The GR-SI system at Hennepin Unit 1 was designed to reduce NO_x emissions by 60% and SO_2 emissions by 50%. The GR process involves injection of reburning fuel (natural gas), corresponding to 15 to 20% of the total heat input, at an elevation above the primary coal burners. The combustion of the natural gas under sub-stoichiometric conditions results in the formation of hydrocarbon fragments and other free radicals which reduce NO_x to molecular nitrogen. First generation GR systems included an inert carrier gas, recycled flue gas, to inject the reburning fuel with sufficient momentum flux for optimum penetration and mixing. The reburning and primary fuels are then fully combusted with OFA, injected at a higher elevation. The OFA is preheated combustion air taken from secondary air ducts, typically accounting for 20 to 25% of the total combustion air.

The SI process involves the injection of a dry calcium based sorbent ($Ca(OH)_2$ or $CaCO_3$) for reaction with the SO_2 that is produced from oxidation of coal sulfur. The sorbent reacts with SO_2 and O_2 to form solid $CaSO_4$ and $CaSO_3$, which are captured with coal ash in the ESP. GR alone achieves an incremental reduction in SO_2 emissions, since natural gas contains no sulfur. This complements the reduction in SO_2 by SI and lessens the need for dust collector upgrades. The emission control effectiveness of GR-SI depends, to some extent, on the design of the boiler. However, GR-SI systems have been designed and operated for two utility boilers with widely varying characteristics.

Application of GR essentially divides the furnace into three zones: the primary (coal) combustion zone, the reburning zone, and the burnout (exit) zone. Figure 2-4 illustrates the processes occurring in the three zones. These may be summarized as:

- Primary Combustion Zone Combustion of coal in the primary zone accounts for 80 to 85% of the total heat input to the unit. The combustion is under low excess air condition, limiting the formation of NO_x in this high temperature zone. The excess air level must be optimized to balance NO_x formation, flame stability, ash carbon loss, and furnace slagging.

- Reburning Zone Reburning fuel (natural gas) is injected at a location above the primary zone to form overall fuel-rich conditions. Generally, GR is applied with natural gas accounting for 15 to 20% of the total heat input. Natural gas injection results in the formation of hydrocarbon fragments and free radicals, which reduce NO_x to N_2 - the desirable species.

- Burnout Zone OFA air is injected at a higher elevation to burn out the unreacted fuels. Sufficient OFA must be injected to bring the overall excess air to the level required for complete combustion. The OFA must be injected at a point where the temperature is sufficiently high to burn out CO and other combustibles. Several GR process parameters require optimization. These include:

    - Primary and reburning zone stoichiometric ratios
    - Penetration and mixing of the reburning fuel with the primary furnace gases

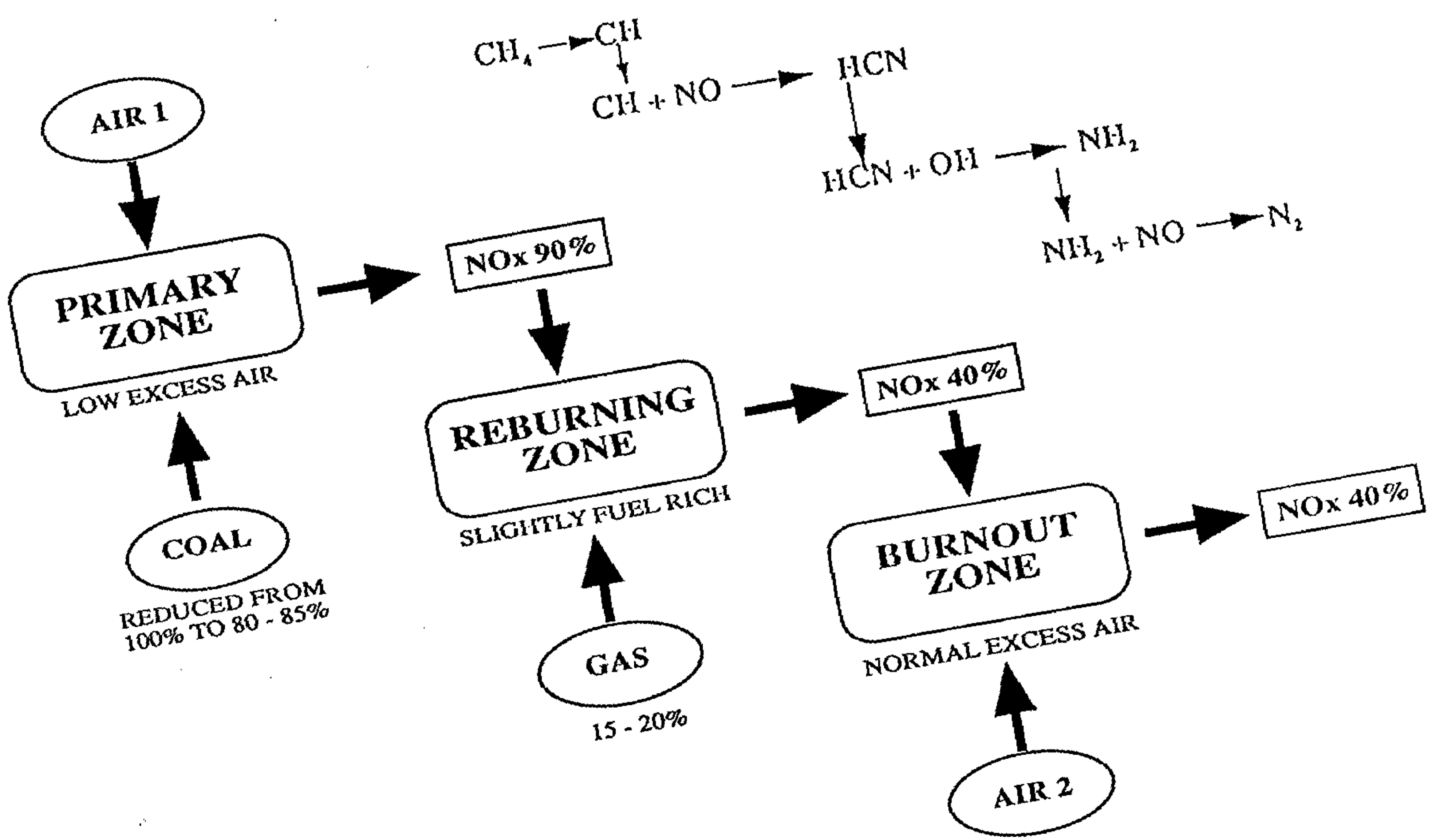


Figure 2-4. Overview of Gas Reburning process.

- Gas residence time in the reburning zone
- Gas temperature in the reburning zone

The formation and reduction of NO_x are optimized by controlling the primary and reburning zone stoichiometric ratios. The formation of NO_x in the primary zone is strongly dependent on operating load, which directly affects flame temperature, and excess O_2, with the excess O_2 being more important. Therefore, the formation of NO_x may be controlled by lowering the primary zone stoichiometric ratio. The reburning fuel is added to form sub-stoichiometric conditions, under which NO_x is reduced. Primary and reburning zone stoichiometric ratios used in the GR process designs of the Hennepin system were 1.1 and 0.9, respectively, corresponding to 110% and 90% of the theoretical air for complete combustion of the fuels. These operating zone stoichiometric ratios must be optimized not only with respect to NO_x emissions control but also with respect to flame stability, carbon burnout and slagging. A minimum burner excess air level must be maintained in order to maintain stable flames, complete ash carbon burnout, and minimize slagging. The injection system design must maximize the reburning zone gas residence time. A higher reburning zone temperature also enhances the process. Burnout of fuel is accomplished with OFA. High temperature in this upper furnace region and rapid mixing provide for rapid CO burnout, resulting in low CO emissions and minimizing ash carbon loss. Studies of reactions of CO in a post flame environment indicate that the CO lifetime is a function of gas temperature. But, at a burnout gas temperature of 2500°F (1370°C), conversion to CO_2 is very rapid, therefore the process is controlled by the speed and completeness of the OFA mixing.

Under GR-SI operation, reductions in SO_2 emissions result from two processes. The replacement of a fraction of the coal heat input with natural gas heat results in an equivalent reduction in SO_2 emissions. This occurs because natural gas contains essentially no sulfur. SI involves the introduction of a calcium-based compound into the upper furnace to react with SO_2. The process, as illustrated in Figure 2-5, involves two basic steps:

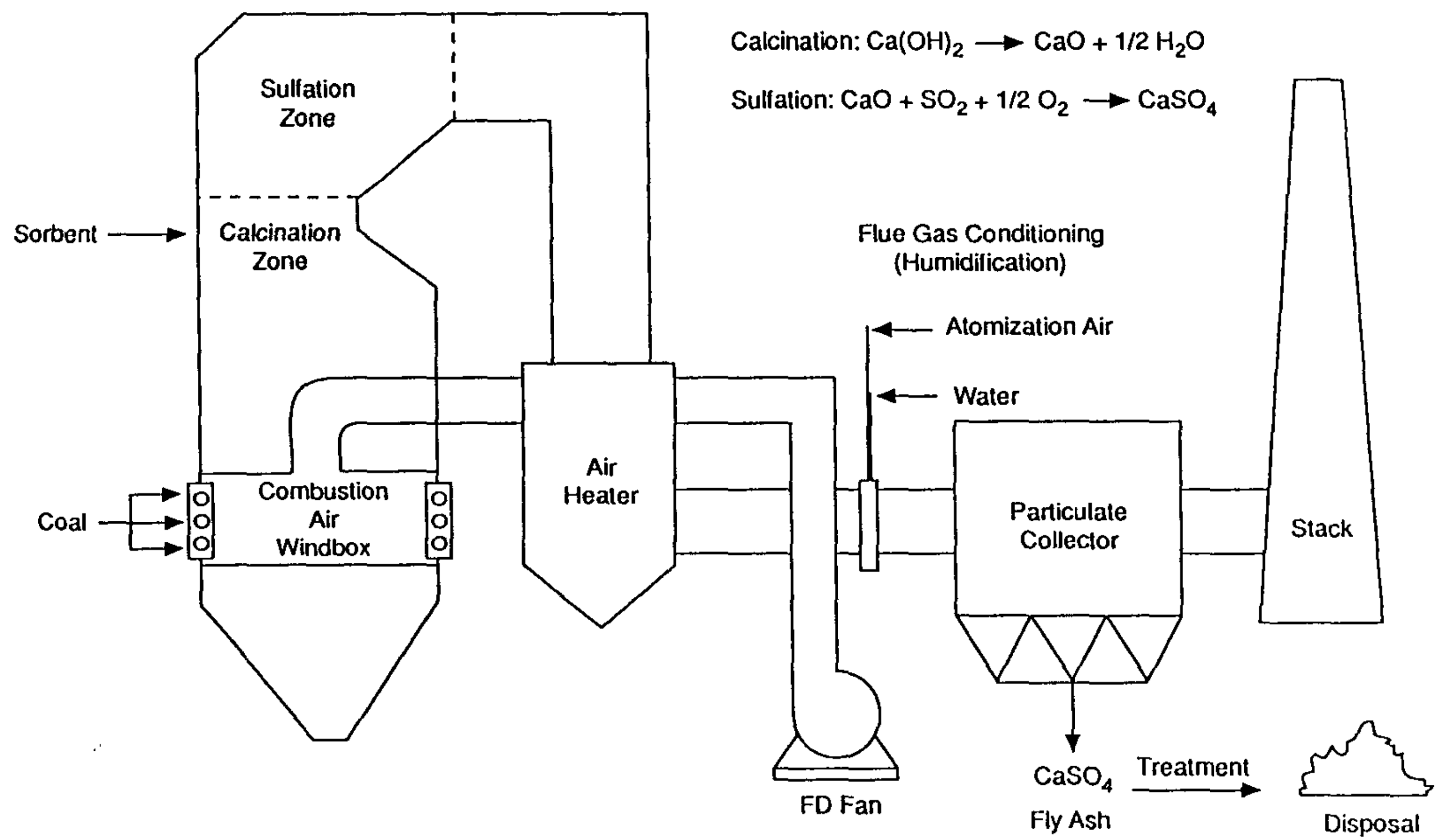


Figure 2-5. Overview of Sorbent Injection process

- Calcination The first step is the thermal decomposition of calcium-based sorbents, such as limestone ($CaCO_3$) or hydrated lime ($Ca(OH)_2$), upon heating. The following two reactions illustrate this process:

$$CaCO_3 + \text{heat} \text{ ----> } CaO + CO_2$$
$$Ca(OH)_2 + \text{heat} \text{ ----> } CaO + H_2O$$

- Sulfation The second step is the reaction of the CaO particles with SO_2 and O_2. The surface area and reactivity of the sorbent are functions of the sorbent type and temperature history. Special additives also enhance sorbent reactivity to SO_2. The sorbent sulfation processes are illustrated by the following equations:

$$CaO + SO_2 + 1/2\ O_2 \text{ ----> } CaSO_4 \text{ (solid) [major]}$$
$$CaO + SO_2 \text{ ---> } CaSO_3 \text{ (solid) [minor]}$$
$$CaO + SO_3 \text{ ---> } CaSO_4 \text{ (solid) [minor]}$$

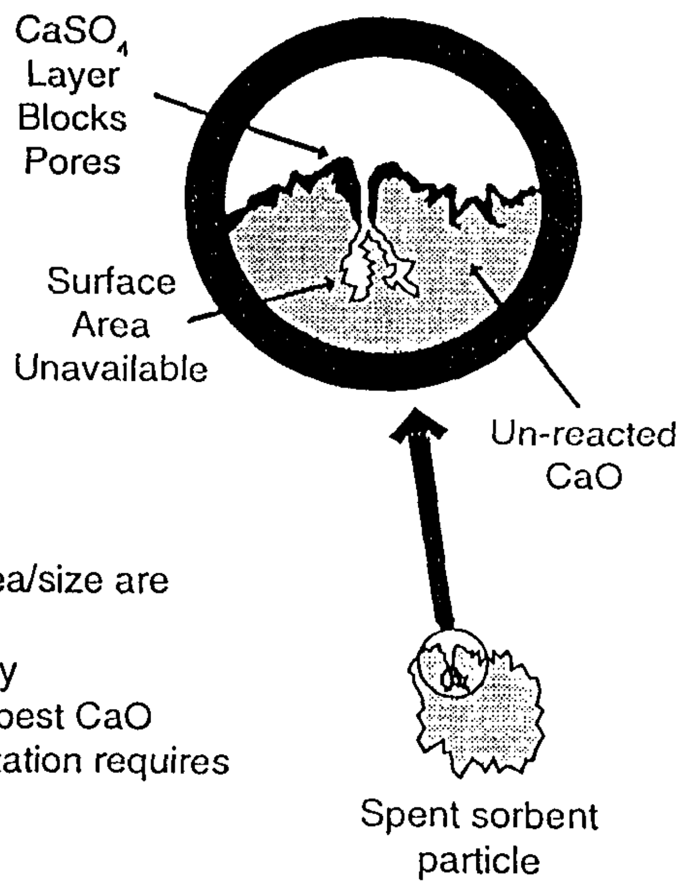
The solid $CaSO_4$ and $CaSO_3$ are captured with the coal ash by the dust collection device.

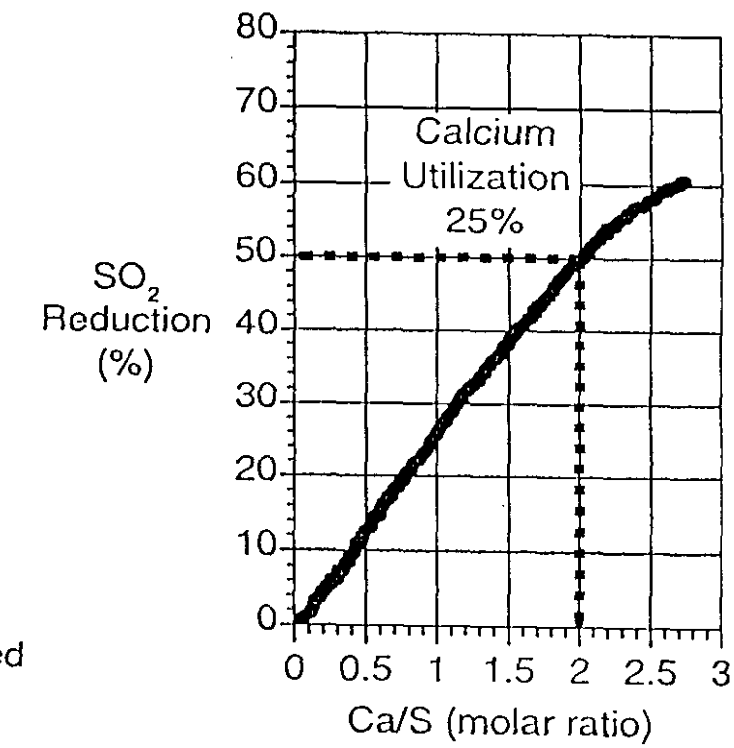
Sorbent reactivity is a function of sorbent type, particle size and surface area, temperature history, and the presence of additives. The smaller the sorbent size, the higher the reactive surface area and therefore the greater the reactivity. Sorbent sulfation occurs in a temperature window of 1,600 to 2,200°F (870 to 1200°C). The process requires a gas residence time of 1 second in this temperature window. Therefore, sorbent must be injected at an optimal temperature and rapid mixing with furnace gases must occur. Injection of sorbent at a temperature above 2350°F (1290°C) may result in a significant loss in sorbent reactivity (deadburning). Loss in reactivity also results when sorbent jets experience rapid temperature quench; therefore, the injection configuration (location of injectors, injector number and size, and amount of injection air) significantly affect the process. The key sorbent properties are summarized in Figure 2-6. The figure also shows that the level of SO_2 control expected from SI at a calcium to sulfur molar ratio of 2.0 is approximately 50%. The maximum SO_2 reduction is limited by the amount of sorbent injected, which leads to convective pass fouling and a higher demand on ESP (or other dust collective device) performance.

The location of the favorable sulfation temperature window in most utility boilers is in the upper furnace, beginning near the exit of the radiant furnace and extending into the convective pass. A practical means of SI into boiler combustion chambers at these locations is by jets using air as the carrier medium. Typically, the sorbent and carrier air are injected into the furnace where they mix into the cross-flowing stream of combustion products.

Mechanisms

SO_2 transport to particle
SO_2 Transport in pores (limiting)
Sulfation reactions





Sorbent Properties

Sorbent surface area/size are second order
CaO structure is key
$Ca(OH)_2$ produces best CaO
Sorbent characterization requires combustion test

Figure 2-6. Key sorbent properties and typical SO_2 control

3.0 GR-SI PROCESS DESIGN AND PERFORMANCE OBJECTIVES

This section presents the results of bench and pilot scale studies in reburning and sorbent sulfation, the GR-SI system design methodology developed by EER, the Hennepin Unit 1 GR-SI system process design, and the performance goals for GR-SI at Hennepin.

3.1 Bench and Pilot Scale Study Results

Extensive bench and pilot scale tests have been conducted to compare the performance of alternate reburning fuels and to evaluate NO_x control effectiveness and appropriate scale-up methodology for U.S. boilers (Chen et al., 1983; Greene et al., 1985; McCarthy et al., 1985; Chen et al., 1986). The results of these studies have shown that the key parameters which influence the effectiveness of the reburning process are the zone operating stoichiometric ratios, furnace gas temperatures, zone residence times, and mixing. The results of small-scale studies have also shown that reburning with natural gas is more effective than reburning with other fuels, particularly at low baseline NO_x levels. Natural gas is also the preferred reburning fuel when available furnace residence time is limited.

Studies of the SI process have helped to define conditions for optimization of SO_2 removal efficiency. Experimental evidence suggests that sorbents lose their reactivity when they are injected into the high temperature regions of a combustor and that the reaction is relatively slow at temperatures representative of those in the convective sections of utility boilers. Experiments in a large number of bench and pilot scale combustors have identified an optimum injection temperature range for SI of 2,190°F (1,200°C) to 2,280°F (1,250°C) for typical calcium sorbents, such as $CaCO_3$ and $Ca(OH)_2$. Modeling studies of the sulfation process indicated that sorbents need to have a residence time of the order of one second in the sulfation temperature window of 1,600°F to 2,200°F (870°C to 1,200°C) for effective sorbent utilization. The limits of this temperature window are dictated by sorbent reactivity as well as equilibrium and kinetic constraints.

Studies on the effective injection of sorbents in the upper furnace for SO_2 removal have indicated that the removal efficiency is strongly dependent on the flow field and thermal environment prevailing in this part of the boiler. A successful injection system design needs to provide adequate coverage of the furnace flow field with sorbent within a small space and in a short time.

3.2 GR-SI Process Design Methodology

Potential GR-SI configurations were evaluated by several techniques. These include process (NO_x formation/reduction, calcination and sulfation) studies, isothermal physical flow modeling, and heat transfer modeling. The NO_x reduction/SO_2 capture modeling was used to predict the impact of various operating parameters on the processes. These resulted in specification of the optimum design of the GR-SI system. Isothermal flow modeling was carried out with a 1/12th scale physical flow model. Potential process stream injector configurations were evaluated with smoke and bubble tracing techniques. The system was optimized with respect to injection location, number of injectors, and process stream velocity (to achieve the required rapid mixing rate). The impact of GR-SI operation on the heat absorption and gas temperature profile was evaluated through thermal modeling using a 2-Dimensional Heat Transfer Code (2 D Code).

3.3 Hennepin Unit 1 GR-SI Process Design

The design tools were used to arrive at an optimum GR-SI system process design. The final design required optimization of parameters which significantly impact the GR-SI process, including zone stoichiometric (air/fuel) ratios, injection velocities and gas temperature at the injection point. Other important considerations included injection configurations (injector size) and transport/injection flow rates required to accomplish rapid mixing of reburning fuel and sorbent jets. The reburning zone residence time was maximized to effectively form a reburning zone with sub-stoichiometric conditions across the furnace width. The reburning process is also enhanced by high reburning zone temperatures. The OFA injector placement and air velocity were optimized with respect to location and mixing in order to ensure optimum temperature for complete burnout of fuels. Since sorbent sulfation is highly temperature dependent, the process required optimization with respect to location of injectors and injection air requirement. Sorbent sulfation effectively occurs over a temperature range of 1600 to 2200°F (870 to 1200°C), with a required residence time of approximately 1.0 second for sulfation over this temperature range. The general arrangement of reburning fuel, OFA, and sorbent injectors is shown in Figure 3-1.

The design basis for the Hennepin Unit 1 GR-SI system is summarized in Table 3-1. The GR-SI process is applied with natural gas input corresponding to 18% of the total heat input. The primary zone and reburning zone are operated at stoichiometric ratios of 1.1 and 0.9. The formation and reduction of NO_x is optimized through the primary and reburning zone stoichiometric ratios. To achieve the required mixing rate with the furnace gases, recycled flue gas - FGR (corresponding to 3% of the total flue gas) - is injected coaxially with the natural gas. The GR system has four injector assemblies, one in each corner of the boiler. Each assembly consists of four rectangular nozzles separated by an optimal distance to prevent impingement of the reburning jet on the furnace walls. The reburning fuel injectors were designed with tilting capability (which was later removed).

The GR process requires adequate penetration of the primary gas stream, without over penetration. The reburning fuel jets must also rapidly mix with (entrain) the primary gases, to form the sub-stoichiometric conditions across the furnace cross-section. Therefore, injection location, velocity, and total mass flow were critical design considerations. The injection locations are also essential for adequate residence time in the reburning zone.

OFA is injected to burn out the fuel at a stoichiometric ratio of 1.18. The OFA is injected through four rectangular ports at a velocity less than one-third that of the reburning fuel jets. The OFA is injected at a distance above the coal burners corresponding to a mean gas residence time of 0.5 seconds in the reburning zone (design case). The OFA temperature of 575°F (302°C) is sufficient to complete combustion with only a small gas temperature

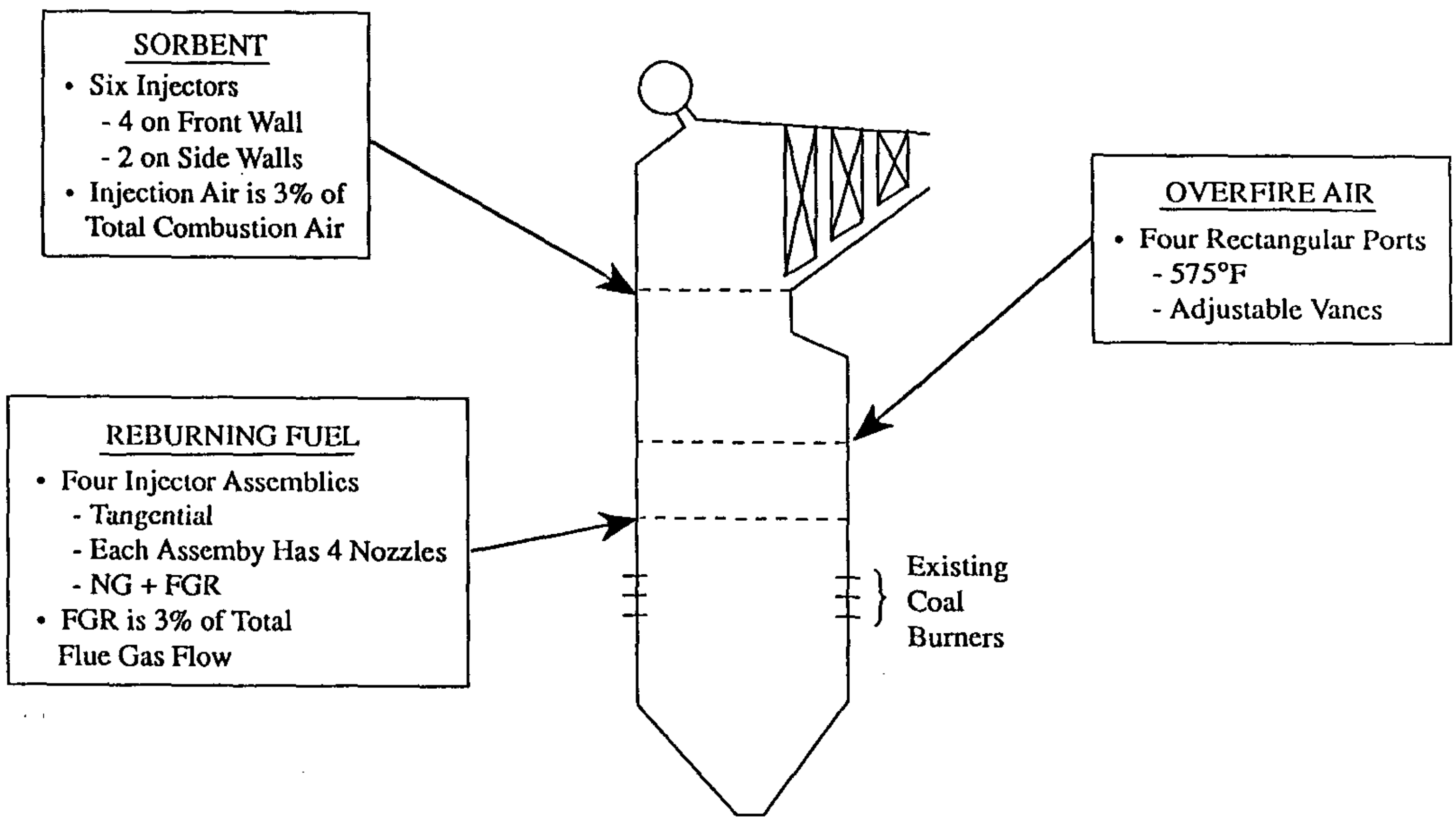


Figure 3-1. GR-SI injector specification for Hennepin Unit 1

TABLE 3-1. DESIGN BASIS FOR HENNEPIN UNIT 1 GR-SI SYSTEM

Hennepin Boiler	
Unit Capacity	71 MWe (Net)
Heat Rate	10,338 Btu/KW-hr
Nominal GR-SI Conditions	
Stoichiometrid Ratios	
Primary Burner Zone	1.10
Reburning Zone	0.90
Burnout Zone	1.18
Natural Gas Flow	18% of total heat input
Recycled Flue Gas	3% of total flue gas
Overfire Air	24% of total combustion air
Ca/S Molar Ratio	2.0
Sorbent Composition	$Ca(OH)_2$
Sorbent Injection Air	3% of total combustion air
Particulate Matter	
Coal Ash	20% Bottom
	5% Economizer
	75% ESP
Sorbent (reacted and unreacted)	5% Economizer
	95% ESP

quench. Isothermal flow modeling showed that a relatively low injection velocity is sufficient to adequately mix with the furnace gas; therefore no pressure boosting fan was required.

Sorbent is injected into the upper furnace, through six injectors. The design case sorbent input produces a Ca/S molar ratio of 2.0, which corresponds to a sorbent input of approximately 7,500 lb/hr (950 g/s), at full load of 75 MW_e with 18% heat input by gas. The injection location was selected based on the optimum gas temperature and quench rate. Six injectors, four on the furnace front wall and one on each side wall, were used with an injection air requirement of 3% of the total combustion air. The injection velocity was optimized for rapid entrainment of the local furnace flow field.

The 2D Code was used to calculate the mean gas temperature as a function of vertical distance for the baseline, GR, and GR-SI operation. The mean gas temperature profiles, shown in Figure 3-2, indicate that GR and GR-SI result in only minor impacts on the gas temperature profile. The gas temperature is slightly higher than baseline in the burner areas, due to reduced air levels (stoichiometric ratio) in the burner zone under GR and GR-SI operation. The gas temperature drops slightly at the reburning fuel injectors due to injection of FGR and then drops significantly at the OFA air ports due to injection of burnout air. The gas temperature is slightly reduced through the convective passes.

3.4 Technology Performance Objectives

The GR-SI system was designed to reduce emissions of NO_x by 60% from the "as-found" baseline of 0.75 lb/10^6Btu (323 mg/MJ) to 0.30 lb/10^6Btu (129 mg/MJ). A 50% reduction in SO_2 emissions from a baseline of 5.3 lb/10^6Btu (2,280 mg/MJ) to 2.65 lb/10^6Btu (1,140 mg/MJ) was also projected.

These emissions reductions were expected with minor impacts on emissions of other species

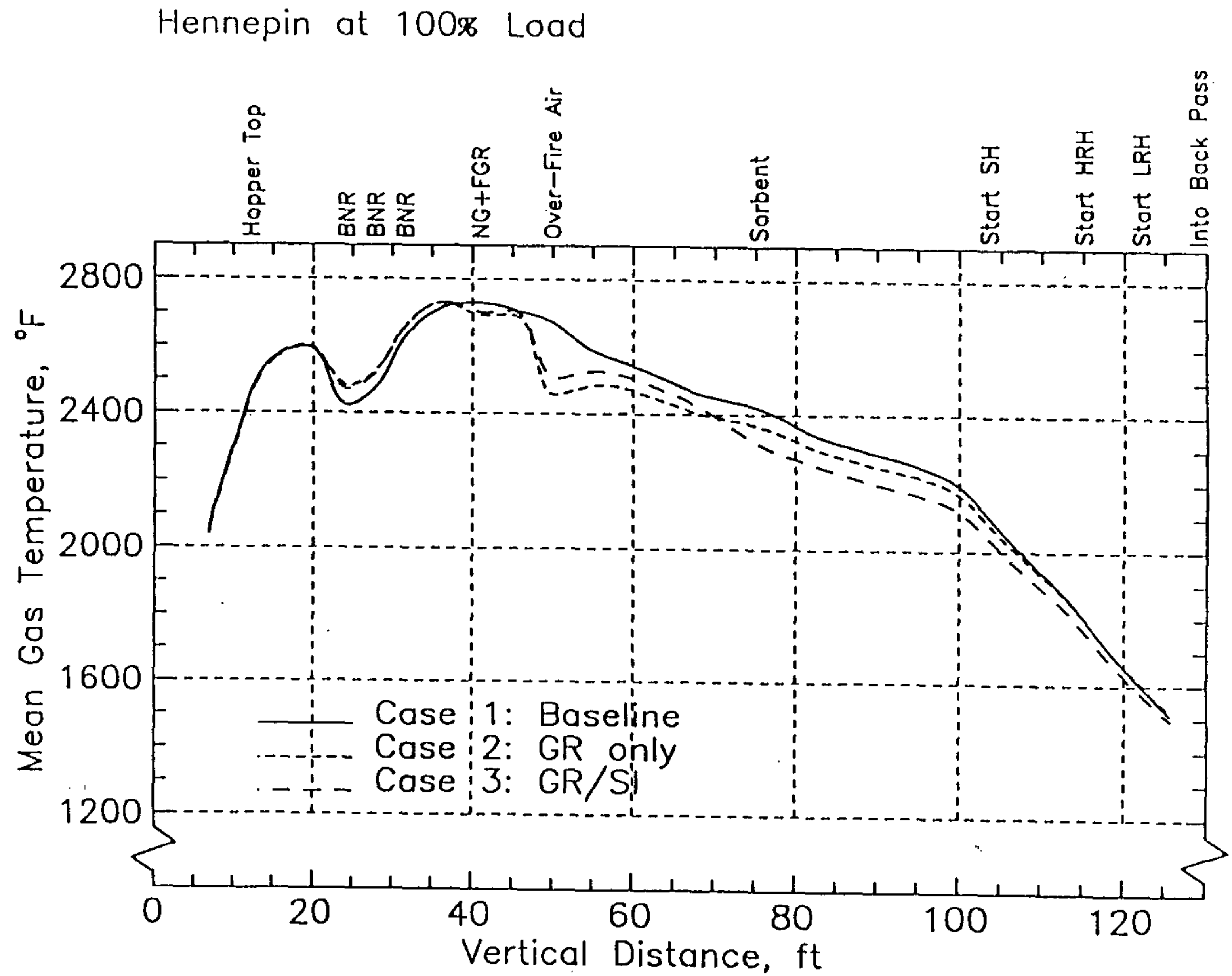


Figure 3-2. Predicted mean gas temperature profile for Baseline, GR and GR-SI at full load

and on other areas of unit operation. Some reduction in CO_2 emissions was expected, due to fuel switching since the C/H ratio of coal and natural gas are significantly different. A reduction in CO_2 emissions by 7% from firing natural gas at a gas heat input of 18% was expected. Essentially no change in CO and hydrocarbon (HC) emissions was expected. The GR–SI system was designed to inject OFA at a sufficient velocity and exit stoichiometric ratio to fully burn out fuel combustible matter. Flue gas humidification was expected to enhance ESP performance during GR-SI, resulting in no increase in particulate matter emissions. A potential increase in PM_{10} (particulate matter with and aerodynamic diameter under 10 microns) was expected since under GR-SI operation approximately 50% of the ESP inlet particulate loading is spent or unreacted sorbent. The sorbent has a mass mean diameter (MMD) of less than 5 microns.

GR-SI operation was expected to have only minor impacts on steam generation/thermal performance. Tables 3-2 and 3-3 list the expected GR-SI impacts on steam production, heat absorption, gas exit temperature, and thermal efficiency. Minor impacts were expected to main and reheat steam flows and temperatures, boiler exit gas temperature, heat absorption rates in the various areas, and carbon in ash. A minor reduction in main and reheat steam flows (approximately 5,000 lb/hr [0.6 kg/s]) was expected. GR-SI was not expected to affect reaching the design steam temperature of 1005°F (541°C) for both main and reheat steam. The heat absorption was expected to shift, with lower absorption in the furnace and by the secondary and reheat superheaters, and higher heat absorption by the primary superheater and economizer. A small increase in the superheater attemperation rate was expected due to firing of the reburning fuel at a higher furnace elevation and heat transfer surface fouling. An increase in the air heater exit gas temperature was also expected, from a baseline of 339°F (171°C) to 352°F (178°C). A reduction in the thermal efficiency was expected, from 87.36 to 85.82% (Table 3-3). This is due primarily to the heat loss resulting from increased formation of moisture from the combustion of additional hydrogen in methane. Combustion of natural gas results in a significant increase in H_2O formation, relative to coal combustion. Additional reduction in efficiency was also expected due to dry gas heat loss, since the boiler exit temperature is slightly higher.

TABLE 3-2. HENNEPIN BOILER PERFORMANCE PREDICTIONS
EFFECT OF GAS REBURNING AND SORBENT INJECTION AT 100% LOAD

ITEM	BASELINE	GR-SI
Steam Mass Flows (klb/hr)		
Into Economizer	540.6	533.9
SH Attemperation Spray	14.5	16.5
Exit Superheater	555.1	550.4
Into Reheater	488.5	484.4
RH Attemperation Spray	9.3	8.1
Exit Reheater	497.8	492.5
Steam-Side Temperatures (°F)		
Into Economizer Bank	475	475
Exit Economizer Bank	511	515
Into Primary Superheater	603	603
Exit Primary Superheater	854	868
SH Attemp. Spray Water	475	475
Into Secondary Superheater	815	822
Exit Secondary Superheater	1005	1005
Into RH Attemperator	750	750
RH Attemp. Spray Water	475	475
Into Low Temp. Reheater	717	721
Exit High Temp. Reheater	1005	1005
Heat Transfer to Steam (10^6Btu/hr)		
Economizer	26.7	28.5
Waterwall	355.5	348.9
Primary Superheater	130.1	133.0
Secondary Superheater	63.8	60.8
Reheaters	76.2	74.4
Gas Side Temperatures (°F)		
Into Back Pass	1424	1414
Exit Primary Superheater	806	817
Exit Economizer	692	701
Exit Air Heater	339	352
Air Temperatures (°F)		
Into Air Heater	115	115
Exit Air Heater	578	591

TABLE 3-3. HENNEPIN THERMAL EFFICIENCY PREDICTIONS USING THE ASME ABBREVIATED HEAT LOSS METHOD

	Baseline	GR-SI
Heat Loss (%)		
Dry Gas	5.04	5.26
Moisture from Fuel	1.45	1.20
Moisture from Combustion	4.02	5.35
Combustible in Refuse	0.30	0.54
Radiation	0.33	0.33
Unmeasured	1.50	1.50
TOTAL LOSSES	12.64	14.18
Thermal Efficiency (%)	87.36	85.82

4.0 PROJECT AND TESTING OVERVIEW

4.1 Project Overview

The project conducted at Hennepin Unit 1 was one of several demonstrations in Round 1 of DOE's CCT Program. EER designed and retrofitted a GR-SI system to Hennepin Unit 1, then evaluated the system with both short parametric tests and over an extended period. The project had three sponsors, the DOE being the primary funding agency, with co-funding provided by GRI, ENR and the host utilities.

4.1.1 Project Organization and Schedule

The project was initiated in June 1987 upon award of a contract by DOE (EER, 1987), GRI and ENR. It has been conducted in three phases:

Phase	Completion Date
I - Design and Permitting	May 1989
II - Construction and Startup	August 1991
III - Operation, Data Collection, Reporting and Disposition	October 1994

In Phase I, the process and engineering designs were completed. This phase included baseline testing, to characterize "as found" operating conditions, then application of a variety of analytical tools to develop the process design aimed at 60% NO_x reduction and 50% SO_2 reduction. The process specifications were then used to develop site-specific engineering plans for the GR-SI system. Permitting issues, including permits to construct and operate GR-SI and formulation of a plan to monitor environmental impacts, were also addressed. In Phase II, GR-SI system construction and start-up were completed. EER provided oversight for the construction, coordinating the work of several sub-contractors. Functional equipment check-out and calibration were completed, yielding a fully operable system. In Phase III, the GR-SI system was operated first, under short parametric tests designed to characterize the impact of each process variable, then over a one-year demonstration at optimum conditions with respect to emissions control and boiler performance. Test data were continually evaluated and results disseminated to funding organizations and to the power generation industry, via technical papers. This report detailing the GR-SI operating results and the Guideline Manual (Volume 5), presenting cost data, were prepared. Each phase was completed under the review and guidance of funding organizations and host utilities.

The tasks completed in each phase are outlined below.

Phase I: DESIGN AND PERMITTING

Task 1 - Project Management
Task 2 - Process Design
Task 3 - Project Engineering
Task 4 - Environmental Reporting, Permitting, Plans and Design
Task 5 - Technology Transfer

Task 1 (project management) entailed coordination of work with participants and subcontractors. In Task 2, the GR-SI process design was established based on the host site characterization. The GR-SI system process design was used in Task 3 to prepare a site specific engineering design and drawings. Task 3 activities included cost estimates, construction plans and schedules, startup plans and a Phase III test plan. In Task 4, relevant environmental data were compiled in Environmental Information Volumes (EIVs) to obtain IEPA approval, Environmental Monitoring Plans (EMPs) were prepared, and assistance was given to the host site in obtaining necessary environmental permits and permit modifications. For the purpose of technology transfer, an industry panel was convened for planning of GR-SI technology transfer as well as review of the process and detailed engineering design.

Phase II: CONSTRUCTION AND STARTUP

Task 1 - Project Management

Task 2 - Installation and Check-out

Task 3 - Technology Transfer

The Phase II project management task was a continuation of the Phase I project management activities and involved establishment of project review meetings at the 20 and 100% completion points. In Task 2, the GR-SI and humidification systems were retrofitted and equipment check-out was carried out. The technology transfer task in Phase II was a continuation of the work begun in Phase I, with continued meetings with members of the Industry Panel to discuss technology transfer and to review the work progress.

Phase III: OPERATION, DATA COLLECTION, REPORTING AND DISPOSITION

Task 1 - Project Management

Task 2 - Technology Demonstration

Subtask 2.1 - GR, SI, and GR-SI Optimization Testing

Subtask 2.2 - Gas/Coal Cofiring and Gas/Gas Reburning

Subtask 2.3 - GR-SI Long-Term Testing

Subtask 2.4 - Evaluation of Alternate Sorbents

Task 3 - Evaluation of Demonstration Results

Task 4 - Restoration

Task 5 - Technology Transfer

The project management task in Phase III was a continuation of previous project management work and culminated with a final project review meeting and this final report. Task 2 (technology demonstration) entailed short term GR-SI system optimization testing, evaluation of an alternate NO_x control technologies - Gas/Coal Cofiring and Gas/Gas Reburning, long-term GR-SI demonstration, and evaluation of advanced sorbents. The purpose of the short-term GR-SI optimization testing was to determine the impacts of each process variable, resulting in a definition of optimum process conditions for NO_x and SO_2 reduction. Following initial GR-SI optimization testing, Gas/Coal Cofiring and Gas/Gas Reburning were evaluated over a two week period. In Subtask 2.3, the GR-SI system performance was evaluated over a one-year period at conditions optimum for emissions reduction/unit performance. The performance of the unit was monitored through a Boiler Performance Monitoring System (BPMS) which continuously monitored emissions as well as impacts on many areas of boiler operation. Manual sampling of a variety of species was also conducted during the extended testing. In Subtask 2.4, newly developed advanced sorbents, prepared by EER, were evaluated as well as a high surface area sorbent prepared by the Illinois State Geological Survey.

In Task 3, the performance data were analyzed and compiled in this Final Report. A guideline manual was also prepared, incorporating design recommendations, cost projections and a comparison with competing technologies. Task 4, restoration of the host site, has been completed with the host site deciding to retain the GR system. The technology transfer task is continuing with industry panel meetings for review of program results and consideration of areas for application of GR-SI technology.

EER is involved at two other sites in DOE CCT programs, including the other CCT Round 1 GR-SI retrofit of a 33 MW_e (gross) cyclone fired unit (City Water, Light and Power's Lakeside Station Unit 7, in Springfield, Illinois). The goals of the program at Lakeside Unit 7 are the same as those at Hennepin, reduction of NO_x and SO_2 by 60 and 50%, respectively. The other program is a CCT Round 3 retrofit of Low NO_x Burners and GR to a 172 MW_e (gross) wall fired unit (Public Service of Colorado's Cherokee Station Unit 3 in Denver, Colorado). The goal of the Cherokee Unit 3 program is 70% NO_x reduction.

4.2 Testing Overview

The primary objective of the test program at Hennepin was to demonstrate that the GR-SI process can simultaneously reduce NO_x and SO_2 emissions by 60 and 50%, respectively, from the "as found" baseline emissions without adverse performance impacts. The parameters which affect GR performance included natural gas usage (percent of total heat input), flue FGR, zone stoichiometric ratio (the ratio of actual air flow in a region of the boiler to the air flow required for complete combustion of the fuel according to theory), load, and burner tilt. Parameters which potentially impact sorbent utilization include sorbent input, sorbent reactivity, injection velocity and configuration, load, excess air, and burner tilt. These parameters were varied systematically to optimize GR-SI performance.

The GR-SI process impacts boiler performance including in-furnace characteristics such as gas temperatures and species concentrations, furnace corrosion, slagging and fouling, and boiler thermal performance such as heat rate, thermal efficiency, and convective section heat absorption. Impacts of GR-SI on boiler operability include downstream impacts such as nitrous oxide (N_2O) emissions, ESP performance and particulate emissions, and solid byproduct handling procedures.

Another important objective of the test program at Hennepin was to demonstrate that GR-SI can achieve the project emissions goals at low total cost. Demonstrated low cost is important for further commercialization and acceptance of GR-SI technology by the end user. The approach to achieve the objective was to establish a data base for the assessment of the capital and operating costs for all aspects of plant operation resulting from the application of GR-SI.

Finally, testing at Hennepin was designed to generate a data base which may be used to assess the technical feasibility and expected performance of GR-SI on other boilers. This data base is used to establish the sensitivity of NO_x and SO_2 emissions reductions to process parameters such as gas usage, recirculated flue gas quantity, sorbent type, SI configuration, coal properties, boiler design, and operating conditions and to validate and improve the design methodology. The test series carried out as part of this test project are:

- GR optimization tests
- SI optimization tests
- GR-SI optimization tests

- Gas/Coal Cofiring and Gas/Gas Reburning
- GR-SI demonstration testing
- Alternate sorbent tests.

The first three test series were designed to optimize the GR-SI process variables. Each series consisted of many short tests designed to determine the impact of one parameter at a time. The optimum conditions of GR-SI operation with respect to process efficiency and unit performance were determined. The optimization/parametric testing was followed by the Gas/Coal Cofiring and Gas/Gas Reburning testing, which involved many short parametric tests (58 Gas/Coal Cofiring, 19 Gas/Gas Reburning) over a period of two weeks. The focus of these tests was NO_x reduction, but also included evaluation of impacts on steam temperatures, heat absorption, capacity, efficiency and ash carbon loss. Following the Gas/Coal Cofiring and Gas/Gas Reburning tests, the year-long GR-SI demonstration took place. This was designed to validate GR-SI effectiveness in NO_x and SO_2 reduction over the long-term and to evaluate any potential impacts of GR-SI on the host unit. Following the one-year demonstration, alternate sorbents were evaluated. The scope of testing and measurement format varied with the test series and are described in Section 5.

4.2.1 Testing Schedule

The schedule under which GR-SI testing was conducted is shown in Figure 4-1. The evaluation of the GR-SI system as initiated with system start-up, performance verification, and QA/QC tests which were conducted from October 1990 to March 1991. Following verification of satisfactory system performance, short test series, over a period of four months, were carried out to optimize GR, SI, GR-SI, Gas/Coal Cofiring and Gas/Gas Reburning processes. Optimization test results were evaluated and long-term testing parameters were established. The results of the optimization test series are presented in Section 6 of this report. The year-long technology demonstration was conducted from October 1991 to October 1992. Following the completion of the long-term demonstration and a month-long outage, advanced sorbent were evaluated. These sorbents, prepared by EER and ISGS, were evaluated in December 1992/January 1993.

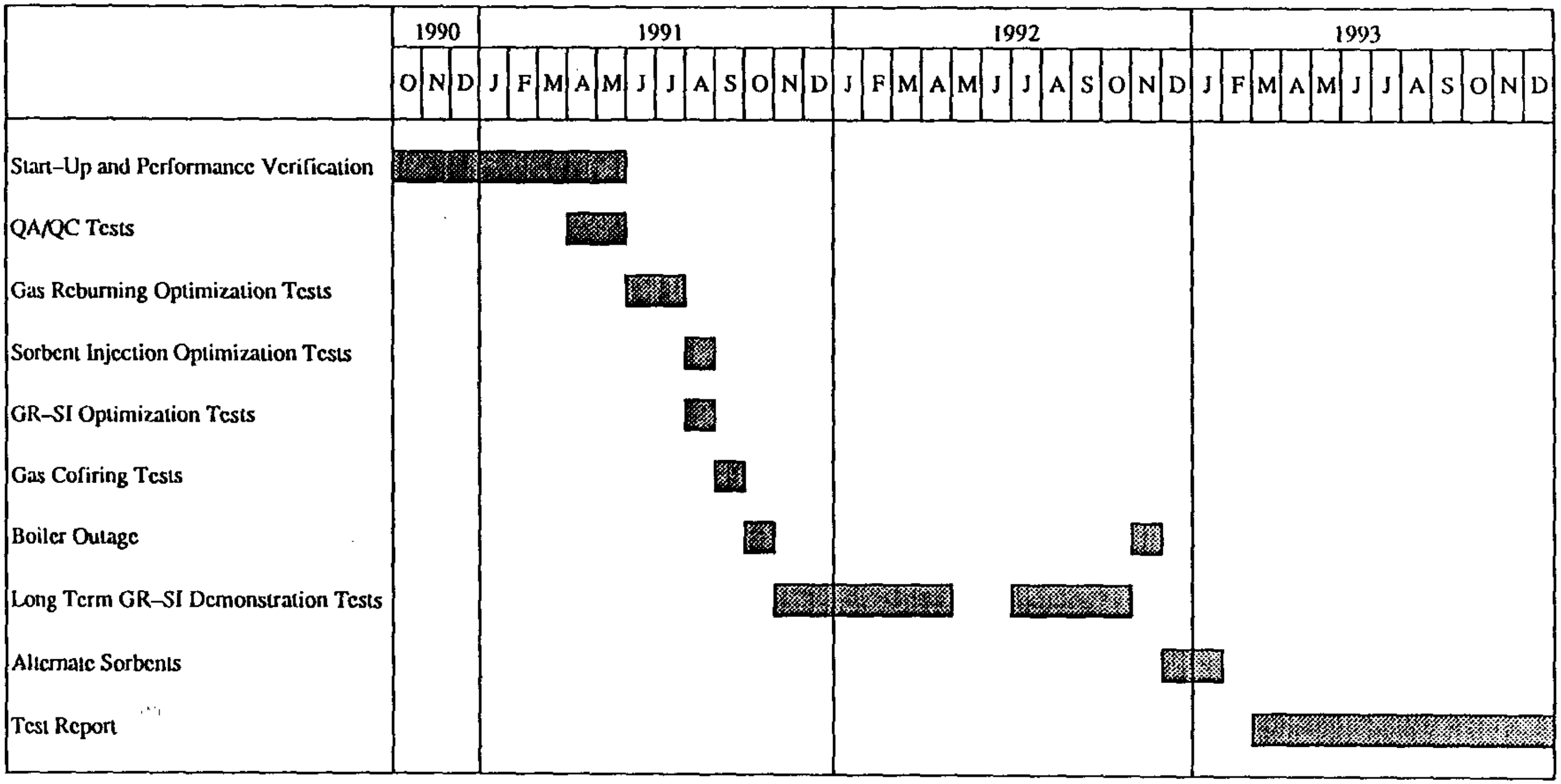


Figure 4-1. Test schedule for the GR-SI evaluation at Hennepin Unit 1

5.0 TEST PLAN

The GR-SI test plan was prepared initially in Phase I of the project and was revised in Phase III, just before the initiation of the GR-SI optimization testing. The test plan specified the purpose, number of tests, operating conditions, and measurements to be taken during each test. The testing was divided into several test series designed to optimize the GR-SI system operation with respect to NO_x and SO_2 reduction and unit performance.

5.1 Test Objectives

The goals of the test program were to initially assess the impacts of process parameters on NO_x and SO_2 reduction and unit operation, then to operate the unit over an extended period (one year) under optimum conditions. To determine the impacts of process parameters, short parametric tests were planned. Tests were organized into test series in which single parameters were evaluated incrementally. Short term tests were carried out to determine optimum GR performance with respect to boiler load, coal zone stoichiometric ratio, reburning zone stoichiometric ratio, gas heat input, recycled flue gas, OFA, burner and reburning fuel injector tilt, and the mills in service. To determine the optimum NO_x reduction with respect to these parameters, the parameters were varied using the GR-SI process design as a guide. The SI process was evaluated by determining the optimum operating conditions resulting in a minimum of 50% SO_2 reduction. The parameters evaluated include sorbent flow rate (or Ca/S molar ratio), sorbent jet velocity, and sorbent configuration (i.e. sorbent nozzles in use). The impacts of boiler load on the SO_2 removal process and required changes in sootblowing were also determined.

These tests led to establishment of the optimum process variables for the long-term testing. The long-term testing was designed to demonstrate the effectiveness of the GR-SI process over an extended period for control of NO_x and SO_2 emissions. An extensive set of measurements was taken to determine GR-SI impacts on the operation of the unit including unit steam generation/thermal performance, fouling/slagging, tubewall wastage rates, species in-furnace concentration/emissions, ESP performance, and ash/spent sorbent impacts. The measurements were designed to verify that GR-SI may be applied without adverse impacts on unit operability and durability.

A further goal of the test program was to assess the economic impacts of GR-SI operation. This was desired to demonstrate the cost effectiveness of GR-SI technology for commercial application. All costs were documented, including GR-SI system capital cost and costs of fuels, sorbent, maintenance and labor. The amount of fuel fired depends on the heat rate, therefore the heat rate during GR-SI operation was quantified. The economic data are presented in Volume 5 of this report.

5.2 Measurement Formats

Detailed measurement formats were used for a thorough evaluation of the GR-SI process and the impact on various areas of boiler performance. Four measurement formats were used to evaluate the impacts of GR-SI operation. Figure 5-1 is an overview of the measurements taken. The ports through which measurements were taken are shown in Figure 5-2a and 5-2b.

The four measurement formats used are: Standard Format, In-Furnace Measurements, Additional Measurements, and ESP Measurements. The measurements specified in each format are shown in Table 5-1. The formats are briefly described below:

- Standard Format The most commonly used format is the standard format. This includes data recorded and evaluated with a Boiler Performance Monitoring System (BPMS) and hand-recorded data from control room displays. These define the operation and performance of the unit including fuel and air flow rates and pressures, gas-side and steam-side temperature/pressure/heat absorption data, ESP electrical data, and equipment/instrument settings. It includes Continuous Emissions

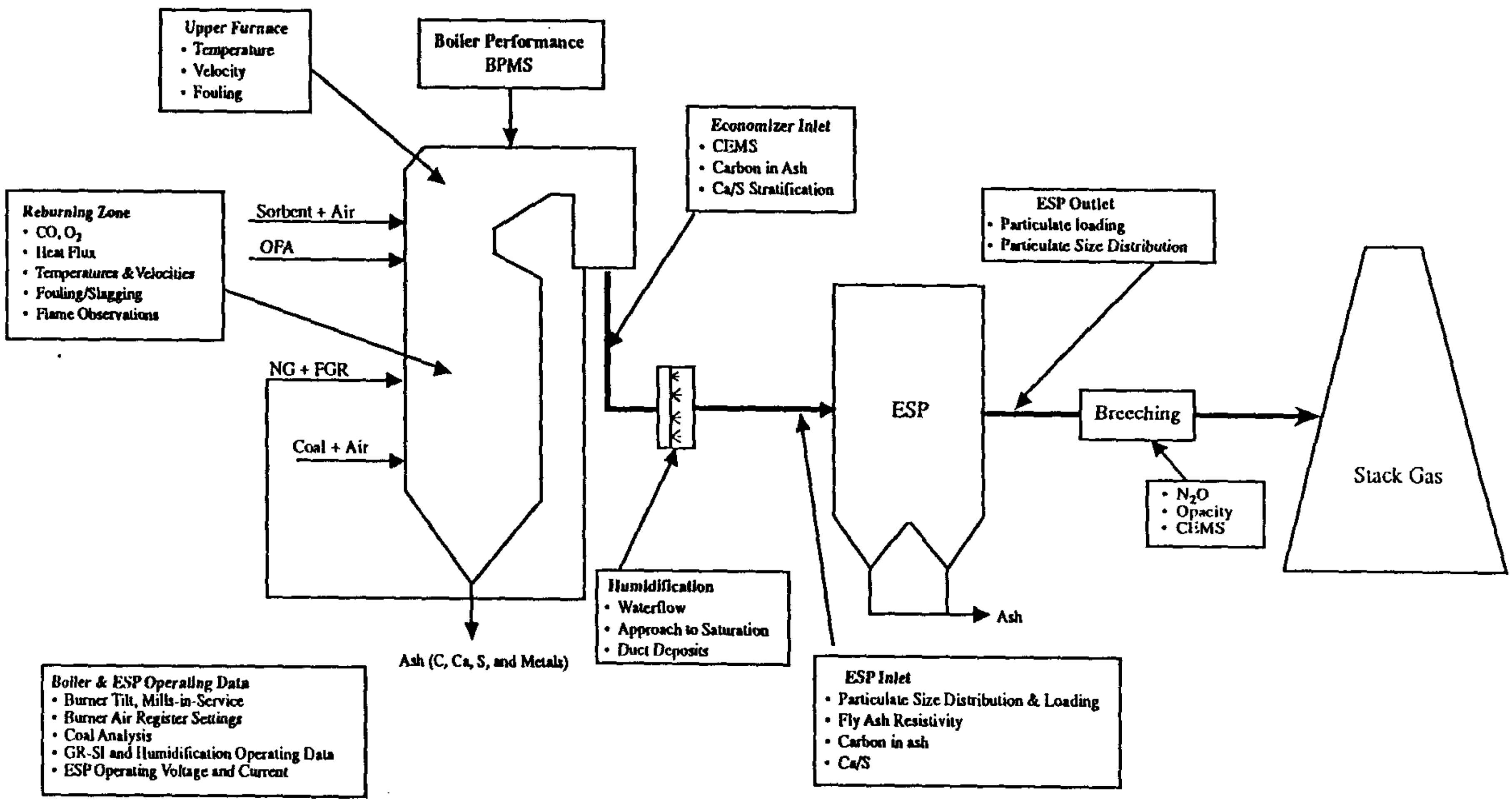


Figure 5–1. Measurement overview

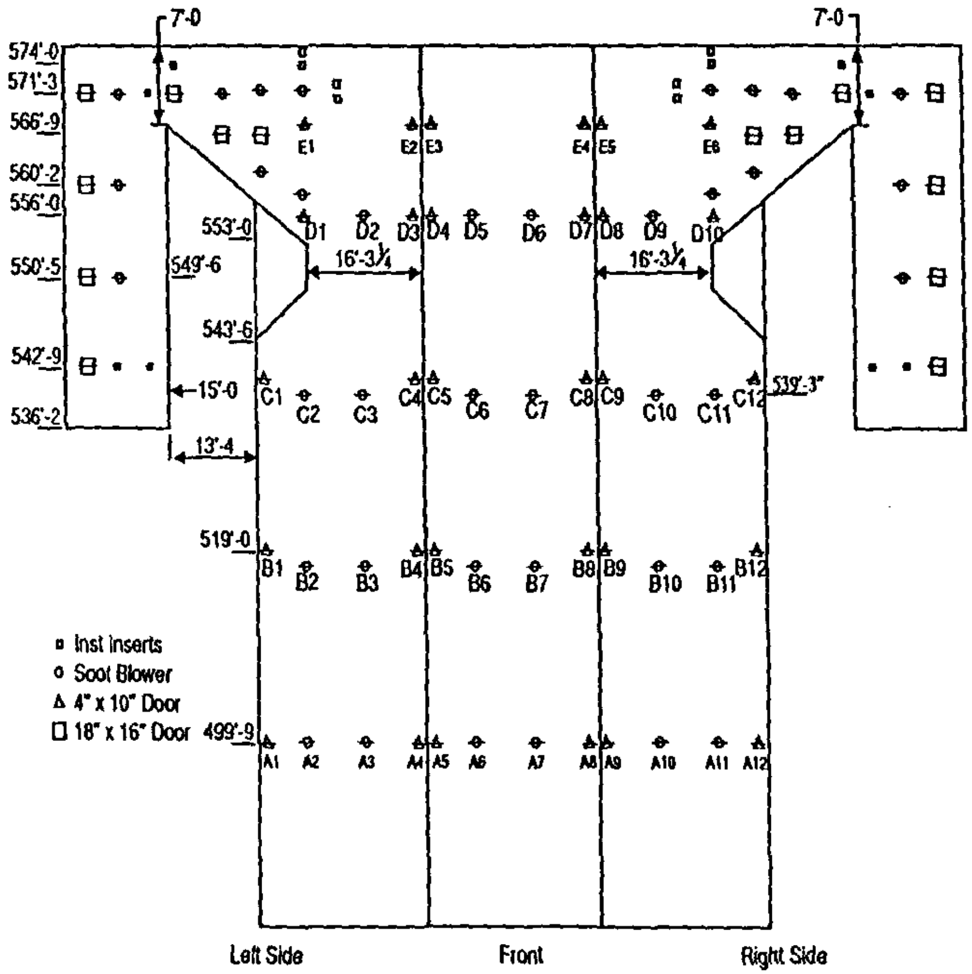


Figure 5-2a. Hennepin Unit 1 furnace ports

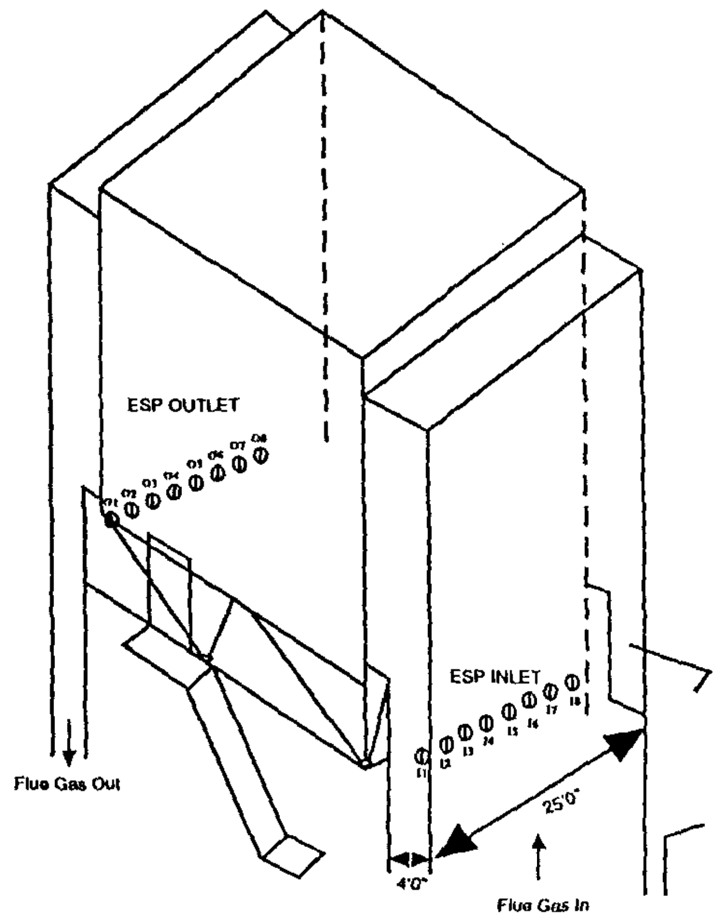


Figure 5-2b. ESP sampling ports

TABLE 5-1. MEASUREMENT FORMATS

Location	Measurement	Format			
		Standard	In-Furnace	Additional	ESP
Control Room	Boiler & ESP Operating Data	X			
	GR-SI System & Humidification Performance	X			
Boiler	Operating Settings	X			
Economizer Inlet	CEMS	X			
	Ca/S Stratification			X	
	Carbon in Ash			X	
	N2O			X	
Breeching (#)	CEMS	X			
Coal Mills	Coal Characteristics			X	
Ash Pond	Water Analysis			X	
Sorbent Silo	Sorbent Analysis			X	
Furnace Ports	Temperatue & Velocity		X		
B2, B3, B6, B7	CO & O2		X		
B10, B11 (*)	Slagging		X		
	Radiant Heat Flux		X		
Furnace Exit Ports	Temperature & Velocity		X		
D2, D5, D6, D9 (#)	Fouling & Slagging		X		
ESP Inlet & Outlet	Particulate Size Distribution				X
	Particulate Loading				X
	SO3				X
	Ash Resistivity				X
ESP Inlet	Temperature				X
(Humidification)	Velocity				X
ESP Hopper	C, Ca, S				X

(*) During Gas Reburning

(#) During Sorbent Injection

Monitoring System (CEMS) measurement of the emissions at either the economizer or the breeching (when operating SI).

- In-Furnace Measurements In-furnace measurements were taken to determine concentration of combustion products and to characterize combustion efficiency (i.e. temperature, radiant heat flux, etc.). These were taken in the reburning zone and in the upper furnace. The measurements include radiant heat flux, CO, velocity, temperature, and visual slag pattern observations. The reburning zone measurements include temperature, velocity, O_2, and CO.

- Additional Measurements This format includes coal, ash, and sorbent analyses. Other measurements made include N_2O emissions and ash/spent sorbent characterization at the economizer inlet. The ash sampling includes determination of the ash carbon content and the ash/spent sorbent Ca/S stratification in the economizer inlet duct.

- ESP Measurements The particulate matter emissions and ESP collection efficiency were characterized through manual sampling of particulate matter at the ESP inlet and outlet. The fly ash size distribution was also obtained. Fly ash size distribution was expected to change due to the difference in the size of coal fly ash in comparison to that of sorbent particles. The fly ash resistivity was measured in-situ. Various ESP operating parameters (e.g. voltages, currents, ramp speed, spark setback) were recorded during testing to evaluate impacts of GR-SI operation.

5.3 Test Matrix

This section describes the test series conducted, the objectives of each test, the set-point of process parameters and the measurements taken. Testing was divided into five test series:

- GR Optimization (Parametric) Tests
- SI Optimization (Parametric) Tests

- Short-Term GR-SI Optimization (Parametric) Tests
- Gas/Coal Cofiring and Gas/Gas Reburning
- Long-Term GR-SI Tests
- Alternate Sorbents Tests

Advanced sorbents, including those developed by EER and the Illinois State Geological Survey, were also evaluated.

5.3.1 Gas Reburning Optimization Tests

GR process parameters, such as primary zone stoichiometrc ratio, reburning zone stoichiometric ratio, natural gas and FGR quantities, coal burner tilt, injector tilt, and OFA flow rate, were varied over wide ranges. It was found from these tests that primary and reburning zone stoichiometric ratios, natural gas input, and FGR flow rate had strong impacts on NO_x emissions. Variation of the OFA flow rate during GR operation was found to have some effect on NO_x emissions although the impacts were not strongly established. Burner tilting was determined to have slight impact on NO_x emissions while natural gas injector tilting had resulted in an insignificant effect on NO_x reduction.

The GR optimization test series was designed based upon the results obtained from these start-up tests. The main objectives of this test series were to: (1) consolidate the impacts of the aforementioned GR parameters on NO_x reductions; (2) obtain a data base for evaluating the impacts of GR-SI on the boiler performance and operability; and (3) confirm and strengthen the GR design methodology.

The GR optimization tests evaluated the impacts on a full range of GR process parameters over a wide range of boiler loads. The following process variables were evaluated:

- Primary Zone Stoichiometric Ratio (SR_1)
- Reburning Zone Stoichiometric Ratio (SR_2)

- Burnout (Exit) Zone Stoichiometric Ratio (SR_3)

These were calculated by the following formulae:

- SR_1 = (TAFLW - OFA)/(CFLW x CTA)
- SR_2 = (TAFLW - OFA)/[(CFLW X CTA) + (GFLW x GTA)]
- SR_3 = 1 + EA/100 = TAF/[(CFLW x CTA) + (GFLW x GTA)]

Where: TAFLW = Total Air Flow (scfh)
OFA = Overfire Air Flow (scfh)
CFLW = Coal Flow (lb/hr)
CTA = Coal Theoretical Air (scf/lb coal)
GFLW = Gas Flow (scfh)
GTA = Gas Theoretical Air (scf/scf gas)
EA = Excess Air (%)

The term "Burnout" Zone corresponds to GR operation and "Exit" Zone corresponds to SI or GR-SI operation. Under SI and GR-SI operation the total air flow includes SI air, which in the design case is 3% of the combustion air.

Other parameters evaluated:

- Boiler load
- Number of mills in service
- Burner tilt
- FGR flow rate
- Reburning fuel injector tilt

The test conditions for the test series are summarized in Table 5-2. The initial test conditions at full load (GR-33a to GR-33g tests) concentrated on evaluating the sole impacts

TABLE 5–2. GAS REBURNING PARAMETRIC TEST CONDITIONS

TEST ID	TEST DESCRIPTION	LOAD (MW)	MILLS IN-SERVICE	BURNER TILT (DEG.)	PRIMARY SR	REBURN SR	BURNOUT SR	NG %	FGR (SCFM)	OFA (SCFM)	MEASUREMENTS			
											STANDARD	IN-FURNACE (REBURNING ZONE)	N2O	C IN ASH
GR-33a	Baseline	70	3	-20	(#)	(#)	1.2	0	Cooling	Cooling	X	X	X	X
GR-33b	Staged Combustion	70	3	-20	(#)	(#)	1.2	0	Cooling	5000	X			
GR-33c	Staged Combustion	70	3	-20	(#)	(#)	1.2	0	Cooling	10000	X	X		X
GR-33d	Staged Combustion	70	3	-20	(#)	(#)	1.2	0	Cooling	15000	X			
GR-33e	Staged Combustion	70	3	-20	(#)	(#)	1.2	0	Cooling	Max.	X	X		X
GR-33f	Low Excess Air	70	3	-20	(#)	(#)	1.2	0	Cooling	As Req'	X			
GR-33g	*Minimum* Excess Air	70	3	-20	(#)	(#)	1.2	0	Cooling	As Req'	X			
GR-34a	Burner Tilt On Baseline NOx Emissions	70	3	Horizontal	(#)	(#)	1.2	0	Cooling	Cooling	X	X		X
GR-34b		70	3	20	(#)	(#)	1.2	0	Cooling	Cooling	X			
GR-35a	Burner Tilt On NOx Emissions During GR	70	3	-20	1.1	(#)	1.2	20 (*)	7000	As Req'	X	X	X	X
GR-35b		70	3	Horizontal	1.1	(#)	1.2	20 (*)	7000	As Req'	X			
GR-35c		70	3	20	1.1	(#)	1.2	20 (*)	7000	As Req'	X			
GR-36a	FGR Flow Variation	70	3	-20	1.1	(#)	1.2	20 (*)	3500	As Req'	X			
GR-36b		70	3	-20	1.1	(#)	1.2	20 (*)	Max	As Req'	X			
GR-37a	Reburning Zone SR Variation	70	3	-20	1.1	(#)	1.2	20 (*)	Max	As Req'	X	X	X	X
GR-37b		70	3	-20	1.1	(#)	1.2	15 (*)	Max	As Req'	X	X	X	X
GR-37c		70	3	-20	1.1	(#)	1.2	10 (*)	Max	As Req'	X	X	X	X
GR-38a	Load Variation	60	3	Normal	(#)	(#)	1.2	0	Cooling	Cooling	X	X		X
GR-38b		50	3	Normal	(#)	(#)	1.2	0	Cooling	Cooling	X	X		X
GR-38c		40-45	2	Normal	(#)	(#)	1.2	0	Cooling	Cooling	X	X		X
GR-39a	Mid Load Reburning Tests	60	3	Normal	(#)	(#)	1.25	0	Cooling	Cooling	X	X		X
GR-39b		60	3	Normal	1.1	(#)	1.25	10	7000	As Req'	X	X		X
GR-39c		60	3	Normal	1.1	(#)	1.25	20 (*)	7000	As Req'	X	X	X	X
GR-40a	Low Load Reburning Tests	40-45	2	Normal	(#)	(#)	1.3	0	Cooling	Cooling	X	X		X
GR-40b		40-45	2	Normal	1.1	(#)	1.3	10	7000	As Req'	X	X		X
GR-40c		40-45	2	Normal	1.1	(#)	1.3	20 (*)	7000	As Req'	X	X	X	X

(*) Or maximum gas available
(#) Calculated by the Boiler Performance Monitoring System -- Results in Table A-4

TABLE 5–2. GAS REBURNING PARAMETRIC TEST CONDITIONS (CONTINUED)

TEST ID	TEST DESCRIPTION	LOAD (MW)	MILLS IN-SERVICE	BURNER TILT (DEG.)	PRIMARY SR	REBURN SR	BURNOUT SR	NG %	FGR (SCFM)	OFA (SCFM)	MEASUREMENTS			
											STANDARD	IN-FURNACE (REBURNING ZONE)	N2O	C IN ASH
GR-41a	SR2 Variation	70	3	-20	1.08	(#)	1.2	10	7000	As Req'	X			
GR-41b		70	3	-20	1.08	(#)	1.2	15	7000	As Req'	X			
GR-41c		70	3	-20	1.08	(#)	1.2	18	7000	As Req'	X			
GR-42a	Staged Combustion	40	2	27	(#)	(#)	1.25	0	Cooling	5000	X			
GR-42b		40	2	27	(#)	(#)	1.25	0	Cooling	10000	X			
GR-42c		40	2	27	(#)	(#)	1.25	0	Cooling	15000	X			

(#) Calculated by the Boiler Performance Monitoring System -- Results in Table A-4

of staged combustion on NO_x emissions, N_2O emissions, and flame zone characteristics. During these tests, combustion air of up to 20% of total was gradually biased to the OFA ports by appropriate adjustments of the OFA damper positions and burner windbox dampers. In effect, the primary zone stoichiometric ratio was allowed to decrease until the flame appearance became unacceptable to the boiler operators. These tests allowed the operating range of the primary zone stoichiometric ratio to be established. The results were used to set an operating limit for the primary zone stoichiometric ratio during GR tests. In addition to the standard measurements (CEMS, coal and ash sampling, control room data, etc), N_2O measurements were carried at the maximum staged combustion condition (Test GR-33e). Time-integrated ash samples were collected during these test conditions for analysis of carbon content. Gas temperature along with concentrations of CO and O_2 in the reburning zone of the furnace were measured under the baseline condition (Test GR-33a).

Impacts of burner tilting on NO_x emissions during baseline and GR operations were also evaluated at full load (series GR-34 and GR-35 tests). During these tests, the firing angle of the burners was varied from their normal downward position to the maximum upward position. Although the tests called for a maximum upward tilt of 20 degrees, the actual firing position for the test was limited by steam temperatures and sootblowing requirements. Since the operating conditions of Test GR-35a approximated the conditions used for the process design, detailed measurements consisting of the standard measurements as well as in-furnace (temperature, CO, O_2, etc.), N_2O, and carbon-in-ash were performed during this test.

Adequate mixing of the reburning fuel with the primary combustion products had been found to have strong impact on the NO_x reduction effectiveness. The effect of the degree of mixing was evaluated by varying the injector velocity through the variation of the FGR flow rates (series GR-36 tests). During these tests, total hydrocarbons at the economizer inlet were measured in addition to standard measurements.The impacts of the reburning zone stoichiometric ratio as well as mixing of the reburning fuel with primary zone combustion products were also investigated (series GR-37 tests). The reburning zone stoichiometric ratio was varied by injecting different amounts of natural gas into the reburning zone while keeping the primary zone stoichiometric ratio constant at approximately 1.10. These tests allowed evaluation of NO_x control due to the quantity of natural gas injected.

Impacts of boiler load on NO_x emissions during baseline operation were also evaluated (series GR-38 tests). The boiler was operated at about 80, 70, and 60% of the full load and at the same excess air level as at full load. These tests determined the baseline NO_x emissions at reduced boiler loads. Time-integrated ash samples were collected from the flue gas during these tests for the analyses of carbon content in the ash.

Limited GR tests were conducted at reduced boiler loads to investigate GR performance versus load variation (series GR-39 and GR-40 tests). In these tests, different amounts of natural gas were injected and boiler emissions and performance were monitored under varied reburning zone conditions.

5.3.2 Sorbent Injection Optimization Tests

Some SI tests were performed without GR. During the tests, appropriate conditions and procedures for SI and humidification systems were established while parametric SI tests were conducted. The tests were used to evaluate the impacts of the following key variables on SO_2 emissions:

- Boiler load
- Calcium-to-sulfur molar ratio (Ca/S)
- Injection velocity
- Sorbent reactivity.

SI test conditions are summarized in Table 5-3. The impacts of the boiler load on SO_2 emissions were evaluated in test series SI-1. At 100% boiler load, conditions were expected to be optimal for SI through the upper furnace injection nozzles. As boiler load was

TABLE 5-3. SORBENT INJECTION PARAMETRIC TEST CONDITIONS

TEST ID	TEST DESCRIPTION	LOAD (MW)	MILLS IN-SERVICE	BURNER TILT (DEG.)	EXIT SR	Ca/S MOLAR	INJECTION ELEVATION	SORBENT FLOW (LB/HR)	TRANSPORT AIR FLOW (ACFM)	INJECTION AIR FLOW (SCFM)	INJECTION VELOCITY (FT/S)	MEASUREMENTS			
												STANDARD	UPPER-FURNACE	ESP	HUMIDI-FICATION
SI-1a	Baseline	70	3	Normal	1.2	0.0	None	0	0	0	0	X	X	X	X
SI-1b	Load Variation	70	3	Normal	1.2	2.0	Upper	11000	546	4200	240	X	X		X
SI-1c		60	3	Normal	1.2	2.0	Upper	8800	539	3400	200	X			X
SI-1d		40-45	3	Normal	1.2	2.0	Lower	7000	533	2600	150	X			X
SI-2a	Ca/S Variation	70	3	Normal	1.2	1.0	Upper	5500	525	4200	240	X			X
SI-2b		70	3	Normal	1.2	1.5	Upper	8250	536	4200	240	X			X
SI-2c		70	3	Normal	1.2	2.5	Upper	maximum	552	4200	240	X			X
SI-3a	Injection Velocity Variation (Mixing)	70	3	Normal	1.2	2.0	Upper	11000	546	2600	150	X			X
SI-3b		70	3	Normal	1.2	2.0	Upper	11000	546	6100	350	X			X

reduced, furnace gas temperatures at the upper nozzles were expected to fall; therefore, SI was switched to the lower nozzles.

Test Series SI-2 was designed to evaluate the impact of calcium-to-sulfur molar ratio at full load. Sorbent flow rates corresponding to Ca/S molar ratios up to 2.5 at full load were varied to evaluate the impacts of sorbent loading on SO_2 removal.

Finally, test series SI-3 tested the impact of injection velocity. Impacts of mixing on SO_2 removal were investigated through variation of injector velocity. During these tests, injection air flow was varied to obtain velocities corresponding to 150 and 350 ft/sec (46 to 107 m/s). These tests allowed the range of injection velocities to be evaluated before the GR-SI optimization tests.

5.3.3 Gas Reburning-Sorbent Injection Optimization Tests

The optimum conditions for GR-SI were expected to be different from those without SI because of the effects of back-radiation and furnace wall deposit changes under SI may have on temperature in the reburning zone. Therefore, another series was conducted to simultaneously optimize the GR-SI processes. Table 5-4 summarizes the GR-SI optimization test conditions. The objective of the GR-SI test series was to optimize the process operating parameters with respect to boiler operability, and cost effectiveness of the process. The optimum conditions would then be used for the long-term test series, which were carried out immediately after the completion of this optimization test series.

The optimum GR conditions, determined from the GR optimization tests, were set and the SI parameters were optimized at high load.

5.3.4 Post-Outage Test Conditions

During the 1991 fall outage, modifications to the humidification duct and reburning fuel

TABLE 5-4. GR–SI OPTIMIZATION TEST CONDITIONS

Test ID	Test Description	Load (MW)	Primary SR	Reburn SR	Exit SR	NG (percent)	Ca/S Molar Ratio	Inj. Elev.	Inj. Vel. (FT/S)	Measurements: Standard	Measurements: ESP	Measurements: Sulfur Trioxide
GRSI–1a	Load Variation	45	1.1	0.9	1.25	18	2.00	Low	150	x	x	x
GRSI–1b		55	1.1	0.9	1.25	18	2.00	Low	150	x	x	x
GRSI–1c		60	1.1	0.9	1.18	18	2.00	Low	150	x		
GRSI–1d		60	1.1	0.9	1.18	18	2.00	High	150	x		
GRSI–1f		70	1.1	0.9	1.18	18	2.00	High	150	x		
GRSI–1g		60	1.1	0.9	1.18	18	2.00	High	150	x	x	
GRSI–1h		60	1.1	0.9	1.18	18	2.00	Low	150	x	x	
GRSI–1i		70	1.1	0.9	1.18	18	2.00	High	150	x	x	
GRSI–2a		70	1.1	0.9	1.18	18	2.00	High	150	x		
GRSI–3a	Inj. Velocity Variation	70	1.1	0.9	1.18	18	1.00	High	150	x	x	
GRSI–3b		70	1.1	0.9	1.18	18	1.00	High	200	x	x	
GRSI–3c		70	1.1	0.9	1.18	18	1.00	High	240	x	x	
GRSI–4	Velocity Trav. at SI inj. air	Dispatch	1.1	0.9	1.18	18	2.00	High	Max.	x		
GRSI–5	Velocity Trav. at SI inj. air	Dispatch	1.1	0.9	1.18	18	2.00	High	Max.	x		
GRSI–6a	GRSI Operation	45	1.1	0.9	1.18	18	2.00	High	240	x		
GRSI–6b		70	1.1	0.9	1.18	18	2.00	High	240	x		
GRSI–7a	Ca/S Variation	65	1.1	0.9	1.18	18	1.00	High	240	x		
GRSI–7b		65	1.1	0.9	1.18	18	1.50	High	240	x		
GRSI–7c		65	1.1	0.9	1.18	18	2.00	High	240	x		
GRSI–8a	Low Excess Air	65	1.05	0.9	1.15	18	1.75	High	240	x		
GRSI–8b		65	1.05	0.9	1.15	18	2.00	High	240	x		
GRSI–9a	Injection Elevation	50	1.1	0.9	1.18	18	1.75	High	240	x		x
GRSI–9b	Optimization	50	1.1	0.9	1.18	18	1.75	Low	240	x		
GRSI–9c		55	1.1	0.9	1.18	18	1.75	Low	240	x		x
GRSI–9d		55	1.1	0.9	1.18	18	1.75	High	240	x		
GRSI–10a	Ca/S Variation	70	1.1	0.9	1.18	18	1.00	High	240	x		
GRSI–10b		70	1.1	0.9	1.18	18	1.75	High	240	x		
GRSI–11a	Injection Configuration	70	1.1	0.9	1.18	18	1.75	High*	240	x		

* *Four front injectors only.*

injection nozzles were made. Post-outage testing ensured that the recommended GR-SI operating conditions would still satisfy the program objectives. Post-outage test conditions are summarized in Table 5-5. Post-outage testing at Hennepin was divided into two test series:

- Checkout Tests To ensure that the modified humidification system, ash handling system and the newly installed reburning fuel injectors were operational.

- Additional Parametric Tests To close the gap in the data base and to confirm some of the optimum operating parameters, which were to be evaluated during the long-term GR-SI demonstration.

5.3.5 Gas/Coal Cofiring and Gas/Gas Reburning Tests

An evaluation of Gas/Coal Cofiring and Gas/Gas Reburning was undertaken at Hennepin Unit 1, in September 1991. The purpose of this study was to evaluate these technologies, primarily for NO_x emissions control, in units affected by the 1990 Clean Air Act Amendments. Hennepin Unit 1 is equipped with corner burners each containing three coal nozzles as well as two levels of main gas burners and warm-up guns and two levels of gas ignitors. The gas burners can supply up to 100% of the full load heat input.

Short parametric tests, 58 Gas/Coal Cofiring and 19 Gas/Gas Reburning tests, of 15 to 60 minute duration were conducted. Gas/Coal Cofiring was evaluated with natural gas heat input up to 42%, but the majority of tests were conducted with natural gas heat input of 34%. The cofiring results were compared to the 100% coal and 100% gas firing cases. Staged combustion with OFA was also evaluated for each condition. Other firing techniques evaluated in the Gas/Coal Cofiring test series include close-coupled GR andrich/lean firing, which were tested by trimming the burner dampers. Gas/Gas Reburning performance was evaluated relative to the 100% gas firing case. The parameters evaluated include primary zone stoichiometric ratio, reburning zone stoichiometric ratio, reburning fuel injector tilt,

TABLE 5-5. POST–OUTAGE TEST CONDITIONS

Test ID	Test Description	Load (MW)	Mills In–Service	Primary SR	Reburn SR	Burnout SR	NG (percent)	FGR (scfm)	Overfire Air (scfm)	Measurements: Standard	Measurements: ESP	Measurements: Hydrogen Sulfide
GR–33a1	Baseline and SR1 Variation	70	3	1.14	1.14	1.15	0	Cooling	Cooling	x	x	x
GR–33a2		70	3	1.08	1.08	1.15	0	Cooling	As Req'	x		
GR–39a1		60	3	1.14	1.14	1.2	0	Cooling	As Req'	x	x	x
GR–39a2		60	3	1.08	1.08	1.2	0	Cooling	As Req'	x		
GR–42a1		45	2	1.14	1.14	1.25	0	Cooling	As Req'	x	x	x
GR–42a2		45	2	1.08	1.08	1.25	0	Cooling	As Req'	x		
GR–43a	FGR Variations	70	3	1.08	0.9	1.15	18	2000	As Req'	x		
GR–43c		70	3	1.08	0.9	1.15	18	4000	As Req'	x	x	
GR–44a		70	3	1.08	0.9	1.2	18	2000	As Req'	x		
GR–44b		70	3	1.08	0.9	1.2	18	3000	As Req'	x		x
GR–44c		70	3	1.08	0.9	1.2	18	4000	As Req'	x	x	
GR–45b		45	2	1.08	0.9	1.25	18	2000	As Req'	x		
GR–45c		45	2	1.08	0.9	1.25	18	2000	As Req'	x		x
GR–45d		45	2	1.08	0.9	1.25	18	4000	As Req'	x	x	
GR–45e		45	2	1.08	0.9	1.25	18	Max.	As Req'	x		
GR–46b		45	2	1.08	0.9	1.25	18	2000	As Req'	x		
GR–46c		45	2	1.08	0.9	1.25	18	3000	As Req'	x		x
GR–46d		45	2	1.08	0.9	1.25	18	4000	As Req'	x	x	
GR–46e		45	2	1.08	0.9	1.25	18	Max.	As Req'	x		
GR–50a	SR2 Variation	45	2	1.08	(#)	1.2	15	Max.	As Req'	x	x	
GR–50b		45	2	1.08	(#)	1.2	12	Max.	As Req'	x	x	
GR–50c		45	2	1.08	(#)	1.2	10	Max.	As Req'	x	x	
GR–51a1		70	3	1.08	(#)	1.2	15	Min.	As Req'	x		
GR–51a2		70	3	1.08	(#)	1.2	15	Max.	As Req'	x		
GR–51b		70	3	1.08	(#)	1.2	12	Max.	As Req'	x		
GR–51c		70	3	1.08	(#)	1.2	8	Max.	As Req'	x		

(#) Calculated by the Boiler Performance Monitoring System -- Results in Table A-4

TABLE 5-5. POST-OUTAGE TEST CONDITIONS (CONTINUED)

Test ID	Test Description	Load (MW)	Ca/S Molar Ratio	Primary SR	Reburn SR	Exit SR	NG (percent)	Injection Velocity (ft/s)	Injection Elevation	Measurements		
										Standard	ESP	
SI-5a	Ca/S Variation	70	1.5	1.15	1.15	1.2	0	250	High	x	x	
SI-5b		70	1.75	1.17	1.17	1.2	0	250	High	x	x	
SI-5c		70	2	1.17	1.17	1.2	0	250	High	x	x	
SI-6a	Ca/S Variation	45	1.5	1.1	1.1	1.25	0	250	High	x	x	
SI-6a2		45	1.5	1.1	1.1	1.25	0	250	High	x	x	
SI-6a3		45	1.5	1.1	1.1	1.25	0	250	High	x	x	
GRSI-12a	Ca/S Variation	70	1.5	1.08	0.9	Optimum	18	250	High	x		
GRSI-12b		70	1.75	1.08	0.9	Optimum	18	250	High	x	x	
GRSI-12c		70	2	1.08	0.9	Optimum	18	250	High	x		
GRSI-14a	SI Injection Velocity Variation: 6 Jets	70	1.75	1.08	0.9	Optimum	18	250	High	x		
GRSI-14b		70	1.75	1.08	0.9	Optimum	18	200	High	x	x	
GRSI-14c		70	1.75	1.08	0.9	Optimum	18	150	High	x		
GRSI-15a	SI Injection Velocity Variation	45	1.75	1.08	0.9	Optimum	18	150	High	x		
GRSI-15b		45	1.75	1.08	0.9	Optimum	18	200	High	x	x	
GRSI-15c		45	1.75	1.08	0.9	Optimum	18	250	High	x		
GRSI-19A	SR2 Variation	45	1.75	1.08	0.95	1.2	12	250	High	x	x	

primary burner tilt, and operating load. GR with up to 20% gas heat input was evaluated at various excess air levels.

The primary purpose of the evaluation was to measure NO_x emissions control. The evaluation included the following parameters:

- Emissions (NO_x, SO_2, CO and CO_2)
- Thermal efficiency
- Ash carbon loss
- Steam temperatures
- Gas temperatures
- Load following capability
- Flame conditions

5.3.6 Long-Term GR-SI Demonstration Tests

GR-SI demonstration tests provided an opportunity to assess the long-term impacts of the GR-SI process. Natural gas and sorbent were injected in each test period under optimum injection conditions identified during the GR-SI optimization tests. The unit was operated by plant personnel, under normal dispatch. Boiler performance and pollutant emissions were monitored continuously during the test period. Additional detailed measurements were performed to evaluate the impacts of:

- Boiler slagging and fouling
- Air heater fouling
- ESP
- Particulate emissions
- Ash handling and disposal

The overall operability of the process was evaluated in addition to the above parameters. This includes injection system operation and reliability, deviations from normal boiler operation, maintenance requirements and process data. Measurements conducted on a continuous, daily basis include:

- On-line thermal performances and gas-side pressure drop
- Flue gas composition including O_2, CO_2, CO, SO_2, NO_x, and total hydrocarbons
- Boiler operating parameters (flame characteristics, burner settings, etc.)
- ESP electrical operation (voltage, current)
- Sootblowing schedule
- Ash hopper evacuation schedule

Additional measurements conducted on a weekly or on an as needed basis provided assessment of the following parameters:

- Slagging and fouling rates
- Tube wastage
- N_2O emissions
- Flue gas stratification
- Fly ash resistivity at the ESP inlet
- Furnace gas temperatures and velocities
- Solid waste characteristics
- Coal, sorbent, ash, and water characteristics

5.4 Measurement Procedures

This section contains brief descriptions of the Data Quality Assurance/Quality Control activities designed to verify process and data accuracy, the Boiler Performance Monitoring System (BPMS), and the Continuous Emissions Monitoring System (CEMS).

5.4.1 Data Quality Assurance/Quality Control

Data quality and completeness are essential to the success of any program. Therefore, steps were taken to insure that accurate and complete data were taken. These include:

- Administration of QA/QC activities by a corporate Quality Assurance Officer (QAO) and a program QAO

- Preparation and implementation of a Quality Assurance Project Plan (QAPP). This plan specified the sampling and analytical techniques to be used and the QA/QC activities required, the precision and accuracy goals, methods of QA/QC reporting, and corrective steps. The QA plan was prepared in accordance with the EPA Quality Assurance Management Staff (QAMS), as described in "Interim Guidelines and Specifications for Preparing Quality Project Plan," QAMS-005/80 (December 29, 1980).

Goals for data precision and tolerance were established for both input parameters and performance results. Table 5-6 lists the goals for each measurement. Standard reference methods are included. These were used to evaluate the tolerance of measurements. The measurement tolerance is defined as the ratio of the measured value to the value obtained by a reference method (multiplied by 100). The precision is an indicator of the ease with which a value may be reproduced. It is quantified by the Relative Standard Deviation (RSD), which is the ratio of the standard deviation to the mean (multiplied by 100). Data completeness is an indicator of the ratio (or percentage) of the data set which is required in a valid data set. It is simply the ratio of the number of measurements to the total number required for a valid set.

The data quality goals were established commensurate with program goals and instrument accuracy. A variety of readings/measurements were qualitative or otherwise had no relative accuracy determination. Measurements such as fouling rate, furnace radiative heat flux, and

TABLE 5-6. GR–SI PROGRAM OBJECTIVES FOR MEASUREMENTS

Measurement Parameter	References	Precision RSD (%)	Tolerance (%)	Completeness (%)
Coal:				
Proximate	ASTM D3172	10	90	90
Volatiles	ASTM D3172	10	90	90
Fixed Carbon	ASTM D3172	10	90	90
Moisture	ASTM D3172	10	90	90
Ash	ASTM D3172	10	90	90
Ultimate:				
Carbon	ASTM D3176	2	98	90
Hydrogen	ASTM D3176	5	95	90
Nitrogen	ASTM D3176	10	90	90
Ash	ASTM D3176	10	90	90
Sulfur	ASTM D3176	10	90	90
Coal Ash:	ASTM D3174	10	90	90
Elemental	ASTM D2995	10	90	90
Fusion Temperature	ASTM D1857	10	90	90
Heating Value:	ASTM D2015	2	98	90
Calcium:	ASTM D2795	10	90	80
Sorbent:				
Calcium	ASTM D2795	10	90	90
Sodium	ASTM D3684	10	90	90
Magnesium	ASTM D3684	10	90	90
Potassium	ASTM D3584	10	90	90
Particle Size Distribution	ASME PTC 28	5	95	90
Specific Sufrace Area	ASME PTC 28	5	95	90
Furnace Measurement:				
Gas Temperature		5	95	90
Gas Velocity		10	90	90
Fouling Rate		10		90
Furnace Radiation		10		90

ASTM: American Society of Testing Materials
PTC: Performance Test Code
CFR: Code of Federal Regulations
RSD: Relative Standard Deviation

TABLE 5-6. GR–SI PROGRAM OBJECTIVES FOR MEASUREMENTS (CONTINUED)

Measurement Parameter	References	Precision RSD (%)	Tolerance (%)	Completeness (%)
Gas Composition:				
Oxygen	EPA	2	80	90
Sulfur Dioxide	Performance	2	80	90
Carbon Monoxide	Specifications	2	80	90
Carbon Dioxide	2 and 3	2	80	90
Nitrogen Oxides	"	2	80	90
Hydrocarbons	"	2	80	90
Sufur Trioxide	EPA Method 8 40 CFR 60 App. A	10	90	90
Nitrous Oxide	—	10	80	80
Hydrogen Chloride	EPA Method 26 (proposed)	10	90	90
Flyash:				
Elemental	ASTM D2785	10	90	90
Calcium	ASTM D2785	10	90	90
Sulfur	ASTM D2785	10	90	90
Ash:	ASTM D3174	10	90	90
Elemental	ASTM D2795	10	90	90
Fusion Temperature	ASTM D1857	10	90	90
Loading	EPA Mehtod 5 40 CFR 60 App. A	10	90	90
Particle Size Distribution	EPA 600/2–77–004	10	90	90
Resistivity		10	90	90
Other Measurements:				
Coal Feedrate	—	5	90	90
Combustion Air	—	5	90	90
FGR Flow	—	5	90	90
Sorbent Injection Air		5	90	90
Feedwater and Steam Flowrates, Temperatures, and Pressures	—	5	90	90
Sluice Line Water Flow	ASTM D3370	5	90	90
Sorbent Flowrate	—	5	90	90

ASTM: American Society of Testing Materials
PTC: Performance Test Code
CFR: Code of Federal Regulations
RSD: Relative Standard Deviation

particulate matter emissions and size were determined without relative accuracy. Particulate matter emissions and size were determined through standard methods, so that they may be compared to other results. Qualitative measurements include furnace slagging and observations of wear. Some measurements such as gas temperature, composition, and steam flow were compared to model predictions to assess data quality.

5.4.2 Results of QA/QA Activities at Hennepin

The QA/QC activities were routinely applied to measurement and analytical techniques. Reference method results, in comparison to measured values, showed that data quality objectives were being met. The results of some specific QA/QC activities are presented in this section. These include a QA/QC check of FGR and OFA flows, measured emissions and reference method results, and correlation of coal sulfur and carbon content with flue gas SO_2 and CO_2.

A QA/QC validation of FGR and OFA flows was undertaken in May 1991. The flows recorded by the BPMS were compared to flows measured with a pitot tube, in accordance with EPA Method 2. The FGR flows indicated by the BPMS required re-calibration, but the BPMS OFA flows showed better agreement with the pitot tube measurements and therefore were not adjusted.

Routine CEMS sampling system bias checks were performed to determine system integrity. The measured emissions of O_2, CO_2, SO_2, NO_x, and CO were also compared to EPA reference method results. These were obtained according to EPA Methods 3, 6,7 and 10. The results shown in Table 5-7 indicate that the CEMS measurements were within the relative accuracy goal of 20%. The results show that the CEMS measurements had a relative accuracy of 2.9 to 9.7%.

A comparison of measured SO_2 and CO_2 emissions, under baseline and GR operation, to theoretical emissions based on coal composition was also carried out without SI. Figures

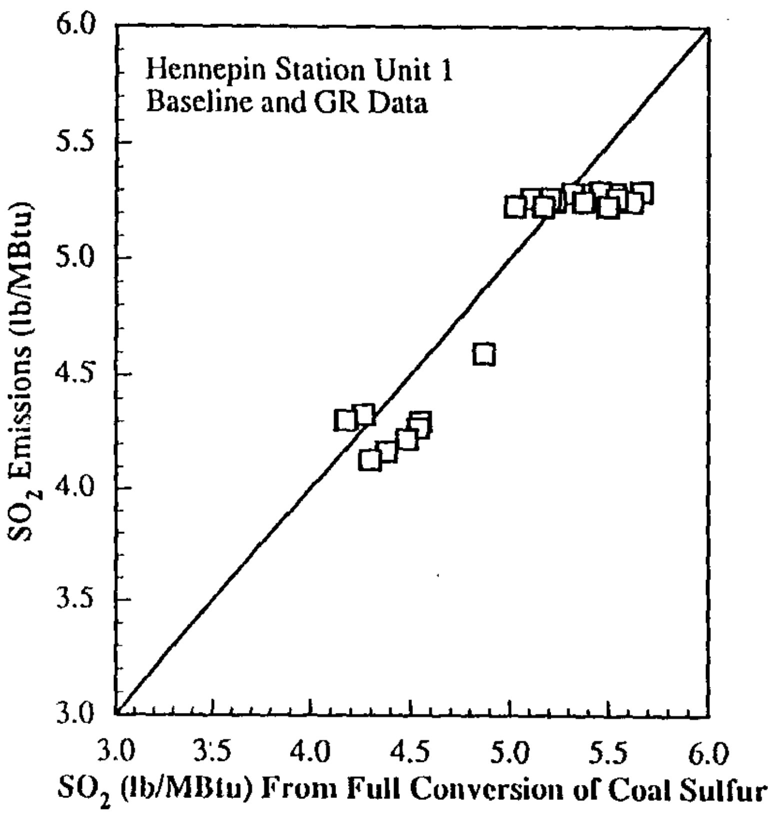
TABLE 5-7. CEMS RELATIVE ACCURACY RESULTS.

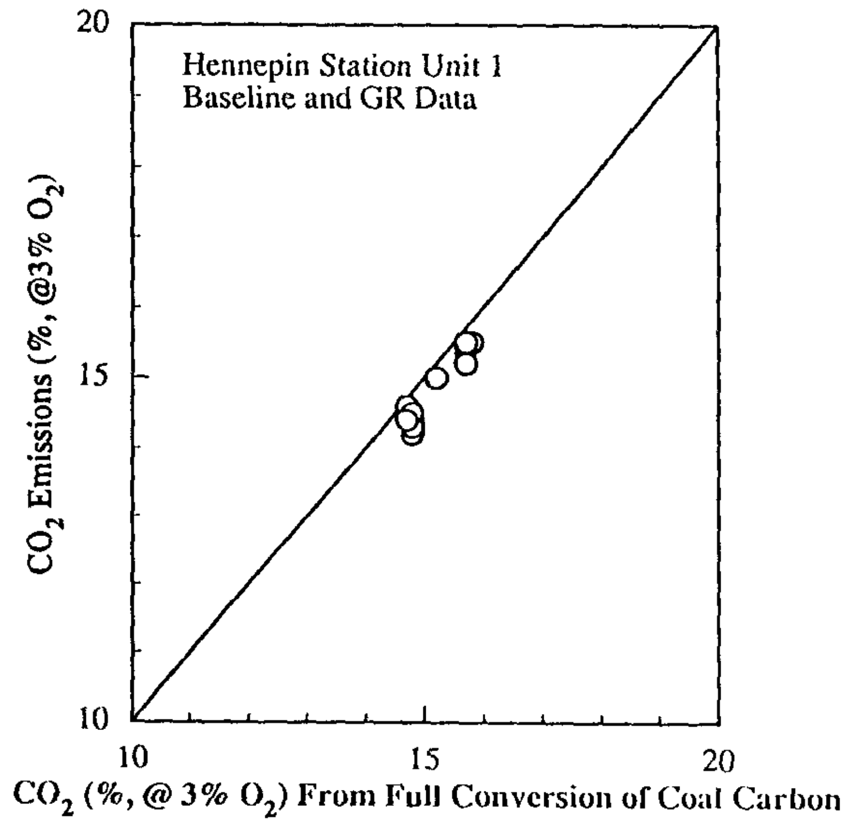
Parameter	Sampling Location	Reference Method	Relative Accuracy	
			Actual (%)	Objective (%)
Oxygen	Economizer	EPA Method 3	4.91	20
Carbon Dioxide	Economizer	EPA Method 3	2.92	20
Sulfur Dioxide	Economizer	EPA Method 6	7.17	20
Nitrogen Dioxide	Economizer	EPA Method 7	7.51	20
Carbon Monoxide	Economizer	EPA Method 10	9.68	20

5-3a and 5-3b show the measured SO_2 and CO_2 emissions as a function of the rates of these species produced from full conversions of coal sulfur to SO_2 and coal carbon to CO_2. Table 5-8 lists baseline data from select dates in January-February, 1992 and the theoretical emissions based on three coal samples taken each day. Table 5-9 compares the measured and theoretical emissions under GR operation. The baseline results show that the average measured SO_2 emissions were on average within 1.68% from the theoretical SO_2 emissions and that the average CO_2 emissions were within 1.94% of the theoretical CO_2 emissions (based on 0 ppm CO, 0% carbon in ash). The GR data show an average difference for SO_2 of 3.49% and an average difference for CO_2 of 2.29%. The differences are due to sulfur retention in ash, carbon loss, CO emissions, and instrument error.

5.4.3 Boiler Performance Monitoring System (BPMS)

A Boiler Performance Monitoring System (BPMS) was used to monitor operating conditions, GR-SI system performance, and unit thermal/steam production performance. The BPMS, developed by EER, is a state-of-the-art PC-based system which takes up to 300 inputs, updates these as often as every five seconds, and performs a variety of process calculations. The Hennepin BPMS was customized to the GR-SI application and received inputs of emissions (O_2, CO, CO_2, NO_x, SO_2, and HC) as well as fuel/air input data, gas side/steam side data, and GR-SI process stream data. Table 5-10 lists typical BPMS input parameters. The BPMS performs process (combustion and heat transfer) calculations with an Excel Spreadsheet and stores the data in a desired format. The outputs are listed in Table 5-11. These include the zone stoichiometric ratios, which indicate the percent excess air in each zone, and input-output and heat loss thermal efficiency calculations according to ASME Power Test Code 4.1, Section 5, 1979. The coal flow and total air flow to the unit were calculated from a heat balance and the flue gas analysis. The fouling of heat transfer surfaces was evaluated as the ratio of the actual heat transfer coefficient to that for clean surfaces (baseline) immediately after sootblowing. Further discussion of cleanliness factors is presented in Section 10.1.3. These were calculated for the furnace, secondary superheater, primary superheater, reheat superheater, economizer, and air heater. The data





Figures 5-3a and 5-3b Comparison of SO_2 and CO_2 emissions with fuel composition

TABLE 5-8. COMPARISON OF CEMS MEASUREMENT AND THEORETICAL SO_2 AND CO_2 EMISSIONS DURING BASELINE OPERATION

Emissions				Theoretical Emissions Based on Coal Composition										
Date	Test ID (All Bsln)	SO2 (lb/MBtu)	CO2 (%, @ 3% O2)	Feeder	HHV Btu/Lb	% S	% C	% H	% N	% O	lb SO2 per MBtu	SCF CO2 per MBtu	DSCF Flue Gas per MBtu	% CO2 (@ 3% O2)
1/7/92	BL (LT)	5.287	15.5	1A	11,785	3.19	65.60	4.50	1.26	8.43	5.414	1787	9747	15.7
1/7/92	BL (LT)	5.287	15.5	1B	11,963	3.31	66.31	4.57	1.27	8.79	5.534	1779	9706	15.7
1/7/92	BL (LT)	5.287	15.5	1C	11,800	3.14	65.75	4.46	1.24	8.72	5.322	1789	9727	15.7
1/8/92	Pro-GR (LT)	5.394	15.4	1A	10,516	2.87	58.22	4.00	1.10	7.98	5.458	1777	9676	15.7
1/8/92	Pro-GR (LT)	5.394	15.4	1B	10,480	2.97	58.13	4.05	1.09	7.72	5.668	1781	9730	15.7
1/8/92	Pro-GR (LT)	5.394	15.4	1C	10,580	2.89	58.42	3.96	1.06	7.70	5.463	1772	9646	15.7
1/16/92	BL	5.251	15.2	1A	10,680	2.87	59.24	4.03	1.10	7.87	5.375	1781	9689	15.7
1/16/92	BL	5.251	15.2	1B	10,606	2.98	58.58	4.03	1.11	7.96	5.619	1773	9663	15.7
1/16/92	BL	5.251	15.2	1C	10,704	2.8	59.47	4.04	1.12	7.86	5.232	1783	9700	15.7
1/29/92	OFA cooling	5.265	15.5	1A	10,724	2.74	59.64	4.05	1.12	7.81	5.110	1785	9709	15.7
1/29/92	OFA cooling	5.265	15.5	1B	10,612	2.94	59.02	4.03	1.15	7.61	5.541	1785	9735	15.7
1/29/92	OFA cooling	5.265	15.5	1C	10,681	2.78	59.22	3.97	1.10	7.81	5.206	1780	9662	15.8
2/5/92	BL	5.230	15.5	1A	10,658	2.93	58.86	4.05	1.09	7.83	5.498	1773	9666	15.7
2/5/92	BL	5.230	15.5	1B	10,860	2.73	60.14	4.15	1.13	8.06	5.028	1778	9680	15.7
2/5/92	BL	5.230	15.5	1C	10,633	2.75	59.17	4.06	1.12	7.63	5.173	1786	9736	15.7
Average		5.285	15.4		10,885	2.93	60.38	4.13	1	7.99	5.376	1781	9698	15.7

CO_2 EMISSIONS - AVERAGE PERCENT DIFFERENCE FROM THEORETICAL: 1.94 PERCENT

SO_2 EMISSIONS - AVERAGE PERCENT DIFFERENCE FROM THEORETICAL: 1.68 PERCENT

TABLE 5-9. COMPARISON OF CEMS MEASUREMENT AND THEORETICAL SO_2 AND CO_2 EMISSIONS DURING GR OPERATION

		Emissions				Coal			Natural Gas			Theoretical Emissions	
Date	Test ID	Gas Heat (%)	Coal Heat (%)	SO2 (lb/MBtu)	% CO2 (@ 3% O2)	SO2 Bsln (lb/MBtu)	SCF CO2 per MBtu	DSCF Flue Gas per MBtu	SO2 Bsln (lb/MBtu)	SCF CO2 per MBtu	DSCF Flue Gas per MBtu	SO2 (lb/MBtu)	% CO2 (@ 3% O2)
1/8/92	GR (LT)1	17.7	82.3	4.298	14.4	5.530	1777	9684	0	1005	8619	4.551	14.8
1/8/92	GR (LT)2	17.9	82.1	4.273	14.2	5.530	1777	9684	0	1005	8619	4.540	14.8
1/29/92	GR On	19.3	80.7	4.331	14.6	5.285	1783	9702	0	1005	8619	4.265	14.7
2/26/92	GR On	18.5	81.5	4.168	14.5	5.375	1778	9686	0	1005	8619	4.380	14.8
3/11/92	GR On	18.7	81.3	4.224	14.3	5.514	1794	9741	0	1005	8619	4.483	14.8
3/25/92	GR On	18.8	81.2	4.306	14.5	5.147	1783	9666	0	1005	8619	4.179	14.8
4/8/92	GR On	10.9	89.1	4.596	15.0	5.467	1781	9661	0	1005	8619	4.871	15.2
4/23/92	GR On	19.7	80.3	4.131	14.4	5.353	1782	9670	0	1005	8619	4.299	14.7
Average		17.7	82.3	4.291	14.5	5.400	1782	9687	0	1005	8619	4.446	14.8

CO2 EMISSIONS - PERCENT DIFFERENCE FROM THEORETICAL: 2.29 PERCENT

SO2 EMISSIONS - PERCENT DIFFERENCE FROM THEORETICAL: 3.49 PERCENT

TABLE 5-10. TYPICAL INPUT (MEASURED) PARAMETERS FOR BPMS HEAT TRANSFER AND COMBUSTION MODELS

CLASS OF INPUT	INPUT DATA	METHOD ACQUIRED	COMMENT
Fuel characteristics	Proximate analysis	Operator	Must be representative
	Ultimate analysis		
	Heating value		
ASME Heat Loss Method	Combustible in refuse	Operator	From design spec. or field data
	Radiation heat loss	Operator	From design spec., empirical formula
	Unmeasured heat loss	Operator	From design spec., empirical formula
Ambient Conditions	Relative humidity	Instrument Signal	
	Barometric pressure	Instrument Signal	
	Ambient temperature	Instrument Signal	
Boiler Instrumentation of Flue Gas Side	Economizer gas in. temperature	Instrument Signal	
	Economizer gas out. temperature	Instrument Signal	
	Air Heater gas out. temperature	Instrument Signal	
	Plant O_2 concentration	Instrument Signal	
GR-SI Instrumentation	FGR flow rate	Instrument Signal	
	Reburn gas flow rate	Instrument Signal	
	Overfire air flow rate	Instrument Signal	
	Sorbent transport air flow rate	Instrument Signal	
	Sorbent transport air temperature	Instrument Signal	
	Sorbent transport air pressure	Instrument Signal	
	Sorbent injection air flow rate	Instrument Signal	
	Sorbent mass flow rate	Instrument Signal	
Continuous Emissions Monitoring	Gaseous species concentration		
	CO_2, CO, NO_x, O_2, SO_2,	Instrument Signal	CEMS Signal
	Hydrocarbon	Instrument Signal	CEMS Signal
Instrumentation of Combustion Air	Air heater air inlet temperature	Instrument Signal	
	Air heater air outlet temperature	Instrument Signal	
Tube Metal Temperature	At the exit of secondary SH	Instrument Signal	
Boiler Instrumentation of Water/Steam Side	Feedwater flow to economizer	Instrument Signal	
	Feedwater press to economizer	Instrument Signal	
	Feedwater temp. to economizer	Instrument Signal	
	Econo. outlet water temperature	Instrument Signal	
	Boiler drum pressure	Instrument Signal	
	Primary SH outlet pressure	Instrument Signal	
	Primary SH outlet temperature	Instrument Signal	
	SH attemp. feedwater flow	Instrument Signal	
	Secondary SH inlet pressure	Instrument Signal	
	Secondary SH inlet temperature	Instrument Signal	
	Steam press. to turbine	Instrument Signal	
	Steam temp. to turbine	Instrument Signal	
	Cold reheat flow rate	Instrument Signal	
	RH attemp. feedwater flow	Instrument Signal	
	RH inlet pressure	Instrument Signal	
	RH inlet temperature	Instrument Signal	
	RH outlet pressure	Instrument Signal	
	RH outlet temperature	Instrument Signal	

TABLE 5-11. SUMMARY OF OUTPUT FROM BPMS HEAT TRANSFER AND COMBUSTION MODELS

CLASS OF OUTPUT	OUTPUT DATA
Calculated flue gas temperatures	Secondary SH Inlet
	Reheater Inlet
	Primary SH Inlet
Fuel heat input	From coal
	From reburn gas
Heat rate	Net heat rate
Heat absorptions and cleanliness factors	Furnace
	Secondary SH
	Reheater
	Primary SH
	Economizer
	Air Heater
Complete combustion calculation	Stoichiometric air
	Stoichiometric ratio (i.e. Air number)
	Flue gas composition
Boiler efficiency based on ASME heat loss method	Heat loss due to dry gas
	Heat loss due to moisture in fuel
	Heat loss due to H_2O from combustion of H_2
	Heat loss due to combustible in refuse
	Heat loss due to radiation
	Heat loss due to unmeasured loss
Boiler efficiency based on heat absorption method	Efficiency based on gross heat input
	Efficiency based on net heat input
Emissions control data	Gaseous species concentration of
	CO_2, CO, NO_x, O_2, SO_2, and HCs quantified in
	Volume concentration (% or ppm)
	Corrected to 3% O_2
	Pounds per million Btu heat input

acquired by the BPMS was used to calculate the heat rate, which is the ratio of the heat input to the electric power generated. The gross heat rate is the ratio of the total heat input to the gross electric power generated. The net heat rate is the ratio of the gross heat input to the power generated minus the power consumed by the plant equipment and power received by the plant from external sources.

5.4.4 Continuous Emissions Monitoring System (CEMS)

A continuous gas sampling system was used to measure the flue gas concentration of O_2, CO, CO_2, HC, NO_x, and SO_2. Gas sampling was carried out at the economizer inlet and at the breeching. The same gas analyzers were used, but separate sampling systems were installed at these locations and a control valve was used to switch the location being sampled. At the economizer inlet a 16-point gas extraction grid was used, while sampling at the breeching was from a single central point. Rotameters were used to monitor the gas flow rate from the 16-point sampling grid so that equal samples were obtained from each point, thereby accounting for gas stratification at the sampling point. Because of the large amount of particulate matter at the economizer, the sampling system made use of phase discrimination probes, whereby small amounts of gas were drawn without the particulate matter. This was required to prevent SO_2 reaction with active particulate matter, much of which is unreacted CaO during SI. The economizer outlet gas analyses were compared to flue gas composition obtained at the breeching. Table 5-12 lists the instruments used in gas analyses. Figure 5-4 is a schematic of the CEMS sampling system, showing the sampling probe, heated sampling line, and analytical instruments.

5.5 Data Evaluation Methodology

The purpose of this section is to present relationships between process parameters used in evaluation of GR. Also presented is an analysis of the degrees of freedom of the GR system, i.e. which parameters must be held constant in order to fix the system. As stated, most of the calculations were performed by the BPMS and output to spreadsheets.

TABLE 5-12. CONTINUOUS GAS ANALYZERS AT HENNEPIN

Species	Detection Principle	Manufacturer	Model No.	Range	Serial #
O_2	Paramagnetism	Servomex	1400	0 – 25%	0142/701/499
CO_2	NDIR	Milton Roy Fuji	3300	0 – 10% 0 – 20 %	NOL68477
CO	Gas Filter Correlation	TECO	48	0 – 1 to 0 – 10000 ppm	31618–242
NO_x	Chemiluminescent	TECO	10AR	0 – 2.5 to 0 – 10000 ppm	10AR–8372–99
SO_2	Photometric	DuPont	400	0 – 1000 0 – 4000 ppm	5357
HC	F.I.D.	JUM Engineering	VE–7	0 – 1000 ppm	9971090

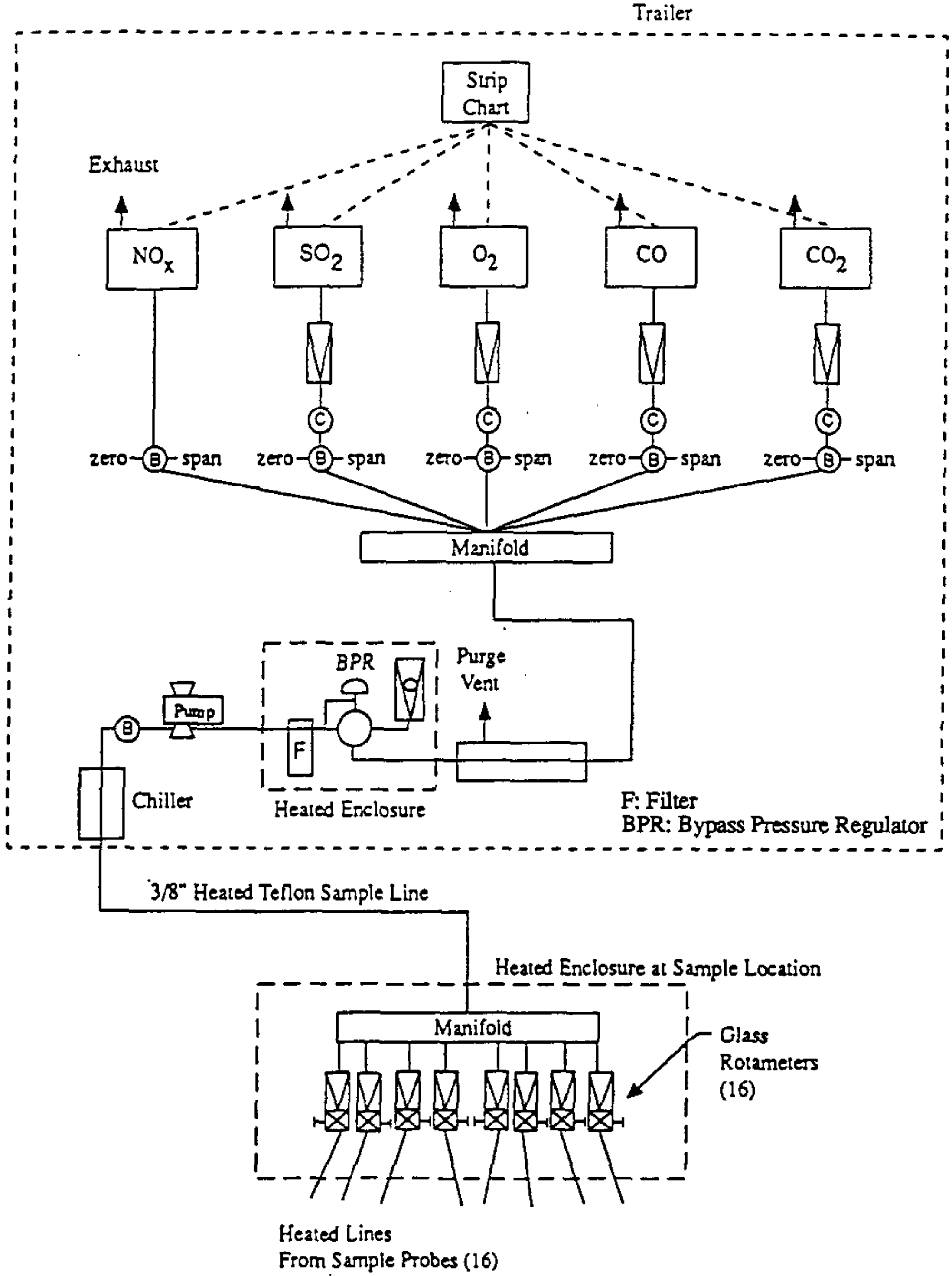


Figure 5-4. Continuous emissions monitoring system

The formulae for calculating SR_1, SR_2, and SR_3 have been presented in an earlier section (Section 5.3.1). The coal fraction (the fraction of heat input from coal) and natural gas fraction (the fraction of heat input from natural gas) may be approximated by the following:

coal fraction = SR_2/SR_1
natural gas fraction = $(SR_1 - SR_2)/SR_1$

These approximations are useful for data correlation purposes only, they were not actually used to calculate the fraction of heat input from each source. Formulae for the calculation of coal air fraction and OFA fraction follow:

coal air fraction = (TAF - OFA)/TAF = SR_2/SR_3
OFA fraction = OFA/TAF = $(SR_3 - SR_2)/SR_3$

The four equations, shown above, relate seven variables: SR_1, SR_2, SR_3, coal fraction, NG fraction, coal air fraction, and OFA fraction. Therefore, at constant load the system is fixed if three of the parameters are held constant. Of the three parameters to be fixed, one or two must be related to natural gas input and OFA. An example of parameters to be held constant in order to fix a system are: SR_1, SR_2, and SR_3. Another example of a set of three parameters which fix a system are: SR_1, natural gas fraction, and SR_3.

In plotting NO_x as a function of SR_2 or natural gas fraction (or percent natural gas heat input), two variables must be held constant in order to fix the system. Examples of parameters to be held constant follow:

Plot	Variables to be Fixed
NO_x vs. SR_2	(SR_1, SR_3), (% NG, % OFA), (SR_1, % OFA), or (% NG, SR_3)
NO_x vs. % NG	(SR_1, SR_3), (SR_2, SR_3), (SR_1, % OFA), or (SR_2, % OFA)

Holding these variables constant results in plots which are reproducible and have limited data scattering.

6.0 OPTIMIZATION TEST RESULTS

6.1 Overview

This section summarizes the results of the optimization (parametric) testing conducted at the beginning of the Hennepin GR-SI system evaluation. During the field evaluation, a wide range of boiler operating conditions and GR-SI parameters were varied to determine conditions which are optimum for NO_x and SO_2 emissions reduction. The project goals of 60 and 50% reductions in NO_x and SO_2, respectively, were achieved during optimization of the GR-SI system.

In the following sections, coal and ash sample analyses taken throughout the GR and SI parametric test series are presented. NO_x and SO_2 emissions data obtained during the GR and SI tests are presented and the optimum parameters are discussed. The QA/QC procedures and sampling methods and protocol used in obtaining the data presented here were described in the previous section.

Reburn NO_x reduction performance depends on a range of different process parameters, which include: initial NO_x level; temperature at the reburn and burnout zones; reburn zone stoichiometric ratio; stoichiometric ratio in the main combustion and burnout zones; residence times in the reburn and OFA zones; and mixing rates of the reburn fuel and OFA. data gathered during EER's various reburn demonstration programs have been reported in graphical format, where measured NO_x reduction performance has been compared with most of the above variable parameters, and where reasonably good correlations with individual parameters can be seen. However, given the rather complex inter-relationship between the various controlling parameters and reburning system performance, EER has elected not to present statistical correlations of the data. We believe that the use of such correlations can be misleading, particularly with respect to extrapolating system performance to other boilers and boundary conditions. To successfully correlate the data requires more complex process models, such as those used by EER during the development of designs for each of the different boiler applications. These process/design models have been validated during the course of the demonstration projects, and have been shown to accurately reflect performance trends as a function of the various process parameters and for boilers of very different design. For business reasons, and because of their importance in developing commercial guarantees, EER prefers not to make public any details of the process models.

6.2 Coal and Ash Analysis Data

Coal samples were taken on a daily basis during the pre-outage test period (5/91 to 9/91) and on a weekly basis during the post-outage test period (11/91 and thereafter). Samples were collected from each of the three coal feeders 1A, 1B, and 1C and analyzed to monitor coal composition and variability. The following analyses were conducted:

- Ultimate analysis
- Heating value
- Ash composition
- Ash fusion temperature

The overall fuel analyses are listed in Table 6-1 including pre-outage and post-outage coal samples and natural gas analysis. The individual coal compositions on an "as fired" basis are tabulated in Table A-1 of Appendix A. The carbon content varied between 59.9% and 67.4%, ash content varied between 9.5% and 13.0%, and the moisture content ranged from 3.9% to 14.5%. Fuel nitrogen content varied between 1.1% and 1.3% and sulfur content was in the range of 2.8% and 3.4%. Moisture content varied with the month the coal was sampled. In summer months, coal samples were generally low in moisture content (9.3%) as observed in the pre-outage test period. In the fall and winter months of the post-outage test period, coal samples had a relatively high moisture content (15.1%). Unusually low values were evident for samples taken from Feeder 1C. The moisture variation was not permanent and did not persist in the post-outage test data. Also presented in Table 6-1 is the natural gas analysis used throughout the design phase and test program.

The higher heating value (HHV) on an "as fired" basis was greater in the pre-outage test period, 11,329 Btu/lb coal (26,333 kJ/kg), than in the post-outage test period, 10,583 Btu/lb coal (24,599 kJ/kg), due to the relatively low moisture content. The average HHV during the pre-outage test period was 6.1% higher than the original design value and 6.5% higher than the post-outage test data.

Stoichiometric air requirements averaged 8.510 lb air/lb coal for the pre-outage data and 7.955 lb air/lb coal for the post-outage data. In comparison, the stoichiometric air requirement used in the original design specifications was 7.999 lb air/lb coal. The variation in air requirement can have a minor impact on the data collected by the Boiler Performance Monitoring System (BPMS) since calculations of zone stoichiometric ratios were based on a standard coal composition. However, for identical full load conditions, the variation in the

TABLE 6-1. COAL AND NATURAL GAS COMPOSITION

ELEMENT	units	Original Design	Pre-Outage Average	Post-Outage Average
Coal:				
Carbon	%	59.16	63.23	58.96
Hydrogen	%	3.97	4.28	4.06
Oxygen	%	7.46	8.51	7.65
Nitrogen	%	1.04	1.21	1.11
Sulfur	%	2.82	3.05	2.97
Moisture	%	15.99	8.94	15.07
Ash	%	9.56	10.78	10.18
HHV	Btu/ lb coal	10,632	11,363	10,583
Theoretical SO_2 Emissions	lb/MBtu	5.30	5.37	5.61
Theoretical Air Demand	lb air/lb coal	7.999	8.510	7.955
Natural Gas:				
CH_4	%	89.83	–	–
C_2H_6	%	4.29	–	–
C_3H_8	%	0.82	–	–
C_4H_{10}	%	0.00	–	–
C_5H_{12}	%	0.00	–	–
CO_2	%	0.57	–	–
N_2	%	4.20	–	–
HHV	Btu/scf	1,014	–	–
Theoretical Air Demand	lb air/scf	0.724	–	–

total air requirement for the above range of stoichiometric ratio requirements would be small and the difference in primary zone stoichiometric ratio would have a maximum error of 1.3%.

Ash samples from the boiler bottom hopper and the economizer hopper were analyzed for chemical composition and their base-to-acid ratio, silica ratio, and slagging index values were calculated. The results are listed in Tables A-2 and A-3 of Appendix A, respectively. Averages of these measurements indicate that the slagging propensity was minimal as long as there was adequate air flow to maintain oxidizing conditions in the furnace.

6.3 Gas Reburning Performance

6.3.1 Gas Reburning Parameters

Pilot-scale studies performed by EER have established that the major process parameters which control the efficiency of the reburning process are:

- Operating stoichiometric ratios
- Mixing
- Furnace temperatures
- Zone residence times

6.3.1.1 *Operating Stoichiometric Ratios*

The reburning zone stoichiometric ratio has the greatest effect. Small-scale testing has shown that overall NO_x reduction is highest when the reburning zone stoichiometric ratio is at about 0.90. To minimize the use of reburning fuel, the primary combustion zone should be operated as close to stoichiometric as possible commensurate with lower furnace performance (carbon loss, flame stability, corrosion, etc). Operation of the primary combustion zone with an excess air level of 10% (i.e. $SR_1=1.10$) is preferred to bring the natural gas requirement to between 18 and 20% of the total heat input to the furnace and to maintain combustion control. Overfire air is used to bring the overall furnace combustion system to its normal operating stoichiometry. However, in practice, it has been possible to reduce the quantity of overall excess air used during GR to help improve the thermal efficiency of the unit.

6.3.1.2 Mixing

Pilot-scale studies of the reburning process have also shown the importance of effective mixing in both the reburning and burnout zones. Effective mixing of the reburning fuel optimized the process efficiency by making good use of the available furnace residence time, while effective mixing of the OFA reduces carbon monoxide emissions and unburned carbon in the fly ash. For most combustion systems, good mixing is important to minimize operational impacts while maximizing NO_x reduction.

6.3.1.3 Furnace Temperatures

The furnace gas temperature at which the reburning fuel is injected has an impact on the process efficiency, with higher temperature preferred. Typically, this suggests that the reburning fuel should be injected as close to the primary zone as possible. However, the reburning fuel must be injected at a distance above the primary zone to allow burnout of the volatile hydrocarbons and reduction of the oxygen concentration entering the reburning zone. The temperature at which the burnout air is injected does not directly influence the process efficiency, but it is important that the temperature be high enough to allow oxidation of CO and hydrocarbon fragments from the reburning zone to occur readily.

6.3.1.4 Zone Residence Times

As discussed above, sufficient residence time must be available in the primary combustion zone to allow combustion of the primary fuel to proceed nearly to completion. In addition, the residence time of the reburning zone is also important to the process. Sufficient residence time in the reburning zone must be available to allow mixing and reaction of the reburning fuel with the residual oxygen and the products from the primary combustion zone. For most combustion systems, small-scale studies have shown that the reburning zone residence time should be between 0.3 to 0.5 seconds. However, the Lakeside GR system, which has achieved NO_x reduction in excess of the 60% goal, has a reburning zone residence time of 0.25 seconds. Therefore, GR may be effectively applied to units where the boiler configuration further limits reburning zone residence time. Finally, sufficient residence time must be provided in the burnout zone to permit oxidation of the CO and hydrocarbon fragments from the reburning zone.

6.3.2 "As Found" NO_x Baseline

In order to fully evaluate the impact of GR on boiler emissions, baseline NO_x emissions were measured during April-May 1988; these results were presented in Figure 2-3. During baseline tests, NO_x emissions of up to 0.77 lb/10^6Btu (331 mg/MJ), were measured at full load with excess air levels of up to 25%. Lower NO_x emissions were observed at decreased boiler loads. At 60 MW_e, NO_x emissions averaged approximately 0.48 lb/10^6Btu (206 mg/MJ). At full load, the excess oxygen shown on the plot corresponds to excess air levels between 18 and 25%. For comparison purposes, 0.75 lb/10^6Btu (323 mg/MJ) will be used as the "as found" baseline for all tests.

6.3.3 Gas Reburning Optimization Test Results

The results of the GR optimization tests are summarized in Table A-4, in Appendix A. These are measurements averaged over the test periods and, unless otherwise stated, the NO_x and CO concentrations were corrected to 3% oxygen. For the GR test series, NO_x emissions averages ranged from a low of 0.188 lb/10^6Btu (81 mg/MJ) to a high of 0.364 lb/10^6Btu (157 mg/MJ), operating with gas heat inputs ranging from 10 to 22%, primary zone stoichiometric ratios ranged from 1.06 to 1.15, and reburn zone stoichiometric ratios ranged from 0.88 to 1.01. GR was operated with an excess air at the furnace exit of 15-18%, in comparison to the baseline of 20–25%.

At Hennepin, the GR system was designed to maximize NO_x emissions reductions while utilizing 18–20% gas heat input. The goal was a minimum of 60% NO_x reduction. Figure 6–1 illustrates how this reduction was accomplished. As discussed above, baseline conditions were evaluated prior to installation of the GR system. For this project, an "as found" NO_x emissions rate of 0.75 lb/10^6Btu (323 mg/MJ) was established for full load operation. Once installed, the GR system was optimized by varying key parameters which affect NO_x emissions. One of those parameters is primary zone stoichiometric ratio. The primary zone stoichiometric ratio established for Hennepin was in the range of 1.08 to 1.10. Further testing established optimum conditions for FGR, burner tilt, and reburning zone stoichiometric ratio to reduce NO_x emissions to 0.25 lb/10^6Btu (108 mg/MJ). In the following sections, an analysis is presented detailing the specific parameters which were varied to improve GR performance. Detailed discussions on the effects of the following parameters are presented:

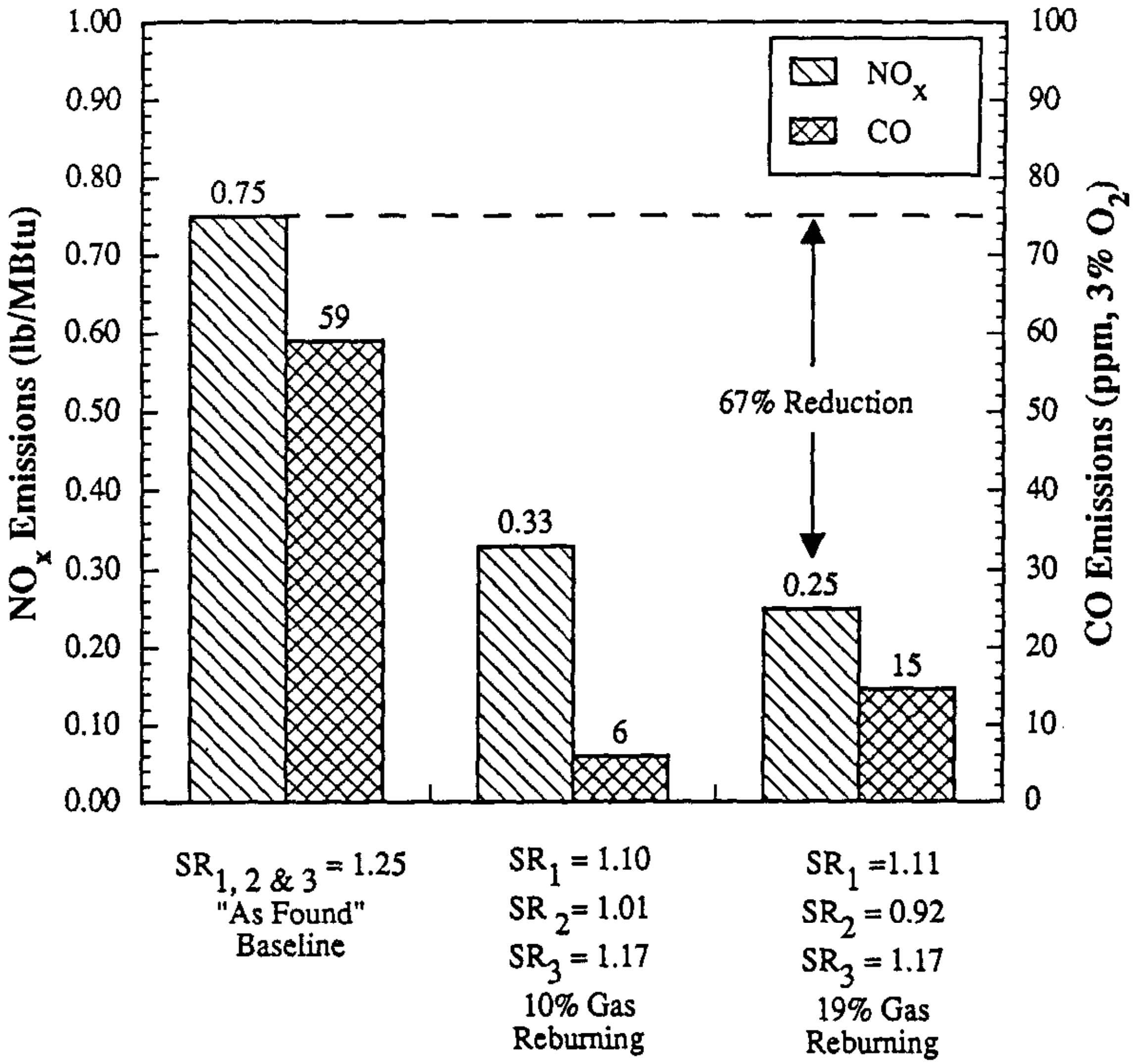


Figure 6–1. Baseline and Gas Reburning NO_x and CO emissions

- *Zone stoichiometric ratios*
- Percentage natural gas
- Percentage of FGR
- Boiler operational parameters

6.3.3.1 Zone Stoichiometric Ratios

The effect of primary zone stoichiometric ratio on NO_x emissions under full load GR operation with 18% gas heat input, is illustrated in Figure 6-2. During this test, the primary zone stoichiometric ratio ranged from 1.07 to 1.11. NO_x emissions increased from an average of 0.21 lb/10^6Btu (90 mg/MJ) to 0.26 lb/10^6Btu (112 mg/MJ), over this increase in primary zone stoichiometric ratio. The increase in NO_x emissions is due to two factors: higher NO_x formation in the combustion zone and a slight increase in the reburning zone stoichiometric ratio which reduced the NO_x control level. During this test, CO emissions were maintained at a maximum of 3 ppm, indicating complete fuel burnout was achieved.

Fly ash samples were collected from various full load tests to determine if low operating stoichiometric ratios, particularly with GR, would increase carbon loss. Figure 6-3 shows the carbon in ash data plotted as a function of primary zone stoichiometric ratio. At primary zone stoichiometric ratio above 1.06, carbon in fly ash varied from 2.2 to 5.2% as compared to the baseline value of 2.6% measured in 1988. Operating the primary combustion zone at a stoichiometric ratio above 1.06 should provide sufficient combustion air to burn out most of the remaining unburned carbon fragments with small changes expected in slagging, corrosion, and wall heat absorption from the baseline condition. More extensive data on carbon in ash are presented in Section 7.

As mentioned above, the reburning zone stoichiometric ratio was the most important parameter in determining the efficiency of the GR process. The primary zone stoichiometric ratio determined how much reburning fuel was needed to reduce the reburn zone stoichiometric ratio to 0.90. In most cases, reburning fuel accounted for approximately 18 to 20% of the total heat input. Figure 6-4 shows the impact of reburning zone stoichiometric ratio on NO_x emissions. For operation with primary zone stoichiometric ratio between 1.07 and 1.13, NO_x emissions were 0.22 lb/10^6Btu (95 mg/MJ) at a reburning zone stoichiometric ratio of 0.90. In addition, there was no significant increase in CO emissions. CO emissions were less than 25 ppm.

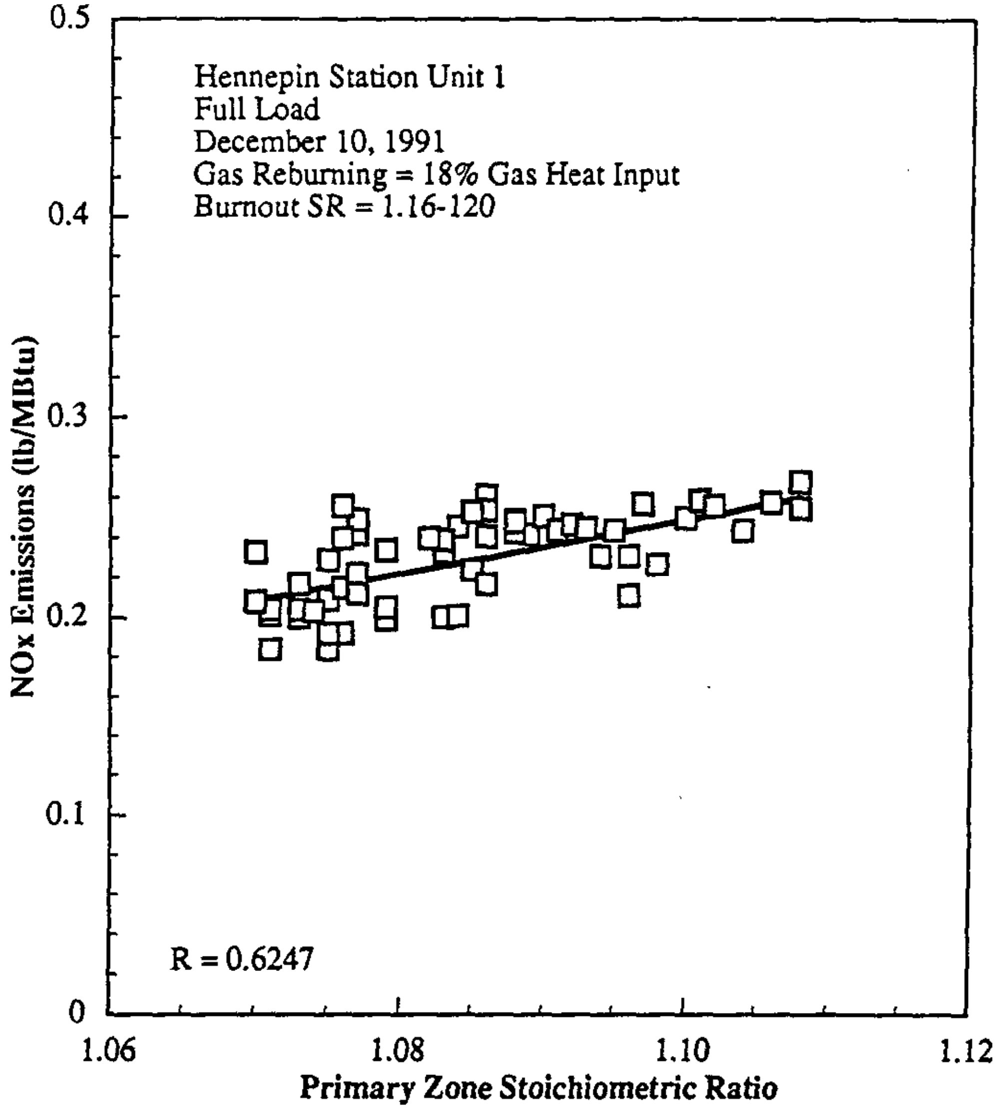


Figure 6-2. Effect of primary air on NO_x emissions

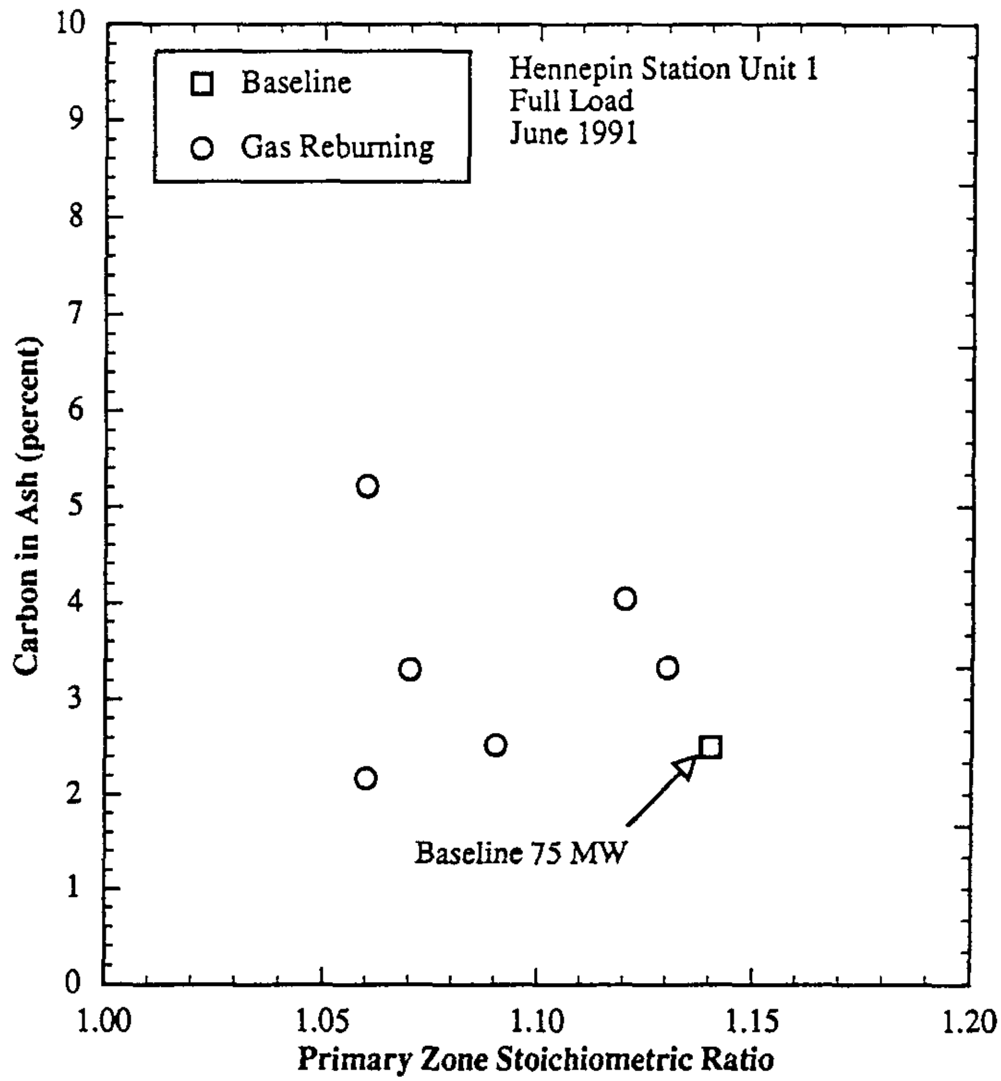


Figure 6–3. Effect of primary air on carbon in ash

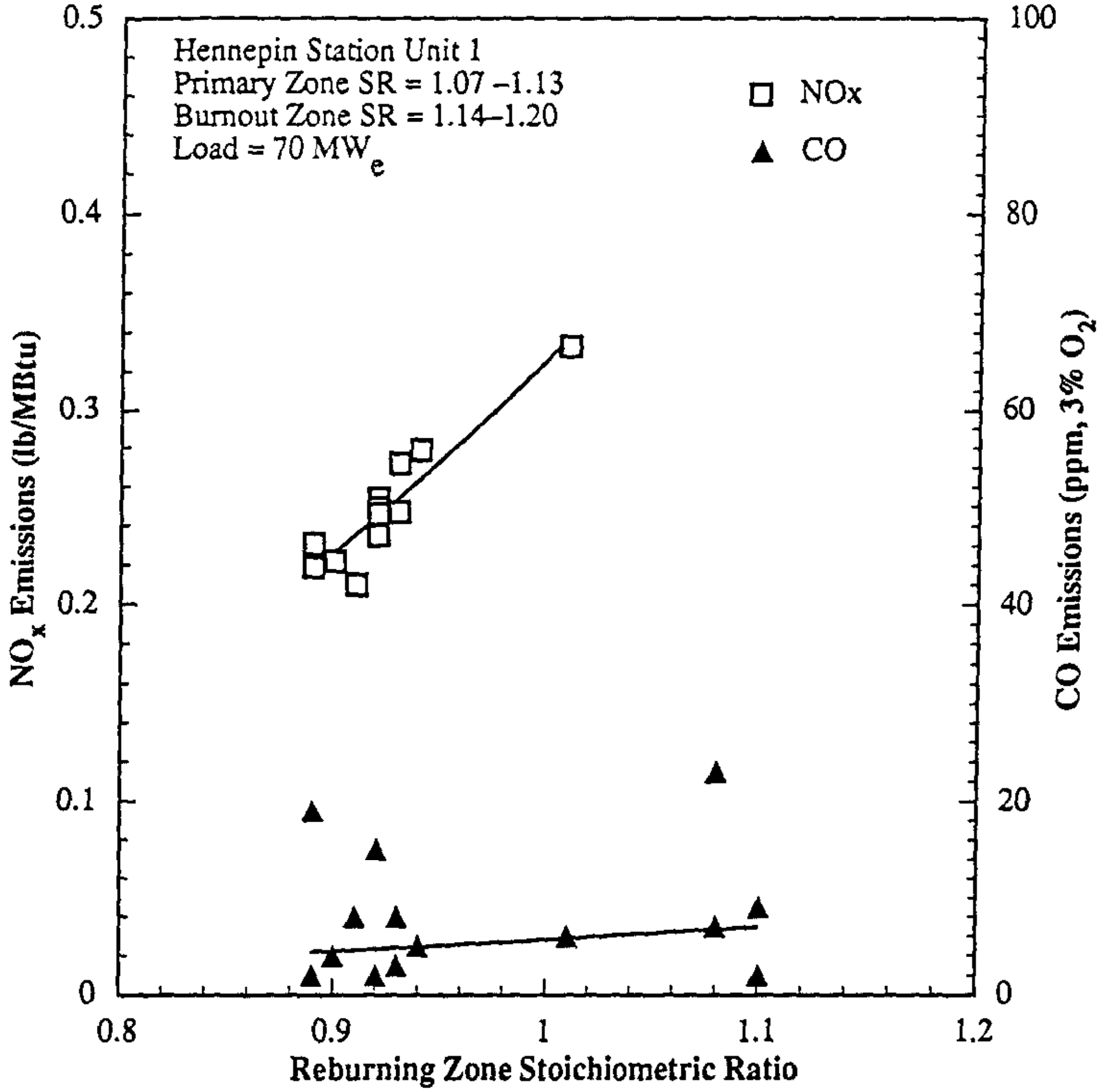


Figure 6–4. Effect of reburning zone stoichiometry on NO_x emissions

The burnout air completed the combustion process initiated in the primary zone and brought the combustion system to its normal operating stoichiometric ratio. In practice, GR allowed the system to operate at lower excess air levels. Figure 6–5 shows the NO_x emissions levels achievable under baseline operation, staged combustion operation, and GR operation. Baseline tests at excess air levels between 13 and 21% resulted in NO_x emissions from 0.52 lb/10^6Btu (224 mg/MJ) to 0.77 lb/10^6Btu (331 mg/MJ). Staged combustion operation, plotted here with acceptable combustion characteristics, showed NO_x emissions from 0.46 lb/10^6Btu (198 mg/MJ) to 0.51 lb/10^6Btu (219 mg/MJ). GR data are plotted for excess air levels from 12 to 21%. The total NO_x reduction from the uncontrolled level, when utilizing 18% excess air at the burnout zone, was approximately 67%.

6.3.3.2 Flue Gas Recirculation

Isothermal flow modeling provided an in-depth characterization of the reburning fuel jet behavior. The study showed that adequate residence times could be achieved with proper penetration and that would allow sufficient time for NO_x reduction reactions. In the GR optimization test series, the focus was to optimize mixing by varying the FGR flow rate. In this report, FGR flow rates are expressed as a percentage of the total flue gas flow.

To determine the effect of mixing on NO_x emissions, tests were run with three levels of FGR at full load and with primary stoichiometric ratios between 1.08 and 1.12. Figure 6–6 illustrates the effect of FGR on NO_x emissions performance as functions of reburn zone stoichiometric ratio. Satisfactory mixing performance was evident for FGR levels between 2.6 and 3.6%. In fact, as more reburning fuel was added the difference between 2.6 and 3.6% FGR flow was insignificant. Lower levels of FGR flow had a relatively small negative effect on mixing rate and NO_x emissions performance. Therefore, satisfactory mixing can be accomplished with FGR levels greater than 2.6%.

6.3.3.3 Reburning Fuel Injector/Coal Burner Tilt Angle

The reburning fuel injectors were equipped with tilting mechanisms which allowed them to inject reburning fuel at the same angle as the coal burners. During the optimization test series, the reburning fuel injector tilts were tested through their full angle of rotation with no appreciable change in reduction of NO_x emissions. The purpose of tilting reburning fuel injectors was to follow the primary burner tilts and thus the fire ball. Conceptually, this would allow a consistent separation between the two zones to allow combustion of the primary fuel to proceed nearly to completion, and provide the necessary reburn zone

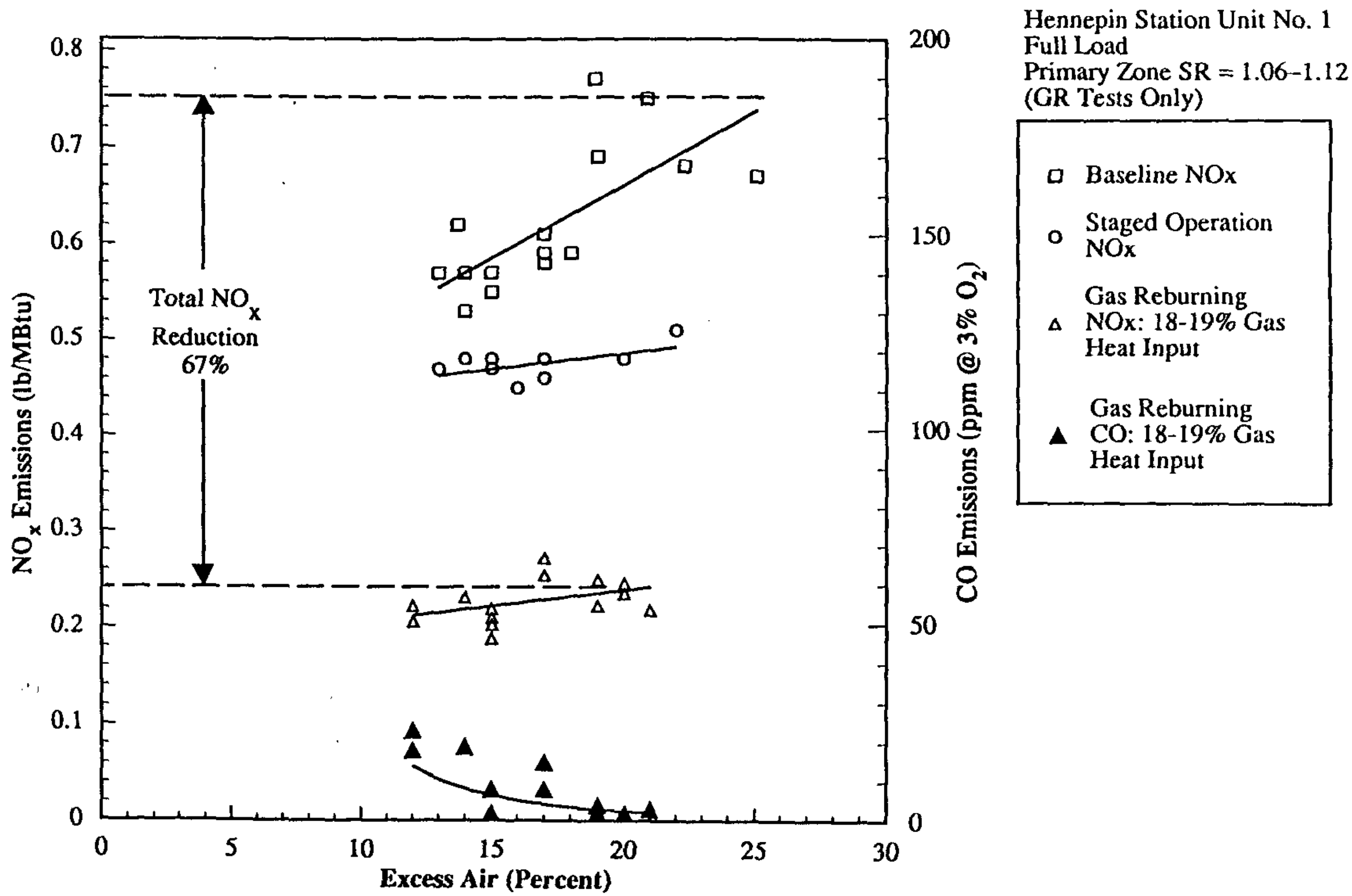


Figure 6–5. NO$_x$ reduction and CO emissions under Gas Reburning

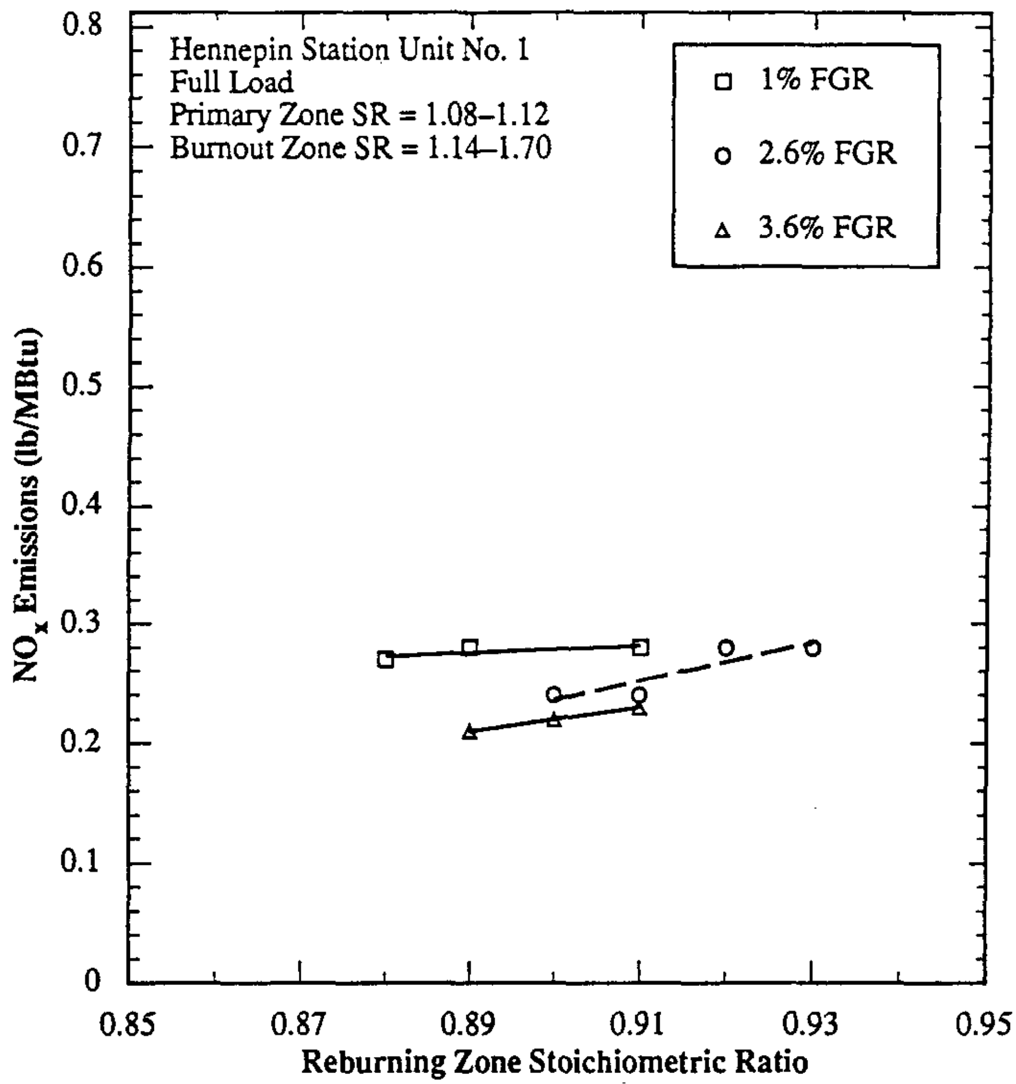


Figure 6–6. Effect of FGR on NO_x emissions

residence time. Figure 6-7 illustrates that reburning injector/coal burner tilting resulted in a negligible change in NO_x emissions as the injector tilt angle varied from horizontal to -27 degrees at full load. The injector tilting capability was eliminated after optimization testing.

6.3.3.4 Boiler Operational Parameters

Boiler operational parameters include:

- Boiler load
- Coal mills in service
- Furnace temperature profile

One of the main objectives of the project was to design a process which would be effective throughout the entire operating range of the unit for the purpose of load following on dispatch control. Optimization tests were conducted at loads from 40 to 75 MW_e.

6.3.3.4.1 Boiler Load

The impact of boiler load on GR performance is due to the primary NO_x emissions level and gas temperature profile. As was observed in the baseline tests, baseline NO_x levels varied from 0.75 lb/10^6Btu (323 mg/MJ) at 75 MW_e, to 0.48 lb/10^6Btu (206 mg/MJ) at 60 MW_e, to 0.50 lb/10^6Btu (215 mg/MJ) at 45 MW_e. Figure 6-8 illustrates the effect of load on NO_x emissions. The baseline NO_x emissions were not measured at constant excess O_2;therefore some variations must be attributed to varying excess O_2 levels. Data at 70 MW_e have already been thoroughly discussed. At 60 MW_e, GR performance is affected by lower primary NO_x levels entering the reburning zone and lower gas temperatures entering the reburning zone; therefore, the reduction efficiency was lower at 60 MW_e in comparison to full load reduction efficiency. At loads below 55 MW_e with GR, the boiler was operated with 2 mills in operation and with the burner tilts raised to +27° to maintain reheat steam temperature, similar to operation at 60 MW_e. GR efficiency at 45 MW_e was also lower due to decreased reburning zone gas temperature and lower initial NO_x.

6.3.3.4.2 Mills in Service

At Hennepin, the normal mode of operation at loads below 55 MW_e with GR is with two mills in service. The top row of burners is fed by Mill C, the middle row of burners is fed by Mill B, and the bottom row of burners is fed by Mill A. The effects of mills out of

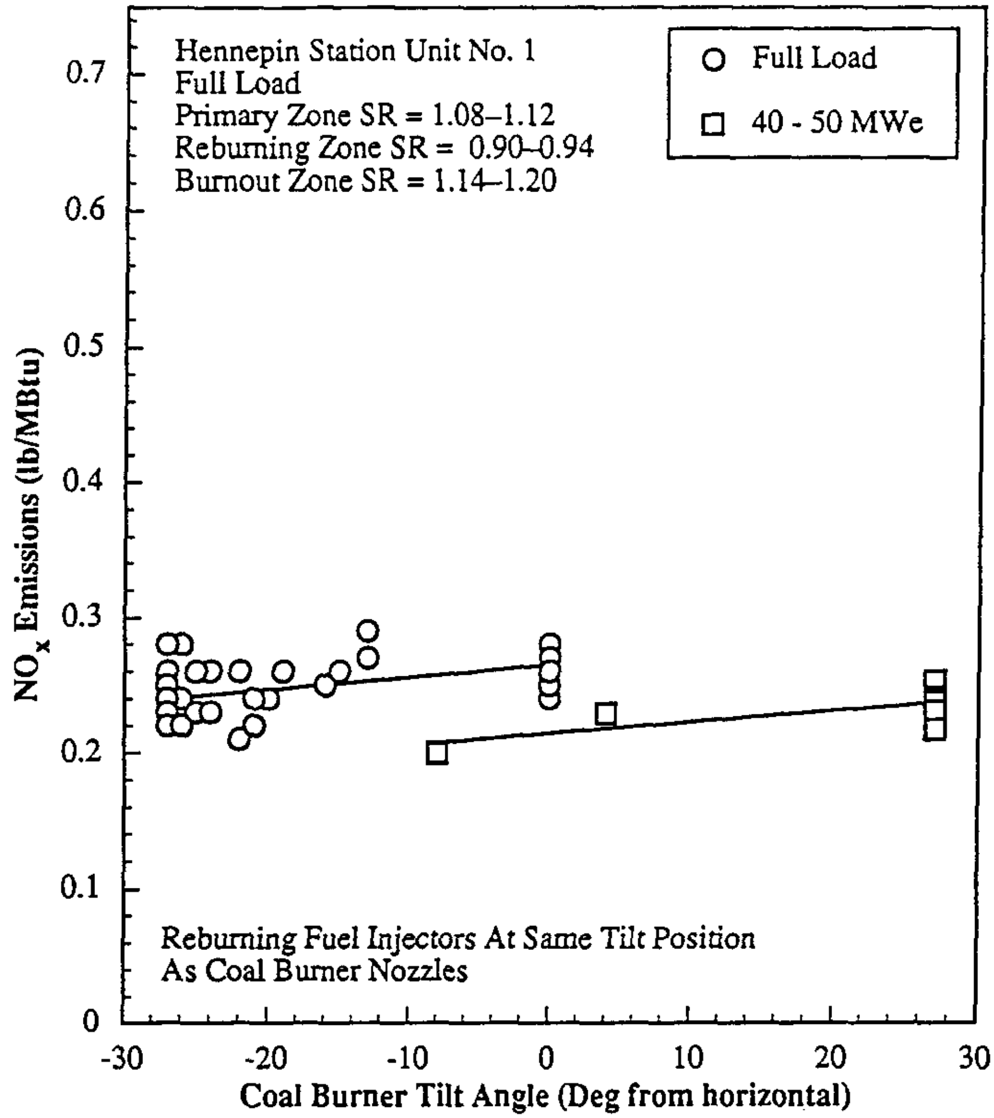


Figure 6–7. Effect of coal burner tilt angle on NO_x emissions

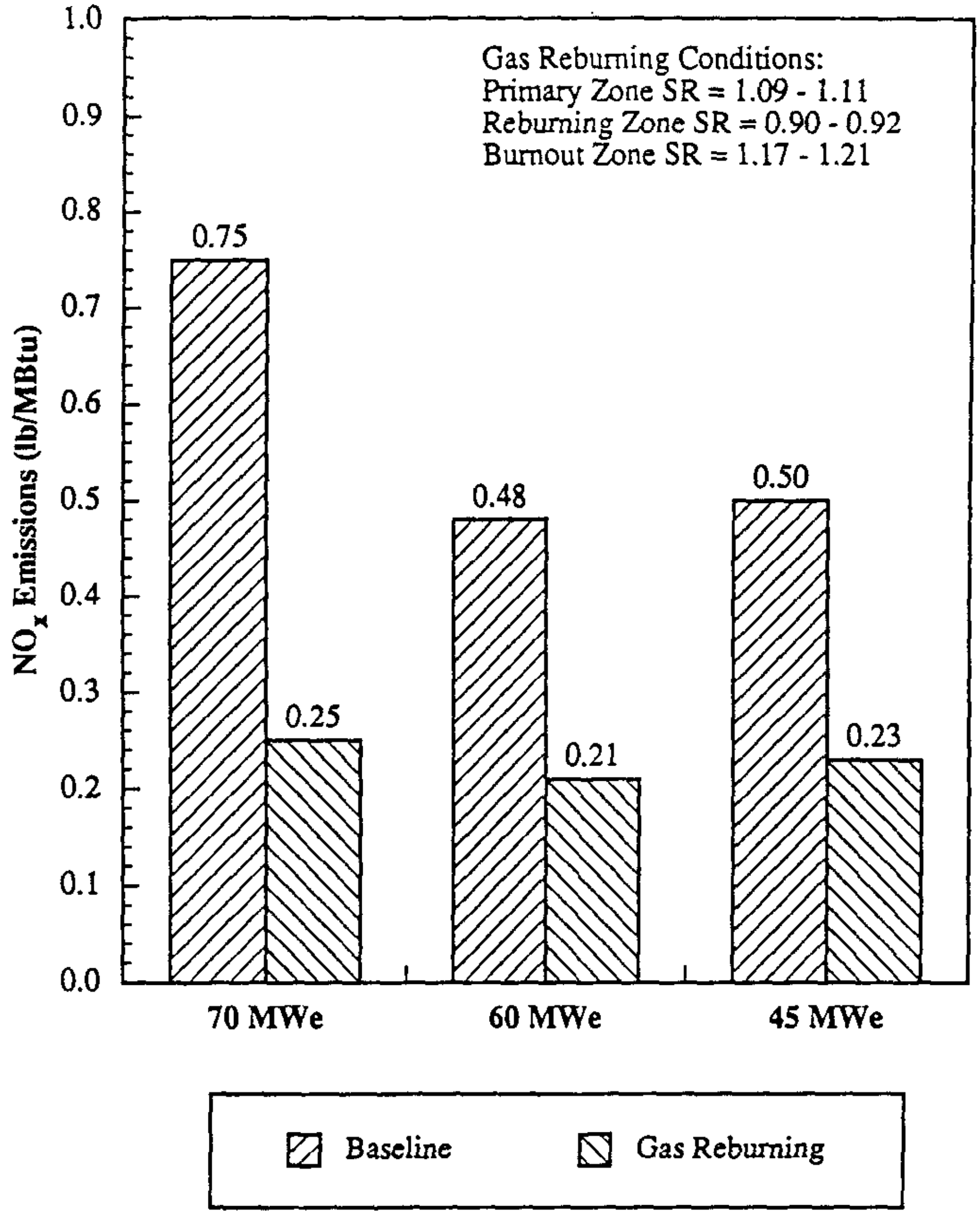


Figure 6–8. Effect of boiler load on NO_x emissions

service at low load was evaluated without GR. Taking Mill C out of service results in reduction in NO_x emissions, shown in Figure 6-9, due to combustion staging.

6.3.3.4.3 Reburning Zone Gas Temperature

Gas temperature measurements were taken at furnace plane elevation "C" at elevation 539' (see Figure 5-1). These were used to evaluate the impact of gas temperature on the GR process efficiency. GR is believed to be more effective at higher reburning zone temperatures due to higher rates of reaction, i.e. more rapid formation of hydrocarbon fragments and free radicals leading to higher rates of NO_x reduction. The reburning zone temperatures may also be an indicator of the primary zone temperature, and may indicate completeness of the primary zone coal combustion. The reburning process is more effective when the primary zone coal combustion is complete. Figure 6-10 shows NO_x emissions as a function of reburning zone stoichiometric ratio, at two levels of gas temperature. The NO_x emissions are approximately in the same range, with slightly lower values for the higher temperature case (2350°F [1288°C]) for reburning zone stoichiometric ratios below 1.00.

6.4 Sorbent Injection Performance

The following sections describe the results of the SI optimization tests conducted in 1991. In this test series, a majority of the tests were conducted with GR. Only a limited number of tests were conducted with only SI. This section includes a design methodology summary todescribe key parameters that were closely monitored during the tests, followed by a discussion and analysis of each parameter.

6.4.1 Sorbent Injection Parameters

Bench-scale studies of the SI process have shown that three major parameters control the utilization of sorbent, and hence the cost effectiveness of the SI process. These parameters are:

- Sorbent reactivity
- Temperature history
- Sorbent dispersion

The sorbent reactivity refers to its ability to react with SO_2. Actually, the sorbents tested at Hennepin were all calcitic hydrates [$Ca(OH)_2$] which do not react with SO_2 directly. Upon

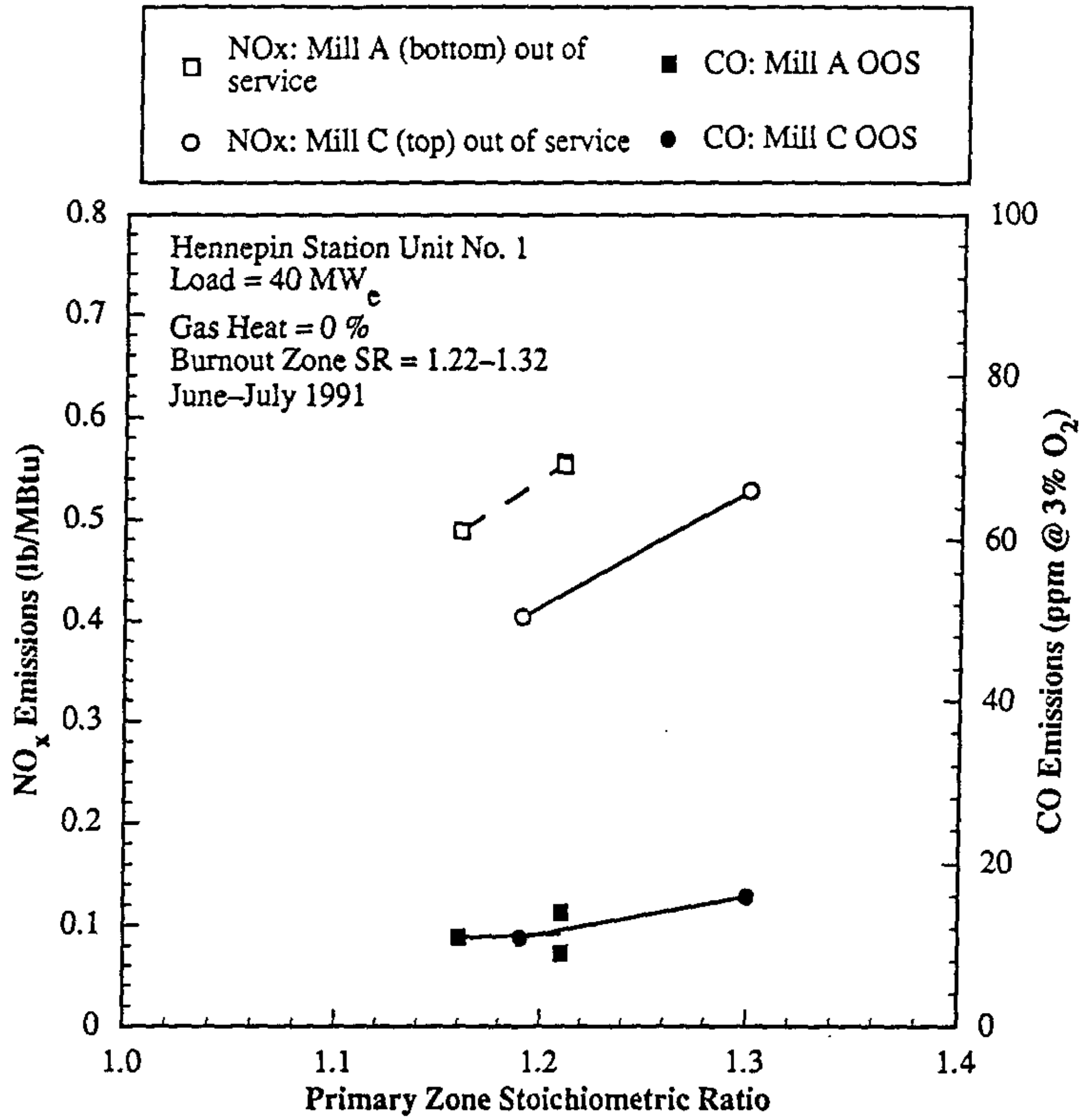


Figure 6–9. Effect of number of mills in service at low loads

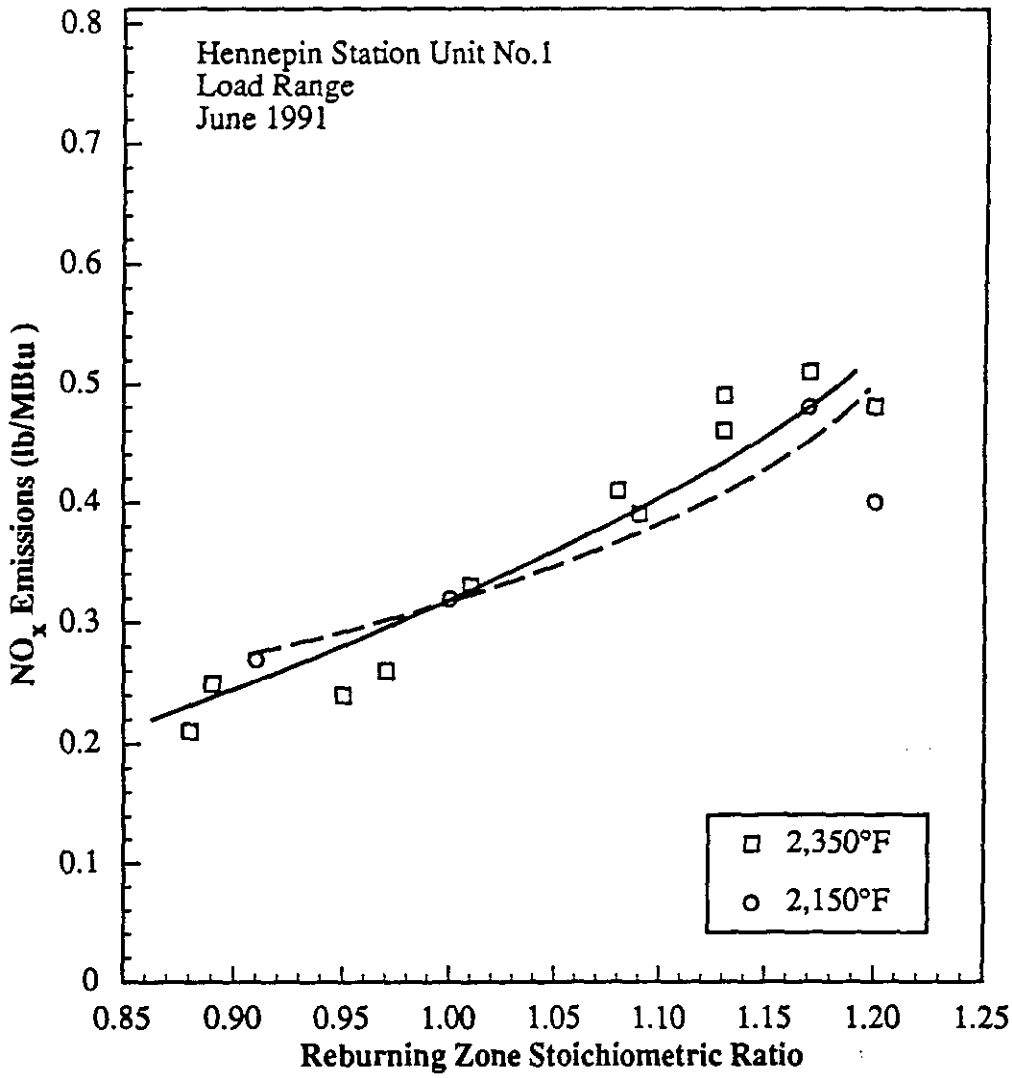


Figure 6–10. Effect of Reburning Zone Stoichiometric Ratio and temperature profile on NO_x emissions.

introduction into the furnace, the sorbent undergoes calcination to produce CaO. It is the CaO which reacts with SO_2. Therefore, the sorbent reactivity depends on the characteristics of the sorbent as well as details of its injection into the furnace. The reactivity of the CaO can be enhanced by altering the hydrating process used to form the calcitic hydrate. Some materials, including the three advanced sorbents tested in this project, are produced with promoting agents which tend to increase the CaO reactivity.

As might be expected, the furnace temperature at the point of sorbent introduction has a pronounced impact on CaO reactivity. Injection at high temperature tends to sinter the surface of the CaO producing a low reactivity "dead burned" material. The optimum injection temperature for most sorbents is near 2,300°F (1,260°C).

The temperature history of the sorbent following injection also affects SO_2 capture. The CaO reacts readily with SO_2 immediately following injection. However, the reaction rate degrades as the temperature drops and is negligible beneath about 1,600°F (871°C). Therefore, SO_2 control is enhanced by long residence time in this temperature window.

Sorbent dispersion across the complete flue gas stream is also important to ensure that the SO_2 has opportunity to contact sorbent for the longest possible time.

EER's SI design methodology evaluated all of these factors. A combination of field measurements, heat transfer modeling and isothermal physical flow modeling was used to establish the furnace gas temperature and flow patterns. Optimum injection temperatures (and hence locations) were selected based on the sorbent characteristics measured in bench scale reactivity tests. Alternate arrangements of the sorbent injectors were evaluated via physical flow modeling to select the final design.

6.4.2 Sorbent Injection Optimization Test Results

Data relevant to SI performance collected during GR-SI and SI operation are presented in Table A-5 of Appendix A. These data were averaged during steady state periods. Sorbent SO_2 capture ranged from a low of 25.3% to a high of 60.6%. Baseline SO_2 emissions averaged 5.24 lb/10^6Btu (2,250 mg/MJ) over the test period.

Figure 6-11 illustrates typical SO_2 emissions trends during GR and GR-SI operation, measured on December 13, 1991. Initial baseline SO_2 emissions were taken prior to commencing GR for a period of 15-30 minutes (not shown in figure). When reburning fuel

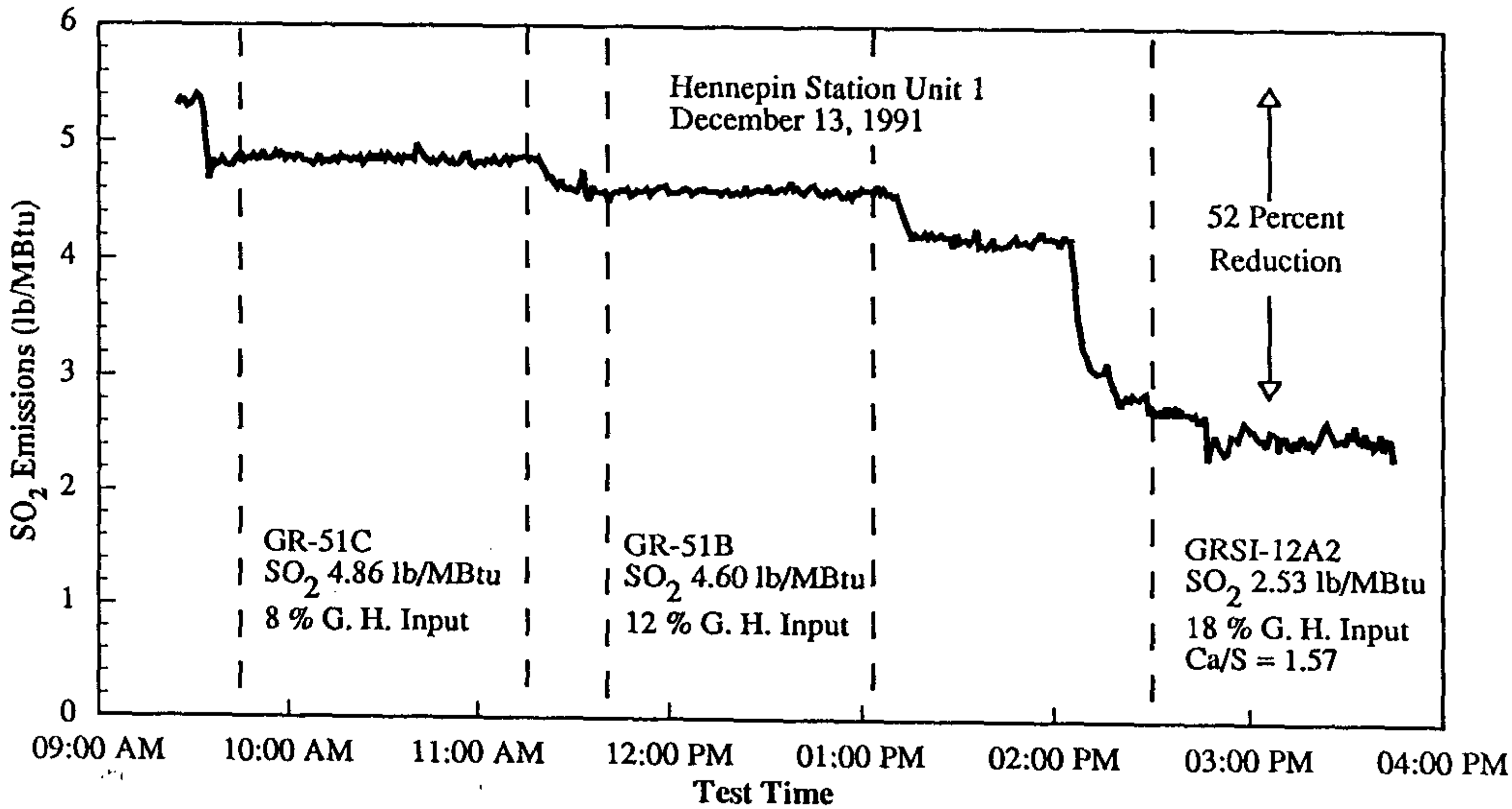


Figure 6-11. SO_2 emissions during GR and GR-SI operation

was injected into the furnace, a second baseline level was established, prior to commencing SI. Once SI was initiated, SO_2 emissions began to decrease but did not reach steady-state for about 30 minutes. Collection of test data did not begin until the steady state condition existed. On December 13, 1991, two GR tests preceded a GR-SI test. On this day, GR tests showed the expected reduction due to 8 and 12% gas heat input of 8 and 13% from the coal baseline. The GR-SI test, showed an SO_2 reduction of 52.6%, from operation with 18% gas heat input and a Ca/S of 1.57.

6.4.2.1 Impact of Sorbent Injection Parameters

Results in this section will focus on SI parameters and GR-SI optimization tests that were used to optimize sorbent SO_2 capture. The following SI parameters were found to affect the SO_2 capture efficiency of the GR-SI process:

- Ca/S molar ratio
- Injection configuration
- Sorbent reactivity
- Boiler operational impacts

6.4.2.1.1 Ca/S Molar Ratio

Extensive bench scale testing and computational modeling has shown that sorbent SO_2 capture efficiency depends on the SO_2 concentration and the Ca/S molar ratio. The effect of Ca/S molar ratio on SO_2 control is shown in Figure 6-12 for three loads. Full load predictions are also shown for comparison and are in good agreement with the data.

Since the cost of SO_2 removal is dominated by the cost of the sorbent itself, the overall cost effectiveness increases with calcium utilization, expressed as the portion of the calcium which is reacted with sulfur. Calcium utilization is calculated as the percentage of SO_2 removal divided by the Ca/S molar ratio. Figure 6-13 shows the same data as Figure 6-12 re-plotted in terms of calcium utilization. The general trend is for lower utilizations at high Ca/S molar ratio. This is consistent with bench scale tests and is caused by blinding of the active CaO as $CaSO_4$ is formed.

Figures 6-12 and 6-13 both showed data under GR-SI operating conditions. Figure 6-14 compares the performance with SI alone. There is a slight improvement in SO_2 removal with GR-SI probably due to changes in the temperature profile.

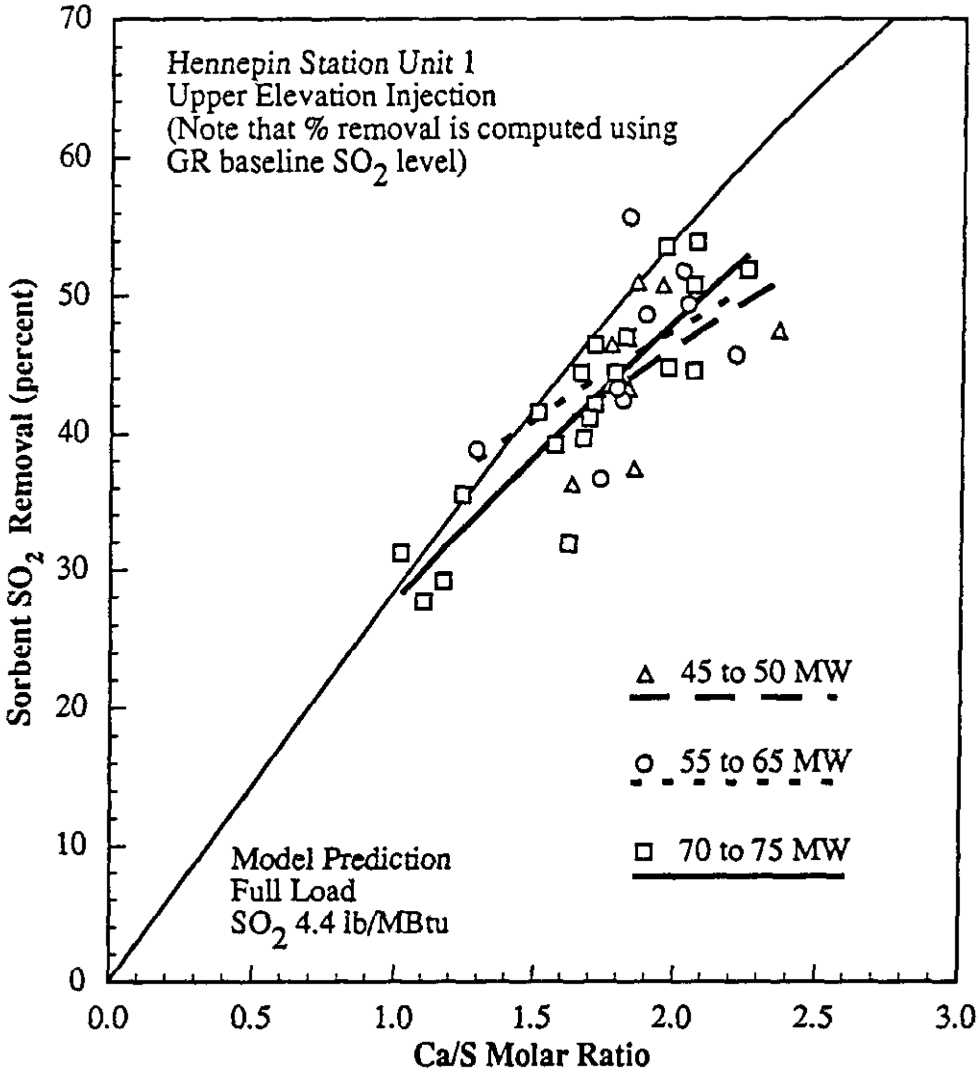


Figure 6–12. Sorbent SO_2 removal for GR-SI under three load ranges

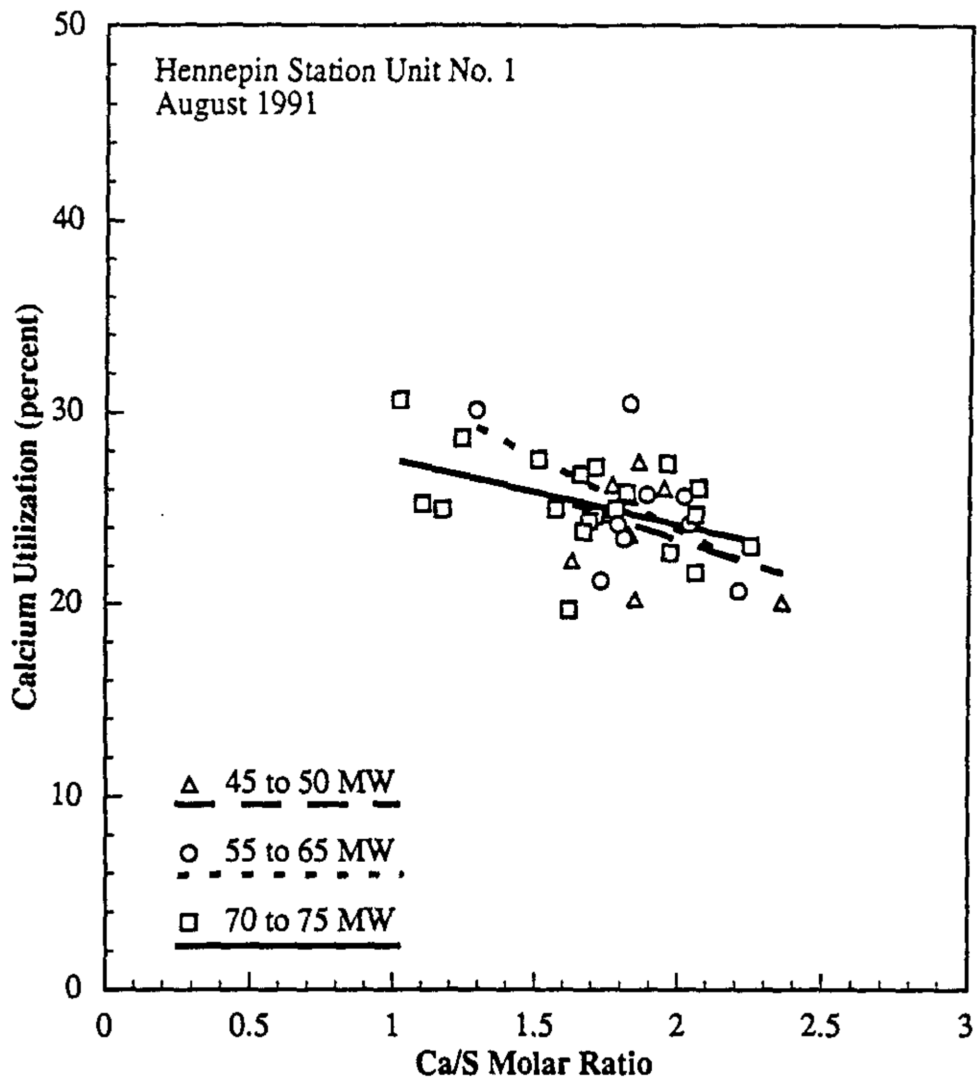


Figure 6–13. Calcium utilization results for GR–SI testing for three load ranges

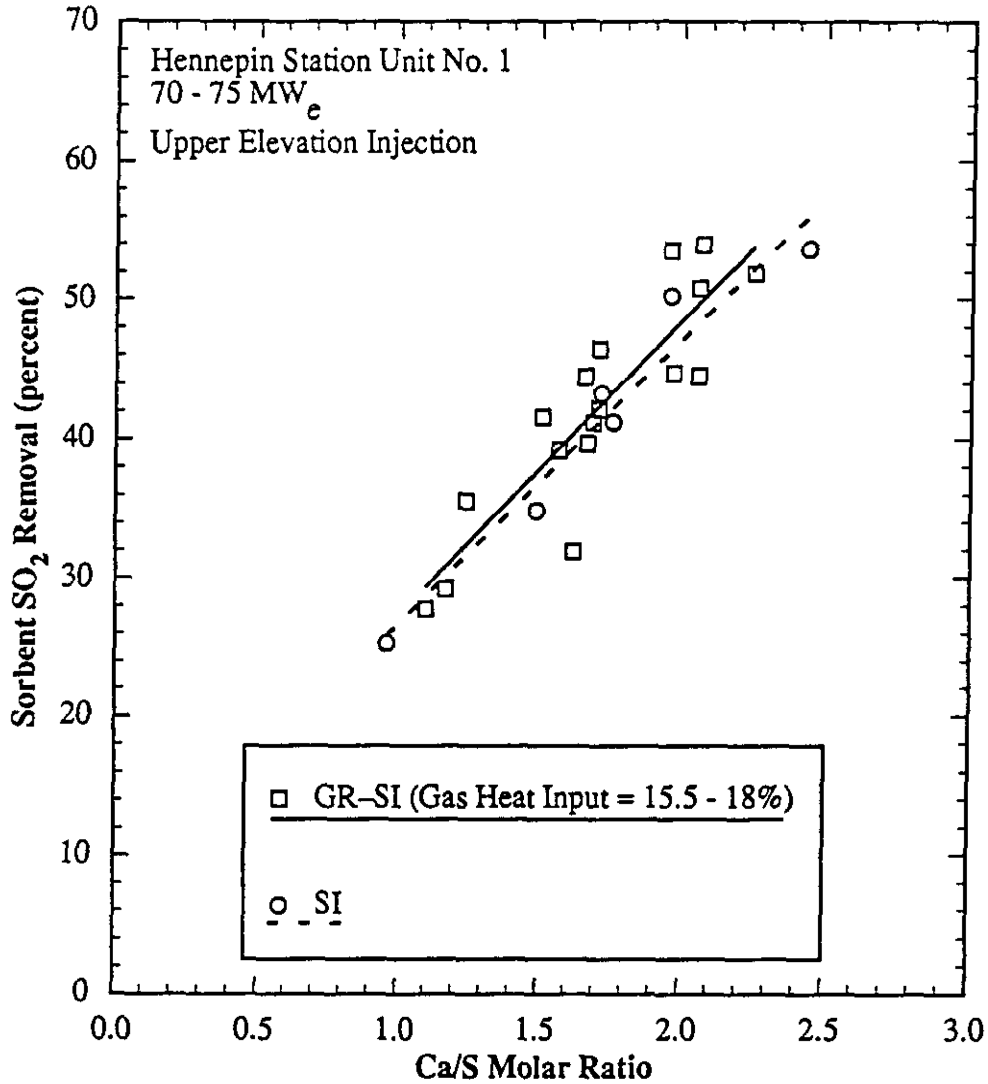


Figure 6–14. Comparison of SO_2 removal from GR-SI and SI tests

6.4.2.1.2 Injection Configuration

The aforementioned computational models account for sorbent dispersion in the furnace to generate a more general prediction of SO_2 capture efficiencies. In these studies, sorbent dispersion and SO_2 concentrations were shown to have a significant effect on sorbent SO_2 capture efficiencies. Sorbent dispersion is dependent on the penetration and coverage characteristics of the sorbent stream and can be altered by varying the SI velocity and the injection configuration.

The SI injection system was designed with 6 jets to mix the sorbent uniformly across the furnace (4 on the front wall and 2 on the side walls). Figure 6-15 compares the performance in this configuration with that measured when the 2 side wall jets were out of service. As expected, calcium utilization degraded significantly with these jets out of service.

6.4.2.1.3 Sorbent Reactivity Parameters

Laboratory studies showed that sulfation is strongly dependent upon the surface area formed during calcination, which is a function of the sorbent type and thermal history of the particle.

In Table 6-2, chemical and physical analysis are presented for the hydrated lime sorbent used for design tasks (Marblehead) and the sorbent that was used for optimization tests (Linwood). In experimental testing, Linwood invariably showed a higher reactivity, indicating that small mean particle size in addition to high surface area and high porosity would be ideal physical characteristics.

In this test series no direct correlation was found linking SO_2 capture to physical characteristics of the sorbent. Thermal characteristics have been found to significantly impact sorbent performance. As previously mentioned, there is an upper limit for injection temperature, above which thermally induced sintering mechanisms take place, and a lower limit, below which sulfation rates are reduced. In-furnace measurements taken near the injection location, Figure 6-16, shows that the temperature in this cross-section is near ideal for calcination, i.e. maximum temperatures of 2350°F.

6.4.2.2 Effects of Boiler Operation on SO_2 Removal

Boiler operational parameters were also found to have impacts on the performance of the SI system. Those parameters are:

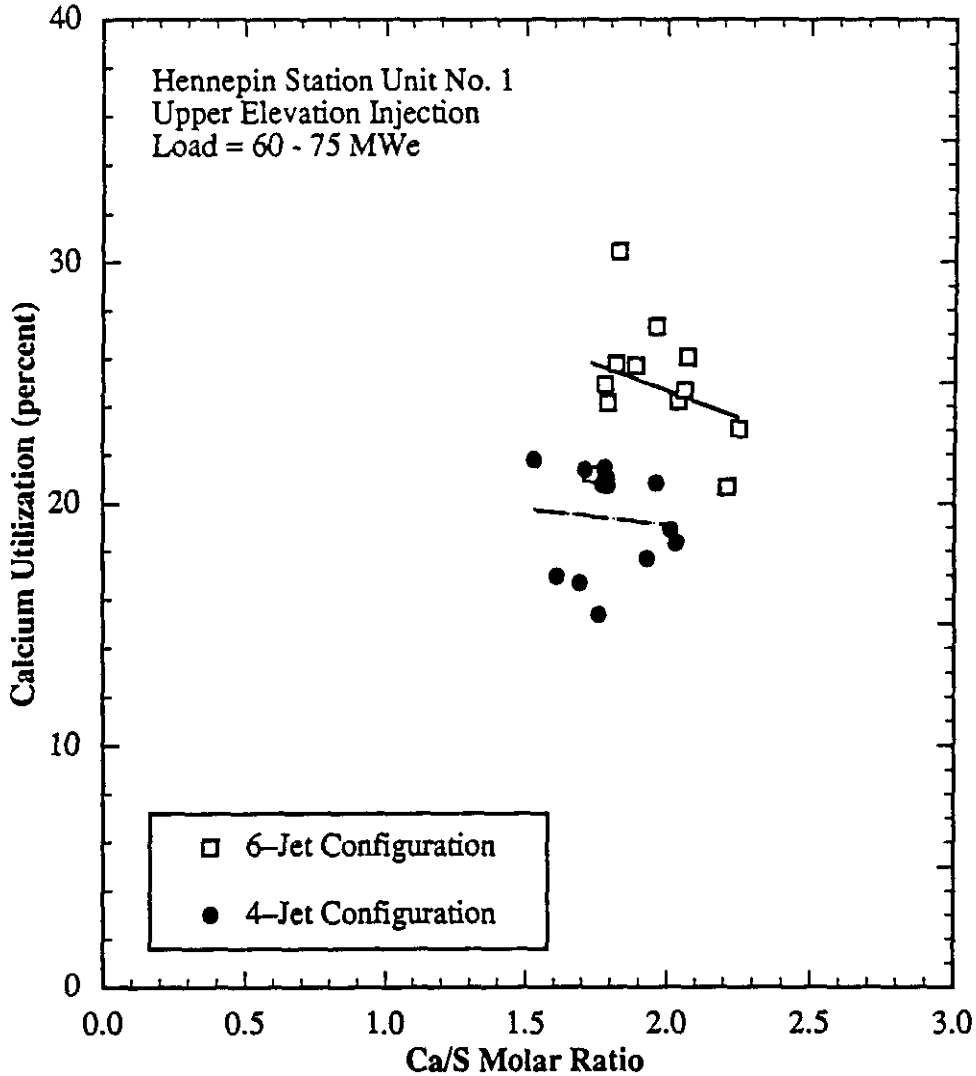
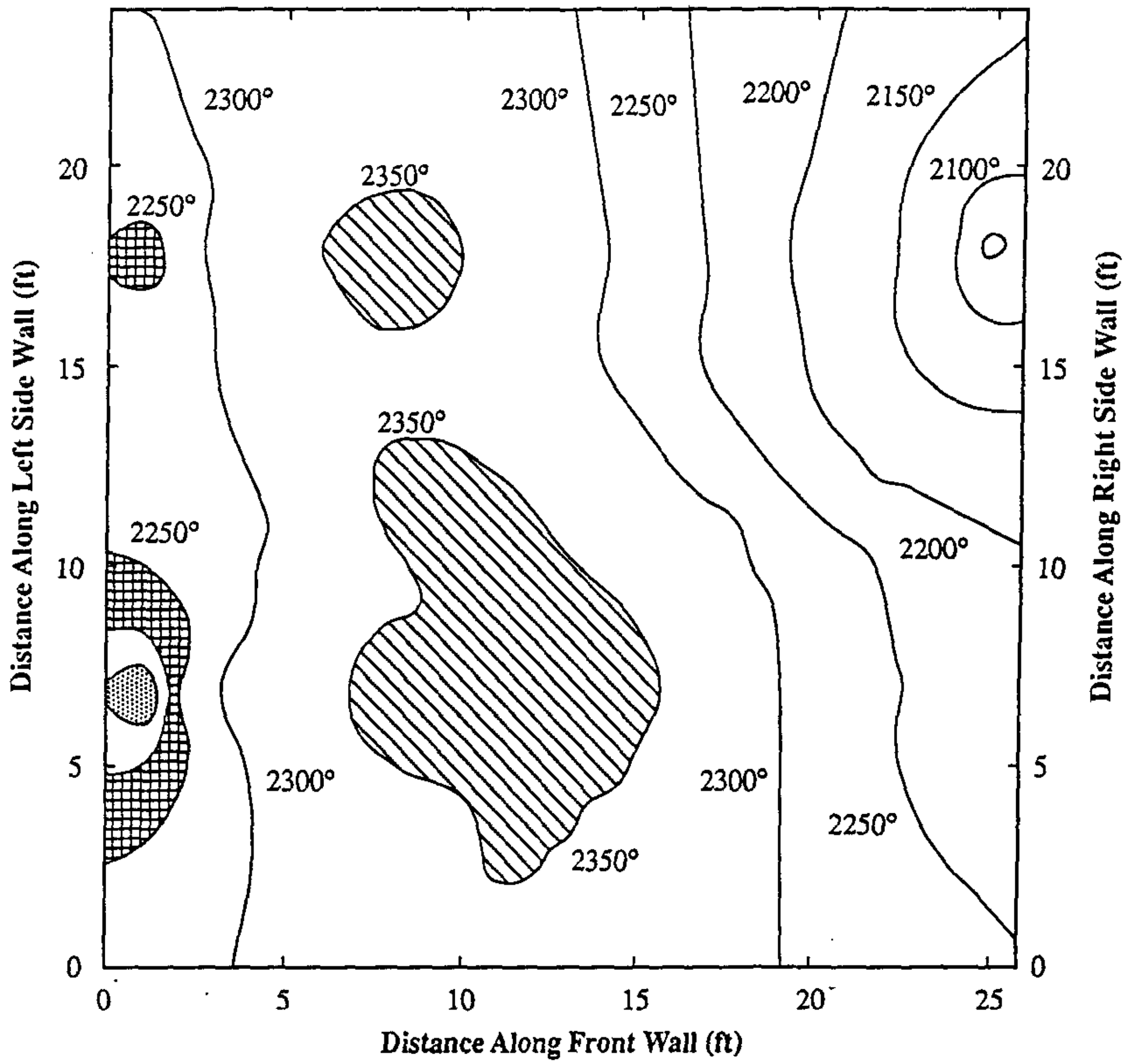


Figure 6–15. Effect of Ca/S on two upper injection configurations at full load.

TABLE 6-2. SORBENT ANALYSES

Constituent	units	Marblehead	Linwood
$Ca(OH)_2$	%	90.00	96.20
$Mg(OH)_2$	%	1.60	0.14
$CaCO_3$	%	6.10	1.22
SiO_2	%	1.10	1.66
Fe_2O_3	%	0.60	0.50
Al_2O_3	%	0.30	0.60
SO_3	%	0.20	0.08
Surface Area	m^2/g	22	15.5
Mass Median Diameter	µ	5.00	2.88
Density	g/cm^3	2.35	2.18
Bulk Density, Loose	lb/ft^3	20-25	25
Bulk Density, Settled	lb/ft^3	30-35	30



Note : Units are in °F.

Figure 6–16. Temperature variation at plane "C" for Full Load Gas Reburning conditions (GR—41B) with -26° burner tilt

- Boiler load
- Burner tilt
- Excess air

6.4.2.2.1 Boiler Load

As shown above, the SO_2 removal goal of the project was consistently achieved at full load using the upper level sorbent injectors. The SI system included a lower set of injectors at the OFA ports for low loads (< 45 MW_e) where furnace temperature decreased. Figure 6-17 compares the calcium utilization using the upper and lower injectors over the load range. As load is reduced, the performance with the lower level injectors improves as expected.

6.4.2.2.2 Burner Tilt

Tests at various burner tilt angles were conducted to evaluate the sensitivity of the temperature profile and its effect on sorbent SO_2 capture, particularly under lower load operation when burner tilt is adjusted to maintain reheat steam temperature. As shown inFigure 6–18, the mid- and full-load tests showed calcium utilization to be insensitive to burner tilt angles between -5 to +19 degrees. At low loads (45 MW_e to 58 MW_e) shown in Figure 6–19, calcium utilization was significantly affected in tests with burner tilts between -6 and +13 degrees, with lower level sorbent injectors in service. A temperature profile taken in July 1991, Figure 6–20, showed that at 45 MW_e with the burner tilts in their normal position, +20 degrees, approximately a third of the furnace, near the front wall, had temperatures exceeding 2,350°F (1288°C). As previously stated, laboratory studies have demonstrated that hydrated limes exposed to temperatures exceeding 2,350°F (1288°C) exhibit a decrease in reactivity due to a loss in surface area. Figure 6–21 demonstrates the burner tilt variation with low loads and upper level SI. Calcium utilization can be increased at lower load with the upper injectors in service, by upward shift of burner tilts.

6.4.2.2.3 Excess Air

As mentioned previously, the sulfation reactions can be represented by the following:

$$CaO + SO_2 + 1/2\ O_2 \text{ ---> } CaSO_4$$
$$CaO + SO_2 \text{ ---> } CaSO_3$$
$$CaO + SO_3 \text{ ---> } CaSO_4$$

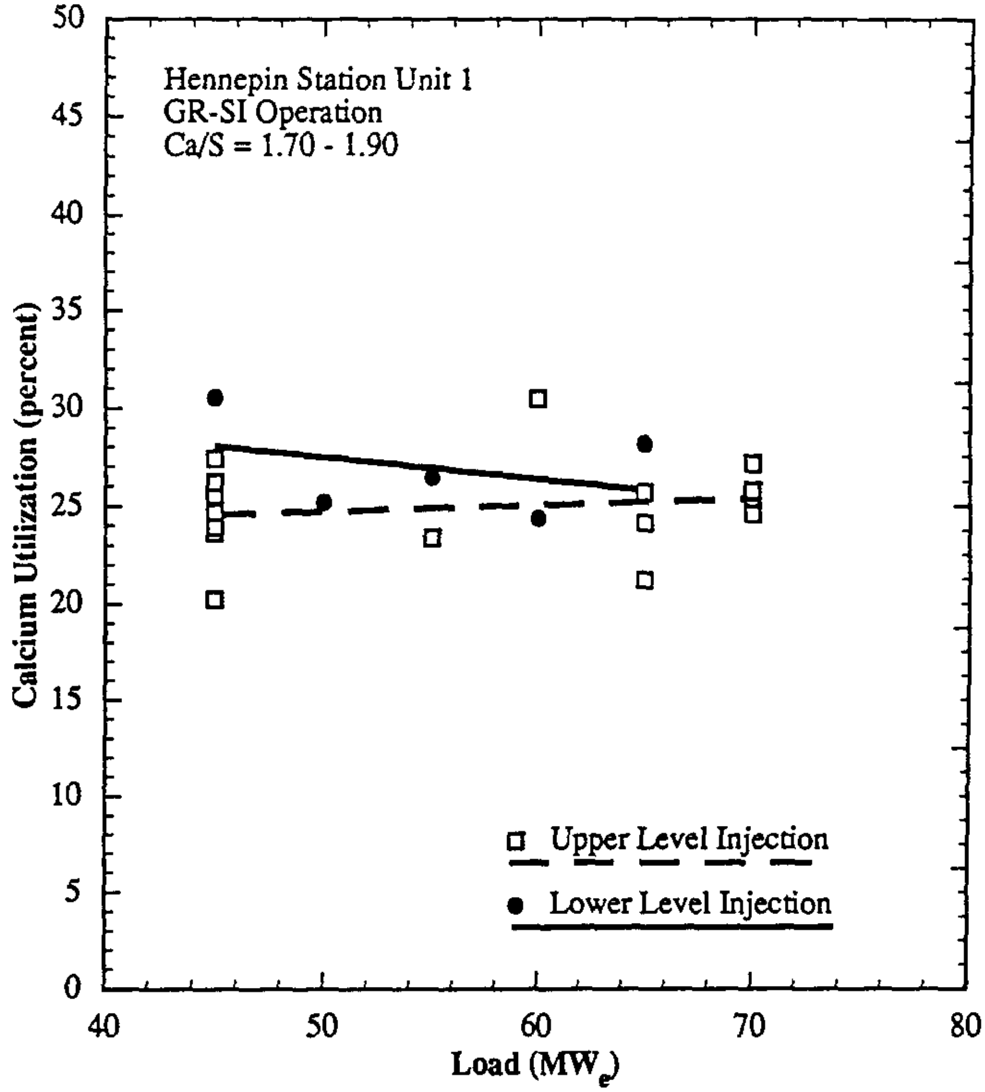


Figure 6–17. Effect of load on calcium utilization

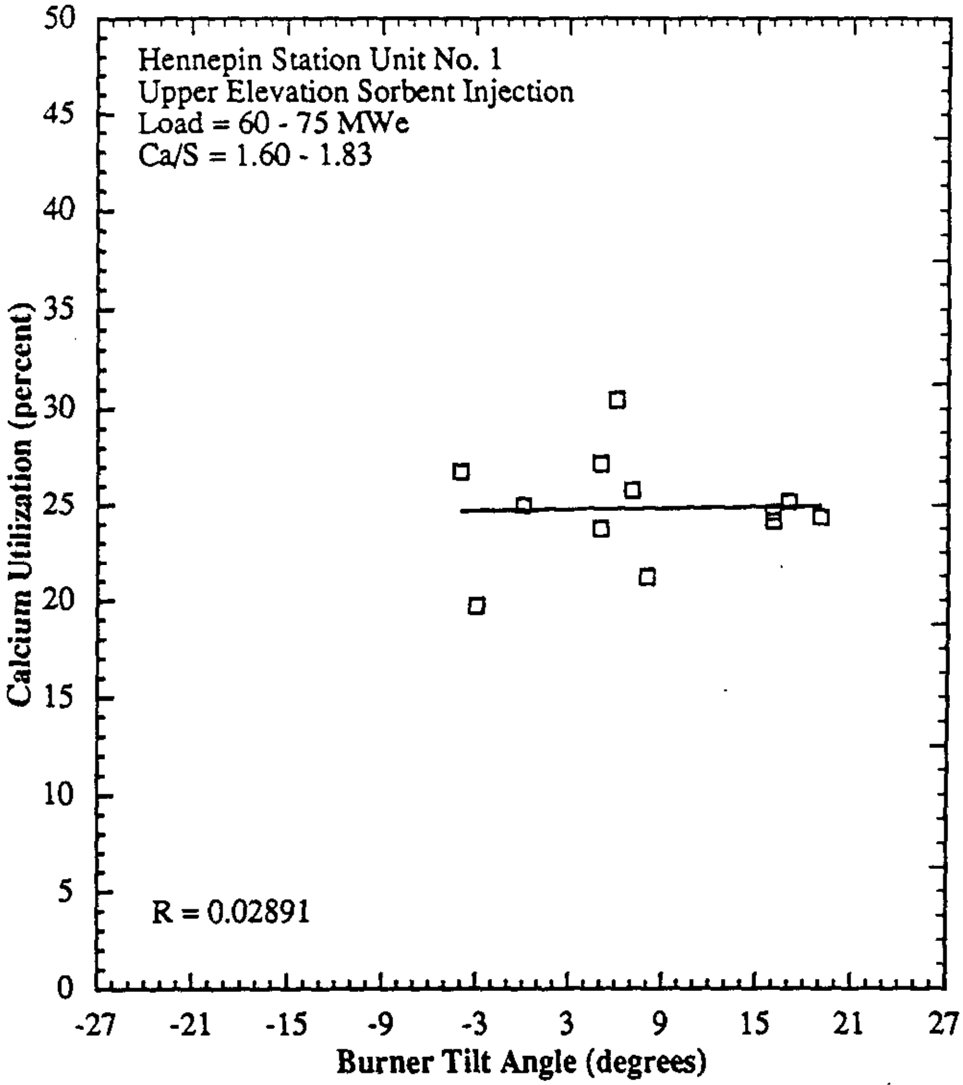


Figure 6-18. Effect of burner tilt on calcium utilization for high load cases

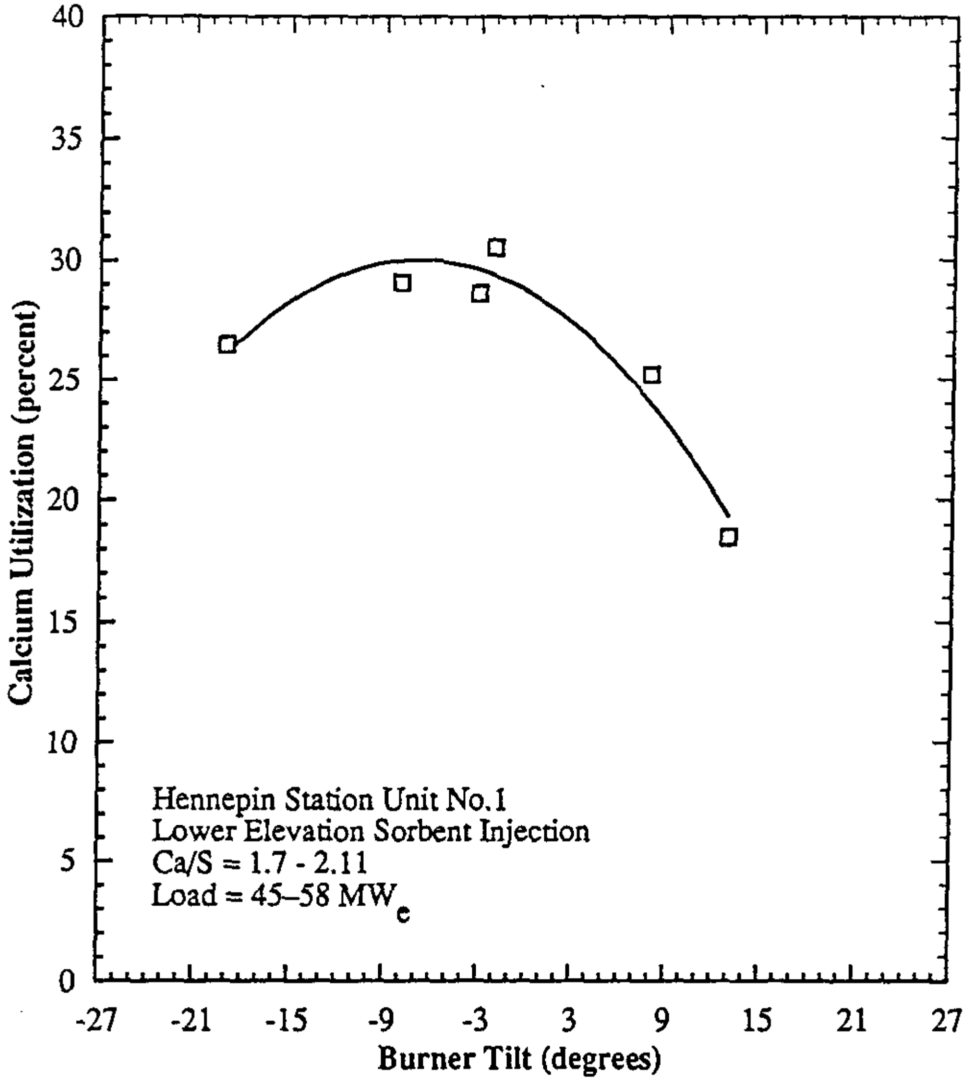
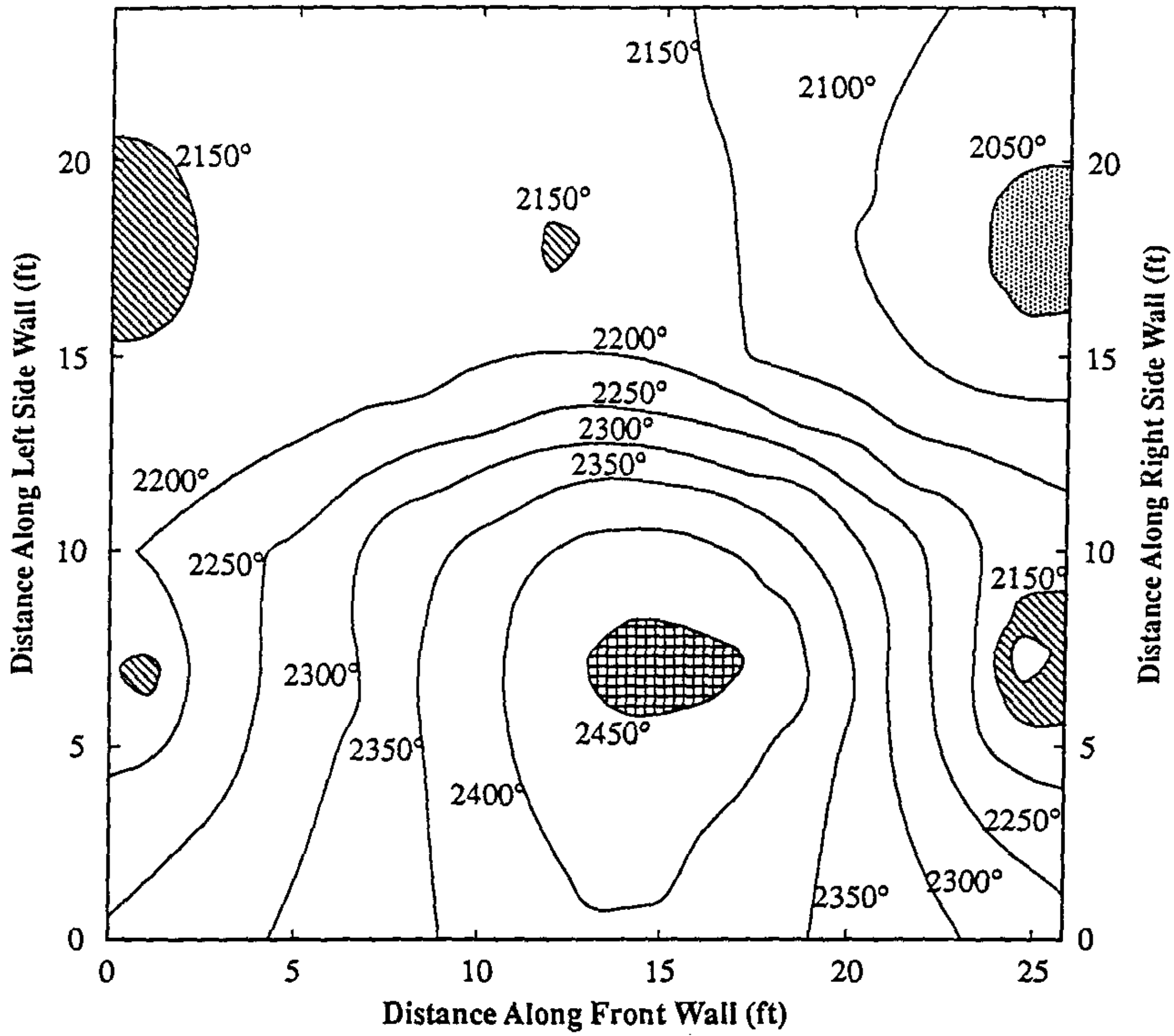


Figure 6–19. Effect of burner tilt on calcium utilization during GR-SI tests with lower injection elevation at low load



Note : Units in °F.

Figure 6–20. Temperature variation across Plane "C" for low load Gas Geburning condition (GR–40C) with -20° burner tilt

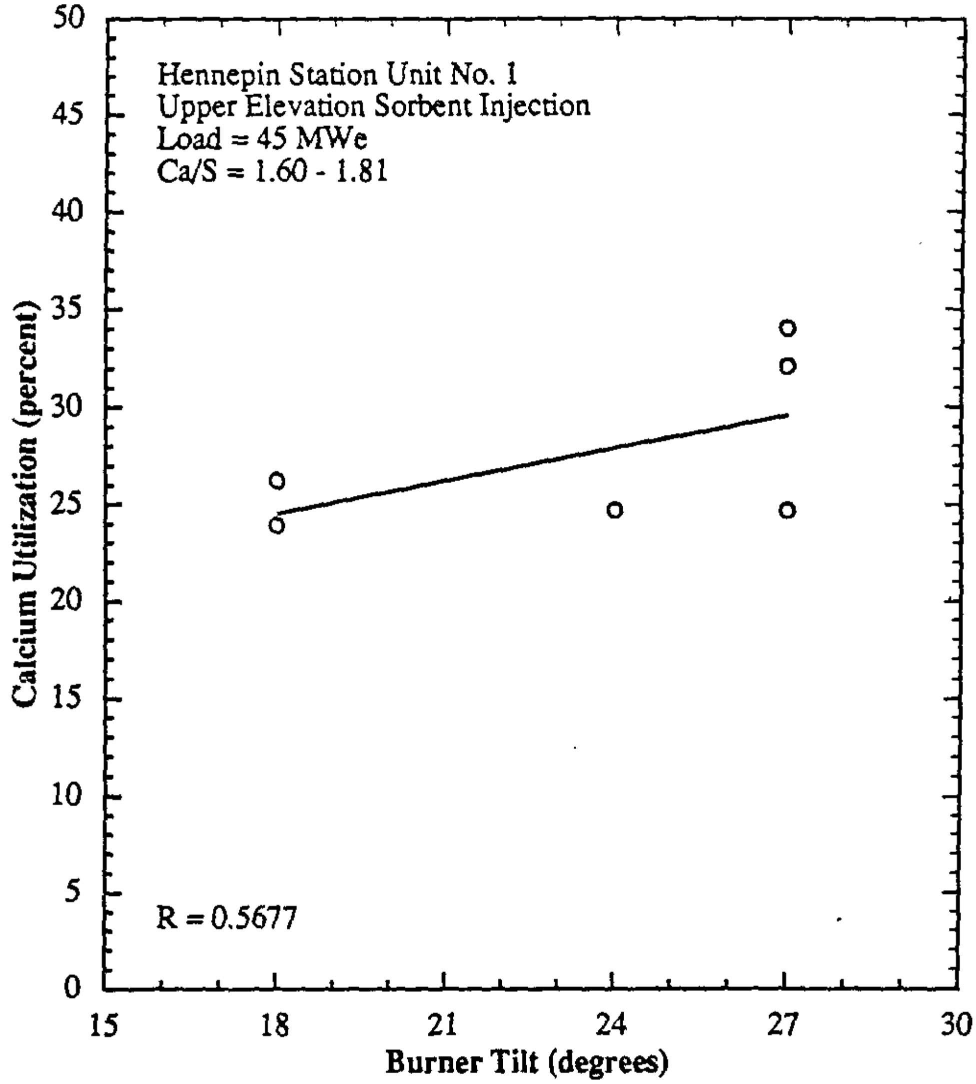


Figure 6-21 Effect of burner tilt on calcium utilization during GR-SI tests with upper elevation injection at low load

In Figure 6–22, excess air had no effect on calcium utilization at full load and reduced loads. However, since the reaction is dependent on oxygen, a significant drop in the excess air level could theoretically reduce the rate of the sulfation reaction. It is unlikely, though, for the boiler to be operated at excess oxygen levels below 2% for extended periods.

6.4.3 Calcium Utilization Data From Ash Analyses

Throughout the test period, single-point ash samples were collected at the economizer inlet to compare with results obtained from the gas-phase analysis and sorbent feed rate measurements used in calcium utilization calculations. The results from the analysis, conducted during GR-SI optimization testing, are summarized in Table 6–3. As explained below, sorbent utilizations based on gas phase measurements would be expected to yield more accurate results due to heavy Ca/S stratification in the economizer inlet duct.

On August 29, 1991 a test was conducted to determine the amount of solid calcium to sulfur stratification across the boiler exit plane at the economizer inlet. During the test, individual samples were taken at 24 points across the economizer inlet plane using upper level sorbent injection with the 6-jet configuration at full load. Gas analyses showed that the Ca/S ratio was 1.78:1 and the sorbent SO_2 capture was 44.4%. These samples were used to calculate local solid matter Ca/S molar ratios across the plane and are plotted in Figure 6–23. In the figure, Ca/S molar ratios were highest along the right side wall, possibly indicating biasing of sorbent flow to one side of the boiler. Due to the heavy stratification observed, single-point measurements would not be expected to be representative of all of the solid matter (i.e. ash and spent sorbent).

6.5 HCl and HF Emissions During Baseline, GR, and GR-SI Operation

Emissions of HCl and HF were quantified in relatively short (several hour) tests during baseline and GR-SI operation. Significant reductions in HCl and HF emissions due to GR-SI were measured. This is due to two processes: fuel switching, since natural gas contains essentially no chlorine and fluorine; and reaction of HCl and HF with sorbent (CaO). Reductions in HCl emissions in the range of 60.4 to 85.5% were measured during GR-SI operation at a gas heat input of 18.5 to 18.7% and a Ca/S molar ratio of 1.64 to 1.66. Reductions of HF emissions were in the 94.3 to 99.7% range. During GR-SI operation at the gas heat input and Ca/S stated above, the emissions of these halides were 9.29×10^{-3} to 24.6×10^{-3} lb HCl/10^6Btu (3.99 to 10.6 mg/MJ) and 1.14×10^{-5} to 19.1×10^{-5} lb HF/10^6Btu

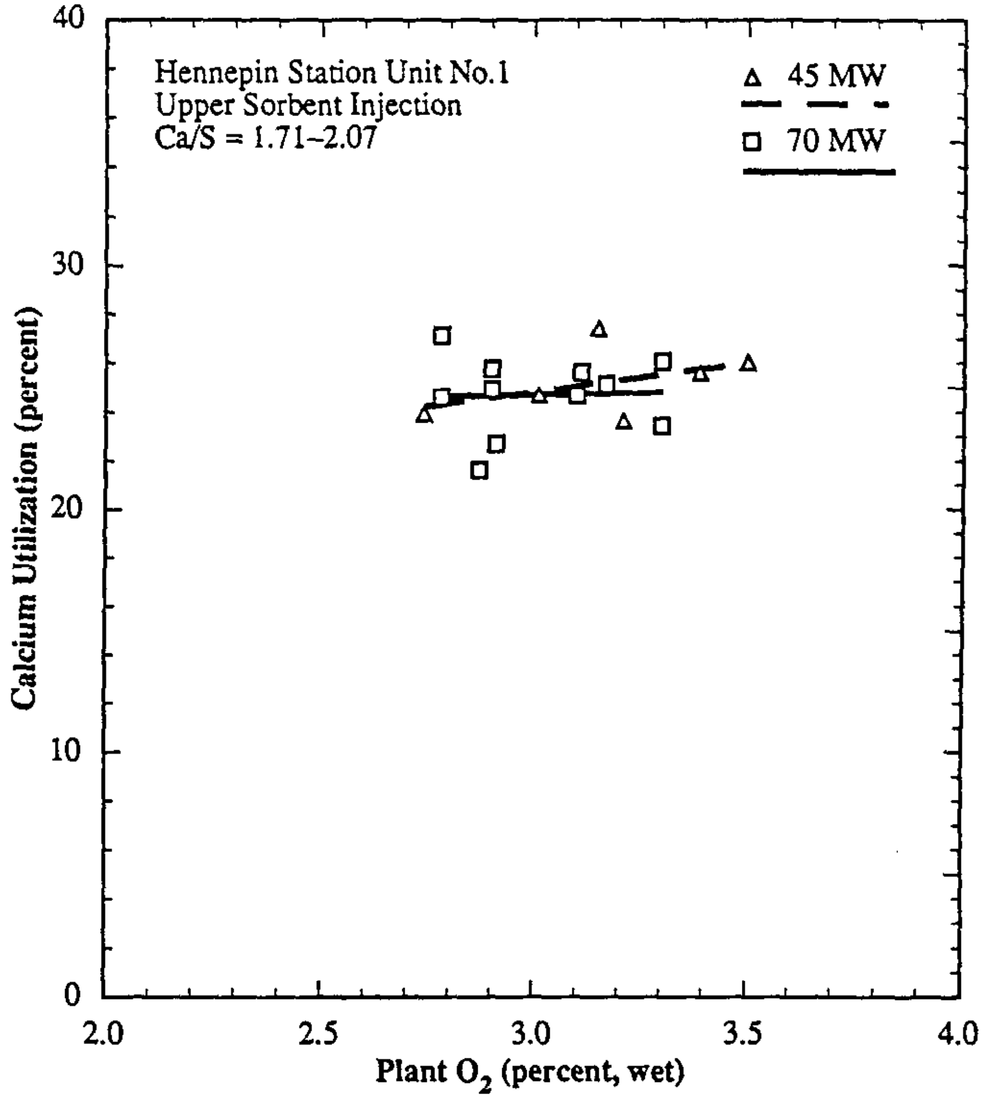


Figure 6–22. Effect of excess air on calcium utilization at full and low load

TABLE 6-3. CALCIUM UTILIZATIONS BASED ON ASH ANALYSES AND SO_2 REMOVAL

Test ID	Date 1991	Calcium Utilization From Ash Analysis (%)	Calcium Utilization From SO_2 Removal (%)
GRSI-1A	Aug-02	16.4	18.5
GRSI-1G	Aug-07	19.3	25.6
GRSI-1H	Aug-08	19.4	27.5
GRSI-1I	Aug-09	19.5	26.0
GRSI-3A	Aug-14	17.6	25.2
GRSI-3C	Aug-14	17.5	28.6
SI-6A	Nov-15	19.4	24.7
GRSI-15A	Nov-20	18.2	25.6
GRSI-15B	Nov-20	23.3	27.4
GRSI-15C	Nov-20	22.7	23.6
GRSI-15C2	Nov-26	21.2	20.2
GRSI-15B3	Dec-03	20.8	24.7
GRSI-15C3	Dec-03	16.2	20.1
GRSI-15A3	Dec-06	17.3	23.9
GRSI-19A	Dec-06	18.9	26.2
GRSI-12A1	Dec-07	17.9	19.7
GRSI-12B1	Dec-07	18.2	23.8
GRSI-12C1	Dec-07	20.7	21.6
SI-5A	Dec-12	19.8	23.4
SI-5B	Dec-12	19.3	25.1
SI-5C	Dec-12	20.0	25.6
GRSI-12A2	Dec-14	20.6	25.0
GRSI-12B3	Dec-17	18.1	24.6
GRSI-12C3	Dec-17	16.4	22.7
GRSI-14A	Dec-18	20.0	24.3
GRSI-14C	Dec-18	19.1	25.4
Average		19.1	24.2

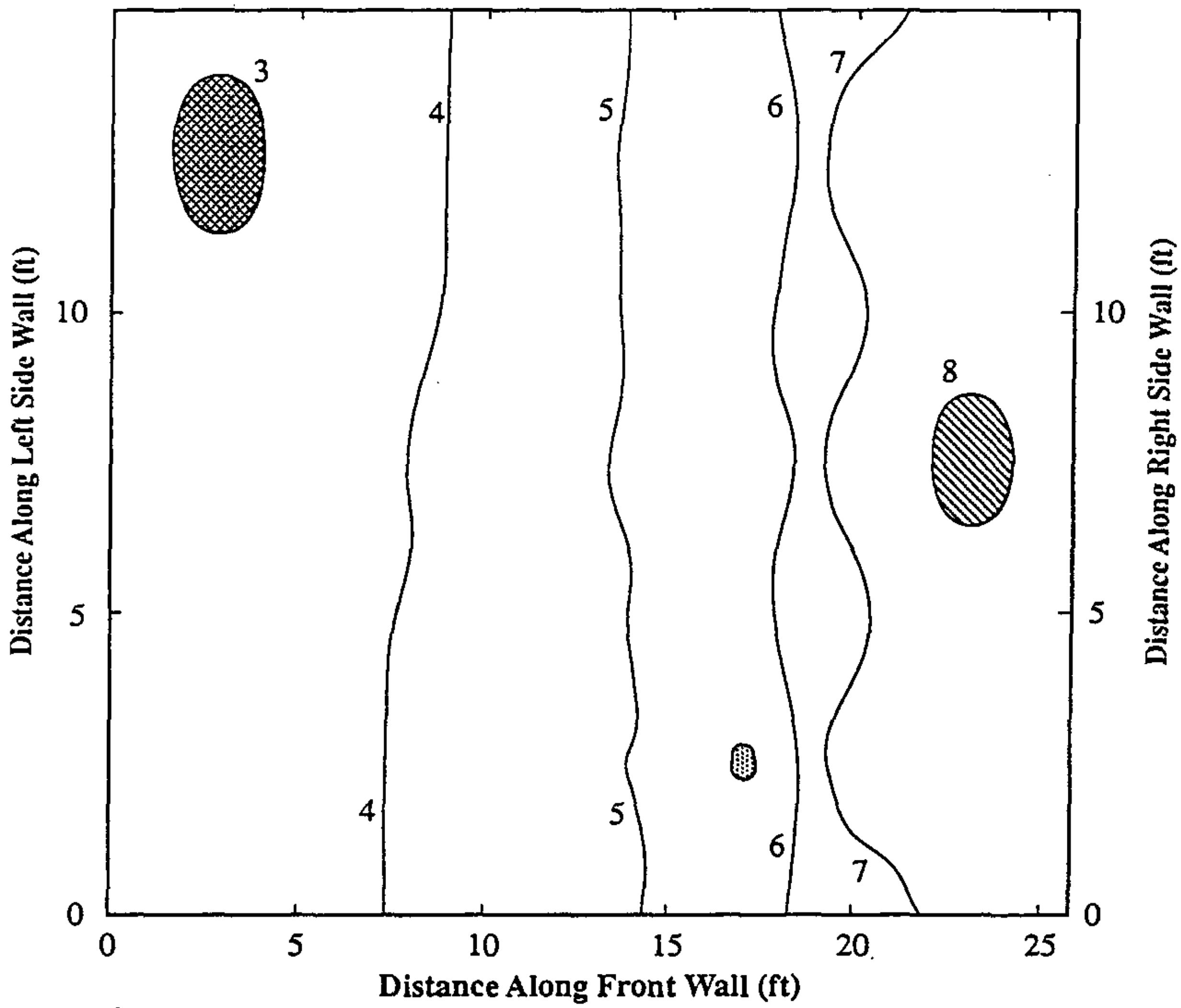


Figure 6–23. Local ash Ca/S molar ratios across the boiler outlet plane

(4.90×10^{-3} to 82.1×10^{-3} mg/MJ). These may be compared to baseline levels of 6.71×10^{-2} lb HCl/10^6Btu (28.9 mg/MJ) and 3.60×10^{-3} lb HF/10^6Btu (1.55 mg/MJ). Coal was not analyzed for fluorine content, but a chlorine content of 0.066% was measured. This fuel Cl content corresponds to an emissions level of 5.40×10^{-2} lb HCl/10^6Btu (23.2 mg/MJ), which is 81% of the measured emissions rate. This difference is due to measurement error (fuel Cl content and Cl in the gas phase).

Emissions of HCl and HF on a yearly basis, with an assumed capacity factor of 32% (1992 capacity factor = 32.01%), would be reduced significantly by GR-SI operation. HCl emissions would be reduced to a range of 6 to 22 tons per year (5.4 to 20.0 tonne/a) while HF emissions would be reduced to a range of 0.01 to 0.17 TPY (0.009 to 0.15 tonne/a). These are compared to baseline emissions of 70 tons HCl per year (64 tonne/a) and 3.8 tons HF per year (3.4 tonne/a).

The primary mechanism for these reductions is through reaction of these halides with CaO. The reactions are illustrated by the following equations:

$$Ca(OH)_2 \longrightarrow CaO + H_2O$$

$$CaO + 2\,HX \longrightarrow CaX_2 + H_2O$$

Where: X is F or Cl

Both processes are strongly favored thermodynamically, but CaF_2 and $CaCl_2$ are unstable at temperatures greater than 1150 to 1500°F (621 to 816°C). Therefore, calcium halide formation must take place at low temperatures, essentially after the sorbent has reacted with SO_2. The reaction rate is probably controlled by the solid state diffusion of the halides through the $CaSO_4$ layer.

6.6 Optimized Parameters for Long-Term Testing

The GR-SI optimization test series showed that the GR-SI system installed on Illinois Power's Hennepin Station Unit No. 1 not only achieved but also exceeded the project goals of reducing NO_x and SO_2 by 60 and 50%, respectively. The goals of the optimization test series were to determine the optimum operating parameters associated with GR-SI. Based on the results of those tests, the following GR parameters were used for the long term test program to achieve at least a 60% reduction in NO_x emissions:

Percent Reburning Fuel	18
Primary Zone Stoichiometric Ratio	1.08
Reburn Zone Stoichiometric Ratio	0.90
Burnout Zone Stoichiometric Ratio	1.18
Flue Gas Recirculation Flow	2,800 scfm (1.32 Nm^3/s)

The SI optimization tests demonstrated that the following SI operating parameters would achieve the required 50% reduction in SO_2 emissions:

Ca/S Molar Ratio	1.75
Injection Configuration	6 nozzles
Injection Elevation	Upper

6.7 Gas/Coal Cofiring and Gas/Gas Reburning Performance

An evaluation of Gas/Coal Cofiring and Gas/Gas Reburning was undertaken in September 1991. The unit is equipped with gas burners, two in each corner, which allows natural gas firing up to 100% of the total heat input. Short parametric tests were conducted to determine reductions in emissions and impacts on steam temperature, thermal efficiency, and boiler operability. The results are highlighted in this section.

Gas/Coal Cofiring at a rate of 34% (natural gas heat input) resulted in an equivalent reduction in SO_2 emissions, 35 to 45% reduction in NO_x emissions, 12% reduction in CO_2 emissions, 20 to 30% reduction in carbon in ash, 1.72% reduction in gross thermal efficiency and no detrimental impacts on unit operability. The test series evaluated 100% coal firing, and cofiring up to 42% gas heat input. The effects of staged combustion on 100% coal firing, 100% natural gas firing, and 34% gas cofiring are shown in Figure 6-24. Combustion staging with 20 to 30% of the total air resulted in additional NO_x reductions during 34% cofiring and 100% gas firing. Compared to 100% coal firing, 34% gas cofiring with staged combustion resulted in 39% NO_x reduction while 100% gas firing resulted in 74% reduction.

Gas/Gas Reburning was evaluated through 19 short parametric tests. The measurements indicate that Gas/Gas Reburning, with reburning gas heat input of 18 to 20%, resulted in NO_x reduction of 60 to 65% over the 100% gas firing case. NO_x reduction from the 100% coal firing case was 90%. At reduced loads, Gas/Gas Reburning NO_x control was improved over the full load case, with a reduction of 80% over the non-GR case. The impact of

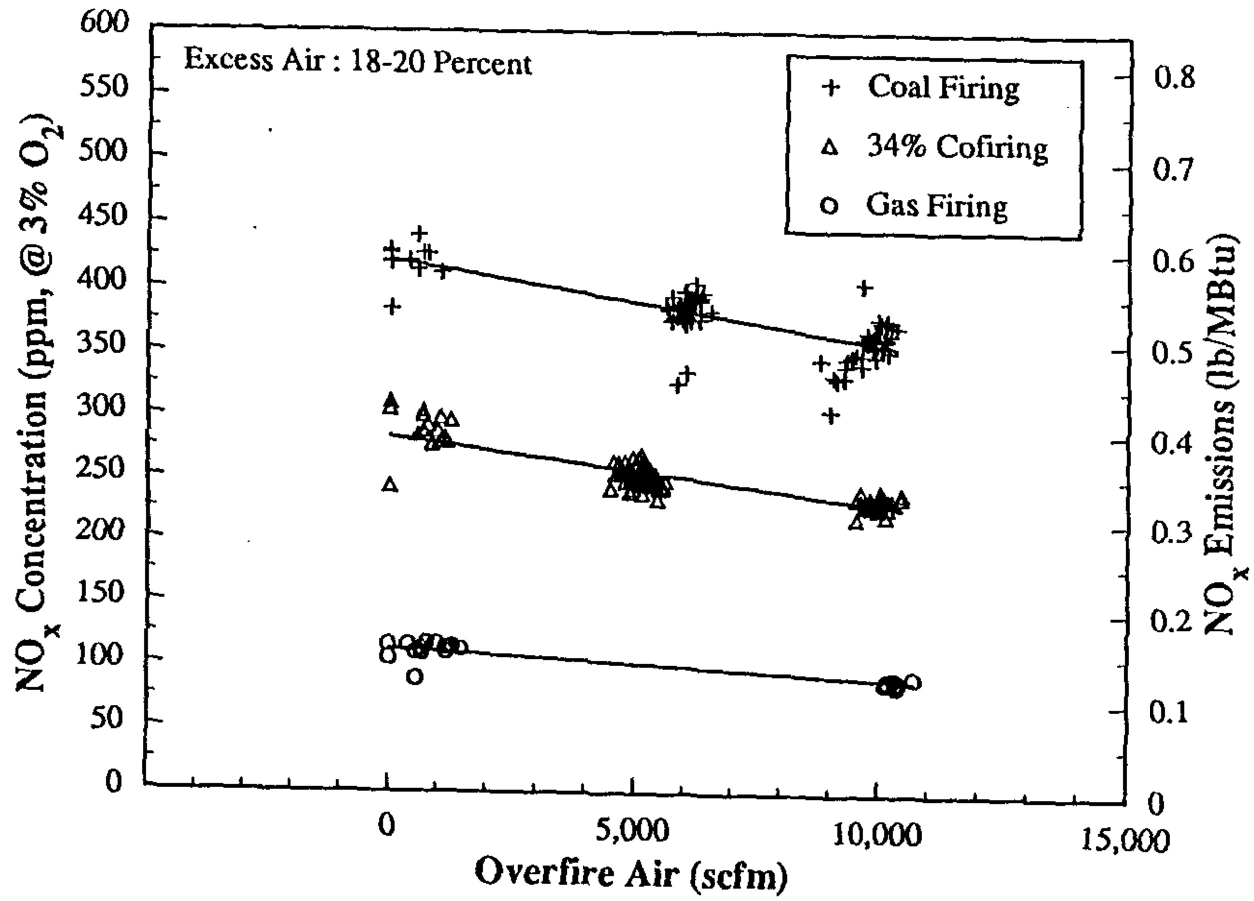


Figure 6-24. Impact of staged combustion on NO_x emissions for 100% coal firing, 34% gas cofiring, and 100% gas firing at full load

Gas/Gas Reburning is compared to staged gas firing in Figure 6-25. These results indicate that staged gas firing results in NO_x reduction of 32% and Gas/Gas Reburning results in an additional reduction of 40%, over the staged combustion case. Gas/Gas Reburning had no effect on boiler efficiency, steam conditions, and unit operation.

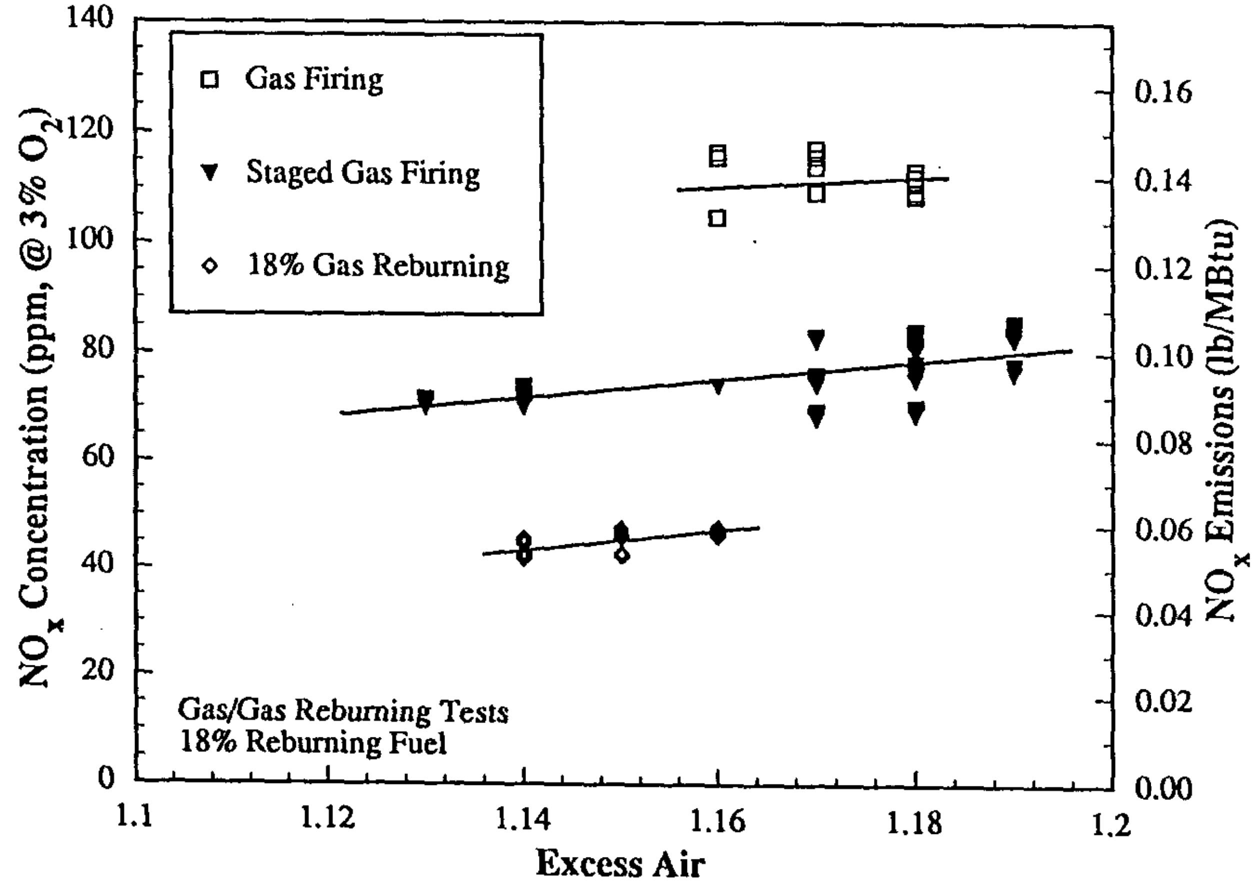


Figure 6-25. Impact of Gas/Gas Reburning on NO_x emissions at full load

7.0 LONG-TERM EMISSIONS PERFORMANCE

The program goals of 60% NO_x reduction and 50% for SO_2 reduction were consistently achieved during the one-year technology demonstration. Over this long-term demonstration period, the average NO_x reduction was 67.3% and average SO_2 reduction was 52.6%. These correspond to emissions of 0.246 lb $NO_x/10^6$Btu (106 mg/MJ) and 2.51 lb $SO_2/10^6$Btu (1,080 mg/MJ). GR-SI operation also resulted in reductions in emissions of CO_2, HCl, and HF, while holding CO emissions to acceptable levels (below 100 ppm in most cases). Gaseous emissions of combustion products during GR-SI operation are discussed in this section, and particulate matter emissions are discussed in Section 10. Rates of consumption of natural gas, sorbent, and auxiliary power requirements are presented in Section 7.4.

The optimization testing data were analyzed to establish the operating conditions under which the program target emissions could be achieved, as discussed in Section 6.6. Several parameters were established, including the primary zone stoichiometric ratio, reburning zone stoichiometric ratio (and corresponding percent gas heat input), FGR flow rate, and the Ca/S molar ratio. To achieve the target NO_x and SO_2 emissions while maintaining low CO emissions, the nominal operating conditions for the long-term demonstration were established as: Primary Zone SR = 1.10, Reburning Zone SR = 0.90, Burnout (Exit) Zone SR = 1.20, Gas heat input = 18%, and Ca/S molar ratio = 1.75. The unit was operated by plant personnel; the emissions and performance monitoring was conducted by EER.

Seventy-six GR-SI tests were carried out to verify the system performance over an extended period. The tests were conducted both at constant loads and with the system under dispatch operation, where the load varied to meet the plant power output requirement. The tests varied in duration, from less than one hour to over 55 hours of continuous GR-SI operation, with a typical duration of 4 to 8 hours. Over the long-term testing period, the average operating parameters were maintained close to the operating goals, as illustrated below:

Operating Parameter	Actual	Operating Goal
Primary Zone Stoichiometric Ratio	1.09	1.10
Reburning Zone Stoichiometric Ratio	0.91	0.90
Burnout (Exit) Zone Stoichiometric Ratio	1.21	1.18
Gas Heat Input	18.2%	18.0%
FGR Flow	2,811 scfm	2,800 scfm
Ca/S Molar Ratio	1.76	1.75

The average test load varied from a low of 44 MW_e to a maximum of 75 MW_e. Over the long-term testing period the average steam load was 461,000 lb/hr (58.1 kg/s), corresponding to an average gross power output of 62 MW_e.

The long-term demonstration average NO_x reduction of 67.3% and the average SO_2 reduction of 52.6% are calculated from the baseline emissions of 0.75 lb $NO_x/10^6$Btu (323 mg/MJ) and 5.30 lb $SO_2/10^6$Btu (2,280 mg/MJ). Figure 7-1 illustrates the NO_x and SO_2 reductions and the program target reductions as well as the range of loads under which the tests were carried out. Emissions of CO were below 50 ppm (@ 3% O_2) in many cases, but were higher during operation at low load. Emissions of CO averaged 57 ppm, over all GR-SI tests. A modest reduction in CO_2 emissions was also measured. This is due to fuel switching, i.e. partial replacement of coal with natural gas. The lower C/H content of natural gas compared to coal resulted in an average CO_2 emissions reduction of 7.1% from the coal fired baseline level. Emissions of N_2O, quantified over a three week period, were low under all operating conditions, baseline, GR, SI and GR-SI. The maximum N_2O emissions rate was 4.3 ppm; average emissions over the test periods ranged from 0.5 to 3.2 ppm. The test average emissions and the operating conditions under which the emissions were measured are shown in Tables 7-1 and 7-2.

One parameter relevant to evaluation of NO_x emissions but not listed in Table 7-2 was the specific mills in service. The mill feeding either the top row or bottom row of burners was not in operation when the load was reduced below 55 MW_e. Removing the top mill from

Note: Load Following Operation Initiated in January, 1992

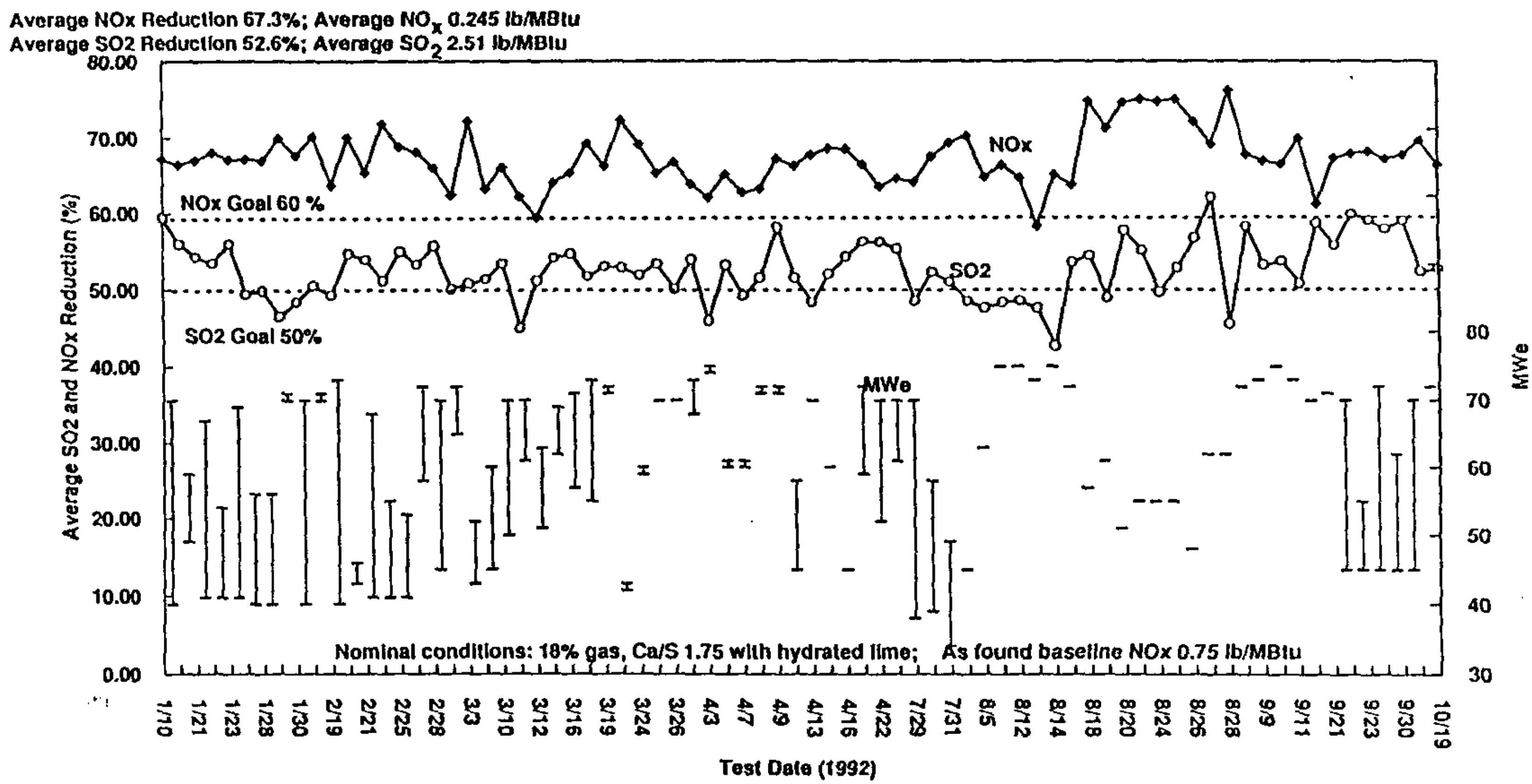


Figure 7-1. Emissions of NO_x and SO_2 from Long-Term GR-SI Testing

TABLE 7-1. LONG TERM GR-SI TESTING AVERAGE DAILY EMISSIONS

Date 1992	Avg. Load (MWe)	O_2 (%, Dry)	O_2 (%, Wet)	CO_c (ppm)	$CO_{2,c}$ (%)	HC_c (ppm)	$NO_{x,c}$ (ppm)	NO_x (lb/MBtu)	NO_x Red (%)	$SO_{2,c}$ (ppm)	SO_2 (lb/MBtu)	SO_2 Red Tot (%)
Jan-10	55	5.83	2.84	74	14.4	0.1	198	0.262	65.07	1,237	2.289	56.81
Jan-13	57	5.58	2.90	75	14.3	0.1	191	0.252	66.40	1,269	2.337	55.91
Jan-21	52	6.37	3.56	117	14.2	1.0	188	0.248	66.93	1,316	2.423	54.28
Jan-22	46	6.78	3.65	66	14.0	1.6	180	0.240	68.00	1,324	2.470	53.40
Jan-23	52	6.43	3.27	150	14.2	2.2	185	0.247	67.07	1,250	2.333	55.98
Jan-27	46	6.67	3.70	65	14.3	2.0	190	0.254	66.13	1,415	2.641	50.17
Jan-28	52	6.25	3.37	58	14.2	3.6	186	0.248	66.93	1,427	2.663	49.75
Jan-29	61	6.00	2.81	69	14.4	2.1	169	0.226	69.87	1,521	2.839	46.43
Jan-30	51	6.12	3.07	164	14.3	3.3	182	0.243	67.60	1,465	2.737	48.36
Feb-06	72	5.97	2.79	18	14.4	0.1	168	0.224	70.13	1,407	2.627	50.43
Feb-19	63	5.93	3.10	32	14.6	2.4	204	0.273	63.60	1,441	2.693	49.19
Feb-20	46	6.38	3.32	196	14.3	1.8	162	0.216	71.20	1,256	2.347	55.72
Feb-21	58	6.22	3.27	109	14.3	1.8	194	0.260	65.33	1,309	2.445	53.87
Feb-24	46	6.32	3.40	166	14.4	1.4	158	0.211	71.87	1,386	2.590	51.13
Feb-25	49	6.66	3.51	93	14.4	1.3	186	0.249	66.80	1,278	2.390	54.91
Feb-26	69	5.56	2.68	43	14.3	1.3	179	0.239	68.13	1,325	2.476	53.28
Feb-28	61	6.24	3.22	28	14.5	1.1	192	0.256	65.87	1,258	2.350	55.66
Mar-02	73	5.78	2.84	20	14.5	1.0	206	0.276	63.20	1,419	2.651	49.98
Mar-03	47	6.51	3.74	179	14.4	4.1	157	0.209	72.13	1,398	2.612	50.72
Mar-04	57	6.16	3.06	84	14.4	1.5	207	0.276	63.20	1,378	2.576	51.40
Mar-10	63	5.67	2.84	29	14.5	2.5	191	0.255	66.00	1,322	2.469	53.42
Mar-11	73	5.71	2.72	31	14.3	2.3	213	0.284	62.13	1,565	2.915	45.00
Mar-12	59	6.14	3.04	22	14.4	1.8	228	0.304	59.47	1,387	2.592	51.09
Mar-13	67	6.36	3.08	41	14.1	2.1	202	0.270	64.00	1,299	2.427	54.21
Mar-16	65	5.87	3.05	30	14.3	1.2	195	0.260	65.33	1,282	2.395	54.81
Mar-17	74	5.70	2.78	13	14.6	2.3	173	0.231	69.20	1,368	2.555	51.79
Mar-19	74	5.89	2.88	16	14.5	2.4	190	0.253	66.27	1,331	2.485	53.11
Mar-23	44	6.44	3.32	140	14.5	1.9	156	0.208	72.27	1,337	2.498	52.87
Mar-24	61	5.90	2.91	23	14.5	2.2	174	0.232	69.07	1,366	2.551	51.87
Mar-25	71	6.01	2.90	20	14.3	1.8	197	0.263	64.93	1,282	2.395	54.81
Mar-26	74	5.87	2.92	16	14.3	1.5	187	0.250	66.67	1,418	2.649	50.02
Apr-02	74	5.85	2.90	35	14.6	1.9	202	0.271	63.87	1,306	2.443	53.91
Apr-03	75	5.80	2.85	51	14.7	1.5	212	0.285	62.00	1,527	2.871	45.83
Apr-06	63	5.71	3.00	56	14.7	0.9	195	0.262	65.07	1,320	2.484	53.13
Apr-07	62	6.04	3.11	76	14.8	1.5	208	0.280	62.67	1,434	2.700	49.06
Apr-08	74	5.76	3.10	38	14.8	1.2	205	0.276	63.20	1,366	2.569	51.53
Apr-09	74	5.81	2.86	25	14.7	1.1	183	0.246	67.20	1,186	2.222	58.08
Apr-10	56	6.10	3.11	254	14.5	2.2	189	0.253	66.27	1,371	2.569	51.53
Apr-13	74	5.56	2.79	27	14.5	1.2	182	0.242	67.73	1,466	2.738	48.34
Apr-14	62	5.78	3.03	20	14.5	1.5	177	0.236	68.53	1,362	2.544	52.00
Apr-16	47	6.48	3.43	102	14.5	1.8	177	0.236	68.53	1,296	2.422	54.30
Apr-21	71	6.28	3.05	17	14.5	1.1	189	0.252	66.40	1,242	2.320	56.23
Apr-22	64	6.16	3.02	74	14.6	1.3	205	0.274	63.47	1,242	2.321	56.21
Apr-23	67	6.22	3.02	26	14.4	2.6	200	0.266	64.53	1,268	2.368	55.32

c: corrected to 3% O_2

TABLE 7-1. LONG TERM GR-SI TESTING AVERAGE DAILY EMISSIONS (Continued)

Date 1992	Avg. Load (MWe)	O_2 (%, Dry)	O_2 (%, Wet)	CO_c (ppm)	$CO_{2,c}$ (%)	HC_c (ppm)	$NO_{x,c}$ (ppm)	NO_x (lb/MBtu)	NO_x Red (%)	$SO_{2,c}$ (ppm)	SO_2 (lb/MBtu)	SO_2 Red Tot (%)
Jul-29	61	6.07	2.94	44	14.5	1.1	201	0.269	64.13	1,463	2.733	48.43
Jul-30	49	5.87	2.74	83	14.4	1.6	183	0.244	67.47	1,354	2.531	52.25
Jul-31	45	6.07	2.99	197	14.7	4.6	172	0.230	69.33	1,391	2.599	50.96
Aug-03	46	6.10	3.06	142	14.7	1.3	167	0.223	70.27	1,461	2.731	48.47
Aug-05	64	5.71	2.94	18	14.9	1.1	198	0.264	64.80	1,485	2.775	47.64
Aug-11	75	5.30	2.37	14	14.7	1.9	188	0.252	66.40	1,465	2.737	48.36
Aug-12	75	5.78	2.74	16	14.8	1.5	198	0.265	64.67	1,460	2.728	48.53
Aug-13	74	6.10	3.21	15	14.9	1.3	233	0.312	58.40	1,487	2.779	47.57
Aug-14	75	5.77	2.61	17	14.7	1.3	196	0.262	65.07	1,629	3.042	42.60
Aug-17	73	5.72	2.83	24	14.5	2.3	204	0.272	63.73	1,317	2.459	53.60
Aug-18	58	5.29	2.72	37	14.5	15.2	141	0.189	74.80	1,292	2.414	54.45
Aug-19	62	5.89	3.09	18	14.5	0.8	161	0.215	71.33	1,448	2.706	48.94
Aug-20	51	6.14	3.10	28	14.6	3.5	143	0.190	74.67	1,199	2.239	57.75
Aug-21	56	5.99	3.02	26	14.6	1.0	140	0.187	75.07	1,272	2.376	55.17
Aug-24	54	5.90	3.05	23	14.5	1.1	142	0.189	74.80	1,427	2.666	49.70
Aug-25	54	5.83	3.06	25	14.5	1.0	140	0.187	75.07	1,337	2.499	52.85
Aug-26	47	6.52	3.26	35	14.5	1.0	156	0.209	72.13	1,224	2.287	56.85
Aug-27	62	5.96	3.13	27	14.4	0.9	173	0.231	69.20	1,078	2.014	62.00
Aug-28	63	5.75	2.76	13	14.4	0.1	134	0.179	76.13	1,546	2.888	45.51
Sep-02	73	5.65	2.59	15	14.1	0.5	181	0.241	67.87	1,183	2.210	58.30
Sep-09	74	5.55	2.85	17	14.5	1.0	185	0.247	67.07	1,329	2.483	53.15
Sep-10	75	5.67	2.71	15	14.5	1.0	188	0.251	66.53	1,313	2.452	53.74
Sep-11	74	5.60	2.86	19	14.5	0.5	169	0.226	69.87	1,395	2.606	50.83
Sep-16	72	6.14	3.06	16	14.4	0.7	218	0.291	61.20	1,175	2.194	58.60
Sep-21	72	5.61	2.51	15	14.5	0.4	183	0.245	67.33	1,253	2.340	55.85
Sep-22	50	6.33	3.25	101	14.5	0.6	180	0.241	67.87	1,140	2.129	59.83
Sep-23	50	6.34	3.29	86	14.7	0.5	179	0.239	68.13	1,162	2.171	59.04
Sep-24	51	6.43	3.35	89	14.2	18.2	185	0.246	67.20	1,194	2.232	57.89
Sep-30	58	6.07	3.17	59	14.2	0.4	181	0.242	67.73	1,162	2.171	59.04
Oct-12	57	6.05	3.01	67	14.4	2.0	171	0.228	69.60	1,351	2.525	52.36
Oct-19	72	5.87	2.74	18	14.2	0.6	188	0.252	66.40	1,341	2.506	52.72
Average	62	6.00	3.02	57	14.5	1.9	184	0.246	67.26	1,343	2.510	52.65
Maximum	75	6.78	3.74	254	14.9	18.2	233	0.312	76.13	1,629	3.042	62.00
Minimum	44	5.29	2.37	13	14.0	0.1	134	0.179	58.40	1,078	2.014	42.60
St. Dev.	10	0.32	0.27	53	0.2	2.6	20	0.027	3.65	108	0.203	3.83

c: corrected to 3% O_2

TABLE 7-2. LONG TERM GR-SI TESTING OPERATING CONDITION SUMMARY

Date 1992	Test Dur. (Hr:Min)	Steam (lb/hr)	Coal Flow (lb/min)	Reb. Gas (scfm)	Gas Heat (%)	OFA, Tot (scfm)	OFA Fraction	FGR (scfm)	Burner Tilt (deg)	SR1	SR2	SR3
Jan-10	3:04	389,154	726	1,550	15.7	19,385	0.179	3,121	23.0	1.086	0.982	1.196
Jan-13	6:17	420,600	745	1,863	17.7	21,278	0.186	3,052	26.9	1.112	0.978	1.198
Jan-21	6:10	380,779	684	1,729	18.0	23,923	0.218	2,933	23.1	1.110	0.982	1.251
Jan-22	5:51	328,711	599	1,520	19.5	22,123	0.228	2,825	23.7	1.127	0.980	1.258
Jan-23	5:05	379,217	681	1,743	19.7	22,712	0.211	2,944	13.4	1.131	0.924	1.226
Jan-27	3:13	342,771	615	1,547	19.3	21,439	0.215	2,760	22.9	1.153	0.946	1.263
Jan-28	5:05	382,532	692	1,735	19.4	23,099	0.211	2,824	20.2	1.140	0.935	1.235
Jan-29	2:57	459,722	802	2,034	19.5	26,129	0.213	2,725	13.2	1.105	0.904	1.191
Jan-30	5:00	379,464	680	1,623	18.5	21,327	0.203	2,794	23.8	1.118	0.926	1.213
Feb-06	3:03	540,712	950	2,296	18.8	35,672	0.248	2,650	8.1	1.056	0.870	1.189
Feb-19	7:25	473,020	844	2,027	18.6	26,723	0.205	2,634	18.6	1.129	0.927	1.214
Feb-20	4:54	337,425	608	1,421	18.2	21,285	0.224	2,671	21.5	1.093	0.902	1.231
Feb-21	3:04	432,847	779	1,847	18.5	27,103	0.223	2,635	19.4	1.112	0.916	1.230
Feb-24	5:00	341,717	610	1,446	18.7	21,033	0.219	2,716	22.2	1.117	0.915	1.241
Feb-25	4:00	353,644	648	1,492	18.1	21,426	0.210	2,741	21.4	1.133	0.938	1.248
Feb-26	7:55	516,901	920	2,197	18.6	30,158	0.218	2,742	19.2	1.086	0.897	1.182
Feb-28	8:55	450,355	806	1,895	18.3	27,883	0.223	2,627	17.3	1.107	0.918	1.221
Mar-02	6:28	544,550	966	2,302	18.5	31,478	0.215	2,499	22.1	1.106	0.914	1.193
Mar-03	5:28	351,176	623	1,458	18.3	21,614	0.216	2,763	26.9	1.148	0.953	1.270
Mar-04	6:50	420,472	761	1,794	18.4	24,164	0.206	2,679	25.5	1.119	0.927	1.212
Mar-10	4:15	468,164	828	2,010	18.8	26,935	0.213	2,683	23.6	1.104	0.910	1.195
Mar-11	5:06	549,075	960	2,330	18.7	31,247	0.217	2,719	23.0	1.090	0.898	1.176
Mar-12	3:28	435,651	784	1,858	18.5	25,605	0.213	2,815	26.6	1.113	0.922	1.210
Mar-13	4:37	506,094	893	2,151	18.6	30,263	0.220	2,685	23.4	1.114	0.918	1.210
Mar-16	6:41	481,220	857	2,053	18.6	30,052	0.228	2,912	24.6	1.098	0.907	1.209
Mar-17	6:14	553,848	976	2,359	18.8	35,403	0.239	2,482	6.1	1.072	0.883	1.189
Mar-19	2:14	557,174	976	2,383	18.9	36,805	0.247	2,468	15.6	1.070	0.880	1.196
Mar-23	5:25	325,431	582	1,387	18.5	20,548	0.226	2,546	21.4	1.097	0.909	1.231
Mar-24	8:49	460,407	811	1,970	18.8	27,155	0.219	2,453	19.9	1.102	0.908	1.199
Mar-25	8:49	538,187	940	2,286	18.9	34,940	0.243	2,545	20.4	1.075	0.885	1.198
Mar-26	4:34	553,423	974	2,352	18.8	36,599	0.246	2,525	20.3	1.073	0.885	1.200
Apr-02	7:28	551,590	981	2,266	18.1	35,608	0.239	2,607	16.6	1.074	0.892	1.199
Apr-03	3:45	577,896	1084	1,655	12.8	30,306	0.197	3,273	21.4	1.066	0.940	1.195
Apr-06	6:45	468,314	895	1,340	12.6	24,788	0.193	4,272	26.5	1.071	0.948	1.206
Apr-07	3:55	468,630	890	1,284	12.1	23,700	0.186	4,063	26.9	1.085	0.964	1.214
Apr-08	8:54	553,470	1049	1,576	12.5	29,369	0.194	4,274	21.6	1.085	0.960	1.213
Apr-09	8:48	554,190	1012	1,970	15.7	33,536	0.225	3,983	17.2	1.067	0.911	1.195
Apr-10	1:15	424,248	777	1,514	15.7	23,694	0.204	3,904	29.1	1.101	0.942	1.214
Apr-13	8:00	552,063	971	2,382	19.0	36,734	0.249	2,520	22.1	1.068	0.878	1.190
Apr-14	7:27	461,155	823	1,986	18.7	31,220	0.247	2,623	20.1	1.076	0.888	1.207
Apr-16	6:02	347,162	629	1,474	18.3	24,102	0.244	2,529	20.9	1.088	0.904	1.239
Apr-21	6:21	531,414	935	2,255	18.7	34,960	0.243	2,579	-0.5	1.089	0.898	1.209
Apr-22	6:18	482,486	851	2,056	18.7	31,200	0.238	2,826	24.7	1.088	0.898	1.207
Apr-23	3:45	502,086	883	2,145	18.9	33,248	0.244	2,618	22.0	1.084	0.894	1.208

TABLE 7-2. LONG TERM GR-SI TESTING OPERATING CONDITION SUMMARY (Continued)

Date 1992	Test Dur. (Hr:Min)	Steam (lb/hr)	Coal Flow (lb/min)	Reb. Gas (scfm)	Gas Heat (%)	OFA, Tot (scfm)	OFA Fraction	FGR (scfm)	Burner Tilt (deg)	SR1	SR2	SR3
Jul-29	2:45	452,259	810	1,931	18.5	28,849	0.233	3,963	23.1	1.087	0.900	1.202
Jul-30	5:45	358,398	652	1,520	18.2	22,636	0.231	2,750	26.9	1.062	0.884	1.189
Jul-31	4:45	329,116	595	1,407	18.4	20,523	0.225	2,759	26.9	1.082	0.899	1.205
Aug-03	5:35	339,622	617	1,440	18.2	21,901	0.232	2,717	26.9	1.076	0.895	1.210
Aug-05	5:10	472,090	844	1,994	18.4	28,128	0.219	2,617	22.8	1.107	0.917	1.201
Aug-11	2:40	576,925	999	2,433	18.8	36,131	0.245	2,519	-4.0	1.045	0.860	1.158
Aug-12	4:15	566,551	993	2,383	18.7	36,224	0.242	2,557	14.7	1.069	0.883	1.186
Aug-13	3:45	553,956	976	2,338	18.6	35,919	0.237	2,562	23.1	1.108	0.915	1.221
Aug-14	:24	573,120	998	2,423	18.8	36,053	0.240	2,511	17.2	1.067	0.879	1.179
Aug-17	7:00	546,828	958	2,339	18.9	36,598	0.251	2,673	26.8	1.066	0.878	1.192
Aug-18	5:50	437,303	766	1,843	18.7	28,363	0.246	2,743	26.9	1.052	0.870	1.184
Aug-19	5:00	462,437	820	1,955	18.5	30,265	0.240	2,709	26.9	1.097	0.908	1.211
Aug-20	6:55	389,120	679	1,651	18.9	25,518	0.243	2,892	26.9	1.079	0.891	1.214
Aug-21	6:45	419,876	746	1,780	18.5	27,525	0.240	2,830	26.9	1.078	0.892	1.207
Aug-24	3:25	410,617	717	1,745	18.9	26,760	0.242	2,632	26.9	1.089	0.898	1.210
Aug-25	6:50	406,722	715	1,707	18.6	26,355	0.240	2,766	26.9	1.080	0.894	1.210
Aug-26	9:50	358,649	626	1,508	18.7	23,259	0.238	2,866	26.9	1.090	0.902	1.226
Aug-27	7:35	471,330	828	1,985	18.6	30,901	0.241	2,823	26.9	1.090	0.901	1.215
Aug-28	:20	465,328	828	1,979	18.5	30,284	0.242	2,862	9.1	1.063	0.878	1.186
Sep-02	6:20	548,204	964	2,323	18.7	35,672	0.247	2,642	9.2	1.054	0.870	1.176
Sep-09	5:45	556,195	977	2,355	18.6	35,983	0.242	2,569	11.1	1.077	0.889	1.193
Sep-10	8:00	568,195	994	2,404	18.7	36,844	0.246	2,669	17.5	1.064	0.877	1.183
Sep-11	4:25	554,705	977	2,342	18.6	32,058	0.216	2,740	16.7	1.113	0.919	1.194
Sep-16	5:57	542,597	951	2,318	18.8	36,226	0.247	2,598	21.2	1.089	0.896	1.209
Sep-21	7:31	545,511	953	2,324	18.9	33,691	0.237	2,601	7.6	1.065	0.877	1.168
Sep-22	15:08	370,859	666	1,585	18.5	24,238	0.234	2,903	26.7	1.099	0.911	1.225
Sep-23	16:49	367,463	668	1,584	18.5	24,487	0.235	2,972	25.2	1.101	0.913	1.229
Sep-24	24:01	380,486	682	1,626	18.5	25,172	0.235	2,858	25.4	1.107	0.918	1.233
Sep-30	54:52	429,634	772	1,847	18.6	28,775	0.241	2,684	22.7	1.096	0.906	1.218
Oct-12	28:01	422,285	755	1,732	18.0	27,642	0.240	2,407	24.8	1.076	0.895	1.207
Oct-19	32:07	547,716	965	2,248	18.2	35,133	0.242	2,215	24.0	1.068	0.886	1.187
Average	-	460,710	821	1,915	18.2	28,614	0.228	2,811	20.9	1.091	0.909	1.208
Maximum		577,896	1084	2,433	19.7	36,844	0.251	4,274	29.1	1.153	0.982	1.270
Minimum		325,431	582	1,284	12.1	19,385	0.179	2,215	-4.0	1.045	0.860	1.158
St. Dev.		79,748	138	341	1.5	5,375	0.017	413	6.6	0.023	0.028	0.021

service reduced NO_x, as discussed previously. The top mill was taken out of service from August 18, 1992 to August 28, 1992.

The spent sorbent and fly ash mixture collected by the ESP was sluiced to the existing ash pond. The unreacted calcium oxide in the spent sorbent required neutralization to reach an acceptable pH level of 6.0 to 9.0. In this demonstration, the neutralizing agent was CO_2. This was selected over agents such as H_2SO_4 because the groundwater wells in the vicinity of the plant were relatively high in sulfates.

7.1 NO_x Emissions

The NO_x emissions reduction during the long-term demonstration consistently exceeded the target of 60% reduction (which corresponds to 0.30 lb/10^6Btu [129 mg/MJ]). The average NO_x emission over all long-term tests was 0.246 lb/10^6Btu (106 mg/MJ).

Over all the GR-SI tests, the average NO_x reduction was 67.3%, at an average gas heat of 18.2%. The majority of long-term GR-SI tests were carried out with gas heat in the 18 to 19% range, but a few tests were carried out at lower gas input. Tests on January 10 and 13, 1992 were conducted with a gas heat input of 15.7 and 17.7%, respectively, resulting in NO_x reductions of 65.1 and 66.4%. The lowest gas heat input evaluated at full load during long-term testing was 12.5% which yielded 63.2% NO_x reduction. Typically, NO_x emissions and reductions level off with increasing gas heat input.

Figure 7-2 shows the full load NO_x emissions and reduction as a function of gas heat input. The data considered are from operation with coal zone stoichiometric ratio from 1.07 to 1.12 and an exit zone stoichiometric ratio from 1.170 to 1.220. A significant number of full load tests were carried out with a coal zone stoichiometric ratio in the 1.065 to 1.070 range, these data are presented in subsequent figures. Considering both optimization and long-term testing data, 10% gas heat input yielded 55% NO_x reduction, while 18% gas input resulted in 67% NO_x reduction.

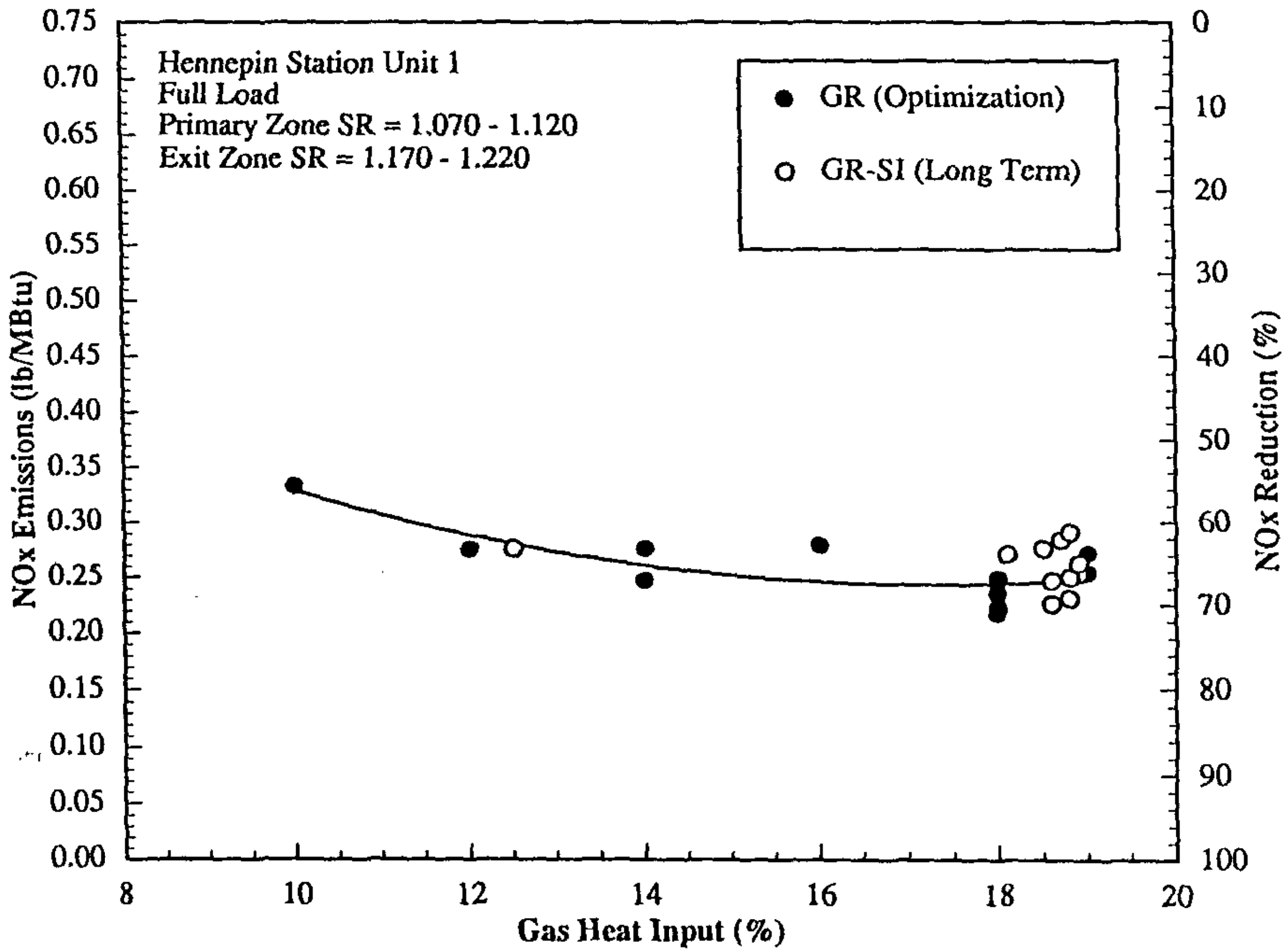


Figure 7–2. Long-Term and Optimization Testing NO_x emissions as a function of gas heat

As expected, parameters such as the primary and reburning zone stoichiometric ratios and mills in service (during low load operation) had significant impacts on NO_x emissions. The optimization testing (carried out in 1991) showed that other parameters such as load, FGR input, and burner tilt (from -30 degrees to the horizontal position) had minor impacts on NO_x emissions.

The lowest NO_x emissions were measured for tests carried out at relatively low load and at low primary zone (and reburning zone) stoichiometric ratio. The impacts of these parameters are illustrated in Figures 7-3, 7-4, and 7-5. Figure 7-3 shows the impact of load on the NO_x emissions. The increase in NO_x emissions with load is relatively modest, from approximately 0.20 lb/10^6Btu (86 mg/MJ) at a load of 44 MW_e to approximately 0.28 lb/10^6Btu (120 mg/MJ) at a load of 74 MW_e. During long-term GR-SI testing, the highest NO_x emissions of 0.312 lb/10^6Btu (134 mg/MJ) were measured at 74 MW_e. The lowest NO_x emissions level of 0.179 lb/10^6Btu (77 mg/MJ) was measured at 63 MW_e, but this was due to operation with Mill C (the top mill) out of service.

Significant change in NO_x emissions (and corresponding change in NO_x reduction) was measured with variation in primary and reburning zone stoichiometric ratios, as illustrated in Figures 7-4 and 7-5. A majority of tests were carried out with gas heat input in the 18 to 19% range; therefore, the change in primary zone stoichiometric ratio corresponds to a similar shift in reburning zone stoichiometric ratio and thus Figures 7-4 and 7-5 show the combined effects.

As indicated in Figure 7-4, the long term and optimization data are generally comparable, but long-term GR-SI NO_x emissions were impacted by coal burner tilt angles above +15 degrees. It should be noted, during the optimization test the coal burners and injectors tilted together. The burner tilt angles at full load were maintained below the horizontal position during GR operation but were automatically shifted upward during GR-SI operation to maintain reheat steam temperature. High burner tilt angles potentially result in incomplete combustion of coal in the burner zone and higher oxygen concentrations into the reburning

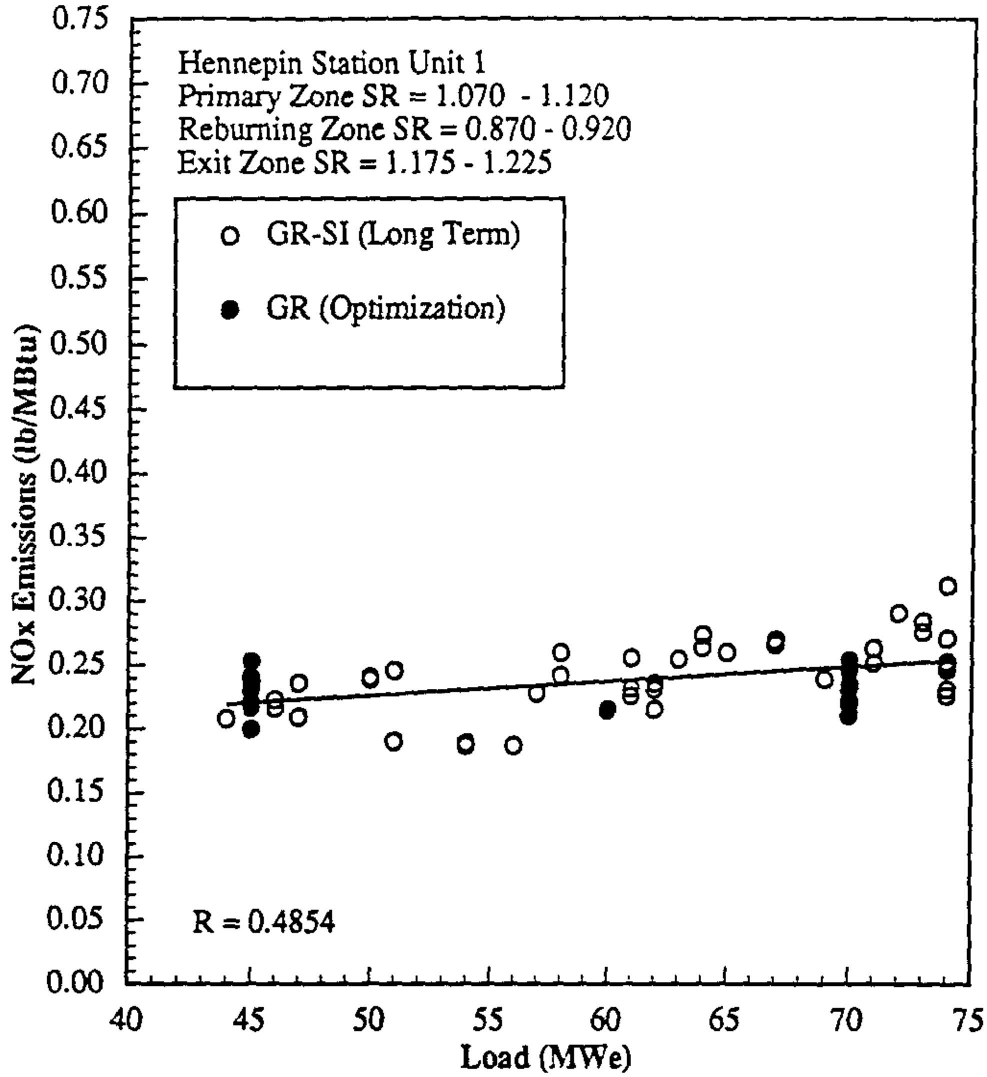


Figure 7–3. Long-Term and Optimization Testing NO_x emissions as a function of load

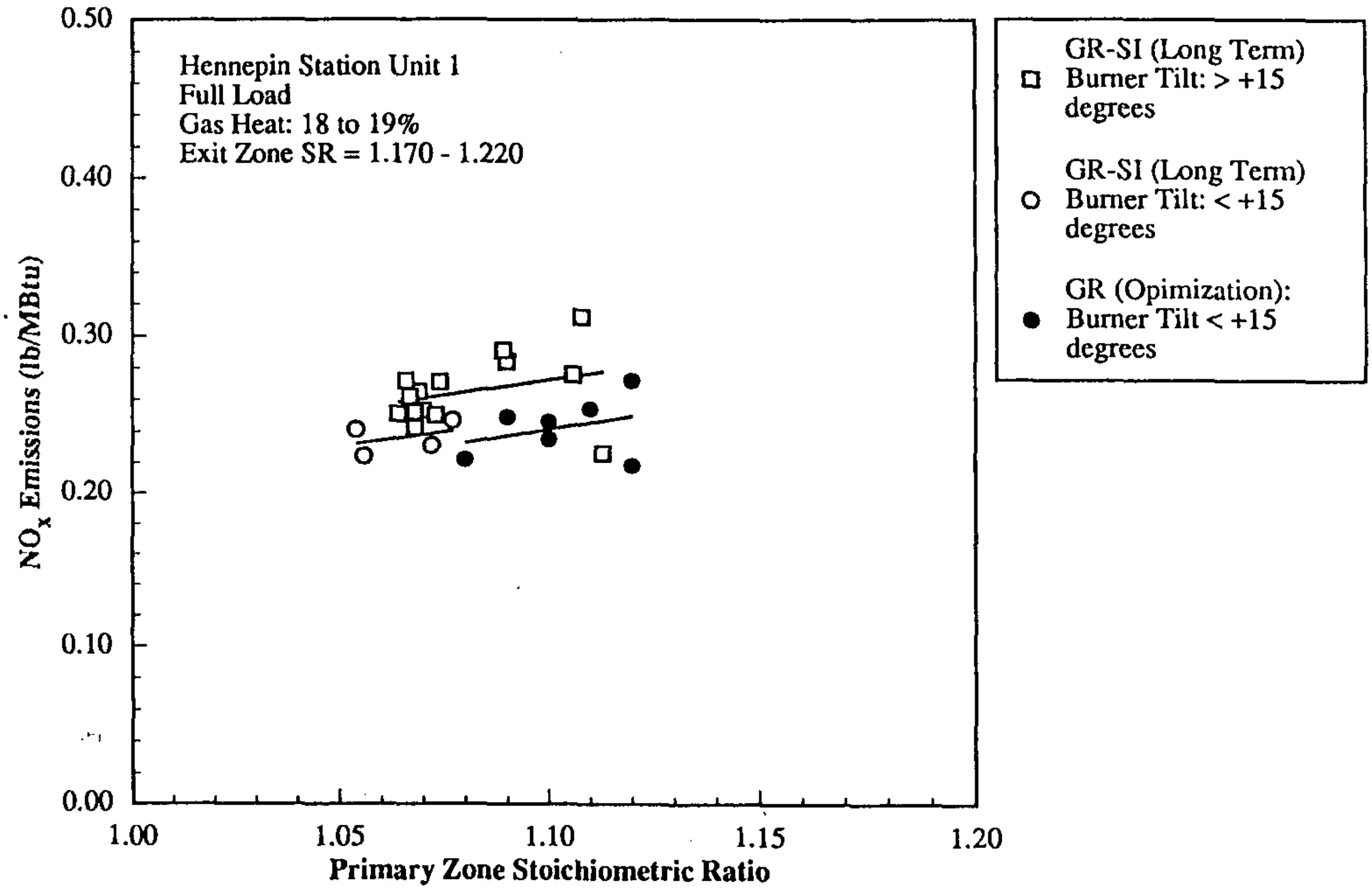


Figure 7-4 Long-Term and Optimization Testing NO_x emissions as a function of primary zone stoichiometric ratio

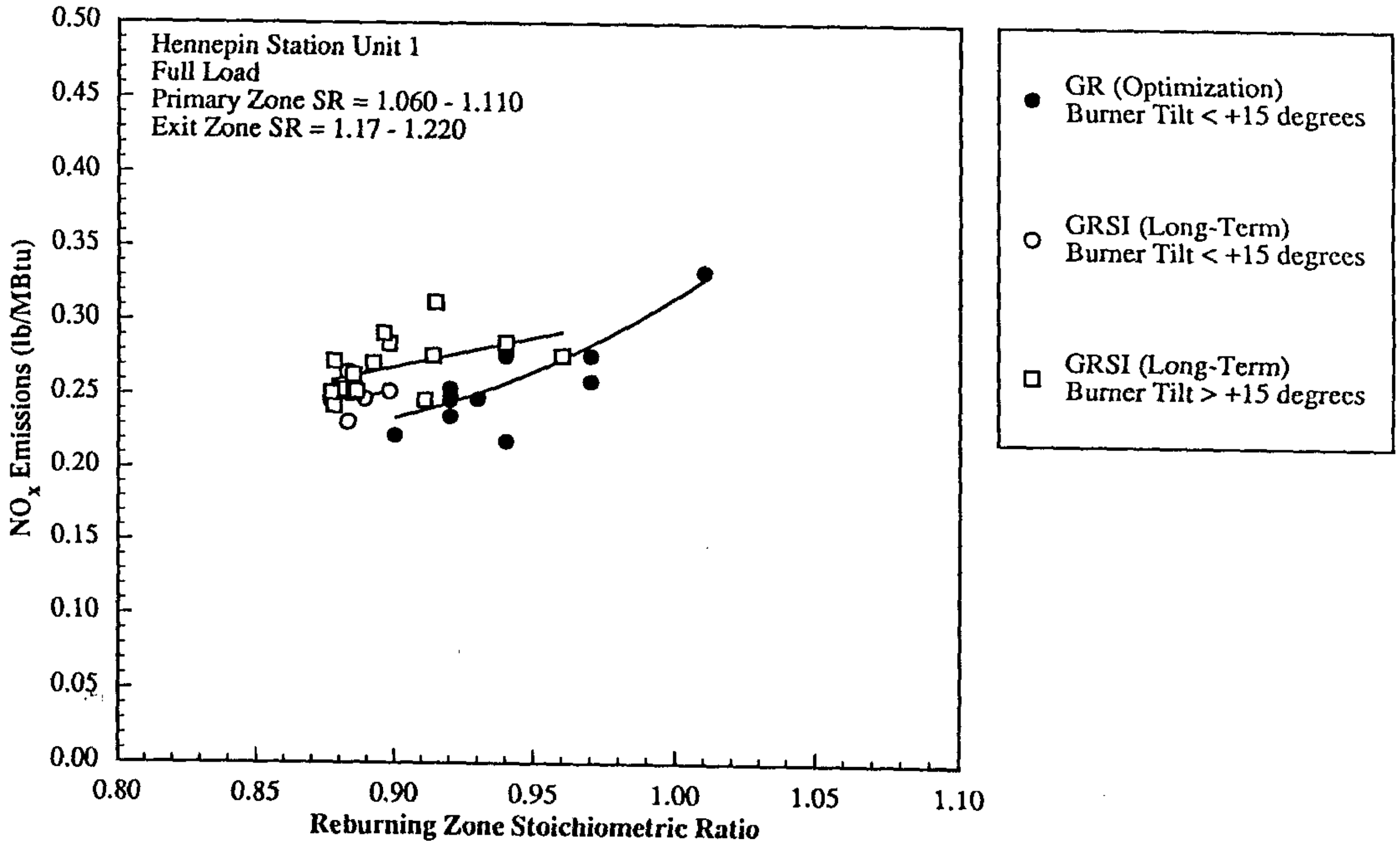


Figure 7–5. Long-Term and Optimization Testing NO_x emissions as a function of reburning zone stoichiometric ratio

zone. Another parameter which has some impact on NO_x emissions at full load is the burnout zone stoichiometric ratio. Formation of NO_x is thought to take place mostly in the primary zone, with little formation in the burnout zone. But during GR-SI operation, the boiler exit temperature (and potentially the upper furnace temperature) increases relative to baseline operation, therefore some NO_x formation in the upper furnace may take place. The impacts of these parameters on NO_x emissions are discussed below. Full load NO_x emissions were in the range of 0.224 to 0.312 lb/10^6Btu (96 to 134 mg/MJ), but were generally under the project goal of 0.3 lb/10^6Btu.

The impact of the burner tilt angle on full load NO_x emissions is evident in the following select results:

Date	Load (MWe)	Primary SR	Reburning SR	Exit SR	Burner Tilt (Deg)	NOx (lb/10^6Btu)
3/17/92	74	1.072	0.883	1.189	+6.1	0.231
9/21/92	72	1.065	0.877	1.168	+7.6	0.245
9/9/92	74	1.077	0.889	1.193	+11.1	0.247
8/12/92	75	1.069	0.883	1.186	+14.7	0.265
3/25/92	71	1.075	0.885	1.198	+20.4	0.263
8/17/92	73	1.066	0.878	1.192	+26.8	0.272

Relatively low NO_x emissions were recorded for operation with burner tilt angle at and below +11 degrees. Tests on 3/17/92, 9/9/92, and 9/21/92 were carried out with the burner tilt angles at or below +11.1 degrees, resulting in NO_x emissions 0.231 to 0.247 lb/10^6Btu (99 to 106 mg/MJ). GR-SI operation with burner tilt above +20 degrees resulted in somewhat higher NO_x emissions with the highest NO_x level from the tests listed (0.272 lb/10^6Btu [117 mg/MJ]) measured during a test with the highest upward burner tilt angle (+26.8 degrees). In the last case listed, primary and reburning zone stoichiometriic ratios were relatively low (SR_1: 1.066, SR_2: 0.878).

The impact of excess air is shown in Figure 7-6, including baseline and staged data from the optimization and long-term GR-SI results. A significant reduction in NO_x emissions is evident with reduction in excess air during baseline operation. A more moderate effect is evident during staged operation and during GR operation with varied burnout zone SR. The impact of burnout zone stoichiometric ratio at full load is more difficult to quantify, since the majority of full-load tests were carried out with a burnout zone stoichiometric ratio in the narrow range of 1.180 to 1.220. The long-term NO_x data show a dependence on burnout zone stoichiometric ratio (which varies with OFA and SI air). At full load, the OFA input during long-term testing was generally in a narrow range: 35,000 scfm (16.5 Nm^3/s) to 37,000 scfm (17.5 Nm^3/s).

The impacts of FGR input and mills in service on NO_x emissions were also determined. Optimization testing results showed that FGR input had a minor effect, with no significant change in NO_x emissions as the FGR input increased over 2.6%. During long-term testing, the average FGR flow was 2,811 scfm (1.33 Nm^3/s), with a range of 2,215 to 4,274 scfm (1.05 to 2.02 Nm^3/s). Many full-load tests were carried out with FGR flows of 2,450 to 2,650 scfm (1.16 to 1.25 Nm^3/s). At full load with excess air of 20%, the total flue gas flow is approximately 160,000 scfm (76 Nm^3/s); therefore 2,500 scfm (1.18 Nm^3/s) corresponds to 1.6% of the total flue gas. The long-term testing data with this level of FGR are shown in Figure 7-7, indicating a minor improvement in NO_x over that achieved with 1% FGR. The majority of points fall in the parametric range of 1% to 2.6% FGR.

The impact of mills in service is more significant than the FGR input. Generally, at loads below 55 MW_e, two mills are in service, i.e. either Mill A or Mill C is out of service. Usually Mill A was the last mill put on line as load increased. Taking the upper mill out of service results in greater staging of combustion and lower NO_x emissions. During GR-SI testing, the lowest NO_x emission of 0.179 lb/10^6Btu (77 mg/MJ) was measured with Mill C out of service. Testing from 8/18/92 to 8/28/92 was carried out with Mill C out of service, over a load range of 51 to 63 MW_e. The measured NO_x emissions ranged from 0.179 to

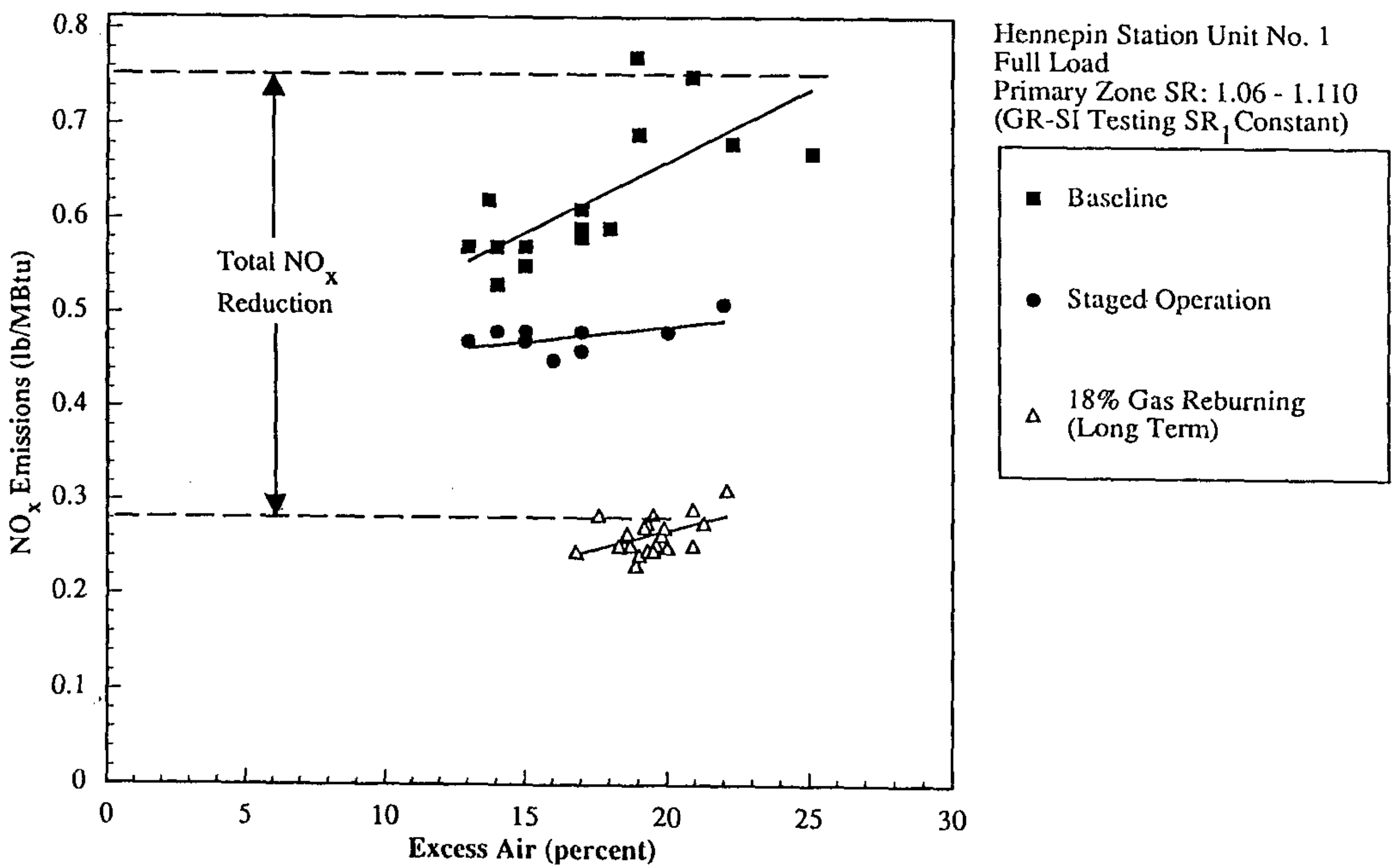


Figure 7–6. Long-Term NO_x reduction as a function of excess air

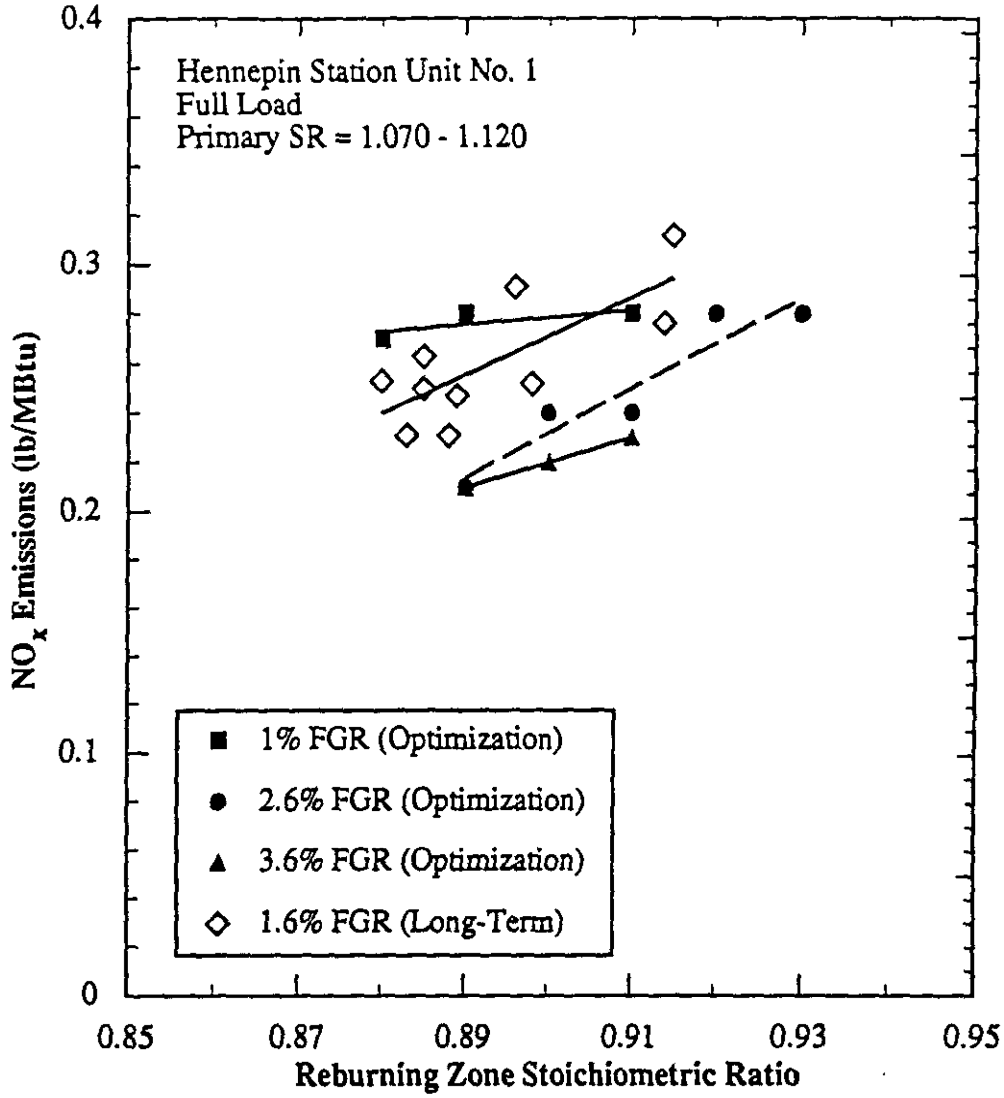


Figure 7-7. Effect of FGR on NO_x emissions during Long Term and Optimization Testing

0.231 lb/10^6Btu (77 to 99 mg/MJ), with an average of 0.197 lb/10^6Btu (85 mg/MJ). Figure 7-8 shows the effect of mills in service on NO_x emissions.

7.2 SO_2 Emissions

Reductions in SO_2 emissions beyond the 50% reduction target level of 2.65 lb/10^6Btu (1,140 mg/MJ) were consistently obtained with Linwood hydrated lime at Ca/S molar ratios of 1.6 to 1.9. Fuel switching, i.e. reburning with natural gas at 18% heat input, theoretically reduces SO_2 emissions to the "GR-Baseline SO_2 emissions" of 4.34 lb/10^6Btu (1,870 mg/MJ). Because of a small drop in thermal efficiency during GR-SI operation, the reduction is not exactly this amount. A slightly higher total heat input is required during GR-SI. Reaction of SO_2 with sorbent then resulted in a reduction in SO_2 emissions, to an average of 2.51 lb/10^6Btu (1,080 mg/MJ). The Ca/S range evaluated during the long-term testing is relatively narrow; therefore the change in SO_2 emissions with Ca/S was minor. Tests at low loads were run generally at somewhat lower Ca/S molar ratios than high load tests. Table 7-3 lists several parameters relating to SO_2 reduction and calcium utilization. The average sorbent input rate was 5,620 lb/hr (0.71 kg/s), achieving a Ca/S molar ratio of 1.76 at an average load of 62 MW_e. The average SO_2 reduction over all of the GR-SI tests was 52.6%. The SO_2 reduction due to reaction with sorbent, termed "sorbent SO_2 reduction", averaged 42.1%, which corresponds to a calcium utilization of 24.1%.

The sorbent SO_2 reduction showed considerable variation during both the optimization and long-term GR-SI testing. This is due to variations in sorbent purity, ash deposition, and gas temperatures which were affected by burner tilt angle variation. Testing was conducted near a set-point Ca/S molar ratio; therefore, the change in sorbent SO_2 reduction with Ca/S molar ratio was minor. The maximum sorbent SO_2 reduction of 53.3% was obtained for a test conducted with a Ca/S molar ratio of 1.64. This SO_2 reduction corresponds to the maximum calcium utilization of 32.5%. The lowest sorbent SO_2 reduction of 29.3% was measured for a full load test at a Ca/S molar ratio of 1.78. The sorbent SO_2 removals were in the range determined during optimization testing. The majority of sorbent SO_2 removals with Linwood

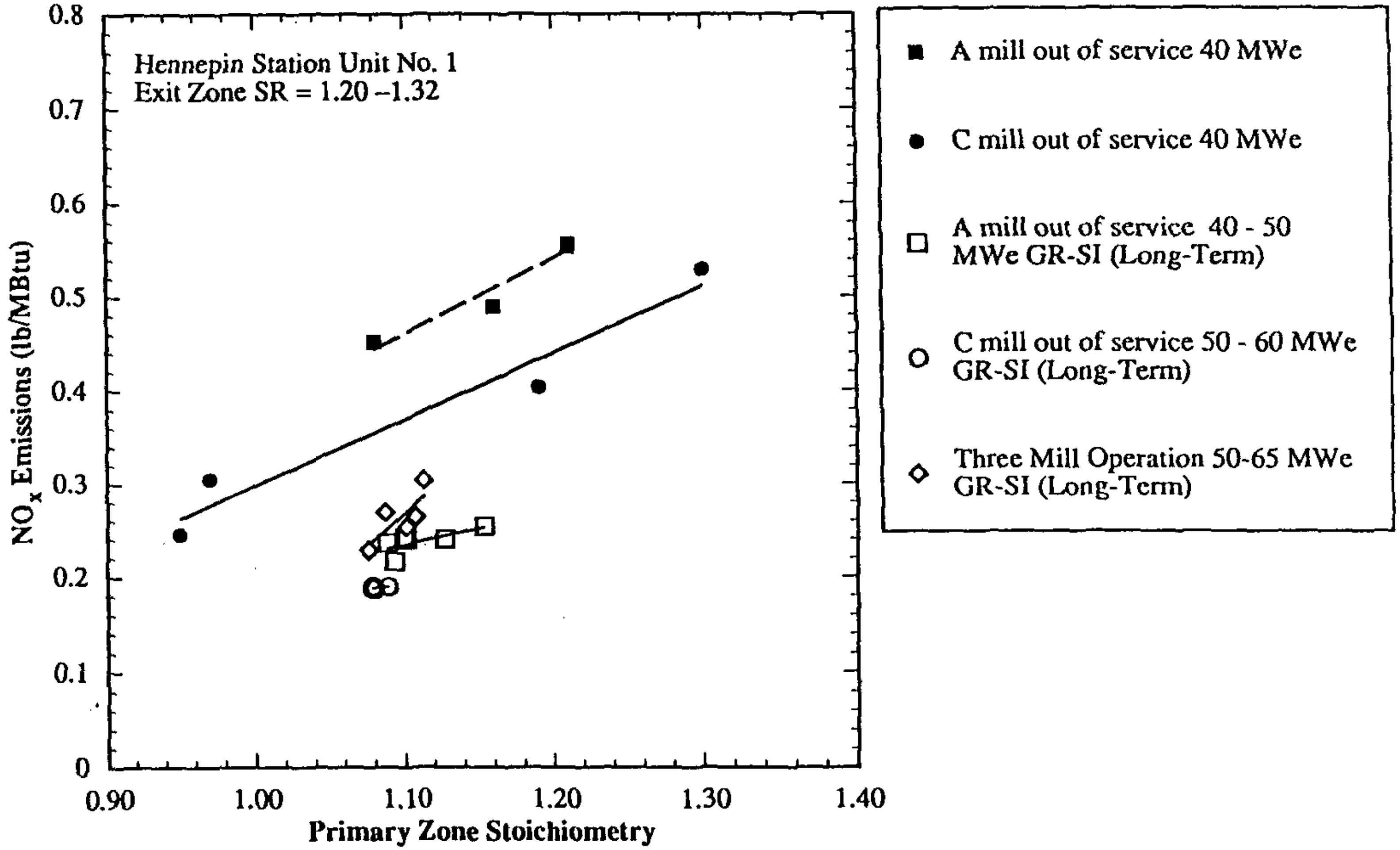


Figure 7-8. NO_x emissions as a function of mill out of service during Long-Term and Optimization Testing

TABLE 7-3. GR-SI SORBENT INJECTION AVERAGE DAILY PERFORMANCE DATA

Date 1992	Avg. Load (MWe)	Gas Heat (%)	Sorb Flow (klb/hr)	Ca/S (mole/mole)	SO_2 Emiss. (lb/MBtu)	GR-SO_2Bsln (lb/MBtu)	SO_2Red Tot (%)	SO_2Red Sorb (%)	Ca Utiliz. (%)
Jan-10	55	15.7	4.96	1.75	2.289	4.468	56.81	48.77	27.87
Jan-13	57	17.7	5.11	1.76	2.337	4.362	55.91	46.42	26.38
Jan-21	52	18.0	4.77	1.78	2.423	4.346	54.28	44.25	24.86
Jan-22	46	19.5	4.14	1.77	2.470	4.267	53.40	42.11	23.79
Jan-23	52	19.7	4.87	1.85	2.333	4.256	55.98	45.18	24.42
Jan-27	46	19.3	4.23	1.77	2.641	4.277	50.17	38.25	21.61
Jan-28	52	19.4	4.75	1.77	2.663	4.272	49.75	37.66	21.28
Jan-29	61	19.5	5.82	1.89	2.839	4.267	46.43	33.46	17.70
Jan-30	51	18.5	4.94	1.88	2.737	4.320	48.36	36.64	19.49
Feb-06	72	18.8	6.80	1.84	2.627	4.304	50.43	38.96	21.17
Feb-19	63	18.6	6.56	2.07	2.693	4.314	49.19	37.58	18.15
Feb-20	46	18.2	4.27	1.79	2.347	4.335	55.72	45.86	25.62
Feb-21	58	18.5	5.58	1.82	2.445	4.320	53.87	43.40	23.84
Feb-24	46	18.7	4.31	1.81	2.590	4.309	51.13	39.89	22.04
Feb-25	49	18.1	4.52	1.78	2.390	4.341	54.91	44.94	25.25
Feb-26	69	18.6	6.60	1.84	2.476	4.314	53.28	42.61	23.16
Feb-28	61	18.3	5.77	1.94	2.350	4.330	55.66	45.73	23.57
Mar-02	73	18.5	6.90	1.84	2.651	4.320	49.98	38.63	20.99
Mar-03	47	18.3	4.56	1.86	2.612	4.330	50.72	39.68	21.33
Mar-04	57	18.4	5.41	1.82	2.576	4.325	51.40	40.44	22.22
Mar-10	63	18.8	5.96	1.82	2.469	4.304	53.42	42.63	23.42
Mar-11	73	18.7	5.29	1.42	2.915	4.309	45.00	32.35	22.78
Mar-12	59	18.5	5.08	1.66	2.592	4.320	51.09	39.99	24.09
Mar-13	67	18.6	6.44	1.86	2.427	4.314	54.21	43.74	23.52
Mar-16	65	18.6	6.10	1.83	2.395	4.314	54.81	44.49	24.31
Mar-17	74	18.8	6.83	1.82	2.555	4.304	51.79	40.63	22.32
Mar-19	74	18.9	7.23	1.90	2.485	4.298	53.11	42.19	22.20
Mar-23	44	18.5	4.16	1.84	2.498	4.320	52.87	42.17	22.92
Mar-24	61	18.8	5.89	1.82	2.551	4.304	51.87	40.72	22.38
Mar-25	71	18.9	6.76	1.86	2.395	4.298	54.81	44.28	23.81
Mar-26	74	18.8	6.69	1.76	2.649	4.304	50.02	38.45	21.84
Apr-02	74	18.1	6.45	1.72	2.443	4.341	53.91	43.72	25.42
Apr-03	75	12.8	7.91	1.87	2.871	4.622	45.83	37.88	20.26
Apr-06	63	12.6	6.98	2.01	2.484	4.632	53.13	46.38	23.07
Apr-07	62	12.1	5.24	1.54	2.700	4.659	49.06	42.04	27.30
Apr-08	74	12.5	6.80	1.68	2.569	4.638	51.53	44.60	26.55
Apr-09	74	15.7	7.35	1.87	2.222	4.468	58.08	50.27	26.88
Apr-10	56	15.7	4.74	1.58	2.569	4.468	51.53	42.50	26.90
Apr-13	74	19.0	7.14	1.87	2.738	4.293	48.34	36.22	19.37
Apr-14	62	18.7	5.90	1.82	2.544	4.309	52.00	40.96	22.51
Apr-16	47	18.3	4.38	1.79	2.422	4.330	54.30	44.07	24.62
Apr-21	71	18.7	6.53	1.79	2.320	4.309	56.23	46.16	25.79
Apr-22	64	18.7	6.04	1.82	2.321	4.309	56.21	46.13	25.35
Apr-23	67	18.9	6.29	1.83	2.368	4.298	55.32	44.91	24.54

TABLE 7-3. GR-SI SORBENT INJECTION AVERAGE DAILY PERFORMANCE DATA (Cont.

Date 1992	Avg. Load (MWe)	Gas Heat (%)	Sorb Flow (klb/hr)	Ca/S (mole/mole)	SO_2 Emiss. (lb/MBtu)	GR-SO_2Bsln (lb/MBtu)	SO_2Red Tot (%)	SO_2Red Sorb (%)	Ca Utiliz. (%)
Jul-29	61	18.5	5.34	1.70	2.733	4.320	48.43	36.73	21.61
Jul-30	49	18.2	4.23	1.66	2.531	4.335	52.25	41.62	25.07
Jul-31	45	18.4	3.92	1.69	2.599	4.325	50.96	39.90	23.61
Aug-03	46	18.2	4.03	1.67	2.731	4.335	48.47	37.01	22.16
Aug-05	64	18.4	5.63	1.71	2.775	4.325	47.64	35.84	20.96
Aug-11	75	18.8	6.95	1.79	2.737	4.304	48.36	36.40	20.34
Aug-12	75	18.7	6.87	1.78	2.728	4.309	48.53	36.69	20.61
Aug-13	74	18.6	6.55	1.73	2.779	4.314	47.57	35.58	20.57
Aug-14	75	18.8	6.92	1.78	3.042	4.304	42.60	29.31	16.47
Aug-17	73	18.9	6.18	1.70	2.459	4.298	53.60	42.79	25.17
Aug-18	58	18.7	4.92	1.63	2.414	4.309	54.45	43.98	26.98
Aug-19	62	18.5	5.14	1.63	2.706	4.320	48.94	37.35	22.92
Aug-20	51	18.9	4.39	1.66	2.239	4.298	57.75	47.91	28.86
Aug-21	56	18.5	4.78	1.64	2.376	4.320	55.17	44.99	27.44
Aug-24	54	18.9	4.76	1.69	2.666	4.298	49.70	37.98	22.47
Aug-25	54	18.6	4.62	1.65	2.499	4.314	52.85	42.08	25.50
Aug-26	47	18.7	4.04	1.66	2.287	4.309	56.85	46.92	28.27
Aug-27	62	18.6	5.27	1.64	2.014	4.314	62.00	53.32	32.51
Aug-28	63	18.5	5.62	1.68	2.888	4.320	45.51	33.14	19.73
Sep-02	73	18.7	6.36	1.71	2.210	4.309	58.30	48.71	28.49
Sep-09	74	18.6	6.12	1.61	2.483	4.314	53.15	42.45	26.36
Sep-10	75	18.7	6.44	1.64	2.452	4.309	53.74	43.09	26.28
Sep-11	74	18.6	6.54	1.71	2.606	4.314	50.83	39.59	23.15
Sep-16	72	18.8	6.31	1.70	2.194	4.304	58.60	49.02	28.83
Sep-21	72	18.9	6.34	1.69	2.340	4.298	55.85	45.56	26.96
Sep-22	50	18.5	4.39	1.68	2.129	4.320	59.83	50.71	30.19
Sep-23	50	18.5	4.39	1.69	2.171	4.320	59.04	49.74	29.43
Sep-24	51	18.5	4.51	1.70	2.232	4.320	57.89	48.33	28.43
Sep-30	58	18.6	5.07	1.68	2.171	4.314	59.04	49.68	29.57
Oct-12	57	18.0	4.98	1.70	2.525	4.346	52.36	41.90	24.65
Oct-19	72	18.2	6.50	1.73	2.506	4.335	52.72	42.20	24.39
Average	62	18.2	5.62	1.76	2.510	4.336	52.65	42.11	24.06
Maximum	75	19.7	7.91	2.07	3.042	4.659	62.00	53.32	32.51
Minimum	44	12.1	3.92	1.42	2.014	4.256	42.60	29.31	16.47
St. Dev.	10	1.5	1.02	0.10	0.203	0.080	3.83	4.73	3.11

hydrate were in the 35 to 50% range for Ca/S molar ratios of 1.60 to 1.90. Figure 7-9 shows the sorbent SO_2 removals over several load ranges and the full load model prediction for 100% pure sorbent and an adjusted prediction based on a purity of 90.35% (the average purity measured during long-term demonstration). These lines indicate the significant impact of sorbent purity and show that when purity is taken into account the results agree with or exceed model predictions.

The calcium utilization was found to depend most strongly on the Ca/S molar ratio. The sorbent utilization varied by approximately 8% at each Ca/S molar ratio and no significant load effect was determined. As expected, sorbent utilization drops off with Ca/S molar levels, due to diffusion limitations as more sorbent is injected. Figure 7-10 shows the calcium utilization as a function of Ca/S molar ratio. A drop in utilization of approximately 5% over the Ca/S molar ratio increase from 1.6 to 1.9 is evident. A small reduction in sorbent utilization with load is evident in some cases and is most likely due to elevated temperature and reduced residence time in the optimal temperature window. This result was also evident from the optimization testing data.

During the long-term testing period, limited SI only testing was conducted. The following table presents the trend of SO_2 reduction.

Load (MWe)	Ca/S (mole/mole)	SO_2 Emissions ($lb/10^6Btu$)	SO_2 Removal (%)	Calcium Utilization (%)
73	1.82	3.260	38.49	21.15
70	1.84	3.394	35.96	19.55
44	1.79	3.292	37.89	21.17

These SO_2 removals are in the lower range for sorbent SO_2 removals calculated from GR-SI operation. The calcium utilizations are also several percent (approximately 3%) below the GR-SI utilizations. The limited SI tests conducted during the year-long demonstration indicate that GR in addition to SI, not withstanding the SO_2 reduction brought about by use

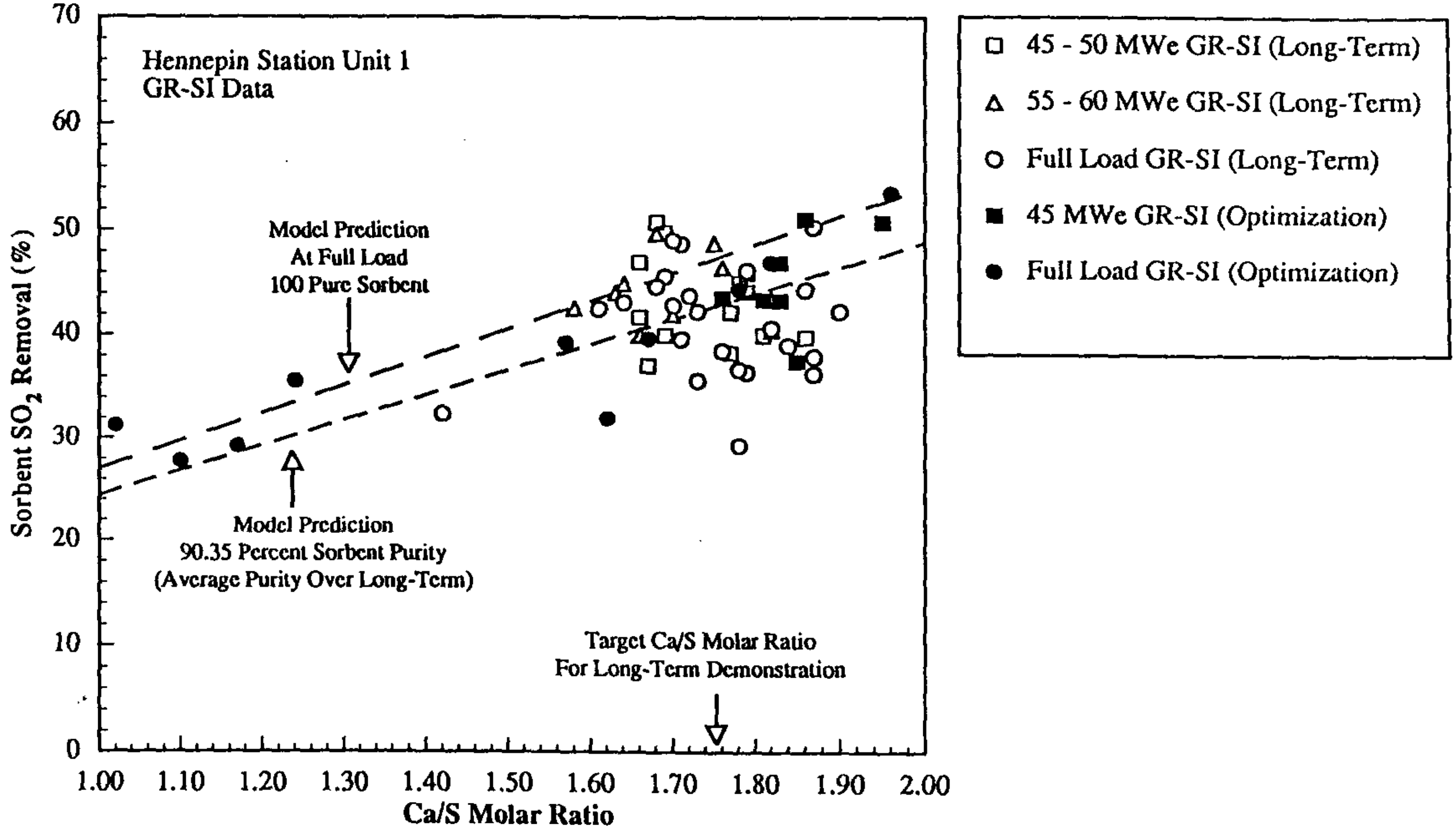


Figure 7–9. Long-Term and Optimization Testing sorbent SO_2 removal as a function of Ca/S molar ratio

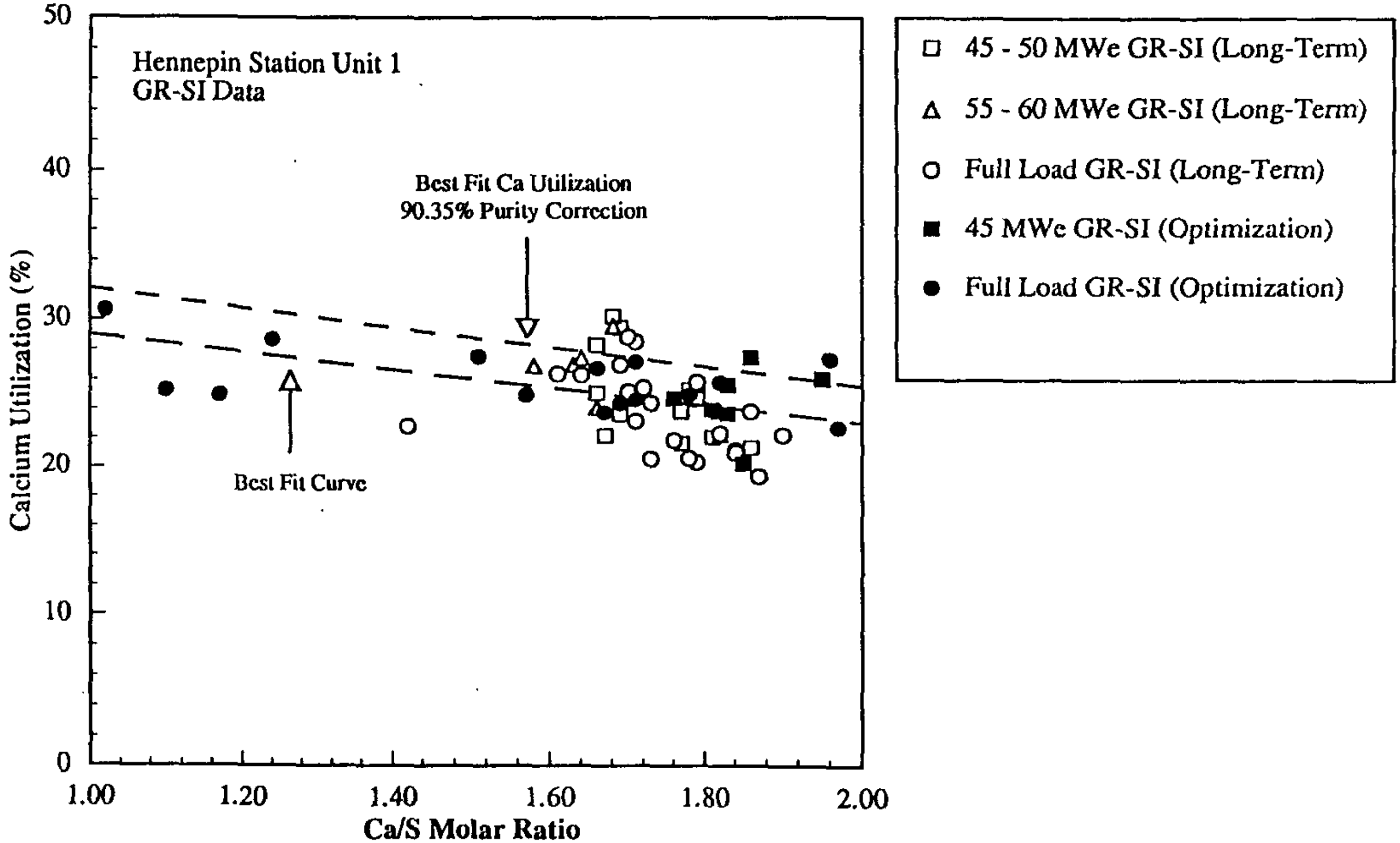


Figure 7–10. Long-Term and Optimization Testing calcium utilization as a function of Ca/S molar ratio

of sulfur free natural gas, appears to have a minor positive impact on sorbent sulfation. SI, without GR, had calcium utilizations in the lower range of GR-SI utilizations.

7.3 CO, CO_2, HC, and N_2O Emissions

During the long-term GR-SI testing, CO emissions averaged 57 ppm (@ 3% O_2). In general, CO emissions were lowest during high-load tests and increased to above 100 ppm for tests in the 45 to 50 MW_e range. Operation at loads of 72 to 75 MW_e typically resulted in emissions below 20 ppm. Emissions of CO and HC result from incomplete combustion of primary or reburning fuel due to low oxygen availability, either low overall excess air or incomplete mixing resulting in pockets of low excess air.

Emissions of CO are shown in two plots as functions of total OFA flow and exit zone stoichiometric ratio in Figure 7-11. The long term GR-SI testing results show that elevated CO emissions (above 100 ppm) were measured at relatively low loads, when the OFA jet velocity was not sufficient to mix rapidly with the furnace gas and fully burn out combustible matter. CO emissions above 50 ppm were measured for tests below 60 MW_e, when the total OFA flow was below 28,000 scfm (13.2 Nm^3/s). Operation with increased OFA flow, to a maximum of 37,000 scfm (17.5 Nm^3/s), resulted in more complete burnout of CO, to a minimum of 13 ppm. CO emissions below 50 ppm were consistently obtained with an OFA input above 28,000 scfm (13.2 Nm^3/s). Emissions of CO did not correlate well with reburning and exit zone stoichiometric ratios. Higher exit zone stoichiometriic ratios would be expected to reduce CO emissions; therefore, the elevated emissions are not due to low excess air operation.

The burner tilt angle is adjusted automatically to maintain reheat steam temperature. The burner tilt also impacts CO emissions, since lower burner tilt angles increase the gas residence time in the high temperature lower furnace. Most tests were carried out with burner tilt angles in the +10 to +27 degree range and reductions in CO emissions were measured with lower burner tilt angles. Figure 7-12 shows that high CO emissions were

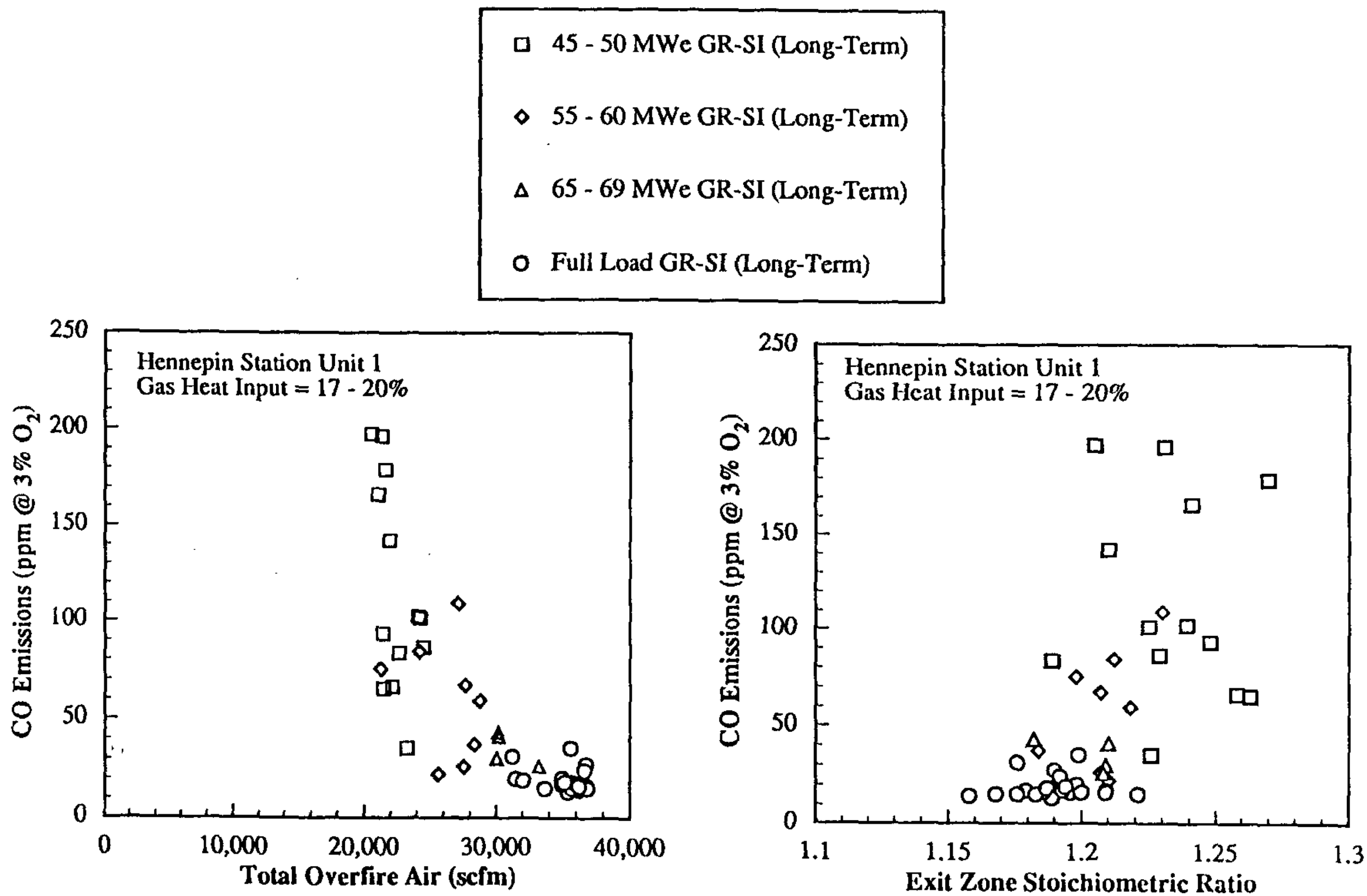


Figure 7–11a & b. Long-Term CO emissions as a function of total overfire air flow and as a function of exit stoichiometric ratio for the same tests

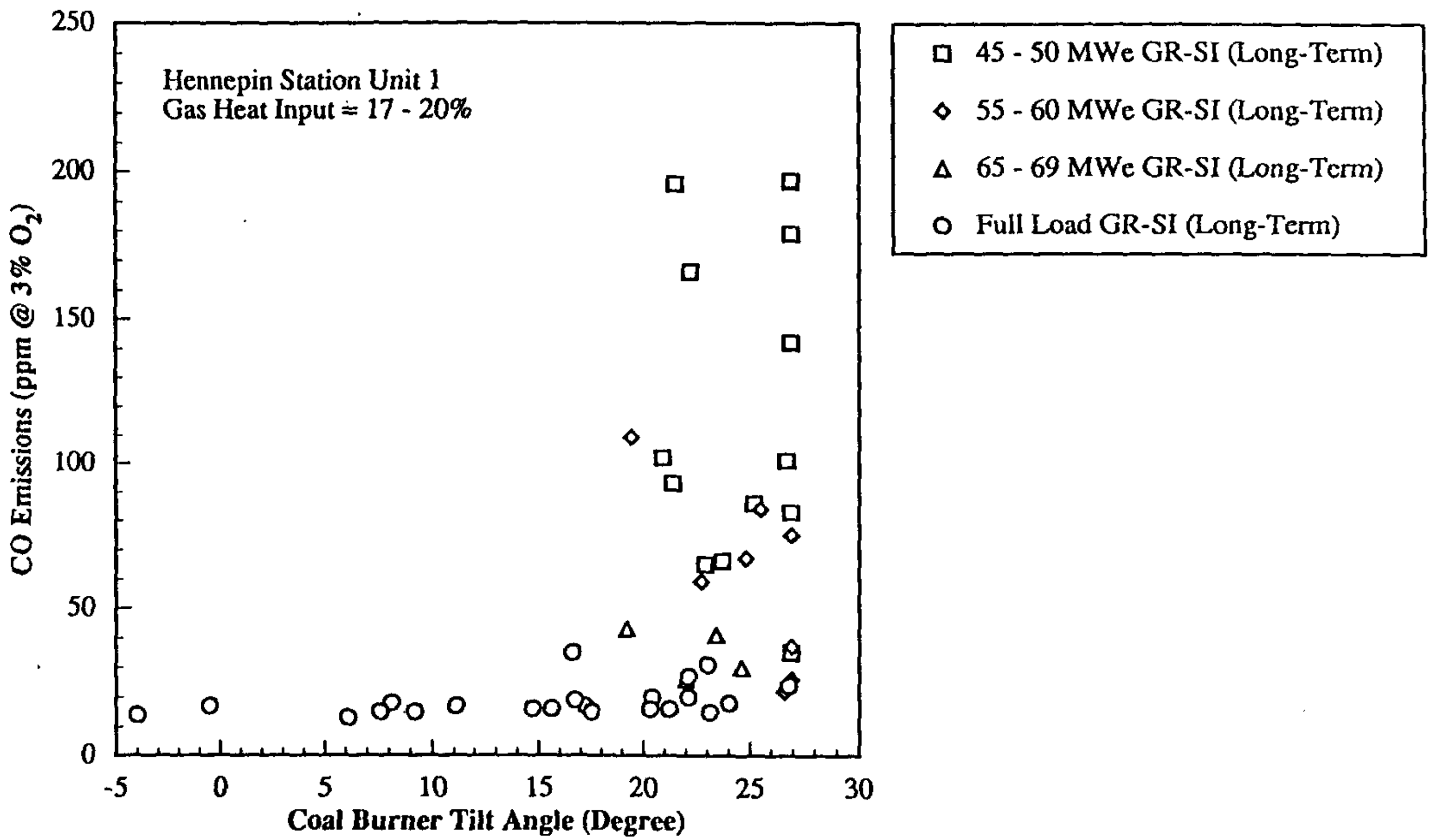


Figure 7–12. Long-Term CO emissions as a function of burner tilt angle

measured only when the burners were tilted upwards. The plant routinely responds to high CO emissions by tilting the burners to a lower position.

A modest reduction in CO_2 emissions was achieved with GR-SI. Reduction of CO_2 emissions is desirable, since CO_2 is a contributor to the greenhouse global warming effect. The decrease in CO_2 emissions is due to the difference in the composition (C/H) of the cofired fuels. Combustion of the coal used in this study results in CO_2 emissions of approximately 205 lb/10^6Btu (88.2 g/MJ), which may be compared to an emissions rate of 115 lb/10^6Btu (49.5 g/MJ) from natural gas firing. Therefore, GR with natural gas at 18% of the heat input theoretically result in CO_2 emissions of 189 lb/10^6Btu (81.3 g/MJ). The CO_2 emissions are shown as a function of percent gas heat input in Figure 7-13. The small difference in measured and expected emissions reduction is due to CO emissions and ash carbon loss. Over the long-term demonstration, CO_2 emissions averaged 14.5%, which is a reduction of 7.1% from the coal baseline of 15.6%. CO_2 emissions were as low as 14.0% (@ 3% O_2) while firing approximately 20% natural gas, which corresponds to 180 lb/10^6Btu (77.4 g/MJ).

Emissions of hydrocarbons (HC) were consistently low during long-term GR-SI operation. They were comparable to the baseline level of 2.7 ppm (@ 3% O_2). The average HC emissions over all long-term tests was 1.9 ppm, with a maximum of 18.2 ppm and a minimum of 0.1 ppm. The parameters which impact HC emissions are the same as those which impact CO emissions. These are boiler load, OFA flow and burner tilt angle. Full-load HC emissions were below 2.5 ppm. The HC emissions exceeded 4 ppm only when the unit was operated at an average load below 60 MW_e. These cases also correspond to operation with ofa flow below 28,500 scfm (13.5 Nm^3/s) and upward tilting burners. As is the case with CO emissions, HC emissions appear to be effectively controlled by a high total OFA flow which increases the OFA jet velocity. Other conditions such as coal wetness and coal mill fineness may impact HC emissions. In general, HC emissions were very low, indicating adequate fuel burnout.

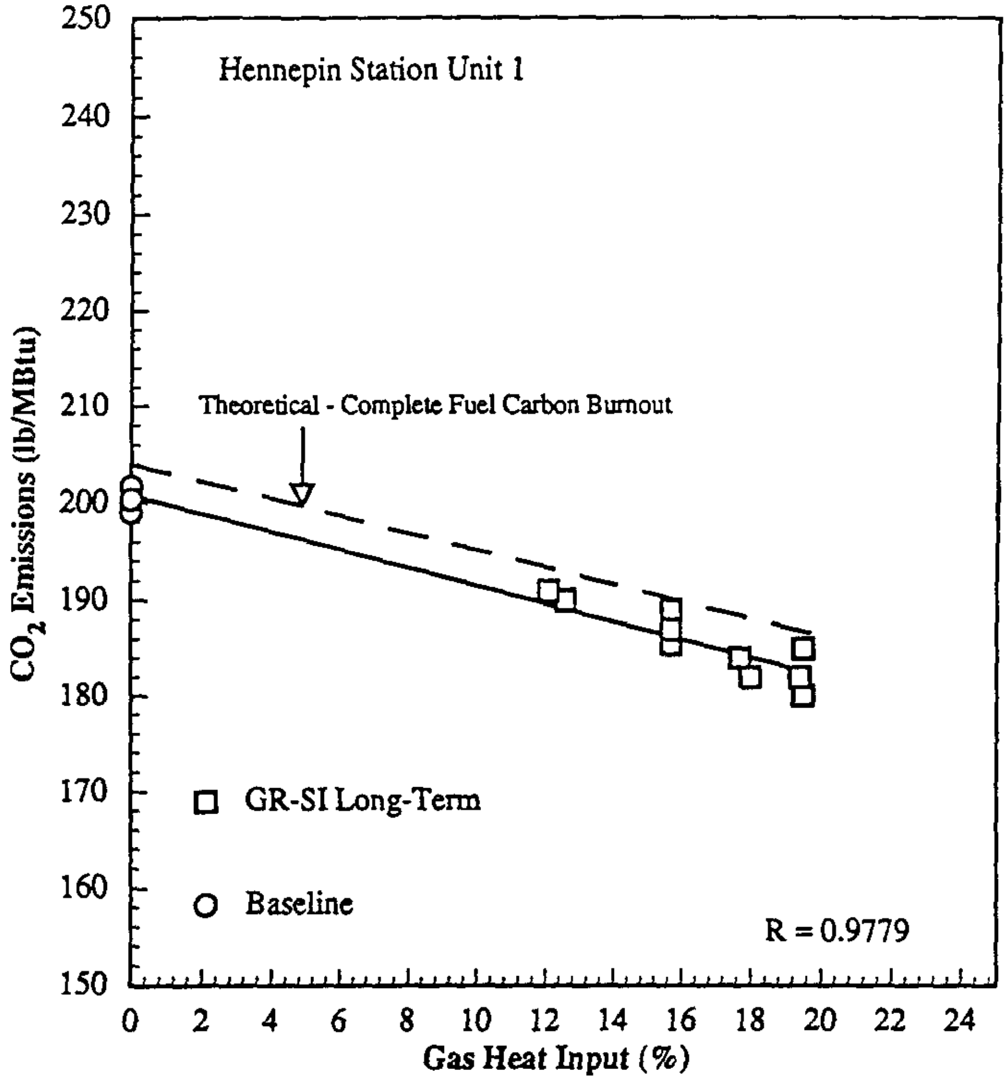


Figure 7-13. Long-Term CO_2 emissions as a function of gas heat input

Emission of N_2O was of concern due to its impact on the atmosphere, since it acts as a greenhouse gas. N_2O was measured during GR, GR-SI and SI testing in February/March 1992. The results are summarized in Table 7-4. The N_2O emission during GR-SI operation averaged from 0.5 to 3.2 ppm. During baseline testing, the emissions averaged 0.8 ppm and during SI testing the average was in the 1.0 to 1.3 ppm range. The maximum N_2O emission was 4.3 ppm, measured during GR-SI testing. These levels are low, indicating that GR-SI may be operated without unacceptably high N_2O emissions. Currently, no EPA standard for N_2O emissions is in effect.

7.4 GR-SI Process Materials and Energy Consumption

The natural gas and sorbent consumption over a range of loads are shown in Figure 7-14a & b. Over the load range 40 to 75 MW_e, the required natural gas flow at 18% heat input increases from approximately 1240 to 2330 scfm (0.59 to 1.10 Nm^3/s). For a gas heat input of 10%, the required natural gas flow increases from 690 to 1290 scfm (0.33 to 0.61 Nm^3/s) over the same load range. For continuous operation of GR with a capacity factor of 35% and gas heat input of 18%, the required natural gas flow over a one-year period is 427 MSCF (12,100,000 Nm^3). For a capacity factor of 40%, the natural gas requirement for 18% gas heat input is 488 MSCF/yr (13,830,000 Nm^3/a). Applying GR at a lower gas heat input rate of 10% over a one year period with a capacity factor of 35% will require a natural gas input of 238 MSCF/yr (6,740,000 Nm^3/a) and for a capacity factor of 40%, 272 MSCF/yr (7,708,000 Nm^3/a). It is more likely that GR would be applied a fraction of the time; therefore, the appropriate quantity above should be multiplied by the actual or projected time fraction to determine the annual natural gas requirement.

The following equations define the natural gas flow rate required to provide two levels of gas heat input.

10% Gas Heat Input:	Natural Gas Flow (scfm) = 17.2 * Load (MW_e)
18% Gas Heat Input:	Natural Gas Flow (scfm) = 31.0 * Load (MW_e)

TABLE 7-4. N_2O EMISSIONS SUMMARY

Date	Test	Gas Heat Input Percent	Ca/S Molar Ratio	N_2O Emissions (ppm, @ 3% O_2)* Average	Maximum	Minimum
2/24/92	GRSI	18.7	1.81	3.0	4.3	2.1
2/25/92	GRSI	18.1	1.78	2.3	4.1	0.7
2/26/92	GRSI	18.6	1.84	2.6	3.4	1.8
2/27/92	Baseline	0.00	0.00	0.8	1.8	0.0
2/28/92	GRSI	18.3	1.94	2.1	3.0	0.8
3/2/92	GRSI	18.5	1.84	3.2	4.1	2.4
3/3/92	GRSI	18.3	1.81	2.5	3.5	1.8
3/4/92	GRSI	18.4	1.82	2.5	3.2	1.8
3/5/92	SI	0.00	1.90	1.3	2.0	0.6
3/6/92	SI	0.00	2.00	1.9	2.5	0.6
3/9/92	SI	0.00	1.84	1.0	2.4	0.6
3/10/92	GRSI	18.8	1.82	1.2	1.9	0.2
3/11/92	GRSI	18.7	1.42	0.5	1.8	0
3/12/92	GRSI	18.6	1.52	0.5	1.3	0
3/13/92	GRSI	18.6	1.86	0.8	1.6	0.5

* N_2O Emissions Corrected to Instrument Zero Drift

Ca/S: Average During Test Period

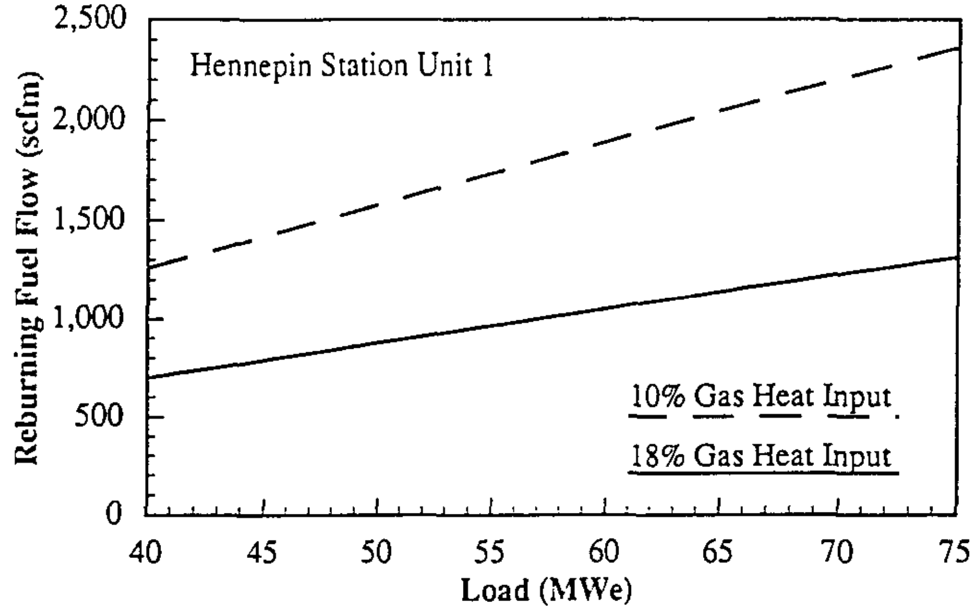


Figure 7–14a. Reburning fuel input as a function of load

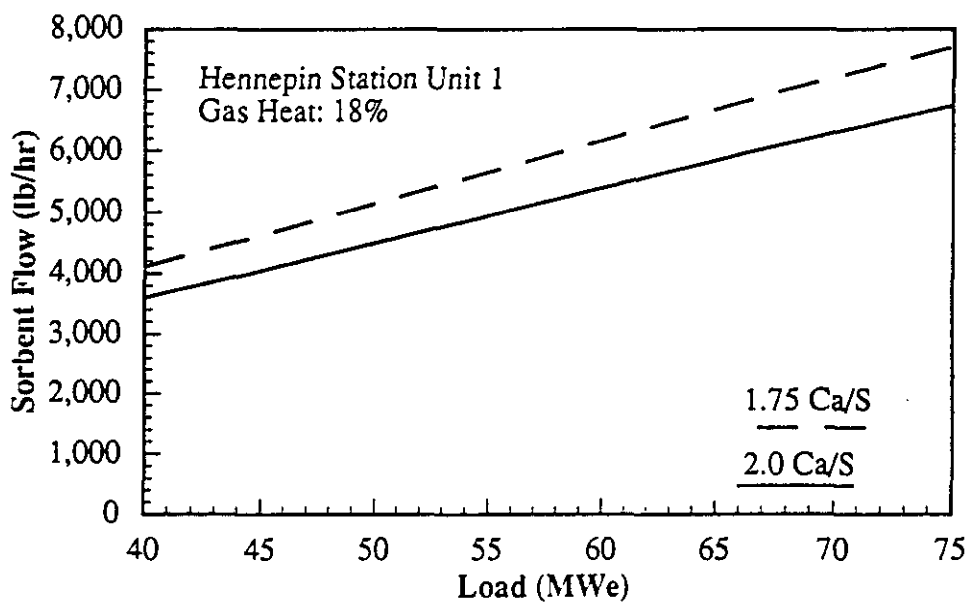


Figure 7–14b. Sorbent input as a function of load

The sorbent ($Ca(OH)_2$) flow required to produce a Ca/S molar ratio of 1.75 (with 18% gas heat) over a load range of 40 to 75 MW_e is 3,600 to 6,750 lb/hr (0.45 to 0.85 kg/s). To reach a Ca/S molar ratio of 2.0, the sorbent required is 4,100 to 7,700 lb/hr (0.52 to 0.97 kg/s) over the same load range. Over a one-year period the sorbent required to operate SI continuously at a Ca/S molar ratio of 1.75 and at a capacity factor of 35% is 10,340 tons (9,390 tonne). At a capacity factor of 40% over a one-year period, the requirement is 11,820 tons (10,730 tonne) for continuous operation at a Ca/S molar ratio of 1.75. Other sorbents which result in greater SO_2 removal would require reduced sorbent input rates.

The following equations define the sorbent mass flow required to produce two levels of Ca/S ratio for 2.89% sulfur coal having a higher heating value of 10,632 Btu/lb.

1.75 Ca/S Molar Ratio:	$Ca(OH)_2$ Sorbent Flow (lb/hr) = 90.0 * Load (MW_e)
2.0 Ca/S Molar Ratio:	$Ca(OH)_2$ Sorbent Flow (lb/hr) = 103 * Load (MW_e)

Carbon dioxide was used to neutralize the ash sluice water to a pH in the 6.0 to 9.0 range, before discharge. The CO_2 consumption was approximately 0.70 lb CO_2/lb sorbent and 0.081 lb CO_2/lb coal, for a sorbent to coal input weight ratio of 0.116.

The GR-SI system auxiliary power usage during long-term testing is found in Table 7-5. Data were taken on a monthly basis and are shown with the hours of Baseline, GR, SI, and GR-SI operation. These are hours over which emissions data were averaged; therefore, they are lower than the actual hours of the GR-SI system operation. A fraction of the power metered by the GR-SI system watt-hour meter is used for lighting and other purposes. A maximum power usage of 800 kW was calculated for GR-SI, during the design of the system. GR, SI and GR-SI operation also affect power utilization by other plant equipment. A small reduction in coal mill power and a small increase in ESP power are expected. The changes in power consumption by coal mills, ID and FD fans, and the ESP are considered for three full load tests conducted under baseline, GR, and GR-SI in Table 7-6. Fan power did not change did not change appreciably, but reduction in mill power consumption and

TABLE 7-5. GR-SI AUXILIARY POWER

Month/Yr	Auxiliary Power (kWh)	Testing Hours Baseline	GR	SI	GR-SI	Total
Jan/92	88,800	161.03	29.28	0	54.58	244.90
Feb/92	79,200	51.72	8.28	2.53	47.77	110.30
Mar/92	122,400	24.05	18.28	17.72	92.58	152.63
Apr/92	91,200	25.40	19.14	19.17	84.26	147.97
Sept/92	139,200	16.54	6.58	0	124.31	147.43
Oct/92	52,800	1.23	27.72	0	100.13	129.08

TABLE 7-6. PLANT EQUIPMENT POWER CHANGE DUE TO GR AND GR-SI

Condition	Full Load Baseline	Full Load GR	Full Load GR-SI
Date	1/7/92	1/8/92	1/9/92
Gross Load (MWe)	71	72	70
Coal Flow (klb/hr)	68.7	58.4	56.6
Gas Heat Input (%)	0.0	17.9	17.7
Ca/S Molar Ratio	0.00	0.00	1.75
BFP-B (Amps)	360	380	360
BFP Power Change (% of Base)	******	5.6	0.0
ID-1A (Amps)	115	130	130
ID-1B (Amps)	140	140	135
ID Fan Power Change (% of Base)	******	5.9	3.9
FD-1A (Amps)	45	45	45
FD-1B (Amps)	50	55	50
FD Fan Power Change (% of Base)	******	5.3	0.0
A-Mill (Amps)	65	60	60
B-Mill (Amps)	70	65	60
C-Mill (Amps)	65	60	60
Mill Power Change (% of Base)	******	-7.5	-10.0
Precip-A-Primary Current (Amp-AC)	121	124	136
Precip-A-Primary Voltage (Vlt-AC)	381	383	383
Precip-A-Power (kW)	46	47	52
Precip-B-Primary Current (Amp-AC)	105	106	118
Precip-B-Primary Voltage (Vlt-AC)	383	381	383
Precip-B-Power (kW)	40	40	45
Precip-C-Primary Current (Amp-AC)	78	82	87
Precip-C-Primary Voltage (Vlt-AC)	381	383	381
Precip-C-Power (kW)	30	31	33
Precip-D-Primary Current (Amp-AC)	75	82	77
Precip-D-Primary Voltage (Vlt-AC)	383	382	382
Precip-D-Power (kW)	29	31	29
Total Precipitator Power (kW)	145	151	160
Precipitator Power Change (% of base)	******	4.1	10.5

increase in ESP power of approximately 10% in each are evident. The total auxiliary power under the different operating modes is shown in Figure 7-15. Total auxiliary power consumed by Hennepin Unit 1 increased by approximately 300 kW, under GR-SI. GR operation resulted in a negligible increase in auxiliary power, while SI resulted in an increase of 100 to 300 kW.

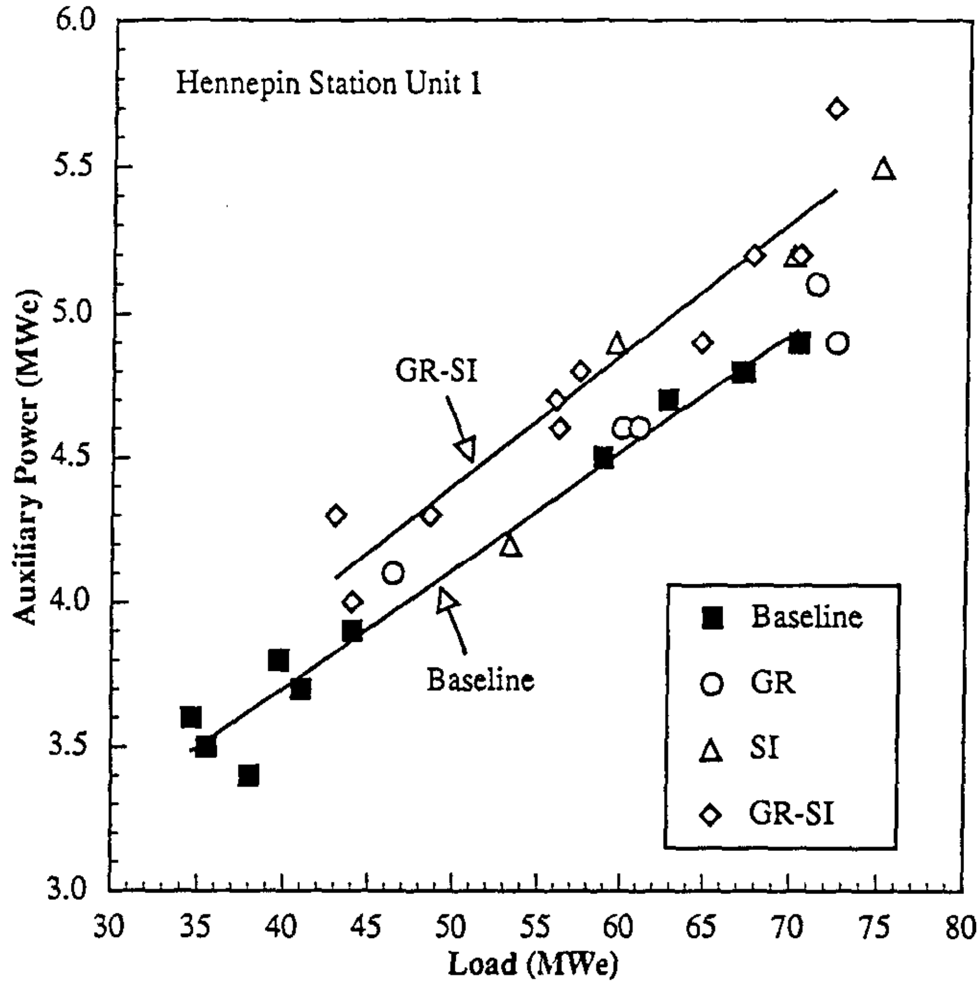


Figure 7-15. Total auxiliary power under GR, SI and GR-SI operation

8.0 LONG-TERM THERMAL PERFORMANCE

Heat transfer modeling conducted in Phase I of the project indicated that GR-SI would have only minor impacts on the thermal performance and operation of Hennepin Unit 1. This section will present the thermal performance data associated with GR-SI over the long-term demonstration period. These data were collected and evaluated to ensure that the Hennepin unit operated at its rated capacity with proper steam temperatures and pressures. It was important to verify that GR-SI operation would have no adverse impacts on steam conditions/heat absorption.

During the design phase, two important predictions relating to steam production/conditions were made. First, Hennepin Unit 1 would produce steam at its rated capacity during GR-SI operation, albeit with a slightly lower thermal efficiency, and that GR-SI would result in minor changes in the heat absorption profile. Second, steam temperatures could be controlled to their design values using the existing steam temperature control systems. These conclusions were based on performance predictions for nominal GR-SI operation. During the long-term testing period these predictions were verified over a wide range of boiler load.

Section 8.1 provides an overview of the thermal performance analysis. Section 8.2 discusses steam temperatures and control mechanisms, while Section 8.3 presents changes in the boiler heat absorption profile. Sections 8.4 through 8.7 then present the impacts of GR-SI on the flue gas temperature, thermal efficiency, carbon loss, and heat rate.

8.1 Boiler Thermal Performance

Various thermal performance parameters were recorded or calculated by the Boiler Performance Monitoring System (BPMS), a software package developed by EER. A data base has been established, including the following thermal performance parameters:

- Steam flow rate, temperature and pressure
- Steam attemperation spray
- Heat transfer to water/steam
- Gas side temperatures
- Thermal efficiency
- Heat rate

Tables 8-1, 8-2, 8-3, and 8-4 summarize the thermal performance of the unit during the long-term demonstration period for Baseline, GR, SI (45 MW_e only), and GR-SI operation, respectively. Since unit operation was generally under dispatch control, the data are summarized for low, mid, and high loads. In addition, the results were compared to heat transfer model predictions to evaluate the validity of the design methodology. The following sections describe the impacts of GR-SI on superheat and reheat steam temperatures, superheat attemperation spray, heat absorption profile, flue gas temperature, thermal efficiency, carbon in ash, and net heat rate.

8.2 Steam Conditions

Hennepin Unit 1 produces both superheat (main) and reheat steam with a design point temperature of 1,005°F (541°C). The operators typically consider this design point to be a maximum and operate conservatively with steam temperatures in the range of 980 to 995°F (527 to 535°C), regardless of whether GR or SI is in service. Three systems are used to control these temperatures as load, excess air, boiler fouling, and other parameters vary.

- Burner Tilt Burner tilt adjusts the position of flames in the furnace. When the burners are tilted up, furnace waterwall heat absorption is reduced shifting heat to the superheater and reheater sections and increasing the main and reheat steam temperatures. Under normal operation, the burner tilt is controlled automatically to achieve the reheat temperature set point.

TABLE 8-1. SUMMARY OF BASELINE LONG-TERM THERMAL PERFORMANCE

Average Load	45 MWe	61 MWe	72 MWe	Predicted*
Process Variables				
Exit Plant O2 (%)	3.57	3.23	2.90	2.80
Steam Side Temperatures (F)				
Exit Secondary Superheater	941	991	993	1,005
Exit Primary Superheater	779	837	841	854
Exit High Temp Reheater	897	982	992	1,005
SH Steam Attemperation (lb/hr)	4,215	7,004	6,678	14,500
Heat Transfer (MBtu/hr)				
Furnace Waterwalls	241	292	351	356
Secondary Superheater	39	53	60	64
Reheater	43	61	70	76
Primary Superheater	63	100	121	130
Economizer	15	19	21	27
Sootblowers On (%)	7	14	7	N.D.
Burner Tilt (degrees)	25	15	8	N.D.
Econ Inlet Gas Temp (F)	630	654	672	N.D.
Air Heater Gas Out Temp (F)	314	326	317	N.D.
ASME Heat Loss Calculation (%)				
Dry Gas	5.39	5.69	5.29	5.04
Moisture from Fuel	1.73	1.75	1.74	1.45
Moisture from Combustion	3.88	3.90	3.89	4.02
Combustible in Refuse	0.48	0.45	0.50	0.30
Radiation	0.48	0.37	0.33	0.33
Unmeasured	1.50	1.50	1.50	1.50
Total Losses	13.46	13.66	13.25	12.64
Thermal Efficiency (%)	86.54	86.30	86.76	87.36
Net Heat Rate (Btu/kWh)	10,464	10,437	10,340	N.D.

*:Heat Transfer Modeling @ 100% Load

N.D.: Not Determined

TABLE 8-2. SUMMARY OF GR LONG-TERM THERMAL PERFORMANCE

Average Load	44 MWe	60 MWe	72 MWe	Predicted*
Process Variables				
Percent Gas Heat Input	18.50	17.68	17.80	18.00
Ca/S Molar Ratio	0.00	0.00	0.00	0.00
Exit Plant O2 (%)	3.66	3.07	2.96	2.80
Steam Side Temperatures (F)				
Exit Secondary Superheater	974	988	994	1,005
Exit Primary Superheater	802	827	845	883
Exit High Temp Reheater	937	978	999	1,005
SH Steam Attemperation (lb/hr)	4,273	5,237	7,881	22,500
Heat Transfer (MBtu/hr)				
Furnace Waterwalls	216	296	347	345
Secondary Superheater	41	52	61	62
Reheater	44	60	72	76
Primary Superheater	67	96	122	136
Economizer	15	19	22	29
Sootblowers On (%)	7	6	16	N.D.
Burner Tilt (degrees)	25.16	15.94	3.48	N.D.
Econ Inlet Gas Temp (F)	636	653	668	N.D.
Air Heater Gas Out Temp (F)	318	321	321	N.D.
ASME Heat Loss Calculation (%)				
Dry Gas	5.85	5.26	5.27	5.10
Moisture from Fuel	1.45	1.46	1.45	1.20
Moisture from Combustion	5.03	4.98	5.05	5.34
Combustible in Refuse	0.33	0.40	0.39	0.49
Radiation	0.40	0.39	0.33	0.33
Unmeasured	1.50	1.50	1.50	1.50
Total Losses	14.56	13.99	13.99	13.96
Thermal Efficiency (%)	85.44	86.00	86.00	86.04
Net Heat Rate (Btu/kWh)	10,743	10,534	10,428	****

*:Heat Transfer Modeling @ 100% Load

TABLE 8-3. SUMMARY OF SI LONG-TERM THERMAL PERFORMANCE

Average Load	43 MWe
Process Variables	
Ca/S Molar Ratio	1.95
Exit Plant O2 (%)	3.43
Steam Side Temperatures (F)	
Exit Secondary Superheater	950
Exit Primary Superheater	803
Exit High Temp Reheater	895
SH Steam Attemperation (lb/hr)	2,673
Heat Transfer (MBtu/hr)	
Furnace Waterwalls	232
Secondary Superheater	33
Reheater	41
Primary Superheater	67
Economizer	15
Sootblowers On (%)	11
Burner Tilt (degrees)	23.88
Econ Inlet Gas Temp (F)	665
Air Heater Gas Out Temp (F)	357
ASME Heat Loss Calculation (%)	
Dry Gas	7.33
Moisture from Fuel	1.75
Moisture from Combustion	4.01
Combustible in Refuse	0.50
Radiation	0.51
Unmeasured	1.50
Total Losses	15.60
Thermal Efficiency (%)	84.40
Net Heat Rate (Btu/kWh)	10,677

TABLE 8-4. SUMMARY OF GR-SI LONG-TERM THERMAL PERFORMANCE

Average Load	45 MWe	59 MWe	72 MWe	Predicted*
Process Variables				
Percent Gas Heat Input	18.53	17.80	17.67	18.00
Ca/S Molar Ratio	1.74	1.73	1.78	2.00
Exit Plant O2 (%)	3.33	3.00	2.81	2.80
Steam Side Temperatures (F)				
Exit Secondary Superheater	978	986	995	1,005
Exit Primary Superheater	825	853	882	868
Exit High Temp Reheater	925	958	989	1,005
SH Steam Attemperation (lb/hr)	4,209	7,300	12,176	16,500
Heat Transfer (MBtu/hr)				
Furnace Waterwalls	229	298	352	349
Secondary Superheater	37	45	55	61
Reheater	43	56	68	74
Primary Superheater	73	102	133	133
Economizer	16	20	24	29
Sootblowers On (%)	21	26	36	N.D.
Burner Tilt (degrees)	24.39	23.17	19.16	N.D.
Econ Inlet Gas Temp (F)	668	690	714	N.D.
Air Heater Gas Out Temp (F)	344	348	350	N.D.
ASME Heat Loss Calculation (%)				
Dry Gas	5.96	5.89	5.78	5.26
Moisture from Fuel	1.44	1.45	1.45	1.20
Moisture from Combustion	5.19	5.15	5.15	5.35
Combustible in Refuse	0.37	0.42	0.41	0.54
Radiation	0.45	0.39	0.33	0.33
Unmeasured	1.50	1.50	1.50	1.50
Total Losses	14.91	14.80	14.62	14.18
Thermal Efficiency (%)	85.09	85.21	85.38	85.82
Net Heat Rate (Btu/kWh)	10,724	10,581	10,509	****

*:Heat Transfer Modeling @ 100% Load

- <u>Reheat Attemperation</u> Feedwater is sprayed into the reheat steam for further reheat temperature control. Since the attemperation water bypasses the high pressure turbine stages, it increases heat rate (reduces thermal efficiency). Accordingly, the reheat attemperation is normally used as a backup system. Throughout this program, the operators maintained reheat attemperation flow at a very low level.

- <u>Main Steam Attemperation</u> Feedwater is also sprayed into the superheat steam to control its temperature. This provides a means to adjust superheat steam temperature independent of reheat steam temperature, which is controlled primarily by burner tilt.

Figure 8-1 shows the reheat temperature as a function of load for both baseline and GR-SI operation. While there is some data scatter, for most baseline conditions the adjustment of burner tilt maintains the reheat temperature at the set point from full load down to about 50 MW_e. Below 50 MW_e the burner tilts are at the full up position and further load reduction causes reheat temperature to sag. The reheat attemperation is maintained constant at about 4% of capacity (essentially leakage flow).

With GR-SI, fouling of the reheater requires higher burner tilts to maintain reheat temperature. This is illustrated in Figure 8-2 which shows the reheat steam temperature and burner tilts as functions of the time after initiation of SI. Over the first hour of SI, the burner tilts increase monotonically as deposits build on the reheater; reheat temperature is maintained at the set point. Operation of the sootblowers at the end of the first hour removed the deposits, restoring the reheater heat absorption. This causes a momentary overshoot in reheat temperature until the burner tilts move downward restoring the set point. A second sootblowing cycle is also shown.

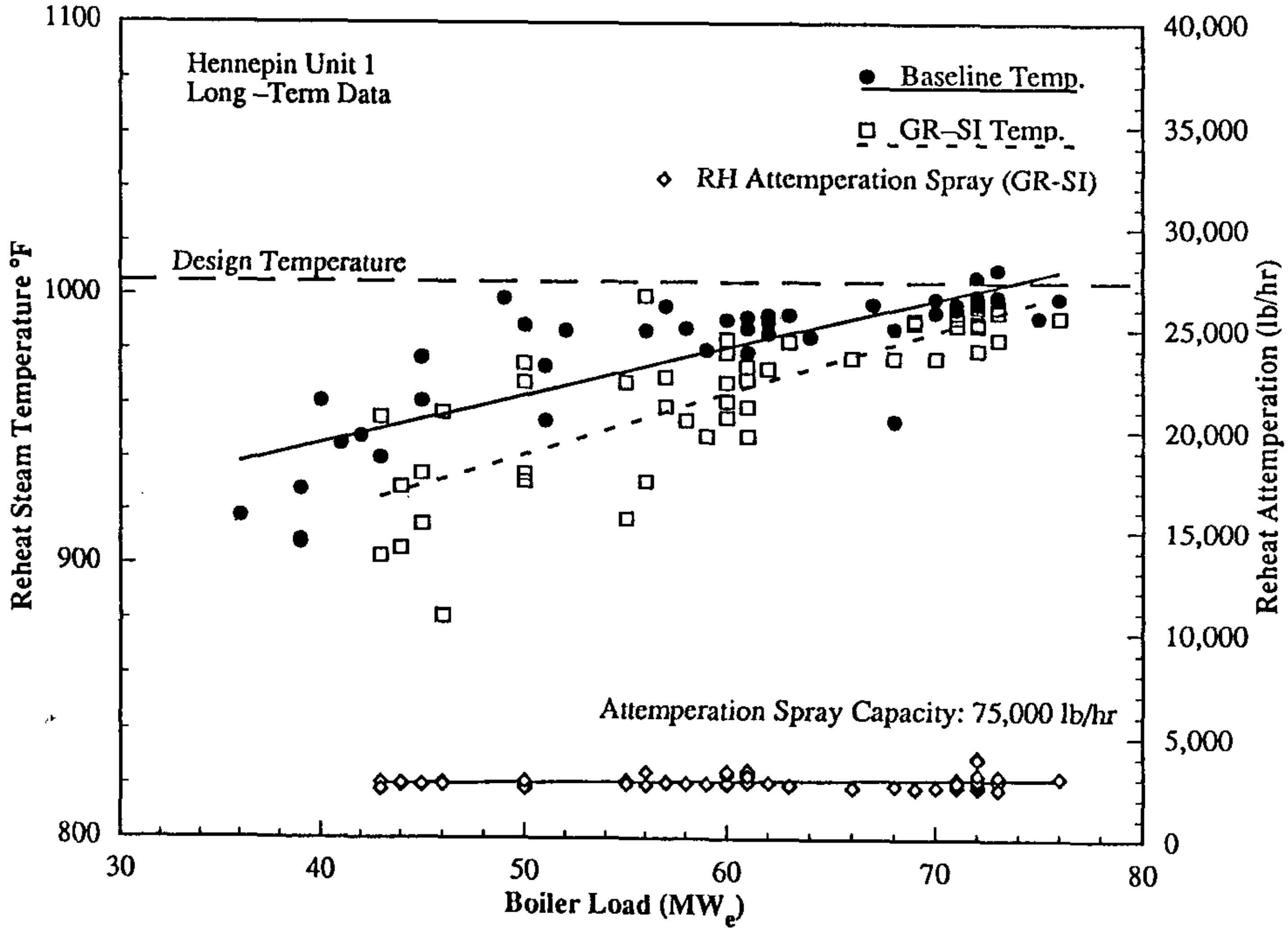


Figure 8-1. Impact of GR–SI on reheat steam temperature

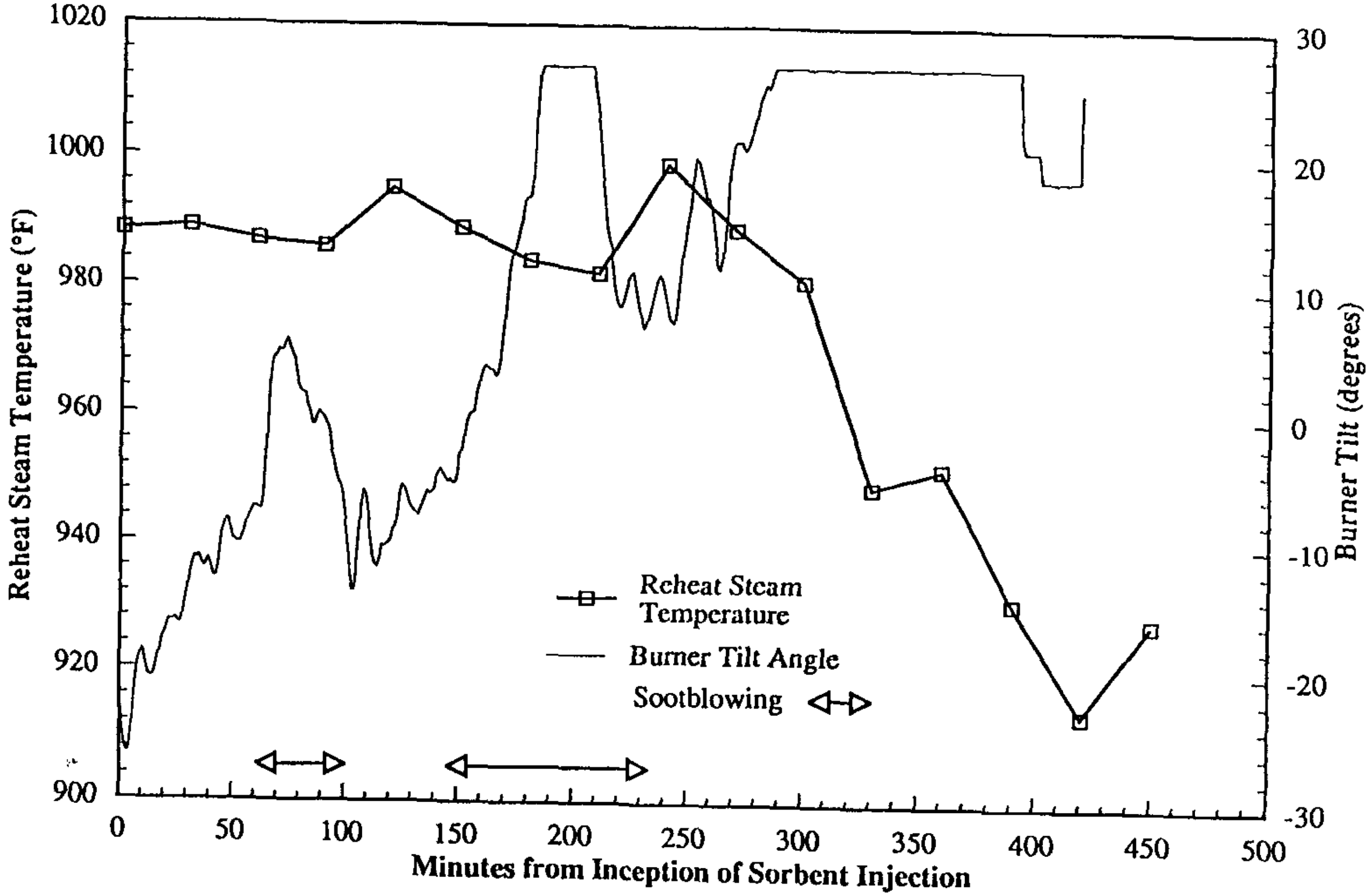


Figure 8–2. Typical effect of burner tilt on reheat steam temperature

As a result of reheater fouling, the GR-SI data in Figure 8-1 show a slightly reduced reheat temperature compared to baseline operation. Since the duration of the SI and scheduling of sootblowing cycles affect reheat temperature, there is substantial data scatter.

Figures 8-3, 8-4, and 8-5 show the superheat steam effects of GR-SI with baseline conditions for comparison. Under both GR-SI and baseline conditions, superheat steam temperature is maintained at close to the set point over the full load range as the burner tilts adjust automatically to maintain reheat steam temperature as discussed above. Figure 8-5 shows that the superheat steam attemperation under GR-SI operation is greater than for baseline operation at full load. This is a consequence of the upward burner tilt required to maintain reheat temperature which also increases superheat temperature. The superheat attemperation is increased to compensate. It should be noted that while the superheat attemperation is increased with GR-SI, the maximum flowrate (nominally 16,000 lb/hr [2.0 kg/s]) is only about 21% of capacity and does not limit boiler performance.

8.3 Boiler Heat Absorption Distribution

Heat absorption profiles were studied for Hennepin Unit 1 to determine the effect of GR, SI, and GR-SI on the heat absorption by each heat exchanger. Heat absorptions were calculated by analyzing the temperatures and flow rates on both sides (steam and combustion products). Five heat exchangers were evaluated including the furnace water wall, reheater, primary superheater, secondary superheater and the economizer. The air heater heat absorption, which is accounted for in the thermal efficiency of the unit, was not included in this thermal performance evaluation because of significant air leakage. In Figures 8-6 through 8-8 the heat absorption profiles are shown at 72 MW_e, 60 MW_e, and 45 MW_e, respectively.

GR operation can affect the thermal performance of the unit in two ways. First, GR affects the furnace heat release profile and second, GR operation changes local stoichiometric ratios and particulate loading resulting in minor changes in lower and upper furnace deposition patterns. During the long-term demonstration, GR operational data showed little impact on

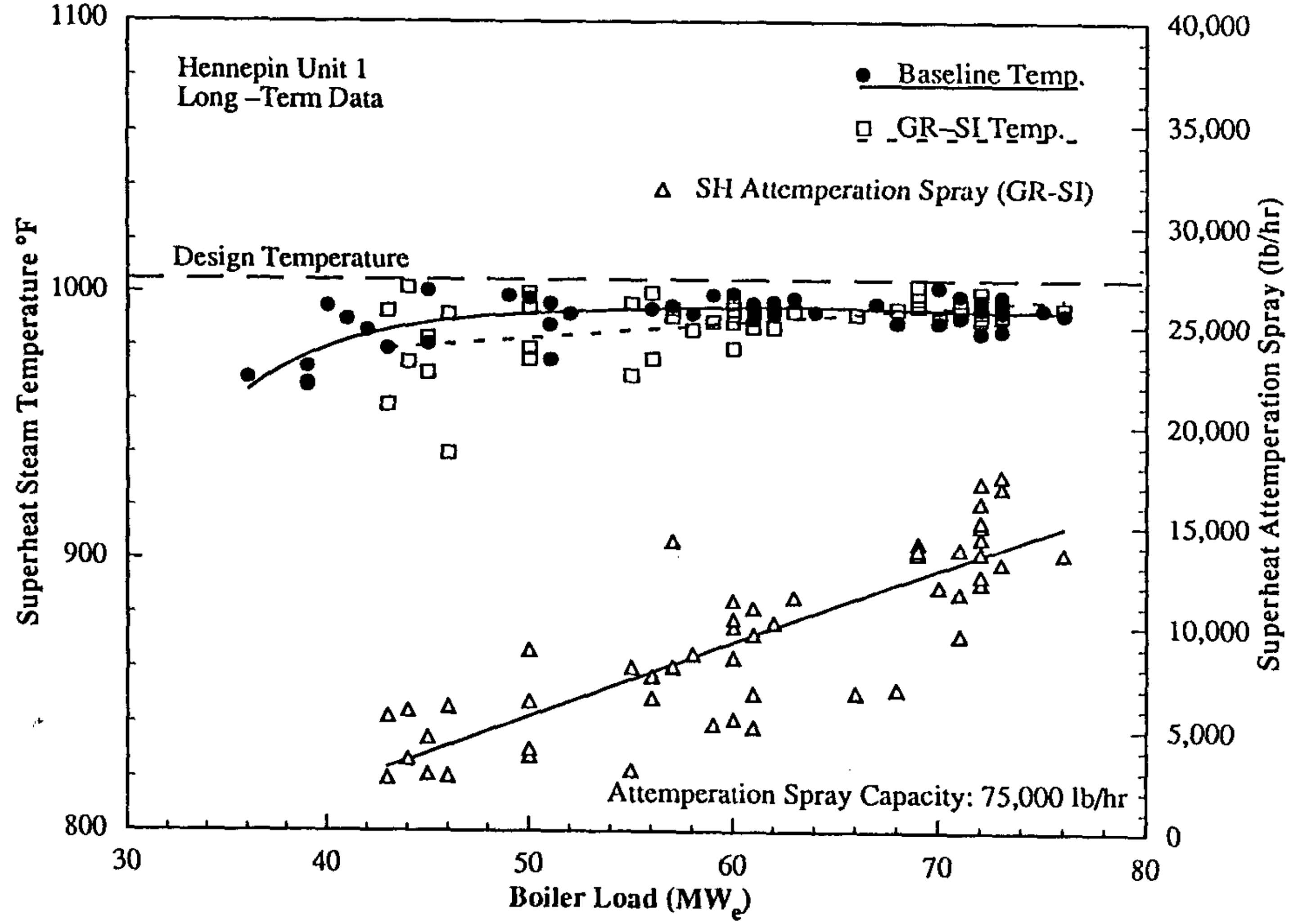


Figure 8–3. Impact of GR–SI on superheat steam temperature (attemperation spray indicated)

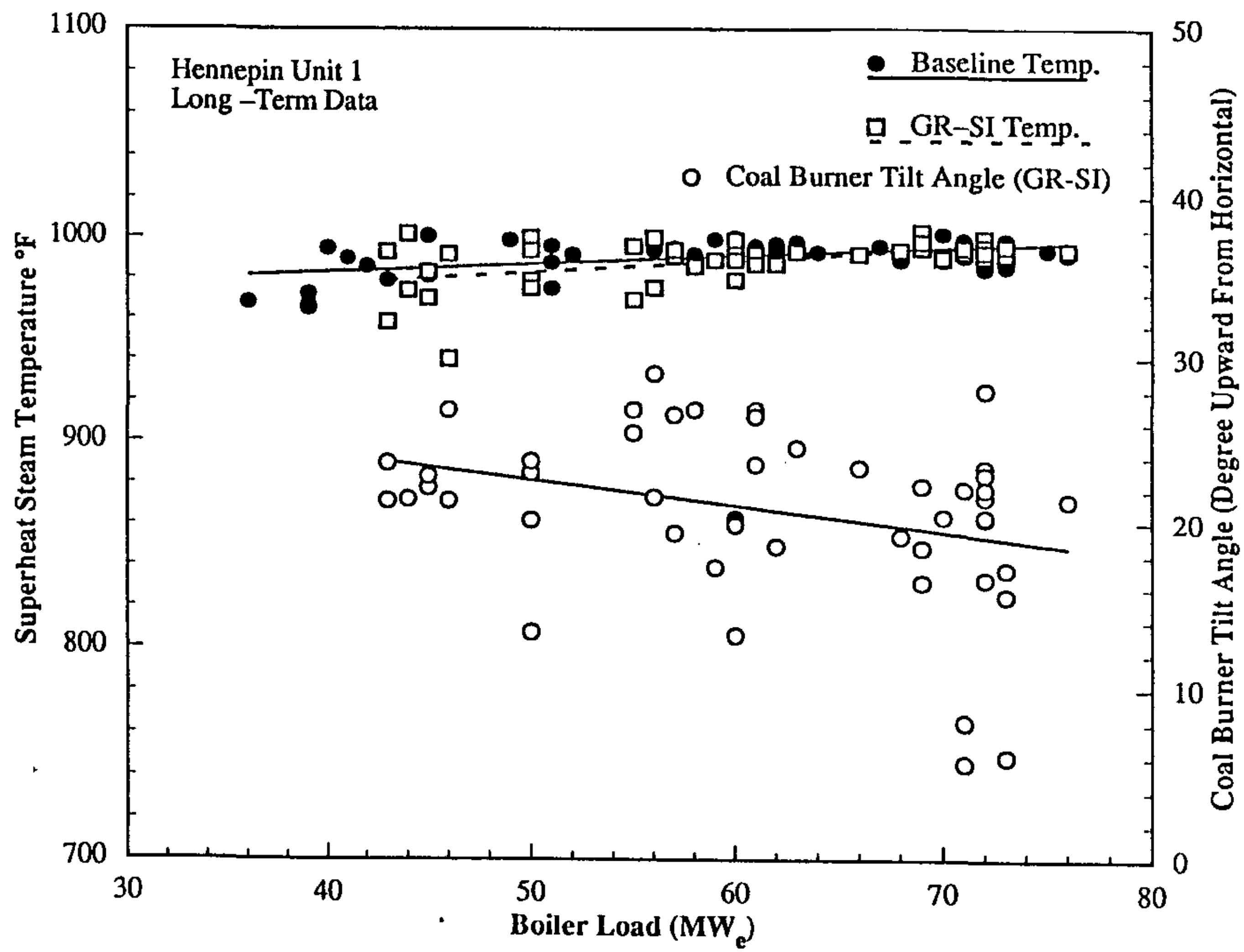


Figure 8–4. Impact of GR–SI on superheat steam temperature (burner tilt angle indicated)

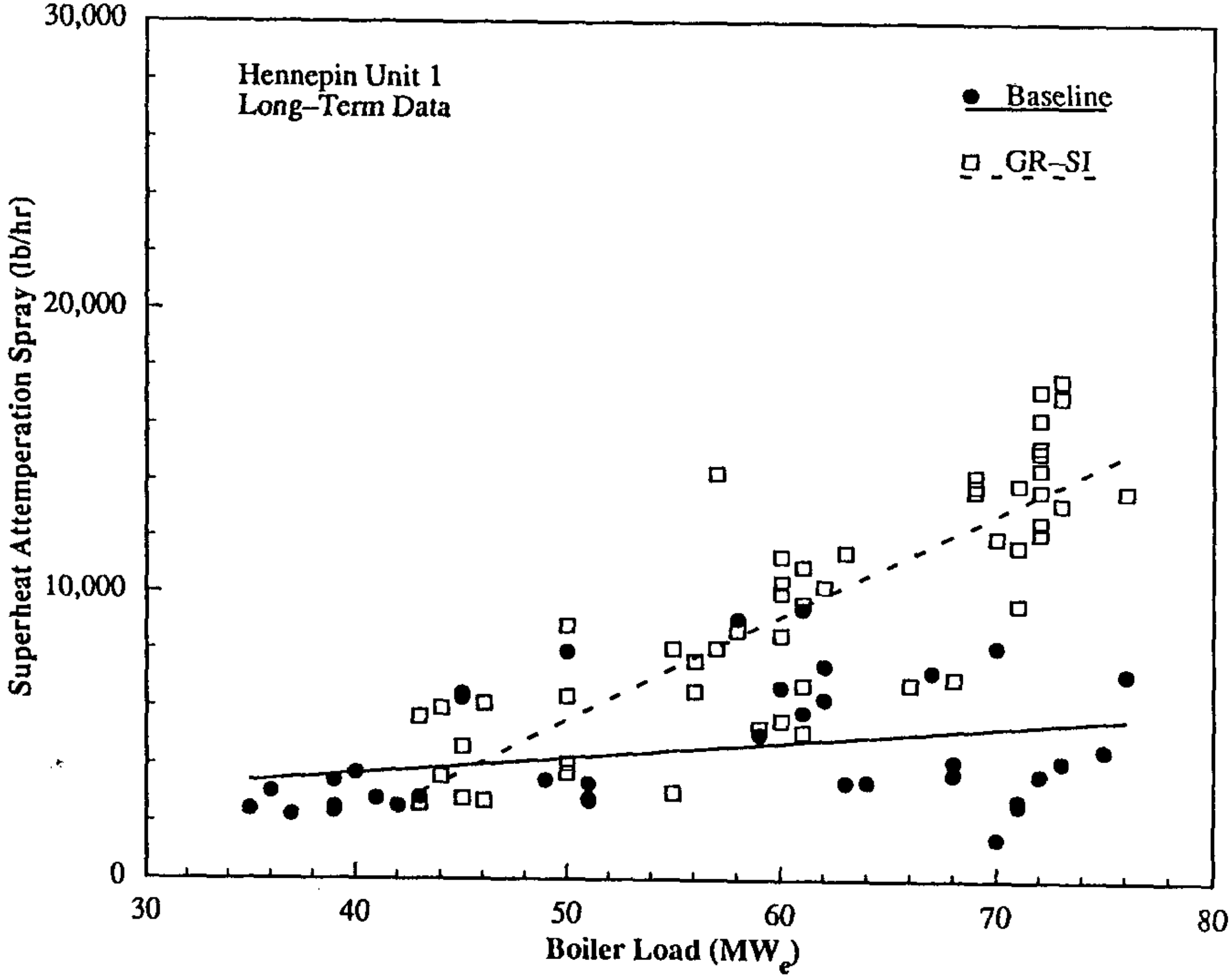


Figure 8–5. Impact of GR–SI on superheat steam attemperation

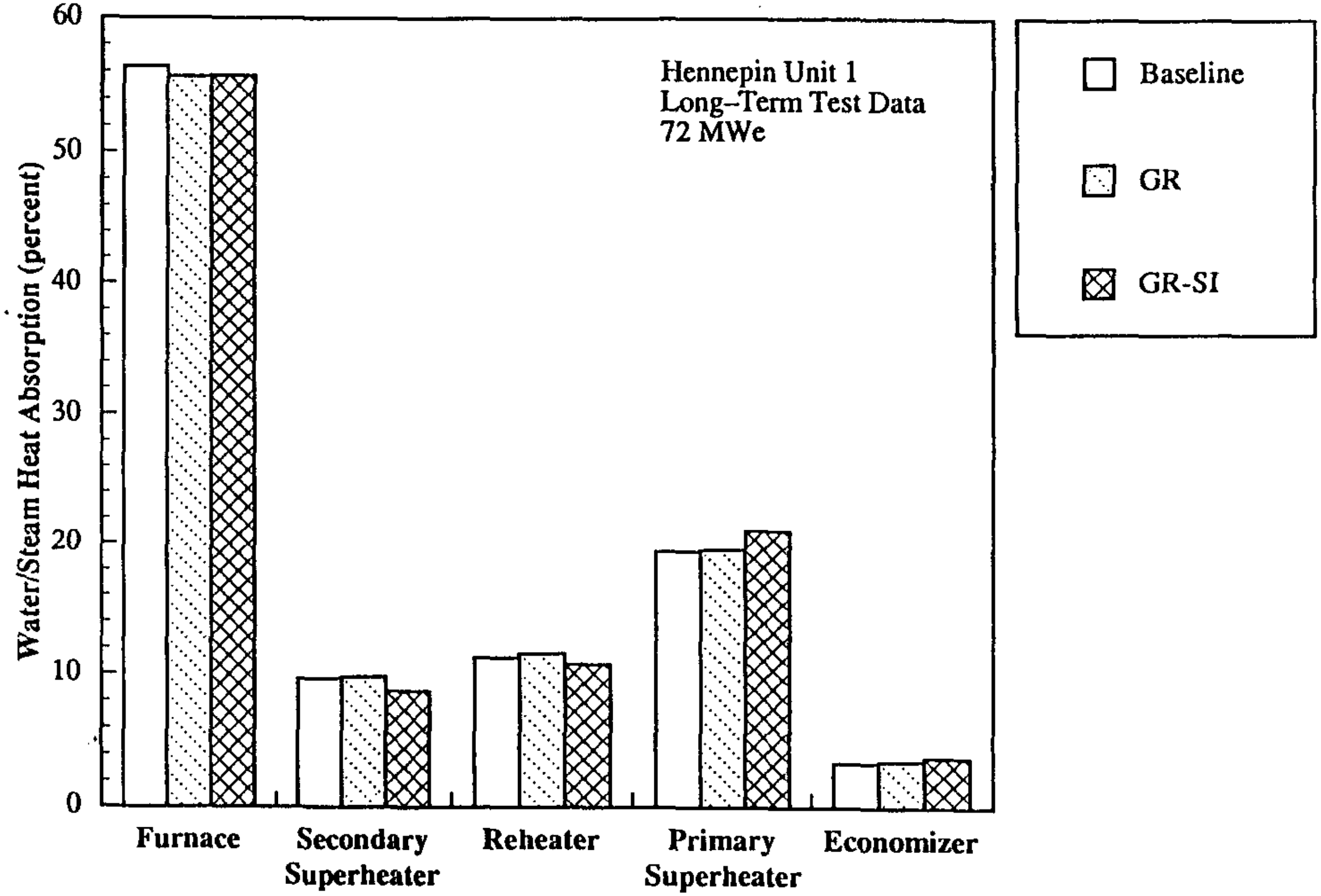


Figure 8–6. Heat absorption distribution at 72 MWe

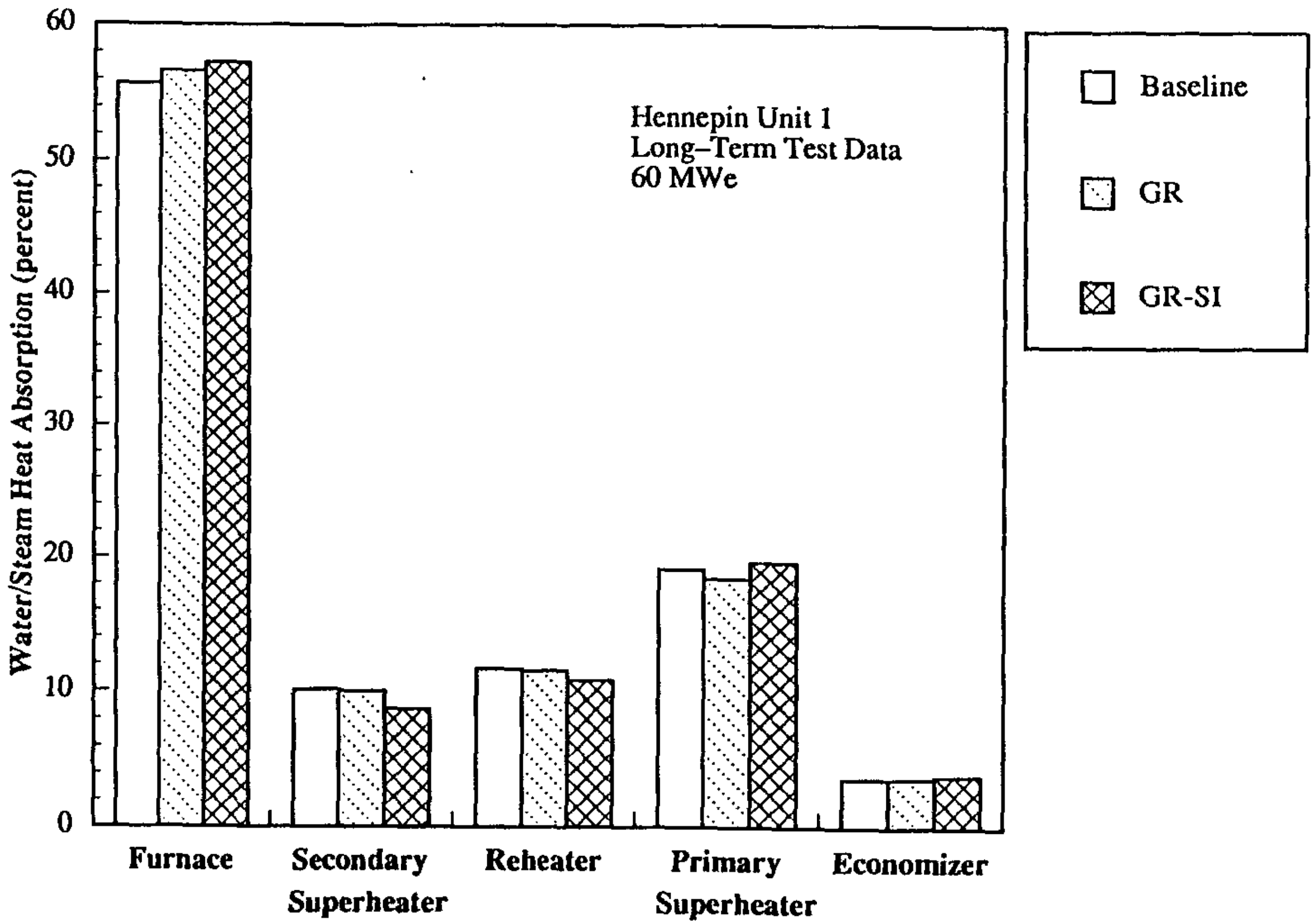


Figure 8–7. Heat absorption distribution at 60 MWe

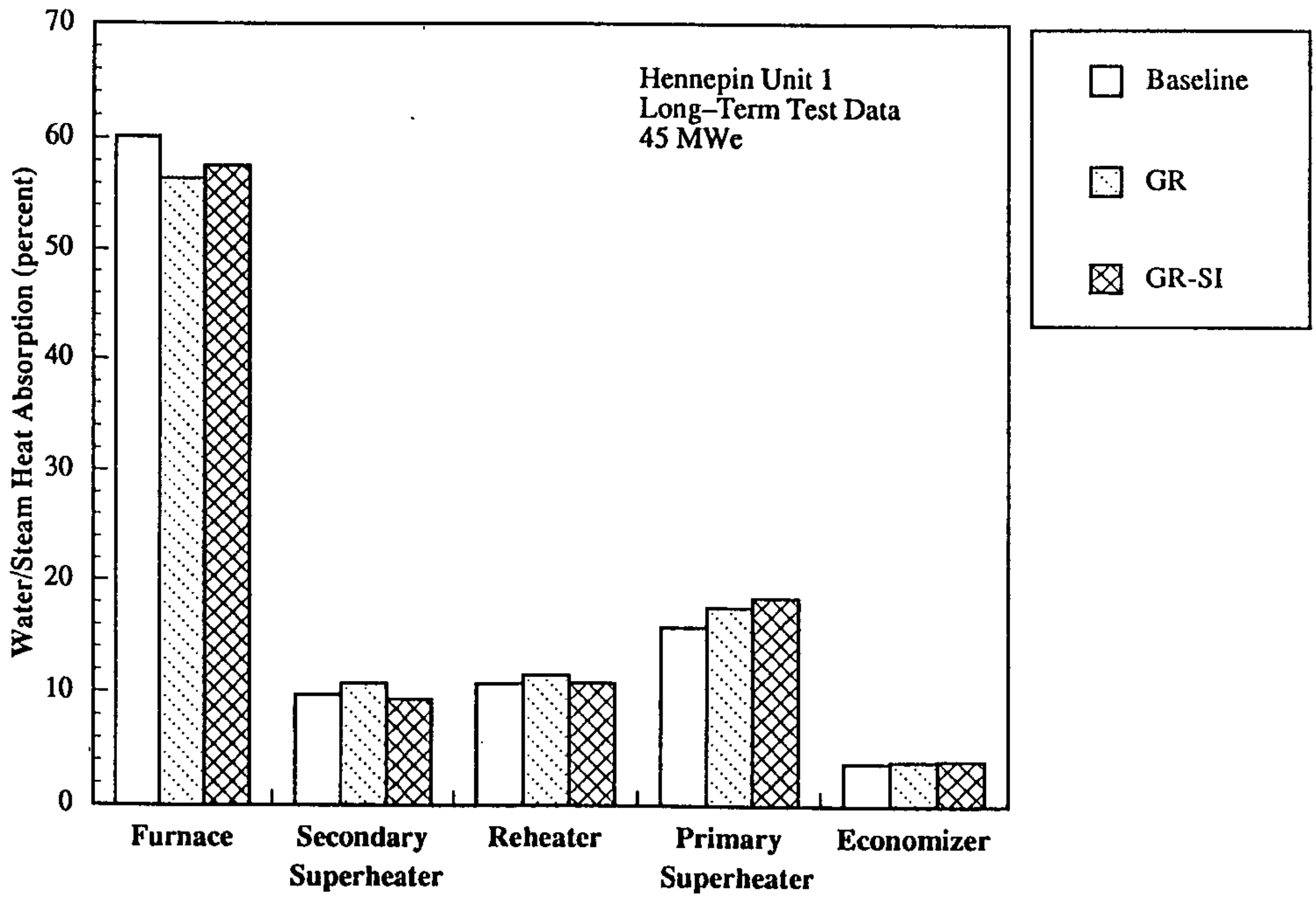


Figure 8–8. Heat absorption distribution at 45 MWe.

the heat absorption profile. As a result, steam temperatures also showed very little variation due to GR operation. At full load a small decrease in furnace water wall heat absorption and small increases in heat absorption in the convective heat exchangers were calculated. The same pattern is evident in low load (45 MW_e) data but at the intermediate load (60 MW_e) the average data show an increase in furnace heat absorption and small reductions by convective heat absorption. The overall impacts of GR operation on the heat absorption profile is very minor. The boiler heat absorption was enhanced by the relatively clean furnace maintained day to day while the boiler cycled out of service during most evenings.

In addition to the impacts caused by GR, the GR-SI thermal performance was affected by the increase in particulate loading through the upper furnace and convective pass. The increased particulate loading caused a familiar pattern over all loads. GR-SI had a relatively minor impact on furnace heat absorption, but more significant effect on the heat absorption by the secondary superheater, reheater, and primary superheater. The changes in heat absorption during GR-SI operation relative to the baseline case at full load were:

- <u>Furnace</u> 0.64% decrease
- <u>Secondary Superheater</u> 0.93% decrease
- <u>Reheater</u> 0.48% decrease
- <u>Primary Superheater</u> 1.62% increase
- <u>Economizer</u> 0.43% increase

The reduction in secondary superheat and reheat heat absorptions and increase in primary superheat absorption was consistent through the load range and is a direct impact of sorbent fouling. In order to decrease the impact of sorbent deposition, sootblowing optimization tests were conducted, as discussed in Section 10 of this report.

8.4 Flue Gas Temperature

Because of the shift in heat absorption from the furnace and the upper convective pass to the convective backpass, the flue gas temperatures measured at the economizer inlet increased with GR-SI relative to baseline operation, as shown in Figure 8–9a. This increase in flue gas temperature had the following impacts:

- Reduction in thermal efficiency (increase in dry gas heat loss)

- Increase in temperature and velocity of the flue gas at the inlet of the humidification duct, requiring higher levels of humidification, possibly resulting in an increase in moisture entering the ESP

- Higher fly ash resistivity, which has been found to vary strongly with temperature, thus potentially reducing the collection efficiency of the ESP

The BPMS temperatures indicate a temperature increase throughout the boiler with GR–SI in comparison to baseline temperatures. The temperature increase at the economizer inlet, under GR-SI varied from 42°F (23°C) at 72 MW_e to 38°F (21°C) at 45 MW_e. The economizer inlet was selected as the location to evaluate gas temperature changes due to the presence of a 12-thermocouple grid; other locations had only a single thermocouple.

The increase in economizer inlet gas temperature was not observed during GR operation since no convective pass fouling took place. A slight reduction in economizer inlet gas temperature (4°F [2°C]) during GR operation was measured.

GR-SI also resulted in a moderate increase in the air heater gas outlet temperature. Under baseline operation, the air heater gas outlet temperature ranged from 314°F (157°C) at 45 MW_e, to 317°F (158°C) at 72 MW_e. During GR-SI the air heater outlet gas temperature increased by approximately 30°F (17°C), from 344°F (173°C) at 45 MW_e to 350°F (177°C)

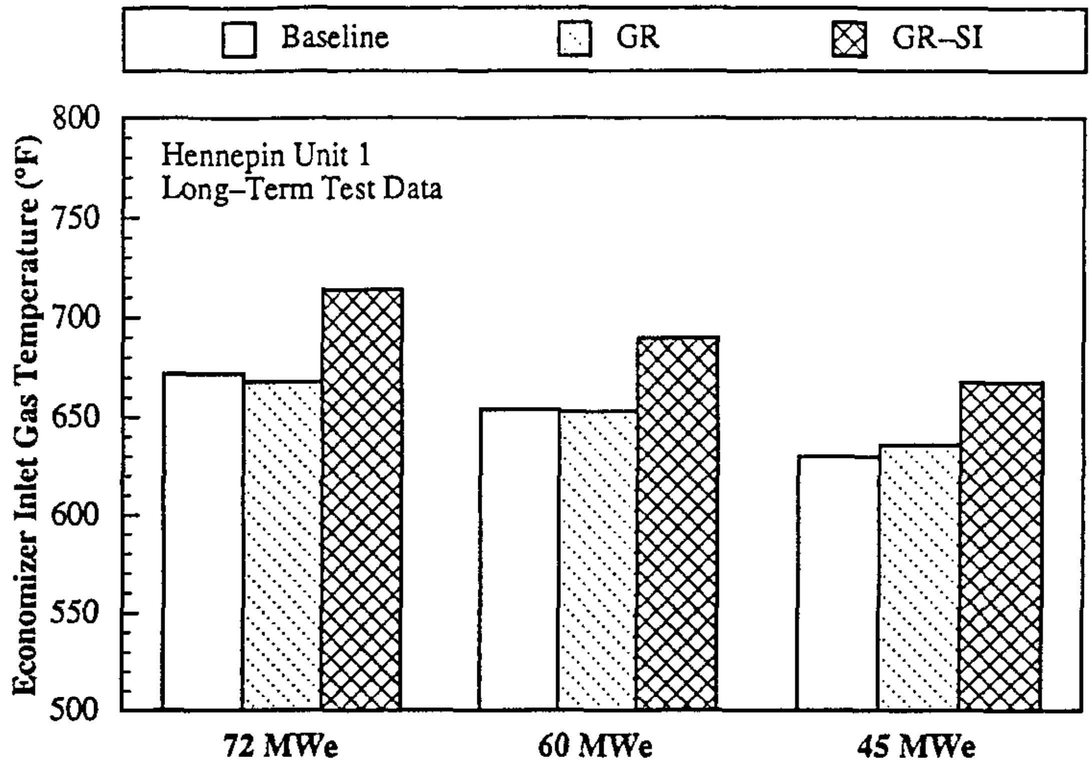


Figure 8–9a. Impact of Long-Term testing on economizer inlet gas temperature

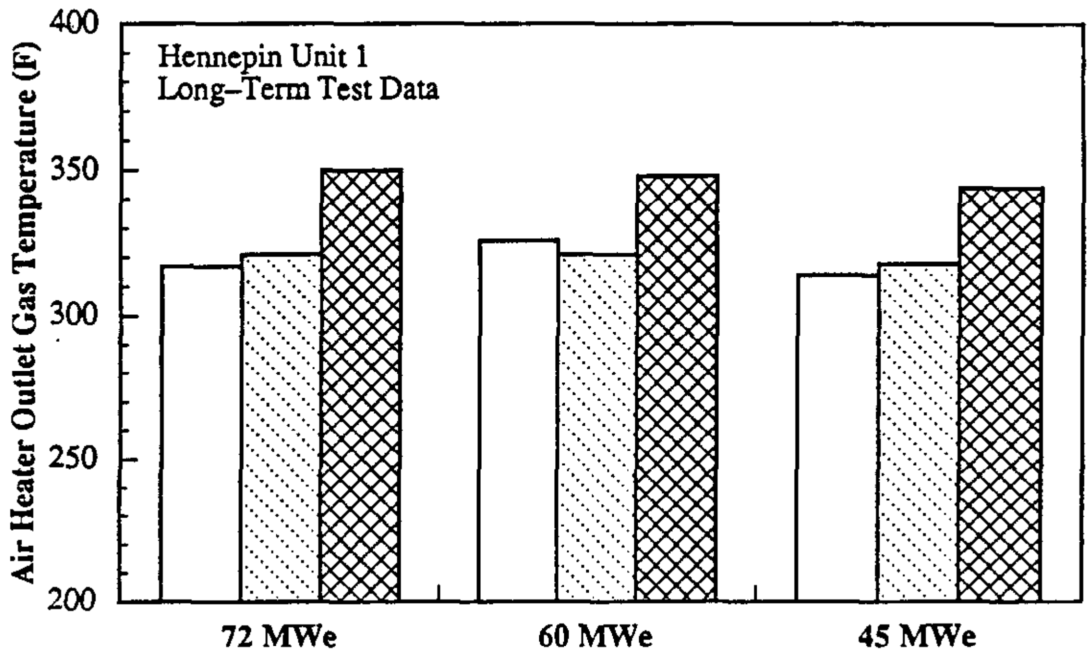


Figure 8–9b. Impact of Long-Term testing on air heater outlet gas temperature

at 72 MW_e. GR operation had virtually no impact on air heater gas outlet temperature; over the load range the temperatures were 318°F (159°C) to 321°F (161°C). These data are compared in Figure 8-9b.

8.5 Thermal Efficiency

A reduction in thermal efficiency was calculated for GR and GR-SI operation using ASME Power Test Code 4.1 (heat loss method). The reduction due to GR-SI was more significant than under GR operation. At full load, the thermal efficiency decreased from a baseline of 86.76% to 86.00% under GR, a reduction of 0.76%, and to 85.38% under GR-SI, a reduction of 1.38%. These were due to changes in three sources of heat loss: dry gas heat loss, moisture in fuel heat loss, and heat loss due to moisture from combustion. The decrease in heat absorption and the resulting rise in the flue gas temperature increases the dry gas heat loss - especially for GR-SI operation. Fuel switching, i.e. replacement of coal heat with heat from natural gas, results in a reduction in the fuel moisture heat loss. Since natural gas has a higher hydrogen to carbon ratio than coal, its combustion results in formation of more moisture and conequently higher moisture from combustion heat loss.

The largest change in thermal efficiency was due to the increase in moisture from combustion heat loss. GR and GR-SI operation with approximately 18% gas heat resulted in combustion moisture heat losses 5.05 and 5.15%, respectively. These may be compared to a combustion moisture heat loss of 3.89% from 100% coal firing. Fuel moisture heat loss during GR and GR-SI operation decreased, from a baseline of 1.74%, to 1.45%. As stated, the dry gas heat loss increased during GR-SI operation, from a baseline of 5.29%, to 5.78%. GR and GR-SI operation resulted in small reductions in ash combustible matter heat loss, 0.39 to 0.41% compared to 0.5% for baseline, while the radiation losses were the same. These results are summarized in the table below. Figure 8-10 shows the thermal efficiencies at low, mid and high loads. In general, the unit was able to generate the necessary power albeit with a slightly lower efficiency.

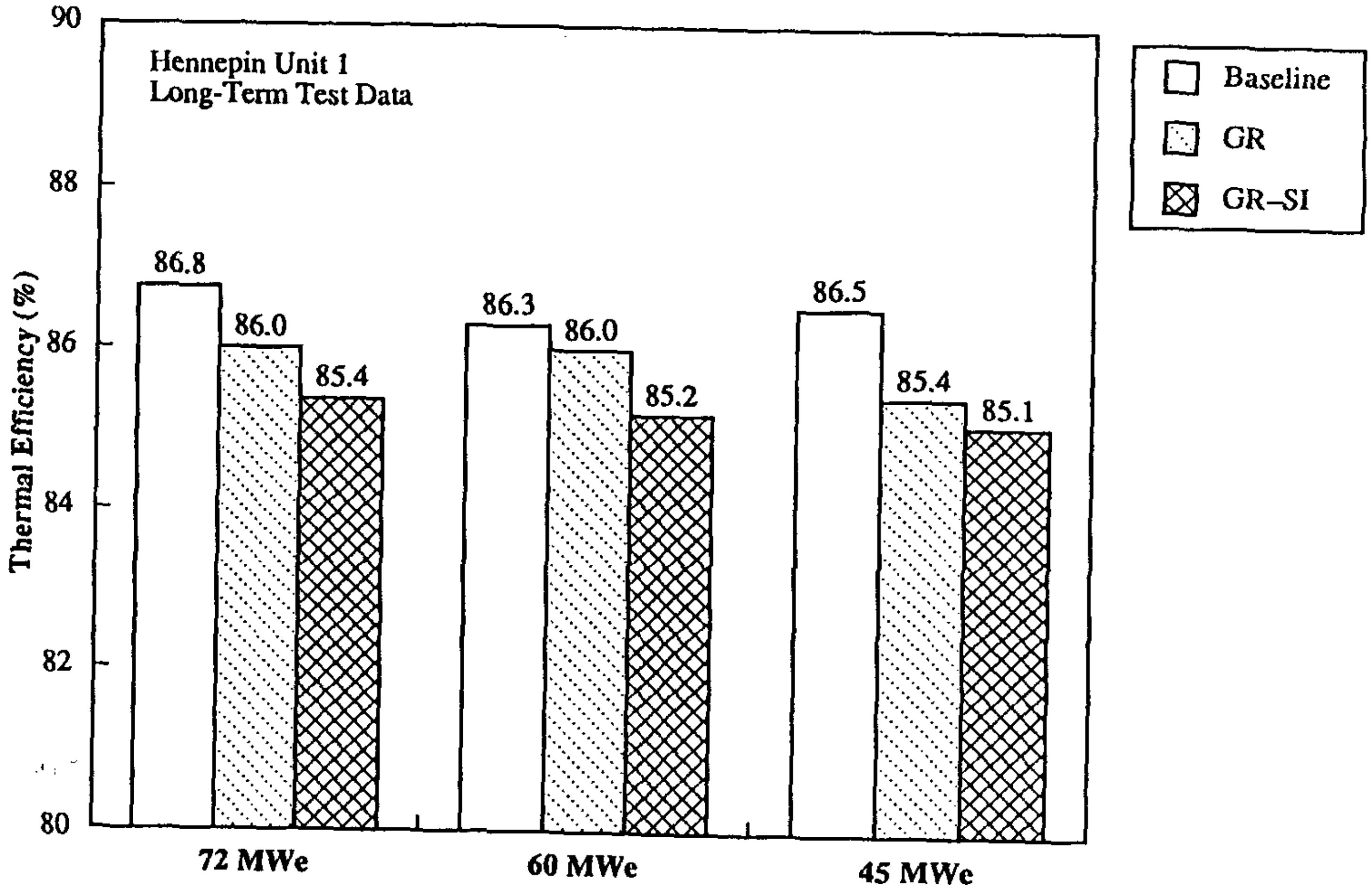


Figure 8-10. Thermal efficiency during Long-Term Testing

	Baseline	GR	GR-SI
Dry Gas Loss (%)	5.29	5.27	5.78
Moisture in Fuel Loss (%)	1.74	1.45	1.45
Moisture from Combustion Loss (%)	3.89	5.05	5.15
Combustible in Refuse Loss (%)	0.50	0.39	0.33
Radiation & Unmeasured Losses (%)	1.88	1.88	1.88
Total Losses (%)	13.25	13.99	14.62
Thermal Efficiency (%)	86.76	86.00	85.38

8.6 Carbon in Ash

Limited Loss On Ignition (LOI) data were taken during long-term GR-SI testing, while extensive measurements were taken during parametric testing, in 1991. The amount of carbon in ash generally depends on combustion conditions in the lower furnace. These include gas temperature, which varies with unit load, and primary zone stoichiometroc ratio. Other factors may impact carbon in ash, such as coal fineness and wetness. As a result of these effects, there was considerable variation in LOI throughout the testing. Generally, the LOI is less than 5%, with some cases below 1% and some extreme cases above 7%. Some results from parametric testing in 1991 are presented in Table 8-5 The data presented are for operation at loads from 45 to 70 MW_e and primary zone stoichiometric ratio as low as 1.07.

8.7 Heat Rate

A common parameter used to quantify Hennepin Unit 1 performance is the net heat rate. The design net heat rate for Hennepin Unit No. 1 is 10,338 Btu/kWh (10,908 kJ/kWh) at 75 MW_e.

During long-term testing, the baseline net heat rate averaged 10,340 Btu/kWh (10,910

TABLE 8-5. ASH LOI MEASUREMENTS.

Date	Test Condition	Location	Load MWe	Primary Zone SR	LOI (%)
11/12/91	GR	Economizer	45	1.11	3.89
11/12/91	GR	Economizer	45	1.11	3.21
11/13/91	GR	Economizer	45	1.08	3.91
11/13/91	GR	Economizer	45	1.08	3.25
11/14/91	GR	Economizer	45	1.07	6.65
11/14/91	GR	Economizer	45	1.07	8.24
11/18/91	GR	Economizer	45	1.08	5.24
11/18/91	GR	Economizer	45	1.08	4.57
11/18/91	GR	Economizer	45	1.07	3.24
11/18/91	GR	Economizer	45	1.07	4.79
12/2/91	GRSI	Economizer	45	1.07	7.24
12/2/91	GRSI	Economizer	45	1.07	0.08
12/5/91	GRSI	Economizer	45	1.09	0.58
12/9/91	Baseline	Economizer	70	1.09	3.20
12/9/91	Baseline	Economizer	70	1.13	2.19
12/11/91	SI	Economizer	70	1.15	1.57
12/11/91	SI	Economizer	70	1.17	0.52
12/12/91	GR	Economizer	70	1.08	3.52
12/12/91	GR	Economizer	70	1.07	2.97
12/16/91	GRSI	Economizer	70	1.06	4.94
12/16/91	GRSI	Economizer	70	1.06	1.00

kJ/kWh) at 72 MW_e.

The net heat rate under baseline, GR, SI and GR-SI operation are compared in Figure 8-11. During GR, the net heat rate increased by 88 Btu/kWh to 279 Btu/kWh (93 to 294 kJ/kWh), over the load range. The heat rate increase at full load was 0.85% of the baseline while at 45 MW_e it was 2.67%. During GR-SI operation, the net heat rate increased by 169 Btu/kWh to 260 Btu/kWh (178 to 274 kJ/kWh). At full load, the net heat rate increased by 1.63% and at 45 MW_e by 2.48. The increase in heat rate under GR and GR-SI operation is a reflection of changes in boiler thermal efficiency, steam temperatures, attemperation flow rates, and auxiliary power.

8.8 Sootblowing

The retrofit of the GR-SI system to Hennepin Unit 1 required attention be given to several areas of unit operation. Among these was sootblowing, used to maintain heat transfer surfaces free of sorbent and ash deposits. Figure 8-12 shows that the use of sootblowers at 72 MW_e increased from 7% of the time during baseline operation to 36% of the operating time during GR-SI operation. GR-SI resulted in an increase in sootblowing over the range of loads with a minimum of 21% of the time at 45 MW_e, compared to a maximum of 14% during baseline operation. Optimization of sootblowing cycles is discussed in Section 10 of this report.

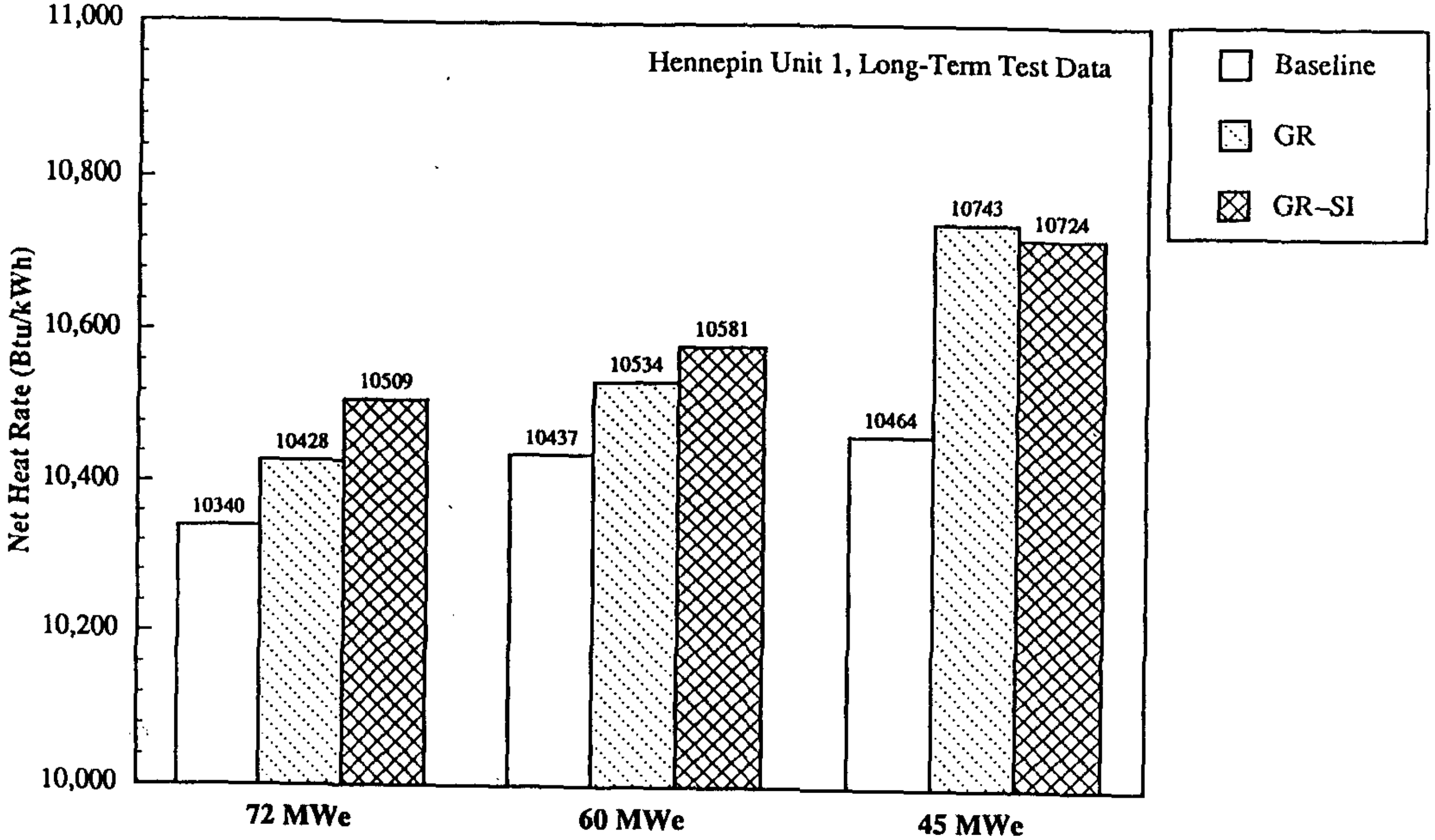


Figure 8–11. Impact of GR, SI and GR-SI on net unit heat rate

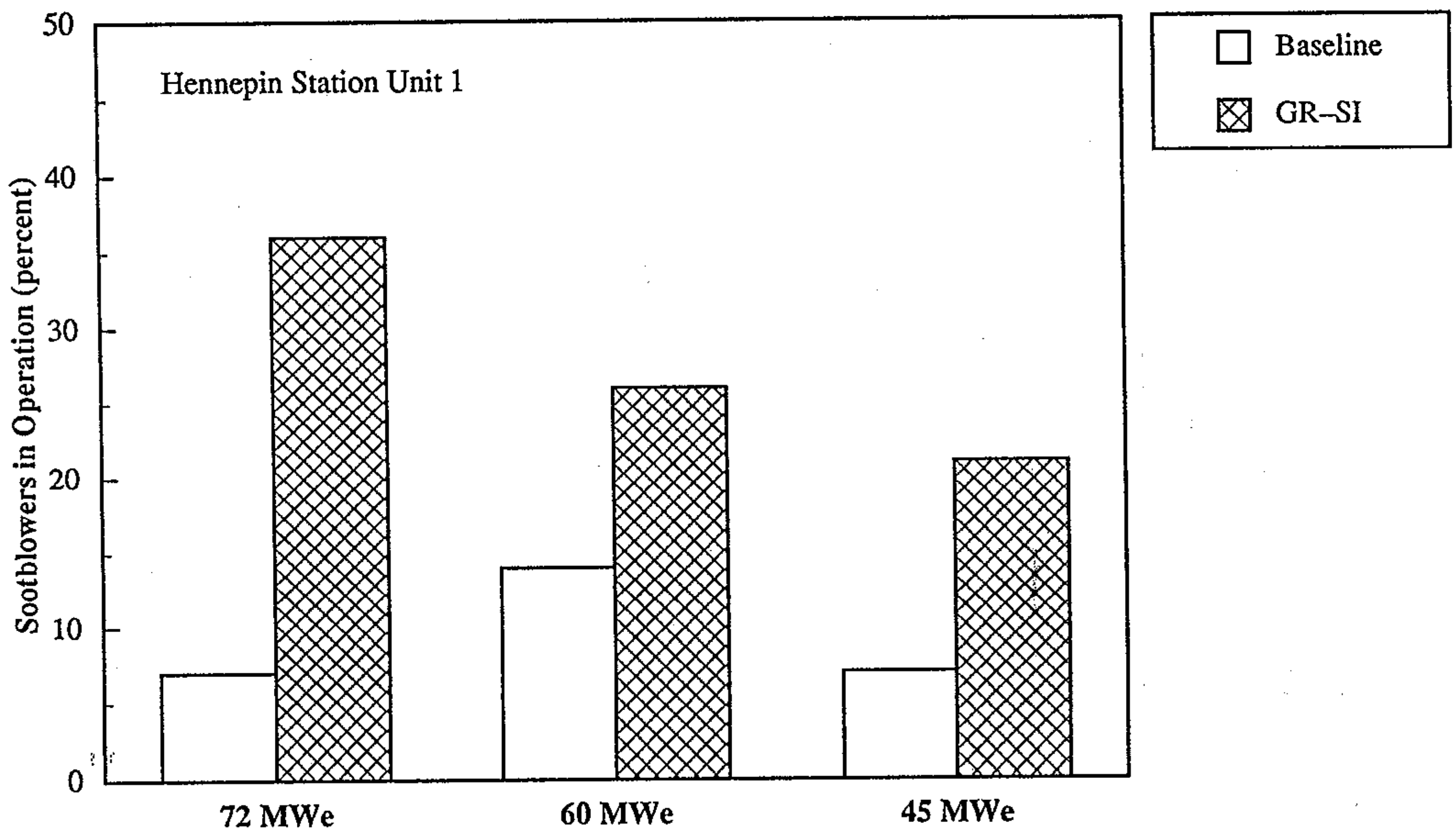


Figure 8–12. Sootblower usage during Long–Term GR-SI testing

9.0 ADVANCED SORBENTS

The GR-SI demonstration was conducted primarily with the conventional sorbent, Linwood hydrated lime. At the conclusion of long-term GR-SI testing, three advanced sorbents were evaluated. Two sorbents containing proprietary agents were prepared by EER and High Surface Area Hydrated Lime (HSAHL) sorbent was provided by the Illinois State Geological Survey (ISGS). The effectiveness of these sorbents in SO_2 removal was evaluated over a wide range of operating conditions. The impacts of load, burner tilt angle, and GR operation with SI were evaluated. Testing in a 1 10^6Btu/hr (290 kJ/s) Boiler Simulator Furnace (BSF) indicated that calcium utilizations depended significantly on injection temperature. Therefore, operating load, GR operation and SI configuration were expected to impact the performance of these sorbents. Each of these parameters has an impact on the furnace temperature to which the sorbent is initially exposed. One of the sorbents has NO_x reduction capability; its performance in this area was evaluated.

9.1 Overview of Advanced Sorbent Performance

Tables 9-1 to 9-3 summarize the results of the short test series with PromiSORB™ A, PromiSORB™ B, and HSAHL. Parametric tests were used to evaluate load, burner tilt, SI only (listed as PS for Promoted Sorbent) or GR with SI (denoted as GR-PS), injection configuration (i.e. injectors in service) and excess O_2. The sorbent SO_2 reduction and calcium utilization for each sorbent for loads of 45 to 50 MW_e are plotted in Figures 9-1 and 9-2. The variations in performance of each sorbent are likely due to variations in boiler conditions such as excess air and to sorbent purity. The sorbent most effective in SO_2 reduction was PromiSORB™ B, followed by HSAHL, PromiSORB™ A, and conventional Linwood hydrated lime. At a Ca/S molar ratio of 1.75, which was the set-point Ca/S molar ratio for long-term GR-SI demonstration, the nominal performance of the sorbents may be estimated from the figures. The sorbent SO_2 reduction and calcium utilization for the three advanced sorbents are summarized and compared with the conventional sorbent, as follows:

TABLE 9–1. SUMMARY OF PROMISORB™ A PERFORMANCE

Date	Test ID	Load (MWe)	Burner Tilt (Deg)	Plant O_2 (%)	Ca/S Molar Ratio	Sorbent SO_2 Reduction (%)	Ca Utilization (%)	Total SO_2 Reduction (%)	Sorbent NO_x Reduction (%)	
12/2/92	GRPS-201	60	26.7	2.71	1.64	35.9	21.9	46.7	16.8	
12/2/92	GRPS-202	60	15.3	2.77	1.65	39.6	24.0	49.8	25.8	
12/2/92	GRPS-203	60	0.5	2.79	1.65	45.3	27.5	54.5	31.8	
12/2/92	GRPS-204	60	-10.5	3.30	1.63	48.6	29.8	57.2	30.9	
12/2/92	GRPS-205	60	-19.5	3.22	1.64	47.8	29.2	56.6	32.1	
12/2/92	GRPS-206	60	-15.0	3.28	1.66	48.3	29.1	57.0	31.1	
12/2/92	GRPS-101	70	15.2	2.52	1.59	40.1	25.2	50.2	20.2	
12/2/92	GRPS-301	45	26.9	2.73	1.79	49.0	27.4	57.6	35.3	
12/2/92	GRPS-302	45	26.9	3.69	1.54	52.4	34.1	60.4	22.4	
Average		58	7.4	3.00	1.64	45.2	27.6	54.4	27.4	
12/3/93	GRPS-303	45	26.9	3.07	1.71	41.4	24.3	50.7	31.0	
12/3/93	GRPS-304	45	20.3	2.96	1.58	46.3	29.3	54.9	35.0	
12/3/93	GRPS-305	45	20.3	3.73	1.56	50.6	32.5	58.5	18.3	
12/3/93	GRPS-306	45	20.3	3.48	1.38	44.5	32.2	54.1	28.3	
12/3/93	GRPS-307	45	20.3	3.38	2.13	58.7	27.6	65.3	31.3	
Average		45	21.6	3.32	1.67	48.3	29.2	56.7	28.8	
12/4/92	PS-301	45	26.9	4.25	1.36	41.6	30.6	41.6	17.1	
12/4/92	PS-302	45	17.4	4.34	1.35	42.1	31.1	42.1	22.4	
12/4/92	PS-303	45	26.9	4.04	1.56	49.4	31.7	49.4	16.9	
12/4/92	PS-304	45	26.9	4.06	1.73	46.9	27.2	46.9	17.4	
12/4/92	PS-305	45	26.9	3.88	1.93	50.7	26.3	50.7	19.5	
12/4/92	PS-306	45	26.9	3.96	2.17	53.8	24.8	53.8	20.0	
Average		45	25.3	4.09	1.68	47.4	28.6	47.4	18.9	
12/7/92	PS-307	45	26.9	3.14	1.51	38.2	25.2	38.2	17.1	
12/7/92	PS-308	45	26.9	3.26	1.59	45.2	28.4	45.2	21.3	
12/7/92	PS-309	45	26.9	3.24	1.58	50.2	31.7	50.2	24.4	
12/7/92	PS-310	45	26.9	3.12	1.54	49.9	32.5	49.9	24.9	
12/7/92	PS-311	45	26.9	3.55	1.59	48.2	30.2	48.2	20.7	*
12/7/92	PS-312	45	26.9	3.45	1.56	45.7	29.3	45.7	16.8	*
12/7/92	PS-313	45	26.9	3.49	1.62	41.1	25.3	41.1	15.2	**
12/7/92	PS-314	45	26.9	3.30	1.54	42.6	27.7	42.6	19.7	**
12/7/92	PS-315	45	26.9	3.35	1.58	43.1	27.3	43.1	19.7	**
Average		45	26.9	3.32	1.57	44.9	28.6	44.9	20.0	

TABLE 9–1. SUMMARY OF PROMISORB™ A PERFORMANCE (CONTINUED)

Date	Test ID	Load (MWe)	Burner Tilt (Deg)	Plant O_2 (%)	Ca/S Molar Ratio	Sorbent SO_2 Reduction (%)	Ca Utilization (%)	Total SO_2 Reduction (%)	Sorbent NO_x Reduction (%)	
12/8/92	PS–316	45	26.9	3.81	1.53	49.4	32.3	49.4	15.2	*
12/8/92	PS–317	45	19.9	3.89	1.56	47.9	30.6	47.9	8.6	*
12/8/92	PS–318	45	22.8	3.75	1.59	51.9	32.8	51.9	9.9	*
12/8/92	PS–319	45	22.8	3.84	1.57	49.5	31.5	49.5	5.8	*
12/8/92	PS–320	45	22.8	3.62	1.73	54.7	31.6	54.7	9.2	*
12/8/92	PS–321	45	22.8	3.67	1.96	57.8	29.5	57.8	10.4	*
12/8/92	PS–322	45	22.8	3.61	2.13	60.9	28.5	60.9	11.2	*
Average		45	23.0	3.74	1.72	53.2	31.0	53.2	10.0	
12/9/92	PS–102	70	0.6	3.35	1.62	37.8	23.3	37.8	30.0	
12/9/92	PS–103	70	0.6	3.47	1.60	33.9	21.1	33.9	24.8	
12/9/92	PS–104	70	0.6	3.60	1.50	34.4	23.0	34.4	19.3	
12/9/92	PS–105	70	0.6	3.94	1.61	38.3	23.9	38.3	12.6	
12/9/92	PS–106	70	0.6	3.88	1.79	39.7	22.2	39.7	10.2	
12/9/92	PS–107	70	0.6	3.80	1.92	45.3	23.6	45.3	15.5	
12/9/92	PS–108	70	0.6	4.14	2.21	55.6	25.2	55.6	22.2	
12/9/92	PS–109	70	0.6	4.09	2.46	57.5	23.4	57.5	21.8	
Average		70	0.6	3.78	1.84	42.8	23.2	42.8	19.6	
12/10/92	PS–323	46	26.9	4.31	1.95	50.6	25.9	50.6	17.2	
12/10/92	PS–324	46	26.9	4.11	2.45	56.3	23.0	56.3	20.2	
12/10/92	PS–401	31	26.9	3.69	1.45	36.8	25.3	36.8	36.4	
12/10/92	PS–402	31	26.9	3.44	1.61	41.3	25.6	41.3	45.0	
12/10/92	PS–403	31	26.9	3.35	2.05	50.9	24.8	50.9	48.1	
Average		37	26.9	3.78	1.90	47.2	24.9	47.2	33.4	

*: 4 front–wall injectors
**: 2 front–wall & 2 side–wall injectors
All other tests: 6 injectors

TABLE 9–2. SUMMARY OF PROMISORB™ B PERFORMANCE.

Date	Test ID	Load (MWe)	Burner Tilt (Deg)	Plant O_2 (%)	Ca/S Molar Ratio	Sorb SO_2 Reduction (%)	Ca Util. (%)	Tot SO_2 Reduction (%)
12/14/92	GRPS2–209	60	26.9	2.79	1.34	45.0	33.5	53.5
12/14/92	GRPS2–210	60	20.2	2.81	1.45	50.1	34.6	57.8
12/14/92	GRPS2–211	60	10.3	3.08	1.44	54.1	37.6	61.2
12/14/92	GRPS2–212	60	0.3	3.37	1.44	53.3	36.9	60.5
12/14/92	GRPS2–213	60	26.9	3.05	1.82	60.2	33.0	66.3
12/14/92	GRPS2–110	70	20.8	2.59	1.54	43.5	28.3	52.2
Average		62	17.6	2.95	1.51	51.0	34.0	58.6
12/15/92	GRPS2–351	45	26.9	3.69	1.29	50.6	39.1	57.1
12/15/92	GRPS2–352	45	26.9	3.48	1.70	62.9	37.0	67.8
12/15/92	GRSP2–353	45	26.9	3.54	2.24	63.5	28.3	68.3
12/15/92	GRPS2–354	45	26.9	3.63	2.46	64.4	26.2	69.0
12/15/92	GRPS2–355	45	26.9	3.74	2.43	72.9	30.0	76.4
Average		45	26.9	3.62	2.02	62.9	32.1	67.7
12/16/92	PS2–360	45	26.9	2.90	1.56	61.3	39.3	61.3
12/16/92	PS2–361	45	26.9	3.37	1.54	60.3	39.3	60.3
12/16/92	PS2–362	45	26.9	4.63	1.54	65.1	42.2	65.1
12/16/92	PS2–363	45	20.4	4.41	1.49	63.5	42.6	63.5
12/16/92	PS2–364	45	10.1	4.23	1.58	67.9	43.1	67.9
12/16/92	PS2–365	45	-0.2	3.93	1.55	70.2	45.3	70.2
12/16/92	PS2–366	45	-10.3	4.27	1.57	68.5	43.7	68.5
Average		45	14.4	3.96	1.55	65.3	42.2	65.3

TABLE 9–2. SUMMARY OF PROMISORB™ B PERFORMANCE (CONTINUED)

Date	Test ID	Load (MWe)	Burner Tilt (Deg)	Plant O_2 (%)	Ca/S Molar Ratio	Sorb SO_2 Reduction (%)	Ca Util. (%)	Total SO_2 Reduction (%)
12/17/92	PS2–370	45	10.2	3.45	1.01	41.2	40.6	41.2
12/17/92	PS2–371	45	10.2	3.44	1.53	62.2	40.6	62.2
12/17/92	PS2–372	45	10.2	3.51	1.55	63.8	41.1	63.8
12/17/92	PS2–373	45	10.2	3.24	1.57	59.4	37.9	59.4
12/17/92	PS2–374	45	10.2	3.48	1.35	66.0	48.9	66.0
Average		45	10.2	3.42	1.40	58.5	41.8	58.5
12/18/92	PS2–380	42	0.5	4.47	2.59	81.2	31.4	81.2
12/18/92	PS2–381	42	0.5	4.48	1.63	56.4	34.6	56.4
12/18/92	PS2–382	42	0.5	3.55	1.50	58.8	39.3	58.8
Average		42	0.5	4.17	1.91	65.5	35.1	65.5

TABLE 9–3. SUMMARY OF HSAHL PERFORMANCE

Date	Test ID	Load (MWe)	Plant O_2 (%)	Gas Input (%)	Burner Tilt (Deg)	Ca/S Molar Ratio	Sorbent SO_2 Reduction (%)	Ca Utilization (%)	Total SO_2 Reduction (%)
1/13/93	ISGS–21	70	2.83	18.5	-21.1	1.36	51.60	37.94	60.3
1/13/93	ISGS–22	70	2.59	18.4	-27.1	1.34	48.02	35.84	57.3
1/13/93	ISGS–23	70	3.41	18.7	-9.2	1.35	49.21	36.45	58.3
Average		70	2.94	18.5	-19.1	1.35	49.61	36.74	58.6
1/14/93	ISGS–10	45	2.96	17.9	26.9	1.37	50.09	36.56	59.1
1/14/93	ISGS–11	50	3.81	17.9	26.9	1.31	52.99	40.45	61.5
1/14/93	ISGS–12	50	3.12	18.0	16.4	1.32	53.30	40.38	61.7
1/14/93	ISGS–13	50	3.41	17.7	10.5	1.29	51.93	40.26	60.6
1/14/93	ISGS–14	50	3.08	17.9	14.7	1.50	59.50	39.67	66.8
1/14/93	ISGS–15	50	3.30	18.0	13.2	1.50	56.90	37.93	64.7
1/14/93	ISGS–16	50	2.71	18.0	14.8	1.64	57.43	35.02	65.1
Average		49	3.20	17.9	17.6	1.42	54.59	38.61	62.8
1/15/93	ISGS–40	45	3.02	0.0	26.9	1.27	48.83	38.45	48.8
1/15/93	ISGS–35	55	2.40	0.0	26.9	1.09	46.96	43.08	47.0
1/15/93	ISGS–36	55	3.35	0.0	26.9	1.30	47.68	36.68	47.7
1/15/93	ISGS–37	55	2.61	0.0	26.9	1.27	54.40	42.83	54.4
Average		53	2.85	0.0	26.9	1.23	49.47	40.26	49.5

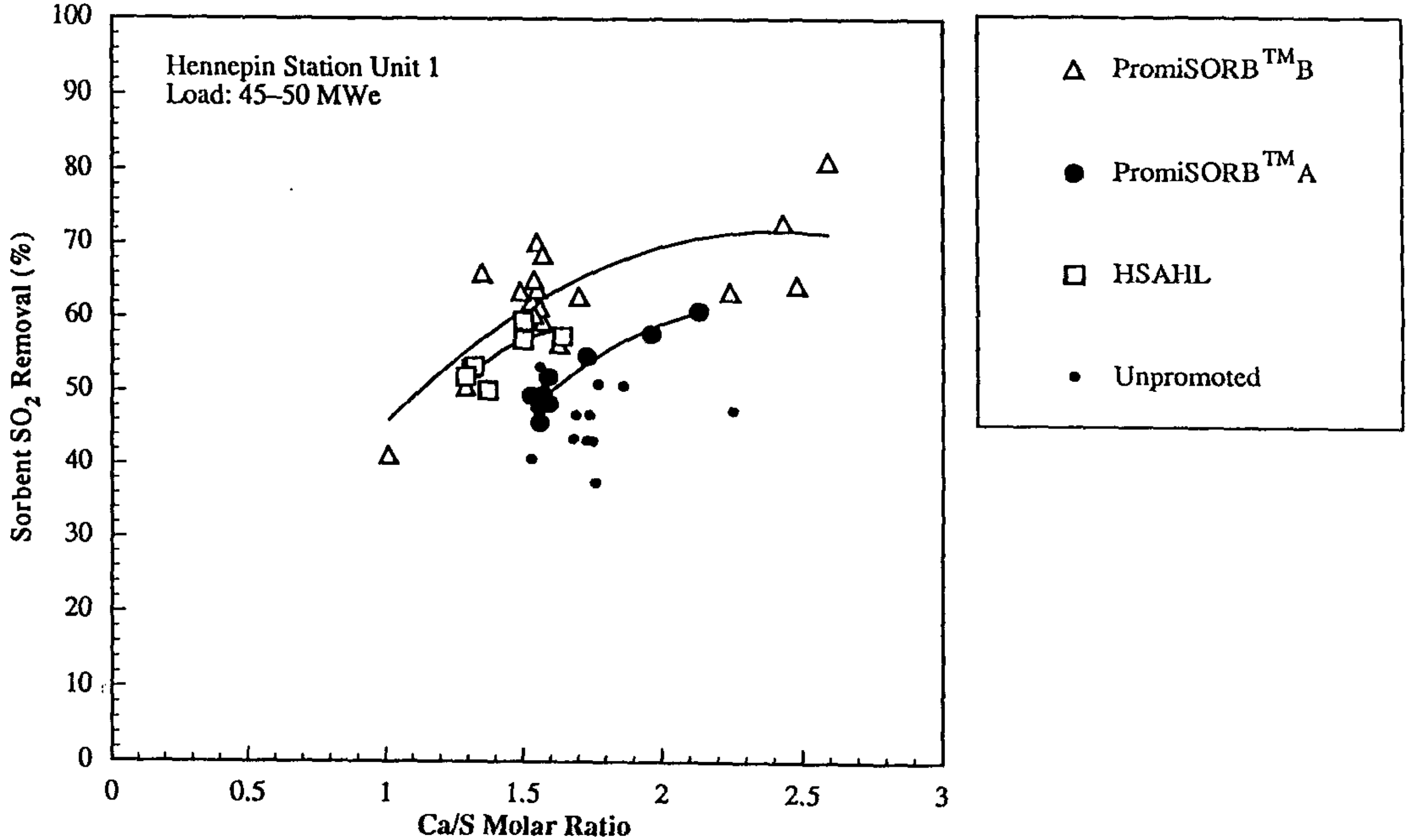


Figure 9–1. Sorbent SO_2 reduction for the four sorbents as a function of Ca/S molar ratio

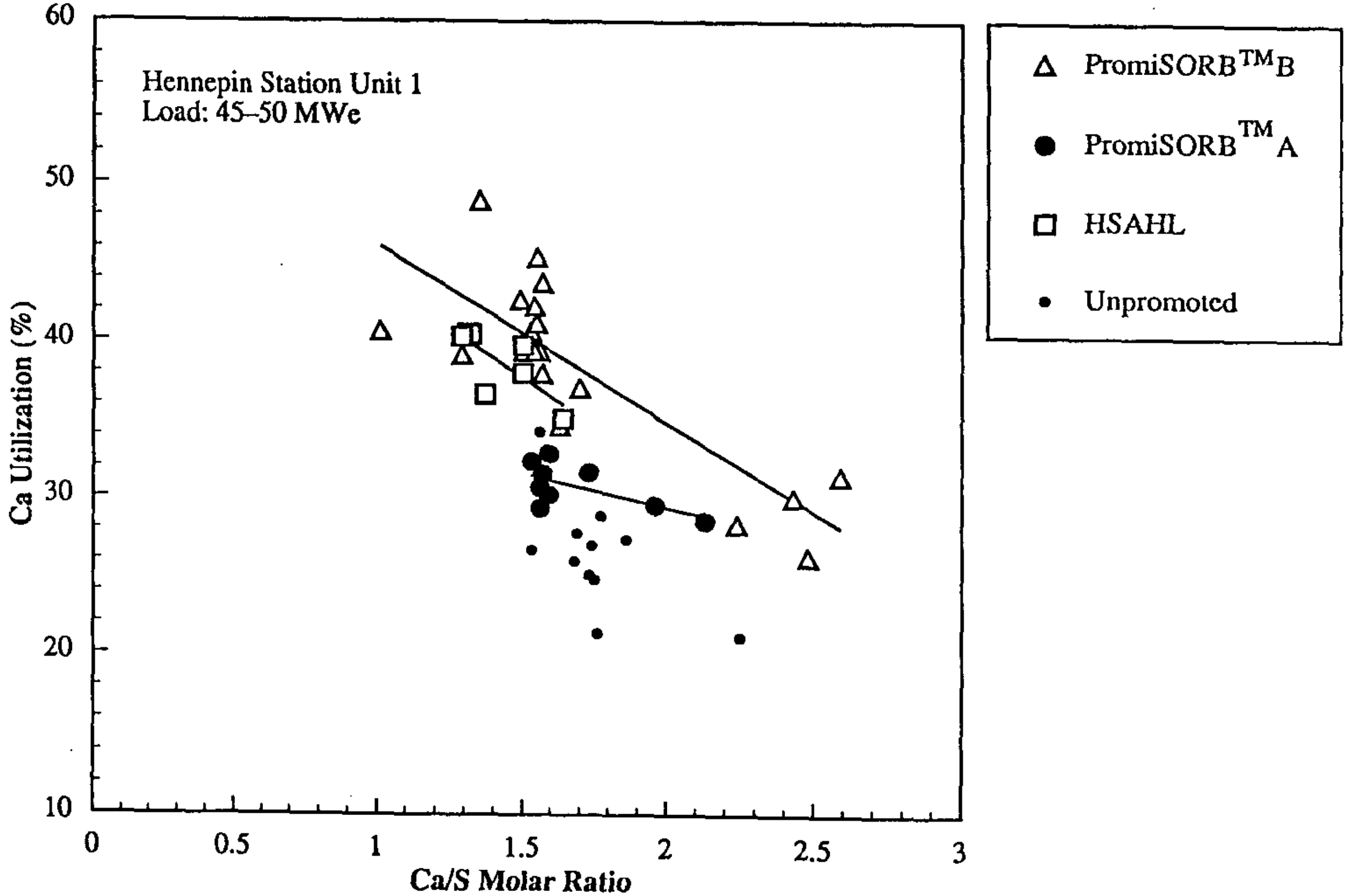


Figure 9–2. Calcium utilization of the four sorbents as a function of Ca/S molar ratio

Sorbent	PromiSORB™ B	HSAHL	PromiSORB™ A	Linwood
SO_2 Capture (%)	66	60	53	46
Calcium Utilization (%)	38	34	31	26

These data were corrected for calcium purity, which ranged from 88 to 95% for the four sorbents. A peak SO_2 capture of 80% was achieved with PromiSORB™ B, with a Ca/S molar ratio of 2.6.

9.2 PromiSORB™ B Performance

PromiSORB™ B injection resulted in significantly higher SO_2 reduction and corresponding sorbent utilization, than measured for the conventional sorbent. However, its performance was affected by GR operation and load. Optimum performance was achieved under low load without GR, i.e. calcium utilizations were lower during GR-PS operation than when operating PS only. The average calcium utilizations during the first two days of GR-PS testing were 34.0 and 32.1%, at Ca/S molar ratios of 1.51 and 2.02, respectively. The average loads were 62 and 45 MW_e, respectively, and gas heat input ranged from 17.5 to 18.7%. These utilizations may be compared to levels of 42.2 and 41.8% for the subsequent two days of PS testing, at Ca/S molar ratios of 1.55 and 1.40, respectively. These tests were conducted at 45 MW_e load. A peak calcium utilization of 48.9% was determined for PS operation at a Ca/S molar ratio of 1.35 and 45 MW_e load. The maximum SO_2 reduction of 81.2% was achieved at a Ca/S molar ratio of 2.59.

An increase in calcium utilization with excess O_2 was also observed. Tests PS2-361 and PS2-362 were conducted under similar operating conditions (load, Ca/S, burner tilt), but PS2-362 was conducted at an excess O_2 of 4.63%, in comparison to 3.37% for PS2-361. PS2-362 had an improved calcium utilization (42.2 vs. 39.3%) and SO_2 capture (65.1 vs. 60.3%). The impacts of GR, load, and excess O_2 may be attributed to the gas temperature at the SI point. The results are summarized in the following table, in which the gas heat input for GR-PS operation was in the 17 to 19% range.

PromiSORB™ B Performance

	Load (MW_e)	Ca/S Molar Ratio	Calcium Utilization (%)
GR-PS	60	1.51	34
GR-PS	45	1.70	37
PS	45	1.54	42

9.3 HSAHL Performance

The performance of HSAHL was impacted by GR and to a smaller extent by load. Testing in the BSF indicated that the injection temperature has a significant impact on the utilization of HSAHL. The evaluation in the Hennepin unit also showed a temperature dependence. Testing of HSAHL with GR at 70 MW_e resulted in an average calcium utilization of 36.7%, at a Ca/S of 1.35. Testing at 50 MW_e with GR and at 45 to 55 MW_e without GR resulted in calcium utilizations of 38.6 and 40.3%, respectively. The average Ca/S molar ratios for these tests were 1.42 and 1.23, for testing with and without GR, respectively. Since both application of GR and operation at high load result in an increase in the upper furnace gas temperature, the results indicate that higher gas temperature reduces sorbent utilization. The impacts of load and GR are summarized in the following table.

HSAHL Performance

	Load (MW_e)	Ca/S Molar Ratio	Calcium Utilization (%)
GR-HSAHL	70	1.35	37
GR-HSAHL	49	1.42	39
HSAHL	53	1.23	40

The injection of HSAHL was limited by its low density, of approximately 20 lb/ft^3 (320 kg/m^3), in comparison to the optimum density of 30 to 35 lb/ft^3 (481 to 561 kg/m^3) for sorbent feed pump operation. This limited the Ca/S ratio to a maximum of 1.64, at which a sorbent SO_2 removal of 57.4% was obtained. The maximum sorbent SO_2 reduction with

HSAHL was 59.5% at a Ca/S of 1.50. The excess O_2 level may be a significant parameter in calcium utilization/SO_2 reduction. Tests ISGS-36 and ISGS-37 were conducted under similar operating conditions (no gas input, burner tilt = 26.9 degrees, Ca/S = 1.27 to 1.30) but different levels of excess O_2 (ISGS-36 = 3.35%, ISGS-37 = 2.61%). A difference in calcium utilization of 5.6% and SO_2 reduction of 6.2% was evident, with the more favorable results at low excess O_2. The HSAHL utilizations were corrected to an average calcium purity of 88%.

9.4 PromiSORB™ A Performance

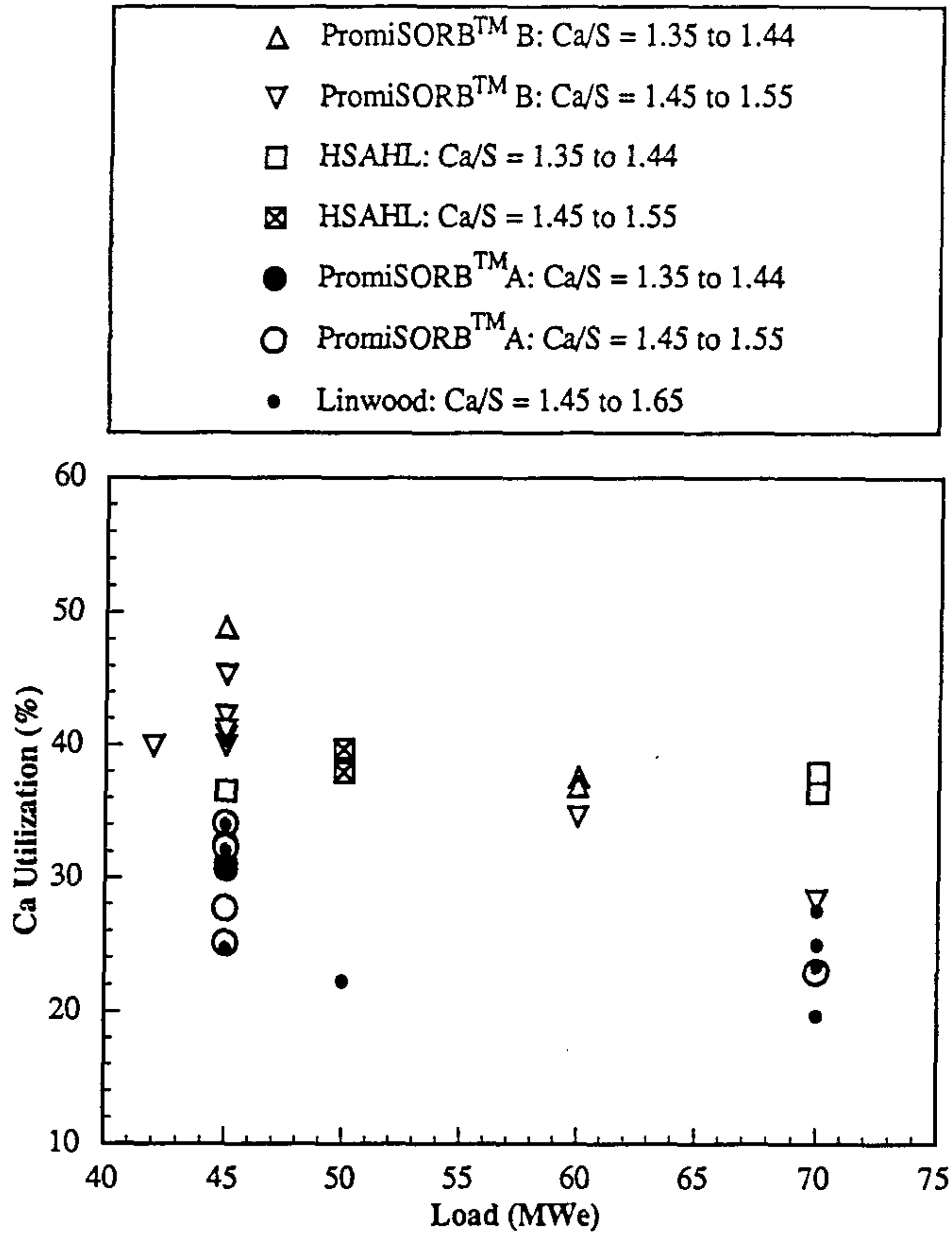
Evaluation of PromiSORB™ A at Hennepin Unit 1 indicates that its performance is intermediate between HSAHL and the conventional Linwood hydrated lime, with utilizations typically in the 25 to 33% range. GR does not appear to negatively impact sorbent utilization of PromiSORB™ A, as was evident in PromiSORB™ B data. Average calcium utilizations during the first two days of GR-PS testing were 27.6 and 29.2%, for Ca/S of 1.64 and 1.67 respectively. This may be compared to average calcium utilization of 28.6%, during the following two days of PS testing, at average Ca/S of 1.68 and 1.57 and 45 MW_e load. One parameter which appears to have a marked impact on calcium utilization is the use of only the 4 front-wall injectors. Using just the front-wall injectors resulted in an average calcium utilization of 31.0%, at an average Ca/S of 1.71. This result may be due to rapid quenching of the side-wall jets. The peak calcium utilization with PromiSORB™ A is 32.8%, resulting in a sorbent SO_2 capture of 51.9%. Some load effect is evident; at 70 MW_e, PS calcium utilization was lower than for 45 MW_e. A difference in calcium utilization of 5% is evident between 70 and 45 MW_e with the same SI configurations.

Significant reduction in NO_x emissions was measured with injection of PromiSORB™ A. Sorbent NO_x reductions were in the 10 to 35% range, with 20% NO_x reduction typically achieved. A decrease in NO_x emissions was expected from injection of PromiSORB™ A, from the action of a proprietary agent. The performance of PromiSORB™ A data is summarized below:

PromiSORB™ A Performance

	Load (MW$_e$)	Ca/S Molar Ratio	Calcium Utilization (%)	Total NO_x Reduc. (%)
GR-PS	58	1.64	27.6	71.6
PS	70	1.84	23.2	19.6
GR-PS	45	1.67	29.2	71.6
PS	45	1.68	28.6	18.9

The load effect for all three advanced sorbents is illustrated in Figure 9-3. A stronger load effect is evident for PromiSORB™ A and PromiSORB™ B than for HSAHL. The performance of advanced sorbents in the Hennepin unit can be enhanced by altering the injection location.



Note: Hennepin Sorbent Injection System was designed to inject conventional sorbent

Figure 9-3. Effect of load on sorbent utilization

10.0 LONG-TERM GR-SI IMPACTS

The impacts of long-term GR-SI operation on various areas of boiler performance are discussed in this Section. Section 10.1 presents slagging and fouling observations made at many points in the boiler. Optimization of sootblower operation is discussed in Section 10.2. Sections 10.3 and 10.4 address the performance of the humidification system and the ESP. Sections 10.5 and 10.6 present data on impacts of GR-SI on tube wall thickness, as determined from three ultrasonic thickness (UT) inspections, and the results of the chimney inspection.

10.1 Impact of GR-SI on Slagging/Fouling

10.1.1 Summary of Slagging/Fouling Assessment

GR-SI operation did not exacerbate slagging in the furnace. Some buildup of slag in the lower furnace, from the top burner elevation to the OFA ports, was observed, but it was not excessive compared to that under baseline operation. Under full load GR-SI over a period of three hours, slag buildup of up to 2 1/2 inches (6 cm) was measured in the lower furnace. This may be compared to buildup of 1 to 3 inches (2.5 to 7.5 cm) at the furnace nose and 3 to 6 inches (7.5 to 15 cm) at the elevation of the wallblowers, observed after day-long baseline operation at full load. Wallblowing more frequently or with greater effectiveness (i.e. higher pressure) has been recommended to reduce slag buildup and to maintain clean GR injection nozzles during future operation.

An assessment of fouling of the convection pass, due to upper furnace SI, showed expected deposition trends. The fouling of each heat exchanger was evaluated through calculated cleanliness factors, which are the ratios of the actual heat transfer coefficients to those under baseline operation, and from observations made throughout the convective pass. These indicated that the secondary superheater and high temperature reheater were experiencing sorbent fouling, but increased heat absorption was taking place at the primary superheater and economizer. Boiler inspections revealed ash accumulations in several areas, due to either a lack of available sootblowers in these areas, insufficient frequency or duration of operation of sootblowers present, or large chunks of ash deposits lodged between the tube elements initiating significant ash accumulations. The back end of the reheater is an example of a location where accumulation was due to the former, while the first bundle of the primary superheater is an example of the latter. The use of sootblowers with greater frequency, resulted in the removal of ash deposits from several areas including the final superheat pendant (secondary superheater) and the top surface of the primary superheater.

10.1.2 Slagging/Fouling Trends

During the long-term GR-SI demonstration at Hennepin Unit 1, there were several opportunities to inspect the furnace slagging patterns and convection pass fouling. These inspections focused on determining the extent of slagging and fouling while operating GR-SI and checking for signs of excessive tubewall wastage. These observations have been supported by a photographic log of the boiler inspections and heat absorption data logged on the BPMS. The impact of GR-SI operation on tubewall wastage was evaluated with before/after UT measurements in the GR section of the furnace and the relevant convection pass sections.

Specific areas of the boiler which were identified as potential problem areas for increased slagging or fouling under GR-SI operation were closely monitored during the test program due to the following concerns:

- The slightly lower primary zone stoichiometric ratio and resulting higher gas temperature in that zone could exacerbate slagging in the lower furnace

- The reducing conditions in the reburning zone could promote slagging in this zone

- The injection of sorbent into the upper furnace may change both the amount and composition of the entrained particulate matter, especially in the convection sections of the boiler

In this section, the boiler inspections which were performed as well as the changes to the thermal performance and availability of Hennepin Unit 1 due to changes in deposition patterns, are discussed. There were a total of three major inspections of the boiler deposition patterns during the long-term testing program: in March, April, and October 1992, as well as numerous minor inspections which were conducted from time to time during the long-term testing program.

10.1.3 Furnace Slagging Observations

10.1.3.1 Waterwall Slagging Observations

The ash deposition patterns during Baseline, GR, GR-SI operation were comparable. During the 1988 baseline tests, baseline deposition patterns were observed and recorded during normal coal firing. The thickness of deposits varied with the furnace height, from 3 to 6 inches (8 to 15 cm) at the elevation of the wallblowers, to 1 inch (2.5 cm) at the economizer elevation. The phase progression of the ash along the furnace walls was typically wet (i.e. not hardened) to molten to dry.

A thorough observation of furnace deposition patterns was performed on 25 March, 1992 after GR-SI operation. The first observation was completed after the boiler had cycled off during the preceding night allowing some ash to shed off the furnace wall tubes. Figure 10-1 shows the deposition patterns which were recorded during the first two hours of GR-SI operation following the nightly off-cycle. Most of the deposits below the nose elevation were small deposits of fine ash particles which most likely consisted of particles with a very low melting point. The small molten particles impinge on the tubes and tend to resolidify as they come in contact with the relatively cooler wall. At the economizer level, there were

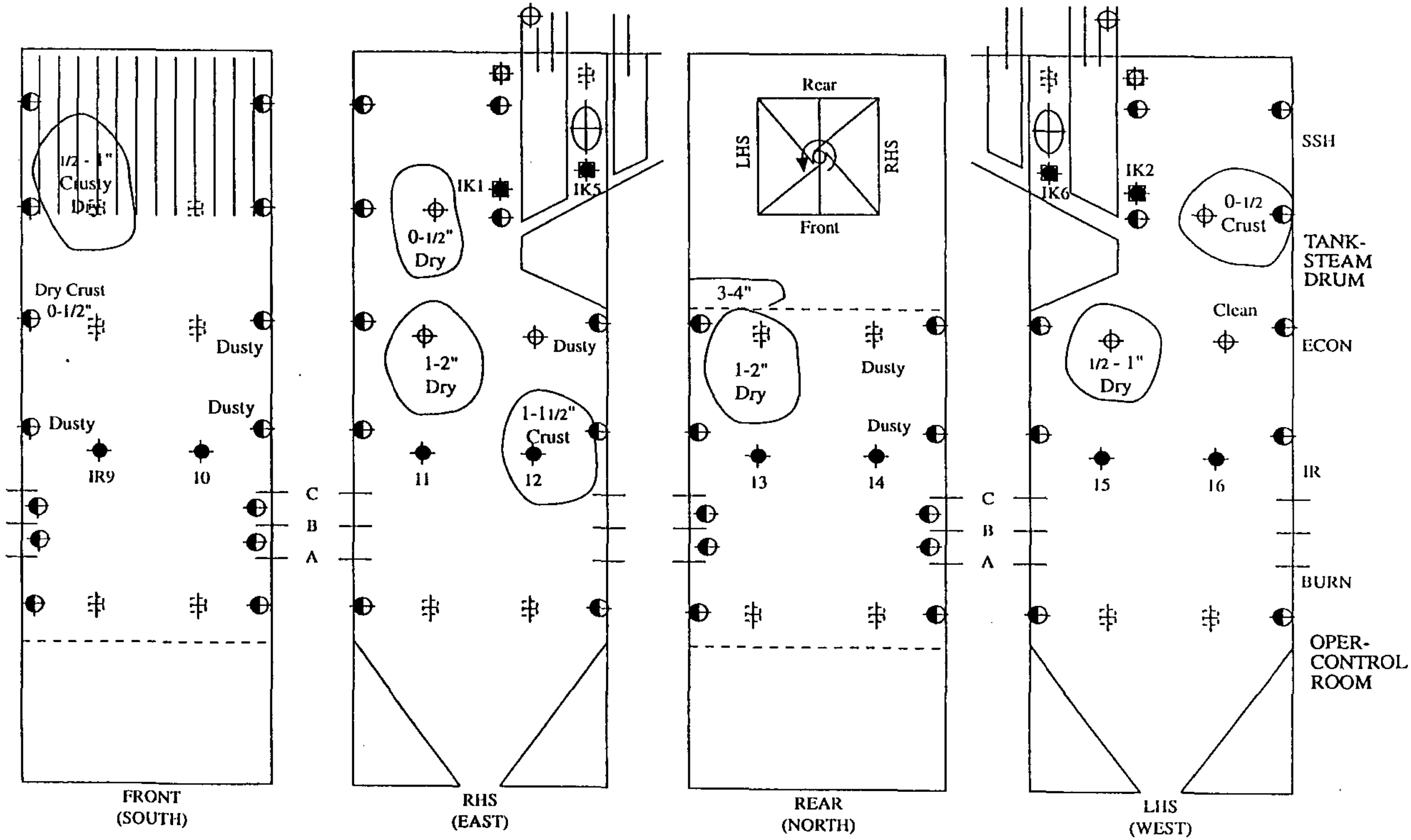


Figure 10-1. Furnace observations at 1130 hours on 25 March 1992

several scattered accumulations on the east, west, and north walls. The accumulations appeared to have a thickness of 1/2 to 2 inches (1 to 5 cm). Above the nose elevation there appeared to be additional deposits, notably on the north wall, which showed ash deposits of 3 to 4 inches (8 to 10 cm). The south, east, and west walls showed scattered ash deposits, of up to 1 inch (3 cm) in thickness.

Figure 10-2 shows the deposition pattern observed after 3 hours of additional GR-SI operation. The dusty layers below the nose elevation, which were described earlier, were replaced with wet to crusty deposits of up to 2 1/2 inches (6 cm) in thickness extending from the burner elevation to the OFA elevation. Little change in the upper furnace slagging was observed, in comparison to earlier observations.

10.1.3.2 Gas Injector Slagging Observations

Some buildup of slag on GR injectors was observed; however periodic manual cleaning (nominally weekly) was sufficient to maintain normal GR operation. For the most part, the injectors in the southwest and southeast corners were reasonably clean. The injectors in the northwest and northeast corners were at times partially to completely blocked. This was especially the case for the northeast corner injectors. Ash accumulation at the port entrances may be attributed to the tempering caused by the injection of gas and FGR and the fuel-rich conditions in the reburning zone. Slag buildup on specific locations may be due to local air deficiency, optimum temperature for molten slag formation, or poor cleaning by wallblowers in that region. Blockage of gas injectors may affect the heat distribution in the furnace, and the mixing of the natural gas with the primary combustion products which can influence GR operation. Therefore, routine cleaning on a weekly basis (or as required) was adopted.

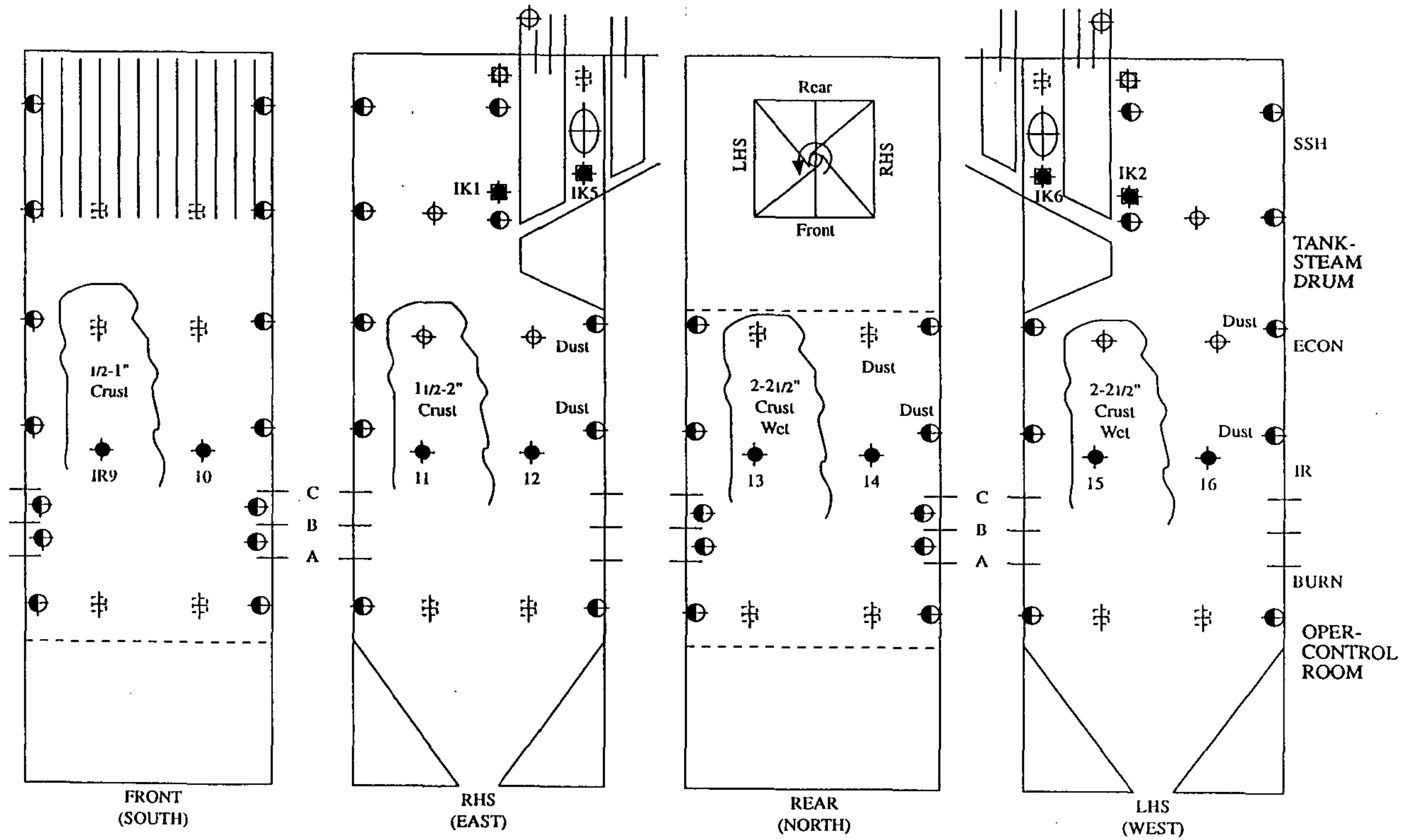


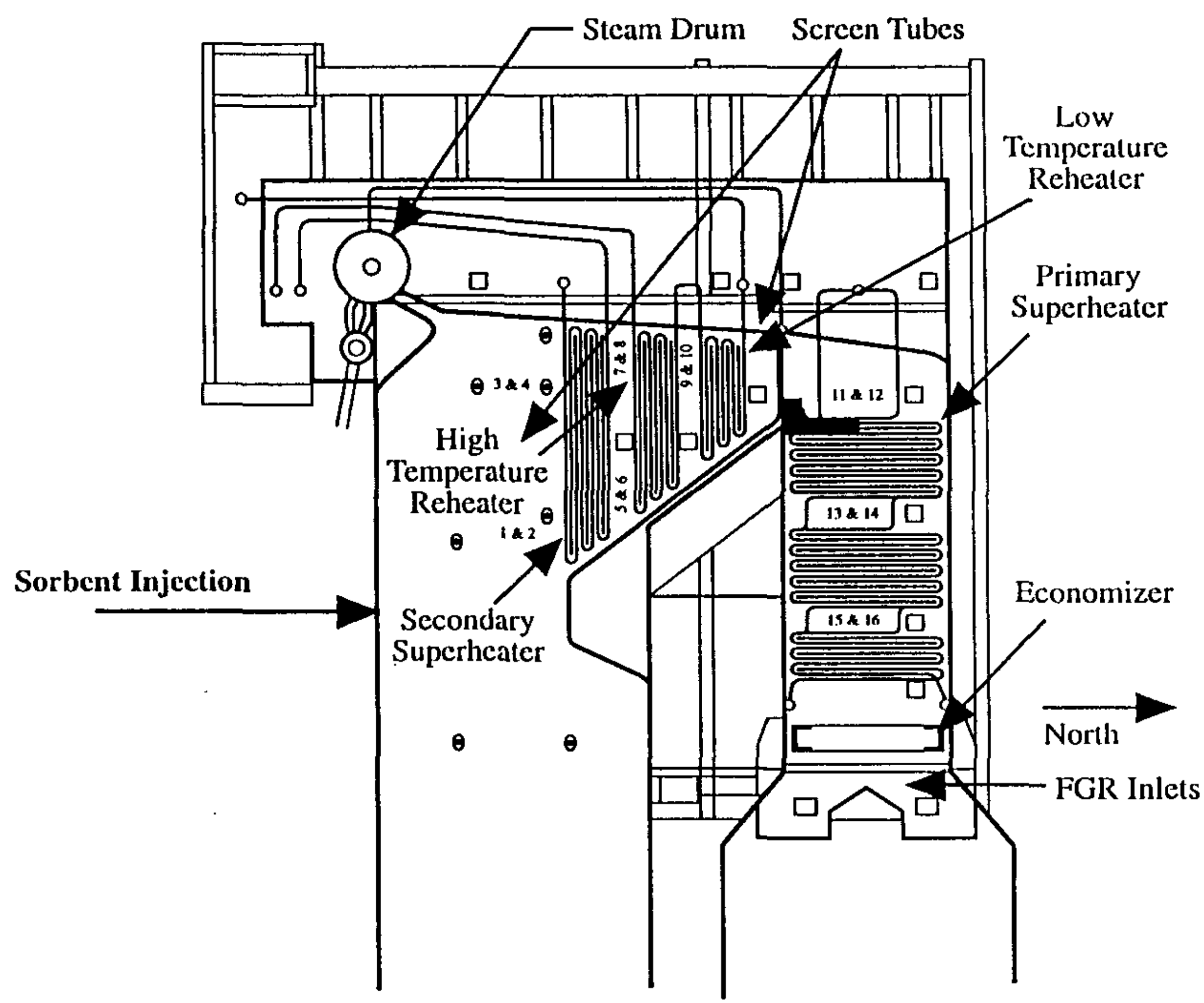
Figure 10-2. Furnace observations at 1430 hours on 25 March 1992

10.1.3.3 Overfire Air Injector Slagging Observations

During normal GR–SI operation, no unusual slagging in the area in and around the OFA penetrations was observed. An April 1992 inspection of the OFA ports, conducted immediately following 6 months of GR–SI operation, showed minor ash buildup in all of the port entrances. Some blockage occurred when the ports were out of service for extended periods. Observations made after 3 months of coal-only operation, with only cooling air supplied to the OFA ports, revealed some slag buildup around port entrances. The worst slag buildup blocked approximately 40% of the port in the northwest corner. Therefore, the ports should be cleaned after periods when the GR system is out of service.

10.1.4 Convection Pass Fouling Observations

SI increased the particulate loading in the convective pass. Ash deposition increased and sootblower operating time increased correspondingly to control the buildup. A visual inspection of the convection sections in March 1992 showed no evidence of scouring from sorbent erosion or from sootblower operation. Some accumulations were noted, particularly on the top surface of the primary superheater. To reduce the amount of accumulated material in this area, IK sootblowers Nos. 11 and 12 were used twice per shift. After two days, another inspection showed that much of the accumulation had been removed. Some evidence suggests that large chunks of hard ash deposits break off the edges of the reheater and become lodged between the tube elements and along the leading edges of the primary superheater which initiate the accumulations. This kind of ash accumulation has been reported from baseline operation also. Detailed summaries of inspections of each heat transfer section are presented below. Figure 10–3 shows the convective pass arrangement for reference.



Note: 1 through 16 designates IK sootblower locations

Figure 10-3. Convection Pass Fouling locations

10.1.4.1 Secondary Superheater

During the March 1992 inspection, ash buildup was noted in front of the final superheater pendant, behind the water wall screen tubes, and along the floor. After that inspection, IK sootblowers 1 and 2 were operated more frequently. The April 1992 inspection showed that the increased sootblowing in the area had eliminated the buildup. An inspection from the rear of the elements showed no signs of sootblower erosion due to the increased use of IK 5 through 8.

10.1.4.2 High Temperature Reheater

This section showed no unusual accumulation of ash on the pendant elements. There were no signs of sootblower erosion in front or rear of the elements from operation of IK sootblowers 5 through 8 or IK sootblowers 9 and 10, respectively.

10.1.4.3 Low Temperature Reheater

Inspection of this section revealed some hard deposits on the leading edge of the pendant elements, primarily toward the west side of the boiler which extended approximately 25% of the width of the boiler. The deposits were approximately 1 inch (3 cm) thick at the peak, triangular in shape, and a pale orange in color. During the October inspection, ash deposits were observed packed between tubes on the back side of the pendant. This was noticed more on the middle of the back side of the pendant. The deposits were easily removed manually. It is noteworthy that there are no sootblowers in this area.

10.1.4.4 Primary Superheater

A complete inspection of the primary superheater elements showed extensive ash buildup. There were hard deposits on the leading edge of the water wall screen tubes, at the top of the arch. The pattern was similar to that observed on the cold reheater, except that the thickness was approximately 1-1/2 to 2 inches (4 to 5 cm) and the deposits were more difficult to remove.

The ash buildup on the top of the upper bank was similar in the March and April, 1992 inspections except that the ash was dark grey during the April inspection instead of the pale orange colored deposits which were observed during the March inspection. The ash buildup was at the south end of the elements, where expanded metal shields had been installed to reduce fly ash erosion of tube bends. The buildup on the top of the elements ranged from a depth of 6 inches (15 cm) near the sides to 18 inches (46 cm) near the center of the boiler. The width of the buildup on top of the elements was approximately 2 feet (0.6 m), measured from the south wall. The depth down into the element bundles appeared to reach 12 to 18 inches (30 to 46 cm) from the top of the elements. It appeared that there were large chunks of ash lodged between the tube elements. These chunks were observed to be hard deposits from the leading edge of vertical tubes which broke off at times during the operation of the unit. This may be the reason for the buildup in this section. There were no signs of sootblower erosion of the tubes. The last two bundles of the primary superheater showed no evidence of ash buildup.

During the October 1992 inspection, 40% of the first bank was plugged with ash chunks. This buildup was similar to that found during the April inspection. This type of pluggage was consistent with previous observations made at this location. The lower bundle of the superheater showed hard ash deposits on top of the tubes. Minor pluggage of the gas passages near the south side wall was also observed. These deposition patterns were observed after several extended periods of continuous GR-SI testing, conducted in September/October 1992.

10.1.4.5 Economizer

There was no evidence of ash buildup on the top of the economizer. However, an inspection of the bottom showed minor pluggage between the elements. This was observed in the

March and April inspections. The October inspection showed that approximately 5% of the gas passes were plugged near the south side wall, from observation made at the top of the air heater.

10.1.4.6 Air Heater

An inspection of the inside of the air heater was performed in April, 1992. The rear half of the tube sheet had no ash buildup. The front half of the tube sheet had a small amount of ash buildup which was also observed during a brief inspection in March. The front inlets to the FGR fan were found to be blocked 40-50% with loose ash during both of the early inspections. The rear inlets to the FGR fan were also blocked 40-50%. A similar inspection of the upper air heater was performed during the October inspection. Loose ash buildup was noted but there were no hard deposits. The tubes were clean with minimal tube pluggage.

10.1.4.7 Ash Deposit

Ash deposit samples were taken from various locations to characterize the fusion temperatures. Table 10-1 shows ash fusion temperatures from samples taken from the Northwest GR nozzle, Northwest OFA port, "D" level, top of the inlet primary superheater section (PSH), inlet to the cold reheater section (CRH), and from the south FGR inlet. The results show that in high temperature regions, ash with lower fusion temperature accumulated. In the furnace, the ash deposition is due to molten accumulation, but at the OFA ports and further downstream the buildup is due to cold ash accumulation. The deposits at the cold reheater inlet have a high fusion temperature, in excess of 2700°F (1480°C).

10.1.5 Tube Bank Cleanliness Factor

Cleanliness factors (CF) were calculated continuously during GR-SI testing to quantify the extent of fouling of convective pass heat exchangers. The cleanliness factors are ratios of the

TABLE 10-1. FUSION TEMPERATURE OF ASH SAMPLES
UNDER REDUCING CONDITIONS

Parameter	Ash Fusion Temperature (°F)						
	NW GR Nozzle	NW OFA	NW OFA Port	Slag on "D" Level	Top of PSH	Inlet CRH	South FGR Inlet
Initial Deformation (IT)	1931	2109	2700+	1960	2293	2700+	2393
Softening (ST)	1953	2144	2700+	1968	2299	2700+	2386
Hemispherical (HT)	2024	2171	2700+	2006	2316	2700+	2389
Fluid (FT)	2095	2227	2700+	2068	2348	2700+	2392

actual heat transfer coefficients (i.e. under GR-SI) to those under baseline operation. Theheat transfer coefficient of each heat exchanger is the ratio of heat absorbed to the product of the heat exchanger surface area and the log mean temperature differential. A cleanliness factor above 1.0 indicates a relatively clean surface and cleanliness factors below 1.0 indicate surface fouling. This section presents the cleanliness factor data associated with the secondary superheater, reheater, and primary superheater during GR-SI operation and compares these with a baseline case. Another parameter used to evaluate heat absorption is the Heat Absorption Ratio (HAR), which is the ratio of the heat absorbed by the heat exchanger under GR-SI operation to that absorbed during baseline operation at the same load. Also presented are the operating parameters which impact heat absorption by the heat exchangers in the convective pass, including sorbent flow rate, burner tilt angle, and sootblower operation. The CF and HAR of the other heat exchangers (furnace, economizer, air heater) are not considered, since heat transfer in the furnace is primarily by radiation, the temperature drop at the economizer is too small to yield consistent results, and air heater heat transfer is impacted by air leakage.

The CF during baseline operation are shown in Figure 10-4. The data show that CF for the secondary superheater, reheater and primary superheater are held in a narrow range over several hours of baseline operation. Slight degradations of secondary superheat and reheat CF with time is evident, necessitating use of sootblowers. Sootblowing quickly improved the CF to unity.

The impacts of GR-SI operation on the heat transfer to the three heat exchangers are evident in two cases, considered in Figure 10-5 through 10-8. Both cases show several hours of GR-SI operation at full load, with sorbent flows of 5,000 to 8,800 lb/hr (0.63 to 1.11 kg/s). Both cases exhibit similar trends. SI results in fouling of each heat exchanger, as indicated by reduction in CF, but sootblowing effectively cleaned the secondary superheater and reheater, restoring the CF back to unity. The heat absorption of the secondary superheater was below the baseline level (i.e. HAR under 1.0), but reheat heat absorption was essentially unchanged and the primary superheat heat absorption increased over the baseline level.

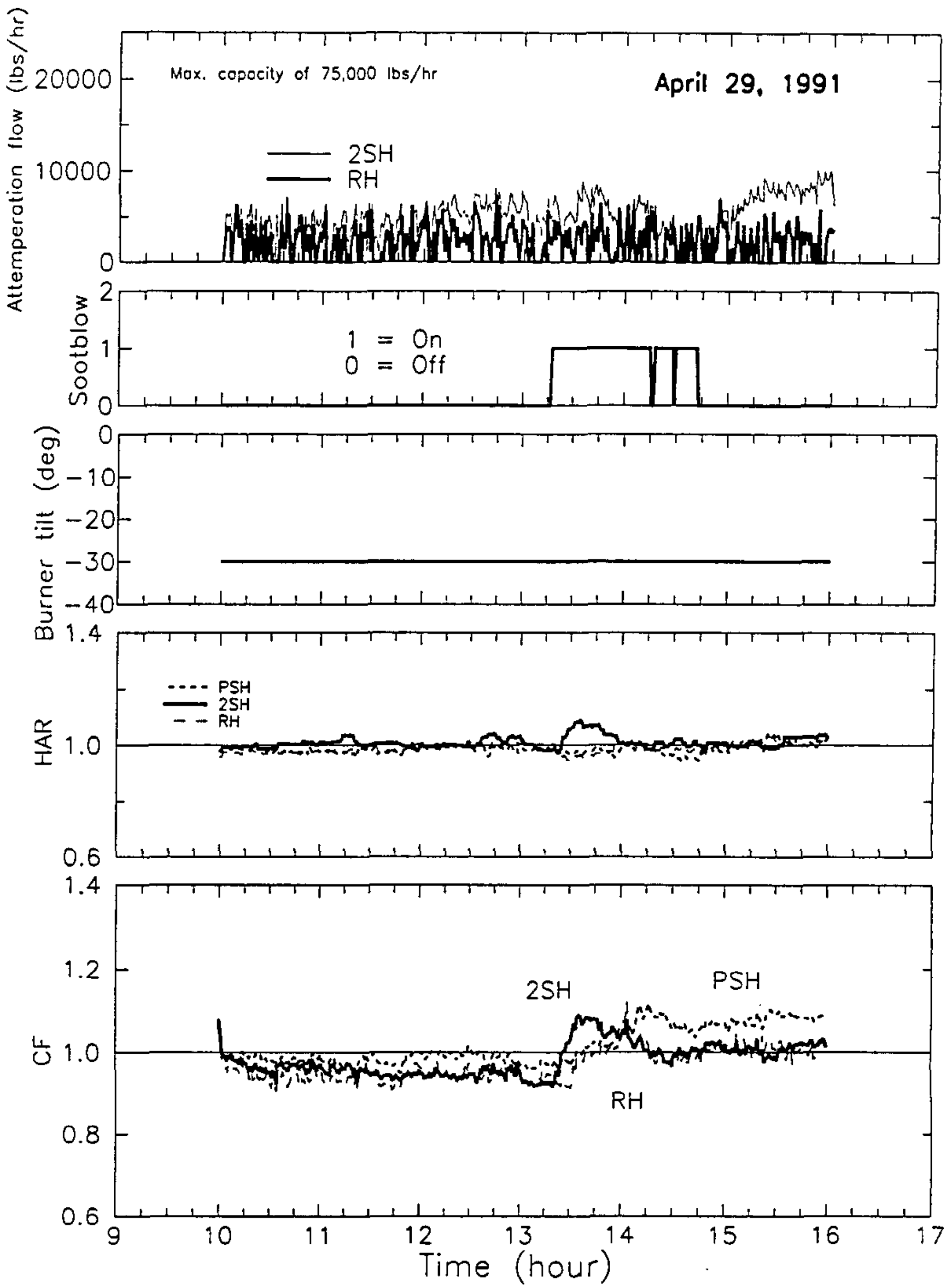


Figure 10-4. Cleanliness factors (CF) and heat absorption ratios (HAR) during baseline operation.

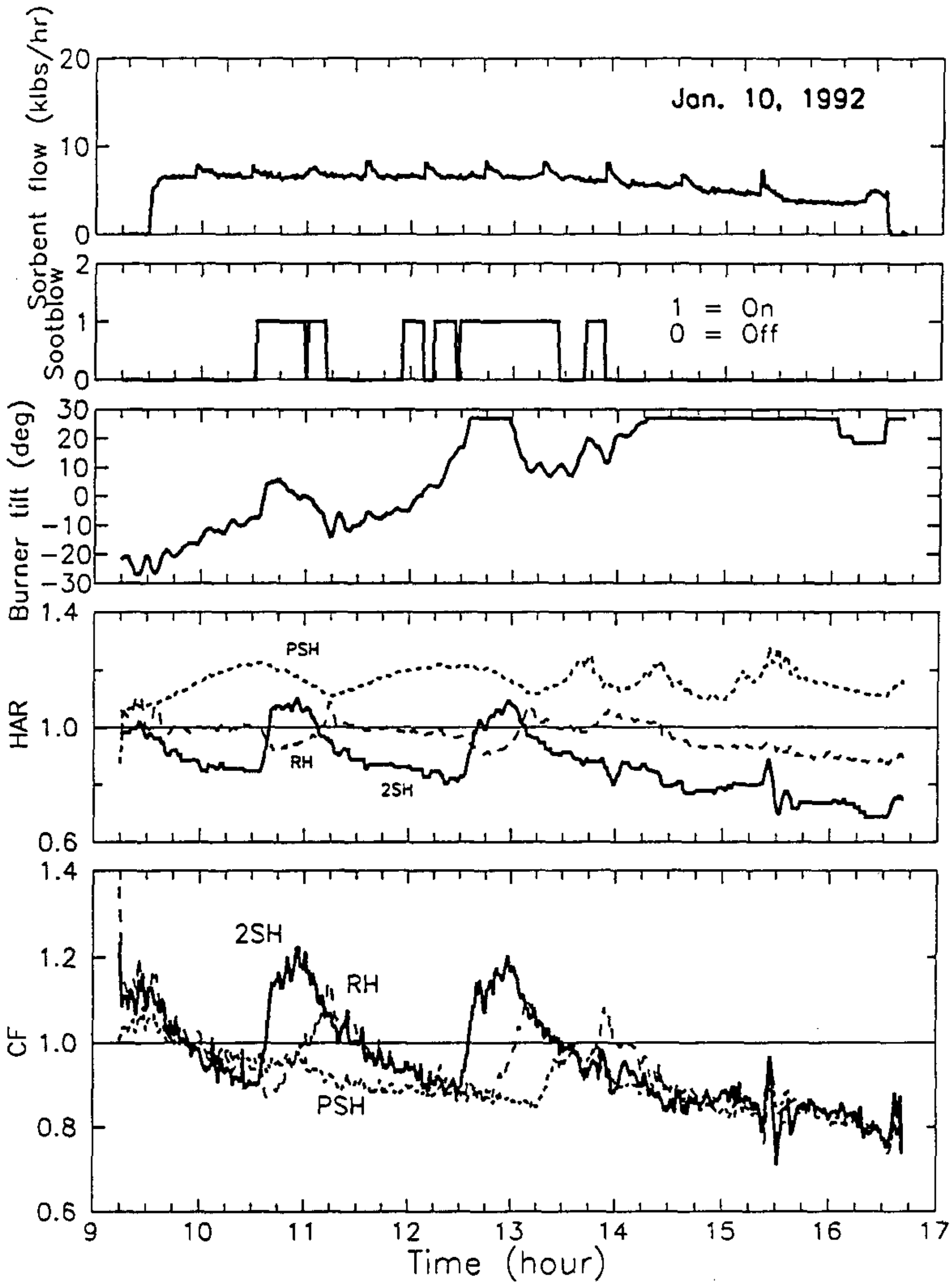


Figure 10-5. Cleanliness factors (CF) and heat absorption ratios (HAR) during GR-SI operation (case 1).

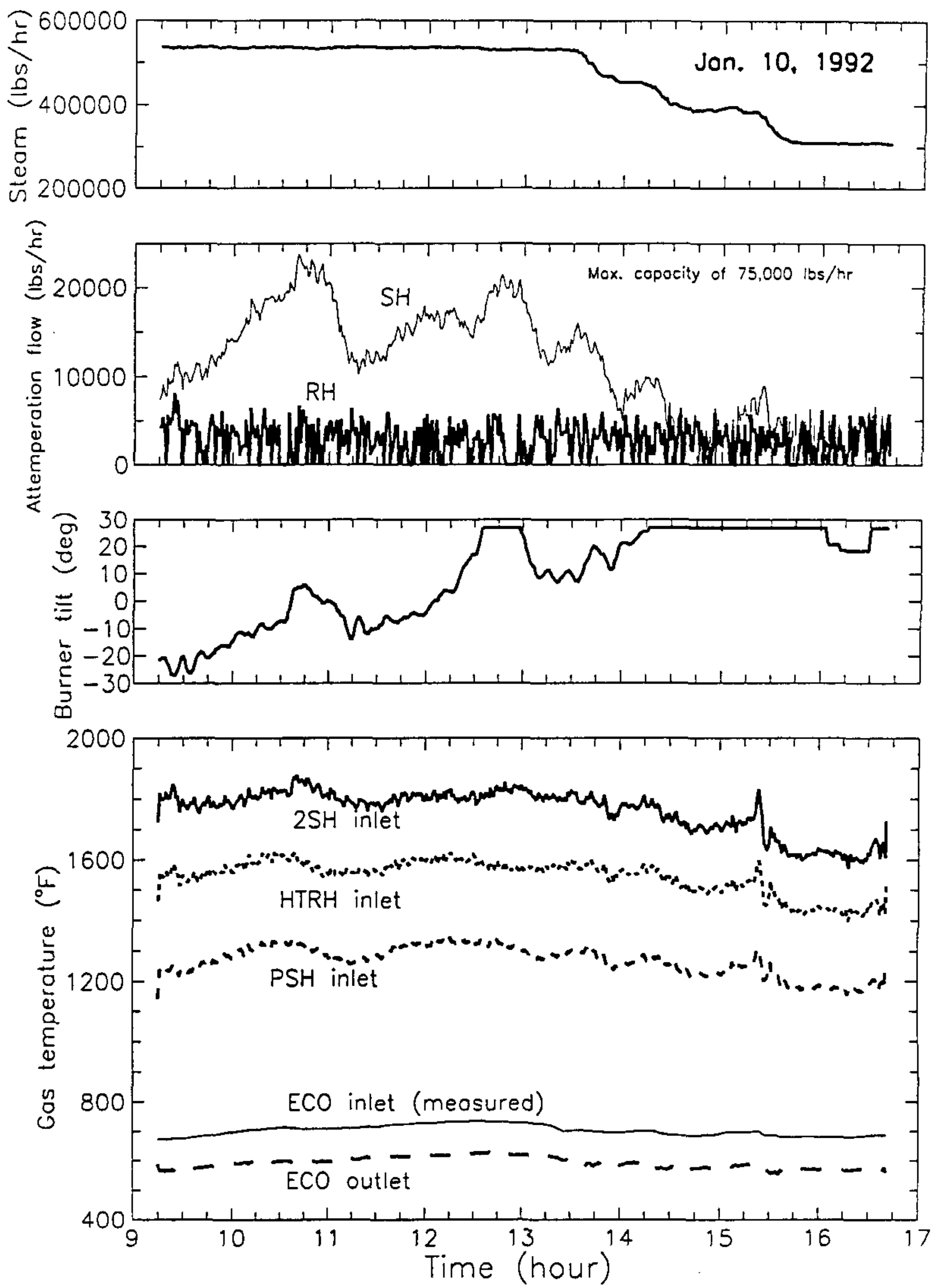


Figure 10−6. Mean gas temperature distribution (case 1).

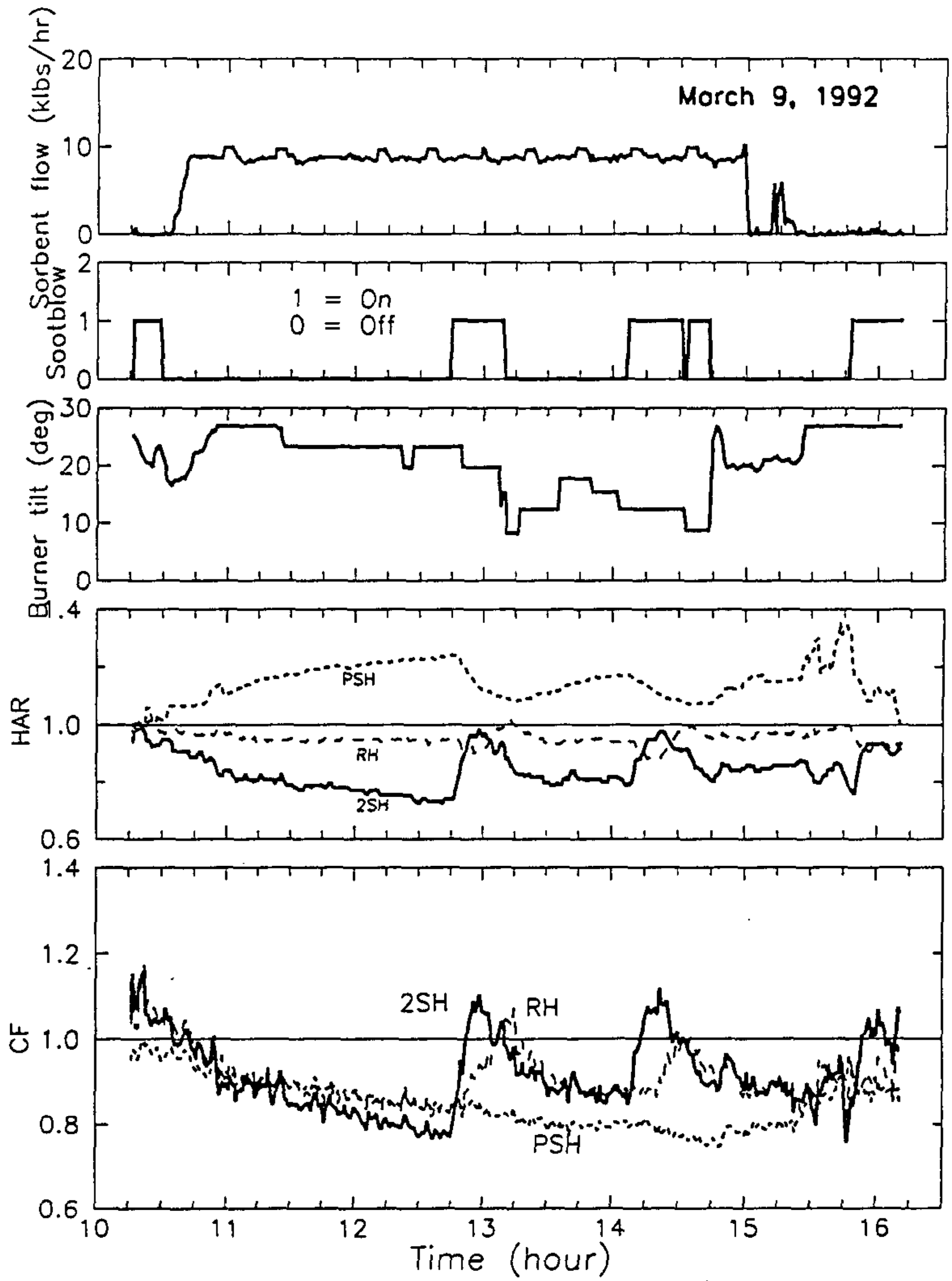


Figure 10–7. Cleanliness factors (CF) and heat absorption ratios (HAR) during GR–SI operation (case 2).

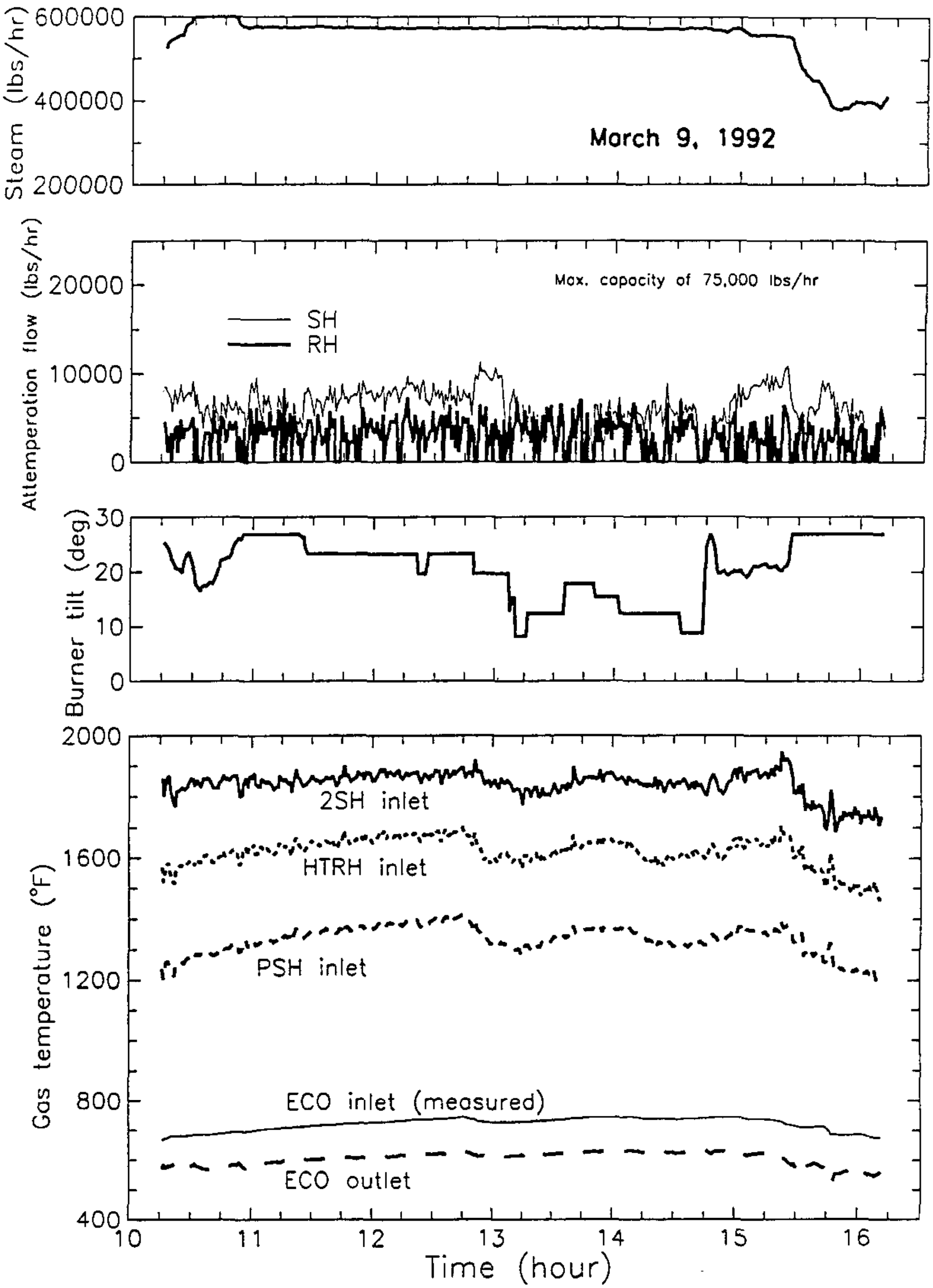


Figure 10–8. Mean gas temperature distribution (case 2).

A cyclic pattern resulted from sorbent fouling, coal burner tilt movement, and sootblowing. At full load, the coal burners were initially tilted downward. SI resulted in fouling of the secondary superheater and reheater, indicated by reductions in CF, resulting in an upward shift of the burners tilts. Superheater fouling triggers sootblowing, which cleans the secondary superheat and reheater surfaces and leads to a downward shift in coal burner tilts. The CF of the secondary and reheat superheaters were restored to unity (baseline level) by sootblowing. The HAR for these heat exchangers show similar fluctuations. The HAR for the secondary superheater varied most widely, but was generally below unity. The reheat HAR was held fairly constant. The primary superheater HAR was significantly above unity during the fouling of the upstream heat exchangers, which resulted in higher gas temperature at the primary superheater. Figures 10-6 and 10-8 show that the superheater attemperation flow varied with burner tilt position, but was still far below its capacity. Similar shifts in the gas temperature profiles, with burner tilt fluctuations, are also evident.

10.2 Sootblowing Optimization

SI in the upper furnace changed the amount and characteristics of the particulate matter flowing through the convective pass and affected the heat absorption distribution of the convective pass heat exchangers. The change in deposition patterns had several impacts on the thermal performance of the boiler. As expected, GR-SI operation resulted in an increase in the exit gas temperature and a drop in the thermal efficiency of the unit. In order to reverse these trends and maintain an acceptable operating efficiency, tests to optimize sootblowing sequences were conducted from September to October 1992. This section presents the results of these tests.

In order to enhance heat absorption by the secondary and reheat superheaters, sootblowing periods were significantly increased. Under optimized operation, sootblowing occurred 84% of the time compared to 34% previously used. This resulted in enhanced heat absorption by the secondary and reheat superheater, reduction in the rate of increase of boiler exit gas temperature, a reduction in thermal efficiency loss, and lower superheater attemperation spray. Comparing optimized sootblowing at full load with normal operation, the rise in boiler exit gas temperature was 7.5°F/hr (4.2°C/hr) instead of 23.75°F/hr (13.2°C/hr), the reduction in thermal efficiency was 0.12 %/hr instead of 0.22 %/hr, and the superheater attemperation was 7,500 lb/hr (0.95 kg/s) instead of 10,900 lb/hr (1.4 kg/s). In each comparison the latter figure was under the normal sootblower operation.

10.2.1 Impact of Sorbent Injection on Thermal Performance

Experience from another program conducted by EER, at Richmond Power and Light's Whitewater Valley Unit 2 (England, 1993), in which upper furnace SI was evaluated on a tangentially fired unit, indicated that significant impacts on the heat absorption distribution and heat absorption rates could occur if not controlled. For this reason several sootblowers were installed in the available "future sootblower" locations of the Hennepin unit to assure complete coverage of all the convective-pass heat-transfer sections.

As mentioned in Section 8, GR-SI operation significantly altered the heat absorptions of the convective pass heat exchangers, which affected the gas temperature profile. Figure 10-9 shows the gas temperature measured at the economizer inlet from the time SI was initiated. Over a 4 hour period, the gas temperature increased by 67°F (37°C). Over this period, the heat loss efficiency decreased from 85.82% to 85.06%. The decrease in thermal efficiency was due to an increase in dry gas heat loss, which resulted from an increase in the air heater gas exit temperature. Thus, selective but more frequent sootblowing was recommended.

10.2.2 Optimization of the Sootblowing Cycle

In order to optimize the sootblowing cycle, the deposition patterns in the convective pass were studied by evaluating the heat absorption rates in the furnace, secondary superheater, reheater, primary superheater, and economizer. The heat absorption rates showed that the secondary superheater and the reheater fouled more rapidly than the primary superheater or the economizer. Due to fouling of the secondary superheater and the reheater, heat

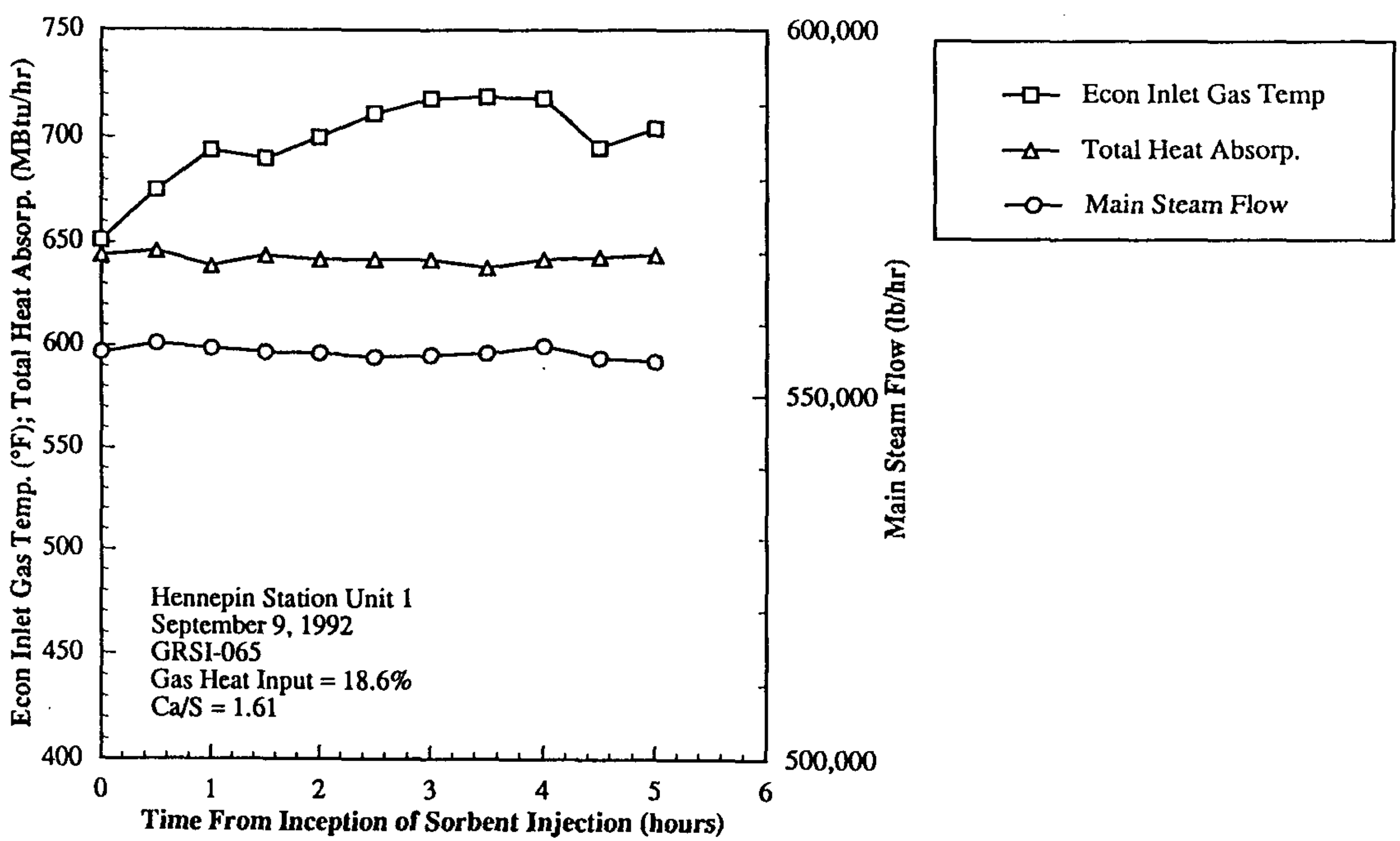


Figure 10-9 Impact of sorbent injection on economizer inlet gas temperature and total heat abosption

absorption by the primary superheater increased by up to 3.8% and heat absorption by the economizer increased by up to 0.8%, based on the total heat absorption. The furnace also showed decreased heat absorption. Slagging in the furnace is due to slightly lower stoichiometric ratios in the burner zone and slightly fuel-rich conditions in the reburning zone. The overall shift in heat absorption resulted in an upward shift in the gas temperature profile and in higher dry gas losses, increased humidification water requirements, and higher spray attemperation to control steam temperature.

To reverse the shift in heat absorption distribution, more frequent sootblowing was required at the furnace, secondary superheater, and reheater surfaces to enhance heat transfer rates. To maintain an acceptable thermal efficiency, the gas temperature, measured by a 12-thermocouple grid at the economizer inlet, was kept in the range of 690°F to 720°F (370°C to 380°C). Figure 10–10 shows the locations of the sootblowers available in the convective pass. Not shown on the figure are the eight furnace wall blowers which are located just above the burners in the lower furnace.

By increasing the use of furnace wall blowers from an average of 2 times during an 8-hour shift with normal GR–SI operation to 3 times a shift, and by increasing the use of IKs 1-10, which are located in the secondary superheater and the reheater, enhancement of thermal performance of Hennepin Unit 1 was achieved. The use of sootblowers increased from 34% to 84% of the time.

10.2.2.1 Heat Absorption Rates

By using an optimized sootblowing cycle, the heat absorption rates were improved as shown in Figure 10–11. At 70 MW_e, furnace heat absorption was restored while heat absorption rates to the secondary superheater and the reheater were greatly improved. The higher absorption rates in the furnace, secondary superheater, and reheater significantly decreased the heat absorption rates of the primary superheater and the economizer. At 60 MW_e, the improvements were less evident, as shown in Figure 10–12. Nevertheless, there was

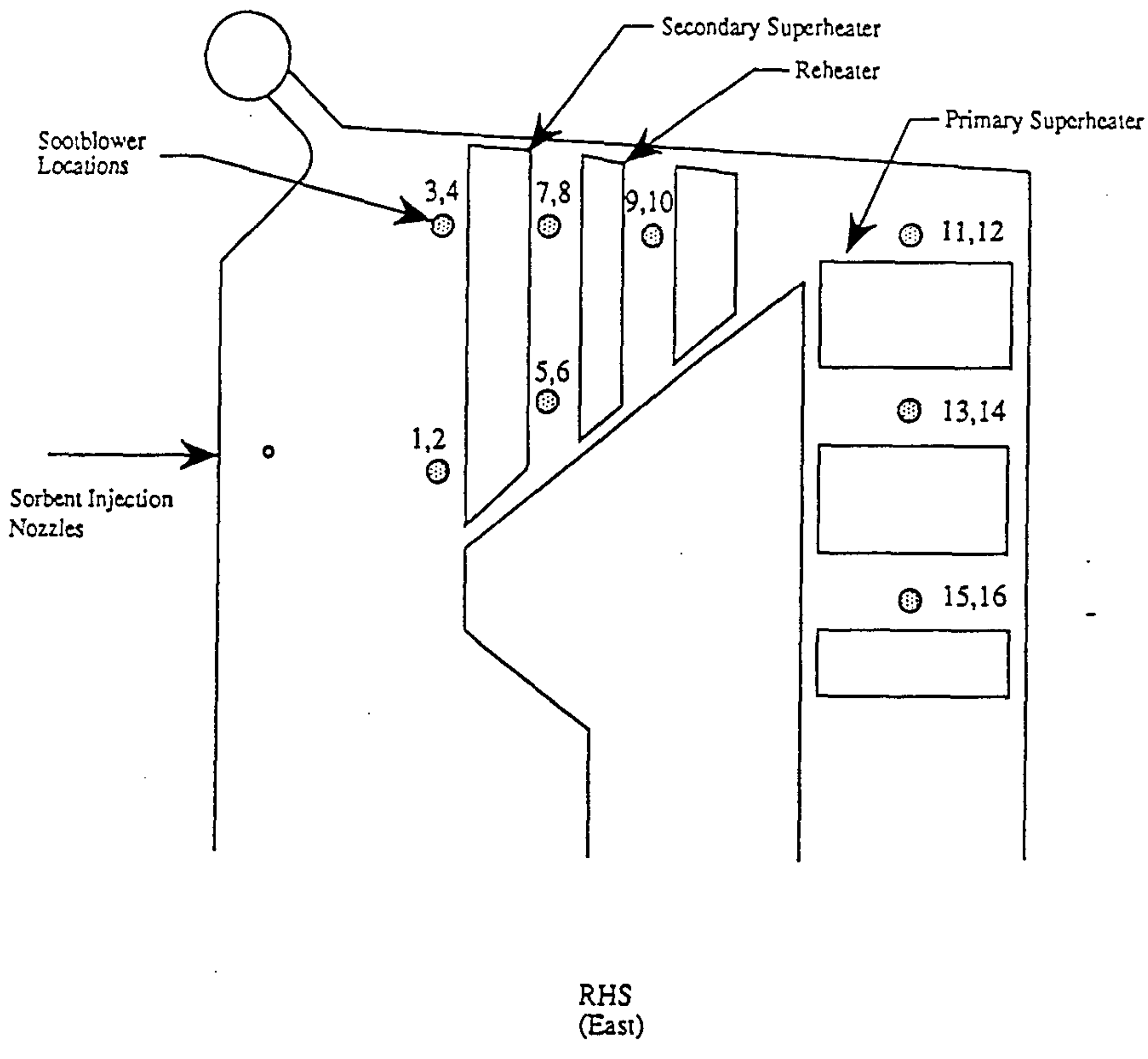


Figure 10–10. Location of IK sootblowers

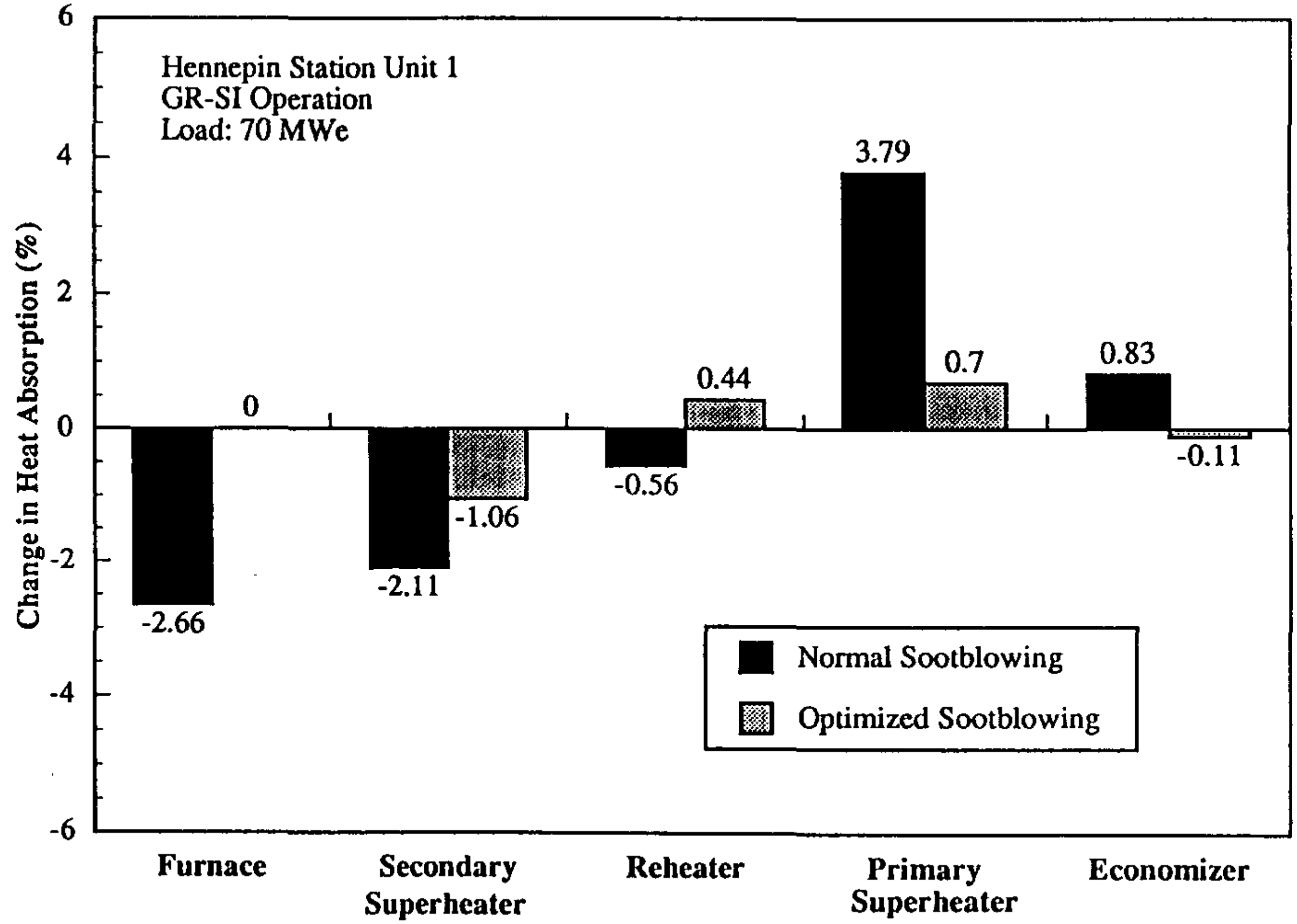


Figure 10-11. Impact of normal and optimized sootblower operation on GR–SI heat absorption distribution at 70 MWe

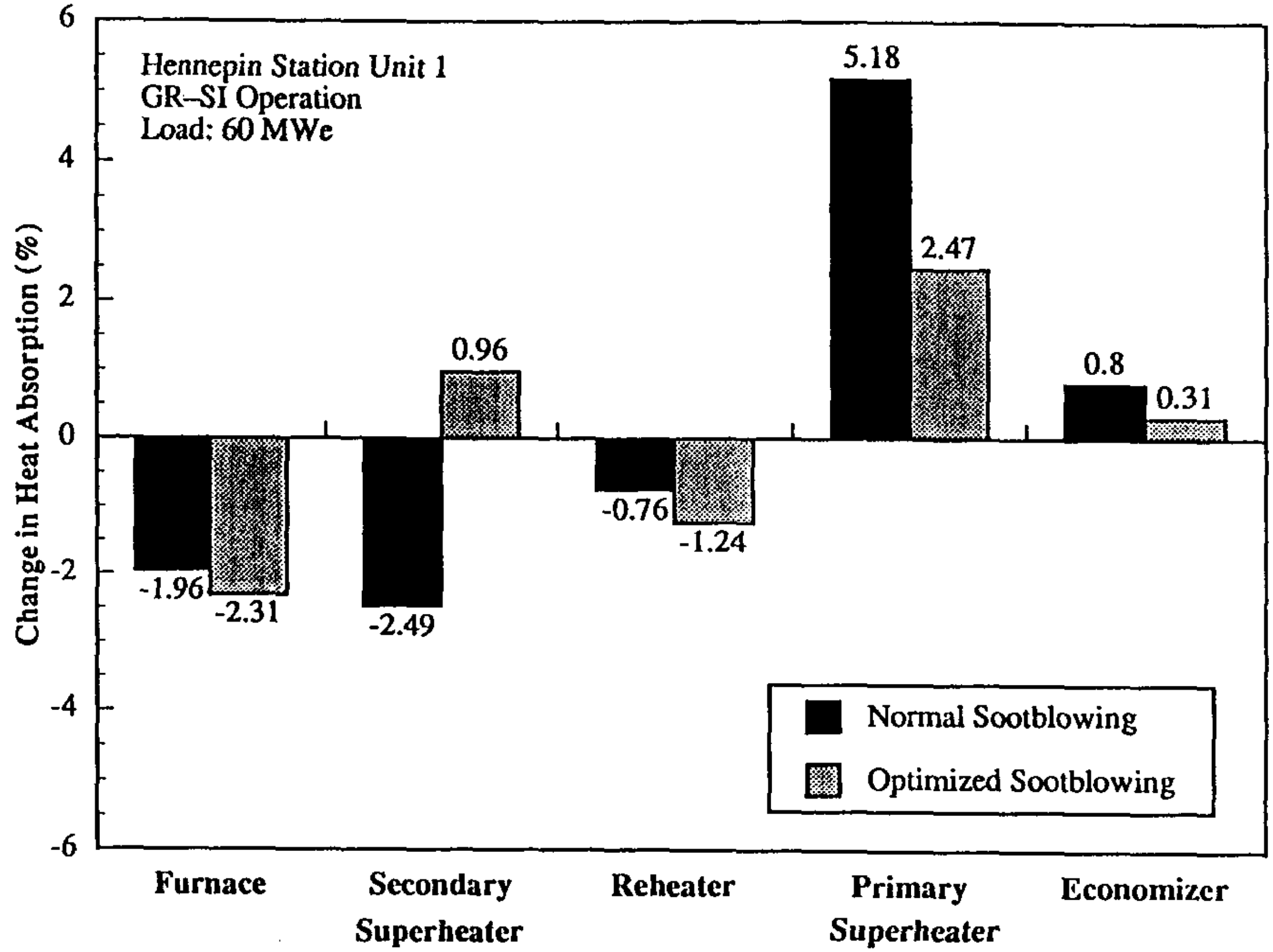


Figure 10-12. Impact of normal and optimized sootblower operation on GR-SI heat absorption distribution at 60 MWe

some restoration of the thermal profile, which is evident in the drop in primary superheater heat absorption.

10.2.2.2 Boiler Exit Gas Temperature

Figure 10–9 showed the rapid rise in boiler exit gas temperature in the early stages of GR-SI operation. During GR-SI with the normal sootblowing routine, the boiler exit gas temperature increased by 23.8°F per hour (13.2°C/h), over a four-hour period. Increased sootblowing resulted in an increase of 7.5°F per hour (4.2°C/h), as shown in Figure 10–13a. The reduction in exit gas temperature helped to restore boiler efficiency and prolong GR-SI operating time, as will be shown in the following section.

10.2.2.3 Boiler Efficiency

Thermal efficiency was improved by the reduction in exit gas temperature, as shown in Figure 10–13b. The efficiency decreased at a rate of 0.22% per hour under the normal sootblowing routine but only at rate of 0.12% per hour during optimized sootblowing. Figure 10–14 shows the results of a 32-hour continuous GR–SI test at a constant 70 MW_e load. The efficiency was maintained constant by holding the exit gas temperature in a pre-defined range.

10.2.2.4 Superheat Spray Attemperation

The combination of lower heat absorption by the secondary superheater and higher heat absorption by the primary superheater during GR-SI operation still increased the rate of heat transfer to steam. For this reason, the superheat steam attemperation rate averaged 10,900 lb/hr (1.37 kg/s) during GR–SI with normal sootblower operation. Figure 10–15 shows that the spray attemperation was reduced by 33% to 7,500 lb/hr (0.944 kg/s) during GR–SI with optimized sootblowing. This was due to a reduction in heat absorption by the primary superheater. The reheat steam attemperation was unchanged.

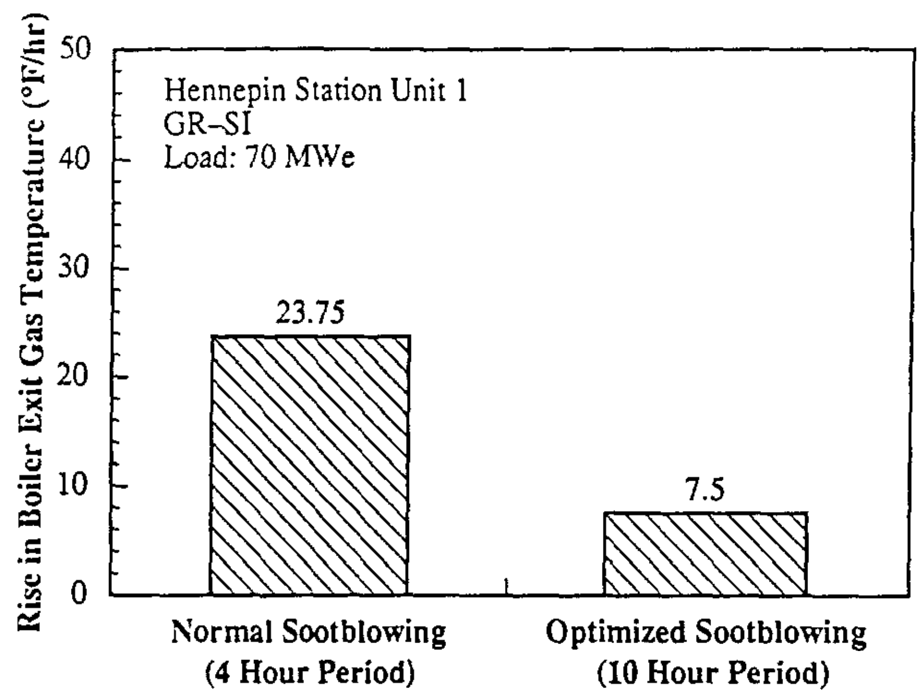


Figure 10-13a. Impact of normal and optimized sootblower operation on boiler exit gas temperature

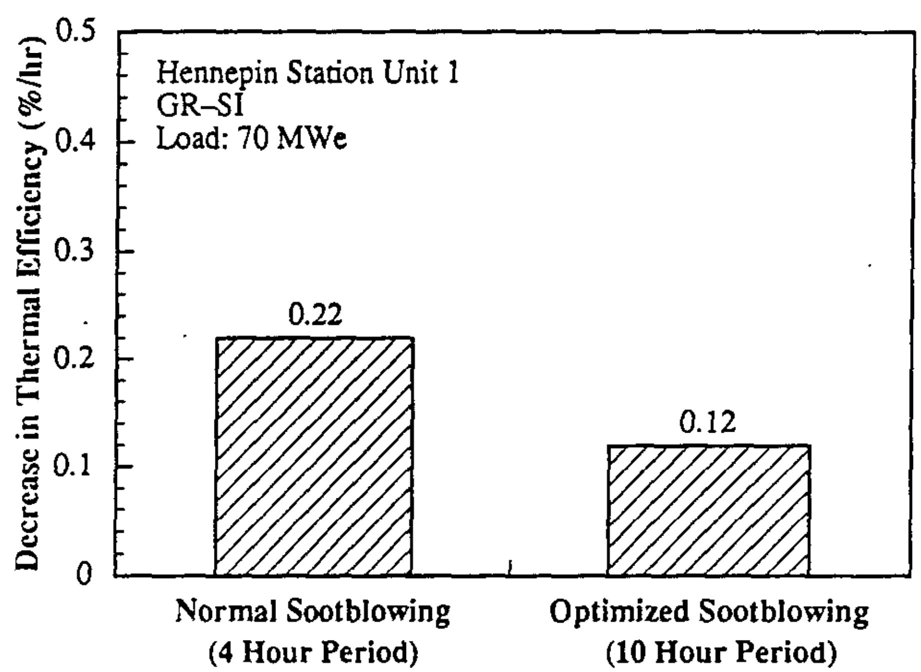


Figure 10-13b. Impact of normal and optimized sootblower operation on boiler efficiency

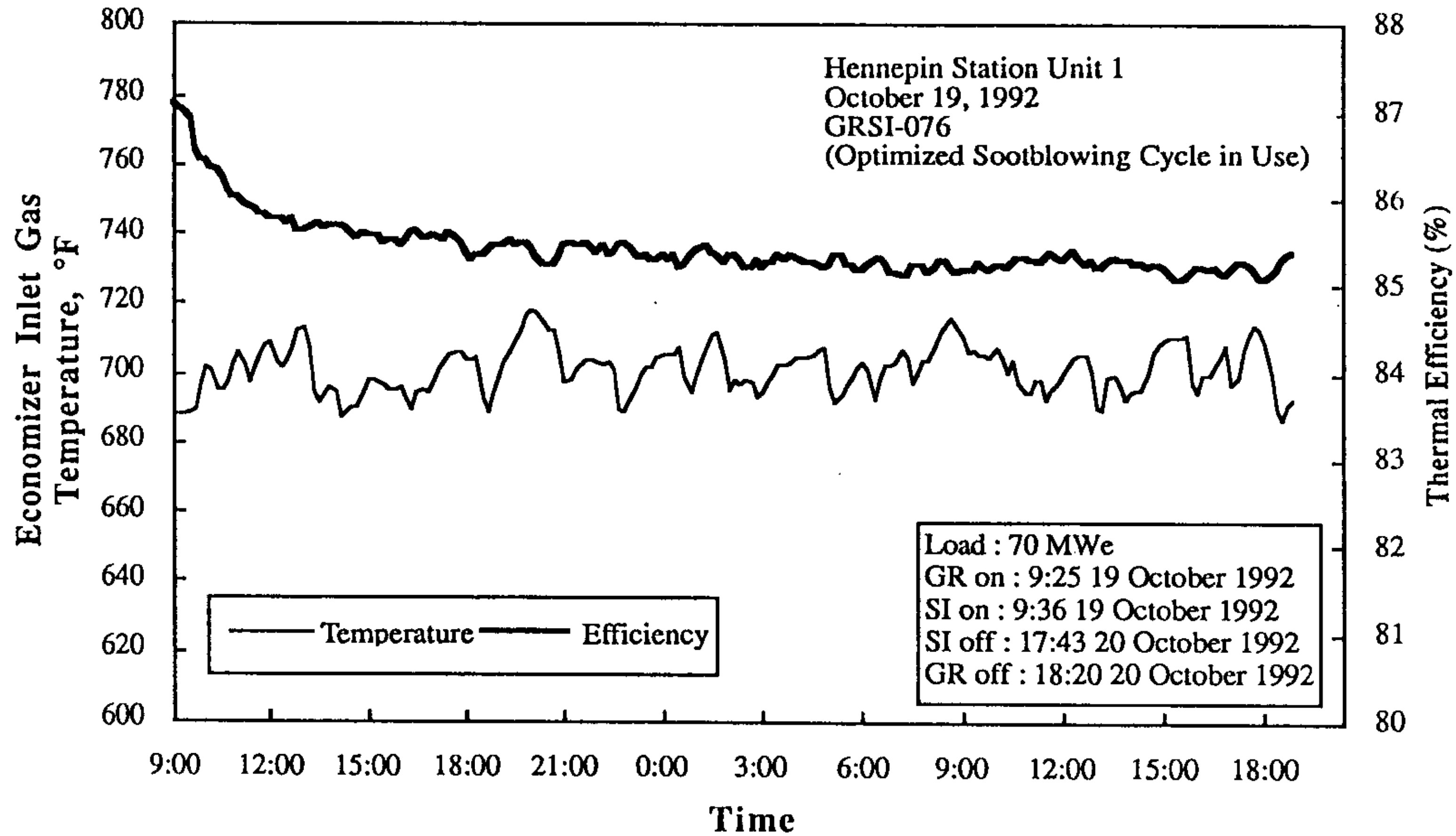
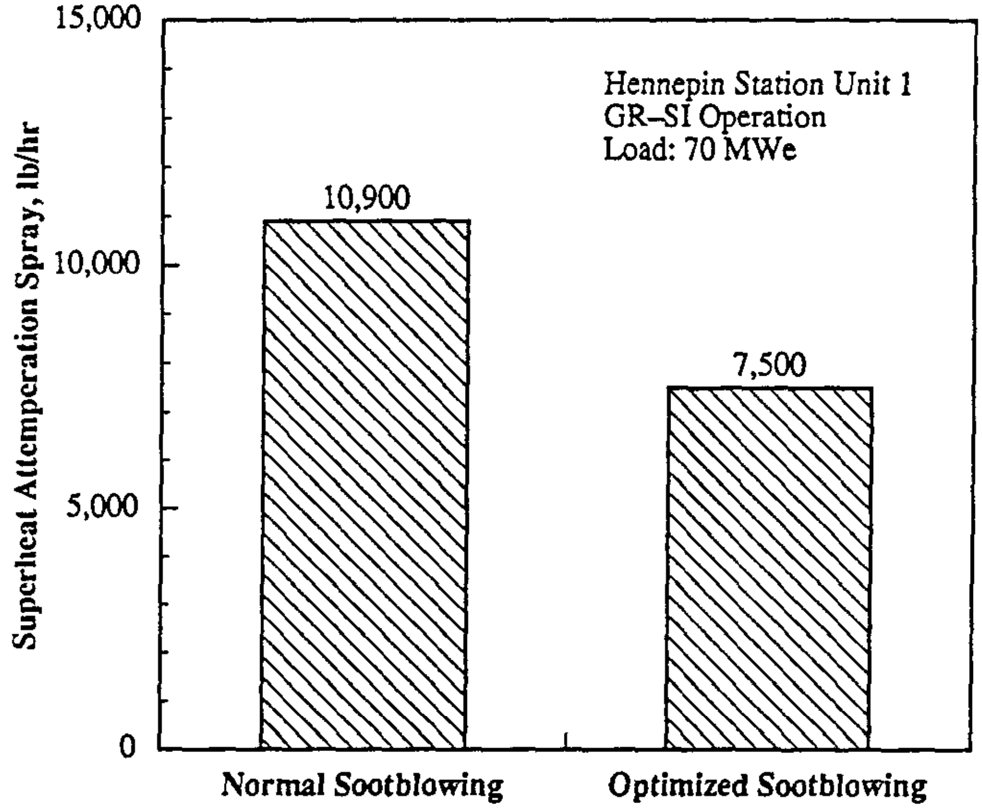


Figure 10-14. Economizer inlet gas temperture and thermal efficiency during 32 hour GR-SI test run (Optimized Sootblowing)



Figuer 10-15. Impact of normal and optimized sootblower operation on superheat attemperation

10.3 Humidification System Performance

One area of concern in applying GR-SI at Hennepin Unit 1 was the impact of SI on the electrostatic precipitator performance and stack opacity. Application of GR-SI resulted in a substantial increase in particulate loading to the ESP. This was due to the added sorbent material. Also, SI increased the ash resistivity by as much as two orders of magnitude. Both factors were expected to result in a significant deterioration in ESP performance. For these reasons it was necessary to consider ESP performance enhancement strategies if SI was to be applied without derating due to opacity problems. ESP evaluation included an internal inspection to assess its condition, extensive performance testing during baseline tests, and computer modeling to predict performance during the GR-SI operation. The computer model was calibrated with the results of the field tests, and was used to predict the impact of GR-SI application on the performance of the ESP before any modifications. With flue gas humidification, the model projection indicated operation with a reasonable safety margin.

Humidification appeared to be the most cost effective option, and modeling indicated that performance can be recovered during GR-SI operation and without a need for an additional ESP field.

10.3.1 Humidification Specifications

In order to accommodate the increased mass loading and altered fly ash characteristics due to SI, the ESP performance was enhanced by flue gas humidification. The humidification system was designed to cool the flue gas to within 70°F (39°C) of the saturation temperature of 125°F (52°C). A single-stage in-duct evaporative cooling system was selected to accomplish this task.

Water was selected as the evaporative coolant. Conditions in the duct, such as flue gas flow, air heater outlet gas temperature, were used along with the desired approach to saturation to determine the design water injection rate. The design case is a water injection rate of 60 gpm (3.8 l/s) for a boiler load of 71 MW_e (net). The humidification system was designed to inject water into the duct and to atomize the water to allow complete evaporation before the gas entered the precipitator. Rapid vaporization of water required the use of twin-fluid nozzles and compressed air as the atomizing gas.

The nozzles were designed and the arrangement of nozzles in the duct was optimized to give uniform humidification and complete vaporization at the precipitator inlet. Twin fluid nozzles were selected with compressed air to provide the energy source for atomization. The nozzle design required 0.3 lbs of compressed air per pound of water, resulting in a flow of 2000 scfm (0.94 Nm^3/s) of compressed air to be supplied at a pressure of 125 psig (862 kPa) to provide acceptable atomization. The nozzle design also required the water to be supplied at a pressure of 100 psig (690 kPa).

Modifications to the flue gas duct were necessary to obtain the residence time required to ensure complete evaporation at the ESP inlet. The design residence time in the humidification duct is approximately 2.0 seconds. The modifications provided uniform gas flow in the humidification duct and also allowed for removal of fly ash and sorbent, which separated from the flue gas.

10.3.2 Process Arrangement

Humidification water was injected in a horizontal section of the modified flue gas ducts just downstream of the air heater outlet. Each horizontal duct section was enlarged to provide the required residence time for evaporation prior to any change in direction in the duct route. The humidification duct sections terminated with a 90 degree turn upward to the ESP inlet. It was intended that sufficient evaporation occur in these sections, so that no liquid would impact on the precipitator fields.

The humidification duct is a low point in the flue gas system. Because of this and directional changes of the flue gas flow, significant amounts of fly ash (and spent sorbent) separate from the flue gas stream in the humidification duct. To collect the fly ash, five hoppers were installed in the bottom of the duct. Screw conveyors for ash removal were installed on the bottom of each hopper. Twenty four thermocouples were pad-welded to the duct skin for monitoring temperatures (6 below the humidification nozzles, 18 on the duct skin on the vertical section before the ESP inlet).

Complete vaporization of water was targeted at the ESP inlet. A temperature sensor was inserted in the center of the gas stream in a short section of duct leading to the precipitator inlet. This temperature signal was used to control water flow to reach a prescribed gas temperature.

Six humidification lances (three for each duct) were designed to support the atomizing nozzles array, as well as deliver compressed air and water to each nozzle. Each lance was designed to accommodate a maximum of six atomizing nozzles. The nozzle array consisted of a total of 17 nozzles per duct, 2 of the 6 lances having 5 nozzles and 4 lances having 6 nozzles. Each nozzle was rated at a nominal water flow of 1.76 gpm (0.11 l/s), requiring approximately 100 psig (690 kPa) of water pressure, and 125 psig (860 kPa) of atomizing air pressure.

10.3.3 Duct Modifications

The flue gas duct leading from the air heater outlet to the electrostatic precipitator was redesigned to accommodate the humidification system. The modified duct has the following features (see Figure 10–16):

- Enlargement of the duct cross–section to increase gas residence time
- A perforated plate at the humidification duct inlet
- Four adjustable turning vanes
- Five hoppers for ash removal

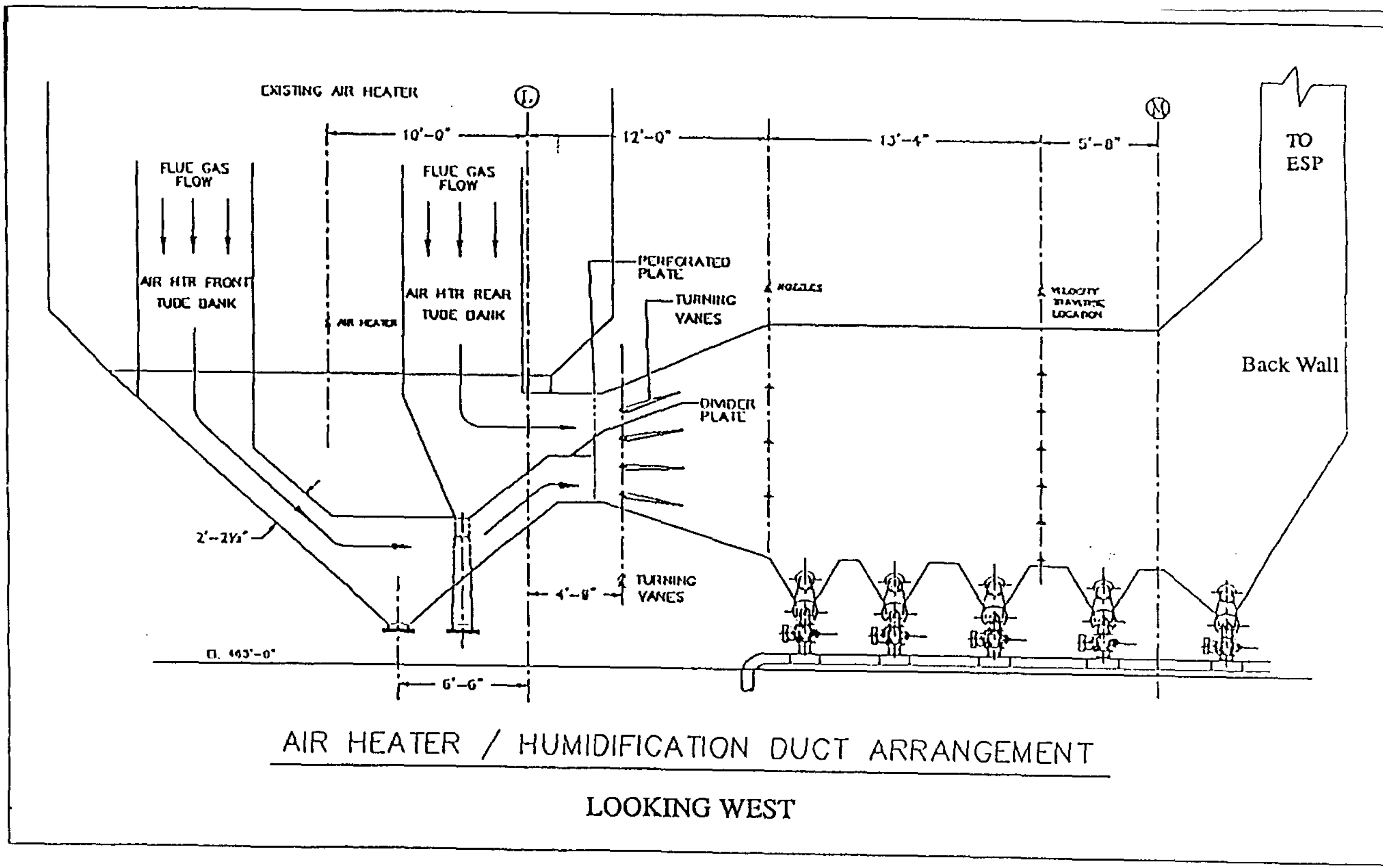


Figure 10–16. Air heater outlet and humidification duct arrangement

A perforated plate was placed at the inlet of each parallel duct to improve the uniformity of the gas flow in the duct. Early flow modeling indicated that the highest gas velocities were near the top of the duct and the gas flow direction near the bottom was actually backward toward the inlet, as shown in Figure 10-17. The perforated plate alleviated the flow imbalance. Figure 10-18 shows the velocity profile obtained after installation of the perforated plate. With the perforated plate, the maximum velocity in the humidification duct (at full load) was 23.5 ft/s (7.2 m/s) which may be compared to a maximum velocity of 34.0 ft/s (10.4 m/s) measured before its installation.

Adjustable turning vanes were installed near each duct inlet, just downstream of the perforated plate, where the duct cross-sectional area increased. This improved the flue gas distribution at the humidification plane.

Five hoppers which ran the full width of both ducts were located below the lances. The hoppers were required to capture any fly ash and sorbent which inertially separated from the flue gas flow and settled to the bottom of the duct. A screw conveyor was bolted to the hopper and moved the collected ash to a single outlet on the end of the conveyor. A rotary feeder/airlock was bolted to the end of the conveyor outlet. The rotary feeder/airlock fed the collected fly ash and sorbent mixture into a (dry) vacuum transport system. The solids were entrained with water and sluiced to settling ponds.

10.3.4 Operation

It was found during GR-SI testing with humidification, that it was not necessary to achieve the design approach to saturation temperature of 70°F (39°C) for successful ESP capture of fly ash and spent sorbent. Actual approach to saturation temperatures was in the range of 140-150°F (78 to 83°C) and actual water usage, at 70 MW_e, was approximately 25 to 40 gpm (1.6 to 2.5 l/s). The amount of water used was as low as 15 gpm (0.9 l/s) for boiler loads in the 45 to 50 MW_e range.

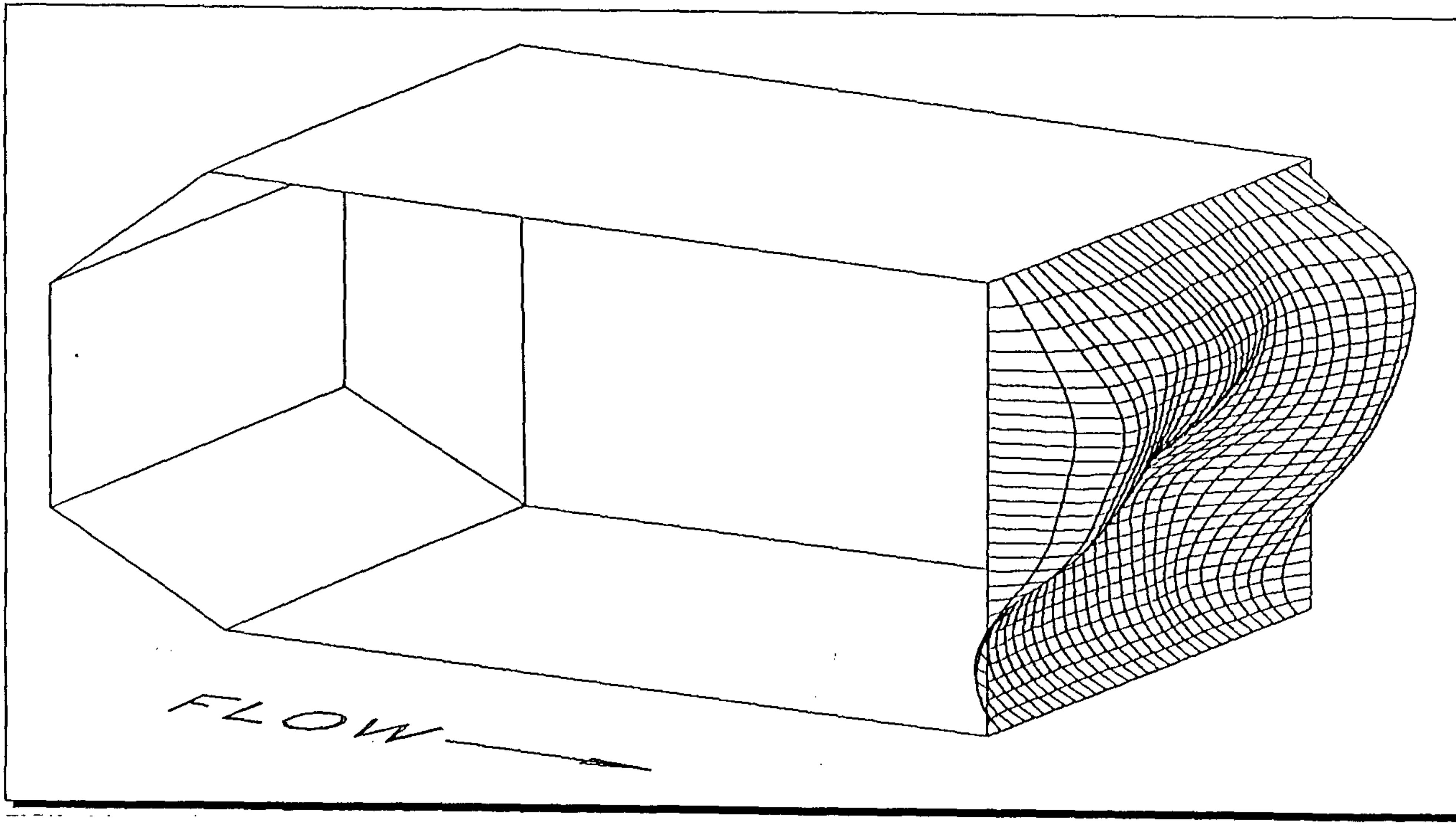


Figure 10–17. Humidification duct velocity profile before modification. (Load = 40 MW, Velocities calculated for load of 70 MW, Maximum Positive Velocity = 34.0 ft/sec, Maximum Negative Velocity = 13.2 ft/sec)

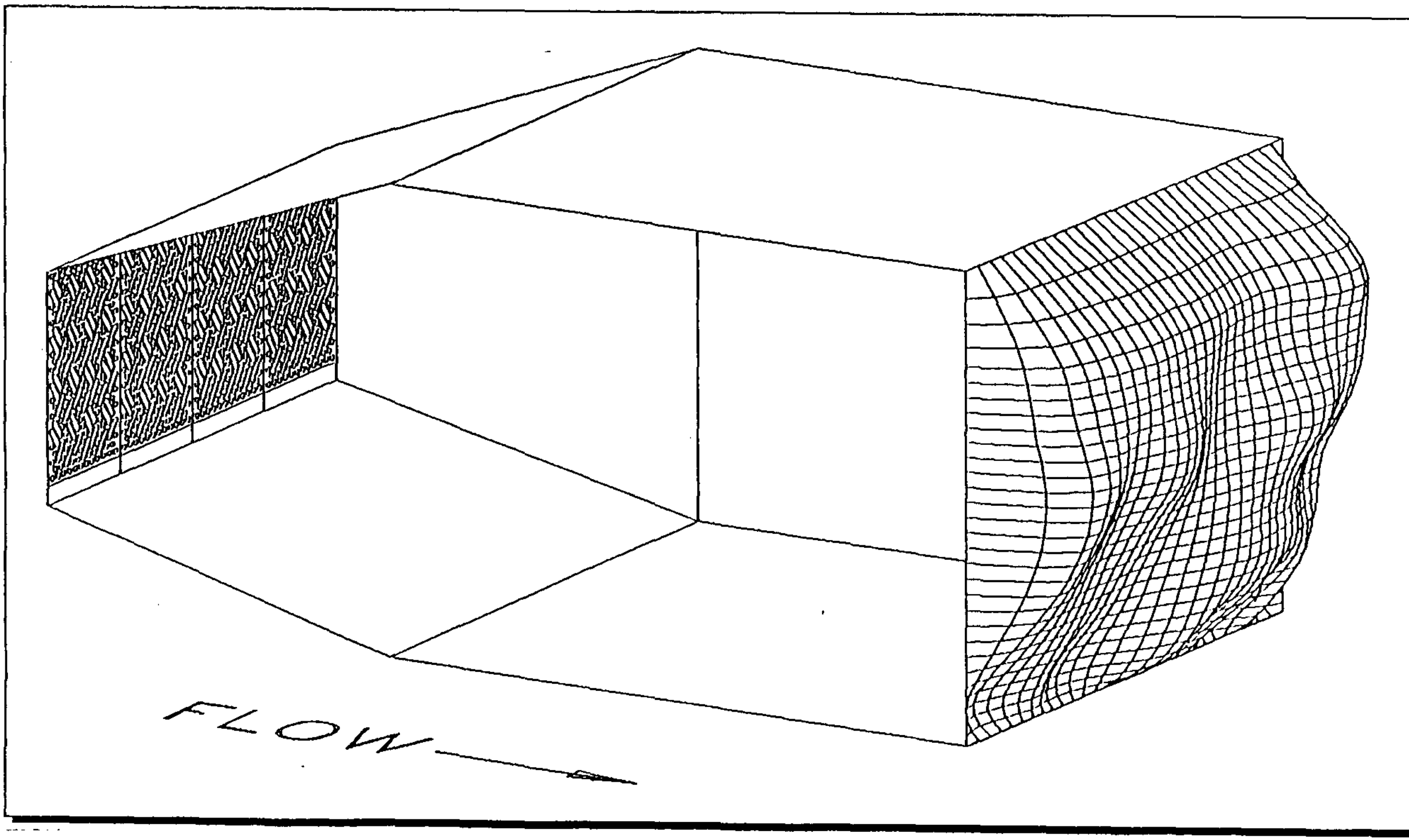


Figure 10-18 Humidificati... ...city profile after modifications (Traverse on Dec 12, 1991, Load = 70 MW

From early operation of the GR-SI and humidification systems, it was determined that using the full array of nozzles was detrimental to operation of the humidification system. The heat content of the flue gas in the lower section of the humidification duct was insufficient to completely evaporate spray water in this region before the gas reached the rear wall. One of the factors contributing to this problem was the difference in temperature of the flue gas streams exiting the two air heater tube banks. Because of incomplete vaporization in the lower section of the humidification duct, the bottom row of nozzles in both ducts were not in service during most of the GR-SI testing. The addition of the perforated plate and turning vanes effectively reduced the vertical nonuniformity in the gas flow in the duct, but improvement in the temperature gradient was not possible.

10.4 Electrostatic Precipitator Performance

Measurement of particulate emissions was conducted during two test periods, in April and August/September 1992. ESP performance was evaluated during baseline, GR, and GR-SI operation. The overall mass collection efficiency of the ESP ranged from 99.48 to 99.95%. During full load baseline operation, particulate emissions ranged from 0.018 to 0.035 lb/10^6Btu (7.7 to 15.1 mg/MJ), while during full load GR the range was 0.025 to 0.033 lb/10^6Btu (10.8 to 14.1 mg/MJ) and during full load GR-SI the range was 0.015 to 0.025 lb/10^6Btu (6.5 to 10.8 mg/MJ). Humidification, used during SI operation, effectively limited to particulate emissions to baseline levels. The mechanisms for ESP enhancement by humidification was by reduction in the flue gas temperature thereby reducing fly ash resistivity and increasing the specific collection area (SCA). Under SI the fly ash/sorbent mixture may have a resistivity two orders of magnitude higher than normal fly ash due to reduction in SO_3 concentration and increase in CaO (Case, 1985; Dahlin, 1985; Gartrell, 1973).

Under normal short-term GR-SI operation with humidification, ESP performance was adequate to maintain particulate emissions below 0.1 lb/10^6Btu (43 mg/MJ) and stack opacity levels below the 30% limit. However, the increased fouling during extended GR-SI operation at full load increased the boiler exhaust temperature beyond the capabilities of the humidification system. As a result, the stack opacity increased over time. This was usually not a problem since Hennepin Unit 1 operates in cycling service. ESP performance was satisfactory during a 55 hour long-term GR-SI test at reduced load. Operation was limited to 32 hours at full load.

This section presents the available data relative to ESP performance. Data were taken to compare ash characteristics that are believed to affect ESP performance. These include particulate matter size and loading, fly ash resistivity, ESP inlet gas temperature distribution, and coal mill fineness measurements. In addition, internal and external inspections of the ESP helped to isolate electrical and mechanical problems that may have limited GR-SI operation.

10.4.1 Particulate Matter Loading

A summary of the ESP particulate loading test data is shown in Table 10-2 for the April and August/September 1992 ESP characterization tests. The particulate tests were conducted using EPA Method 17 at the ESP inlet and Method 5 at the ESP outlet duct. Hennepin Unit 1 is limited to particulate matter emissions of 0.1 lb/10^6Btu (43 mg/MJ), which corresponds to an hourly limit of 76 lb (34 kg) at 70 MW_e.

Figure 10-19 shows particulate emissions measured in the April 1992 tests and Figure 10-20 shows the particulate emissions for the August/September 1992 tests. The April results show that the ESP outlet loading during GR-SI with humidification was lower than under GR or baseline operation. The GR outlet loading results were likely affected by the higher gas temperatures associated with GR without humidification. The same trend was observed during the August/September testing, which showed lower ESP outlet loading during GR-SI operation, especially at 70 MW_e.

TABLE 10-2. SUMMARY OF ESP PERFORMANCE DATA

Date 1992	Run #	Boiler Load (MWe)	Coal Flow (lb/min)	Gas Heat (%)	Ca/S Molar Ratio	Humid H_2O (gpm)	ESP Inlet Loading (lb/hr)	ESP Inlet Gas Flow (dscfm)	ESP Inlet Partic. Conc. (gr/dscf)	ESP Outlet Loading (lb/hr)	ESP Outlet Gas Flow (dscfm)	ESP Outlet Partic. Conc. (gr/dscf)	ESP Outlet Emission (lb/MBtu)	SCA (ft^2/1000 acfm)	ESP Collection Efficiency (%)
13-Apr	1	70-GRSI	969	19.1	1.89	25.1	12,003	169,824	8.246	11.49	175,483	0.008	0.015	267	99.90
13-Apr	2	70-GRSI	971	19.0	1.87	27.6	8,957	171,702	6.086	16.34	182,442	0.010	0.021	259	99.82
14-Apr	1	60-GRSI	817	18.9	1.85	24.0	8,802	154,774	6.635	10.80	157,539	0.008	0.017	294	99.88
14-Apr	2	60-GRSI	826	18.6	1.78	29.0	10,832	159,213	7.937	13.40	162,307	0.010	0.021	286	99.88
15-Apr	1	70-GR	962	19.2	0	0.0	5,152	174,307	3.449	22.09	184,174	0.014	0.029	245	99.57
15-Apr	2	70-GR	962	19.0	0	0.0	5,111	184,444	3.233	18.62	189,905	0.011	0.025	232	99.64
16-Apr	1	45-GRSI	622	18.6	1.81	15.7	3,928	121,427	3.774	6.45	123,695	0.006	0.013	380	99.84
16-Apr	2	45-GRSI	634	18.3	1.79	21.6	4,571	120,891	4.411	6.02	129,095	0.005	0.012	370	99.87
17-Apr	1	70-Base	1167	0.0	0	0.0	6,845	169,014	4.725	13.04	178,952	0.009	0.018	251	99.81
17-Apr	2	70-Base	1168	0.0	0	0.0	5,405	167,864	3.756	16.34	184,509	0.010	0.022	249	99.70
26-Aug	1	45-GRSI	626	18.7	1.66	20.9	5,591	134,382	4.855	10.66	113,163	0.011	0.022	376	99.81
26-Aug	2	45-GRSI	626	18.7	1.66	20.9	5,382	132,116	4.753	2.75	117,334	0.003	0.006	368	99.95
27-Aug	1	60-GRSI	828	18.6	1.64	22.7	8,604	138,758	7.235	12.53	155,423	0.009	0.019	311	99.85
27-Aug	2	60-GRSI	826	18.6	1.64	22.7	7,810	142,615	6.390	10.89	153,547	0.008	0.017	311	99.86
28-Aug	1	60-GR	1171	18.7	0	0.0	7,425	138,236	6.268	10.62	151,162	0.008	0.016	300	99.86
31-Aug	1	70-Base	1171	0.0	0	0.0	7,562	171,351	5.149	21.28	178,405	0.014	0.028	248	99.72
31-Aug	2	70-Base	948	0.0	0	0.0	6,286	170,083	4.312	26.22	188,180	0.016	0.035	241	99.58
1-Sep	1	70-GR	948	19.0	0	0.0	5,120	158,883	3.760	19.80	180,642	0.013	0.027	255	99.61
1-Sep	2	70-GR	964	19.0	0	0.0	4,685	165,563	3.302	24.20	186,302	0.015	0.033	245	99.48
2-Sep	1	70-GRSI	964	18.7	1.71	24.9	8,183	167,188	5.711	18.62	181,596	0.012	0.025	261	99.77
2-Sep	2	70-GRSI	964	18.7	1.71	24.9	8,966	165,055	6.339	15.58	179,694	0.010	0.021	262	99.83
3-Sep	1	70-GRSI					8,346	169,103	5.759	18.08	185,797	0.011	0.024	255	99.78

dscfm: dry standard cubic feet per minute
gr/dscf: grains per dry standard cubic foot

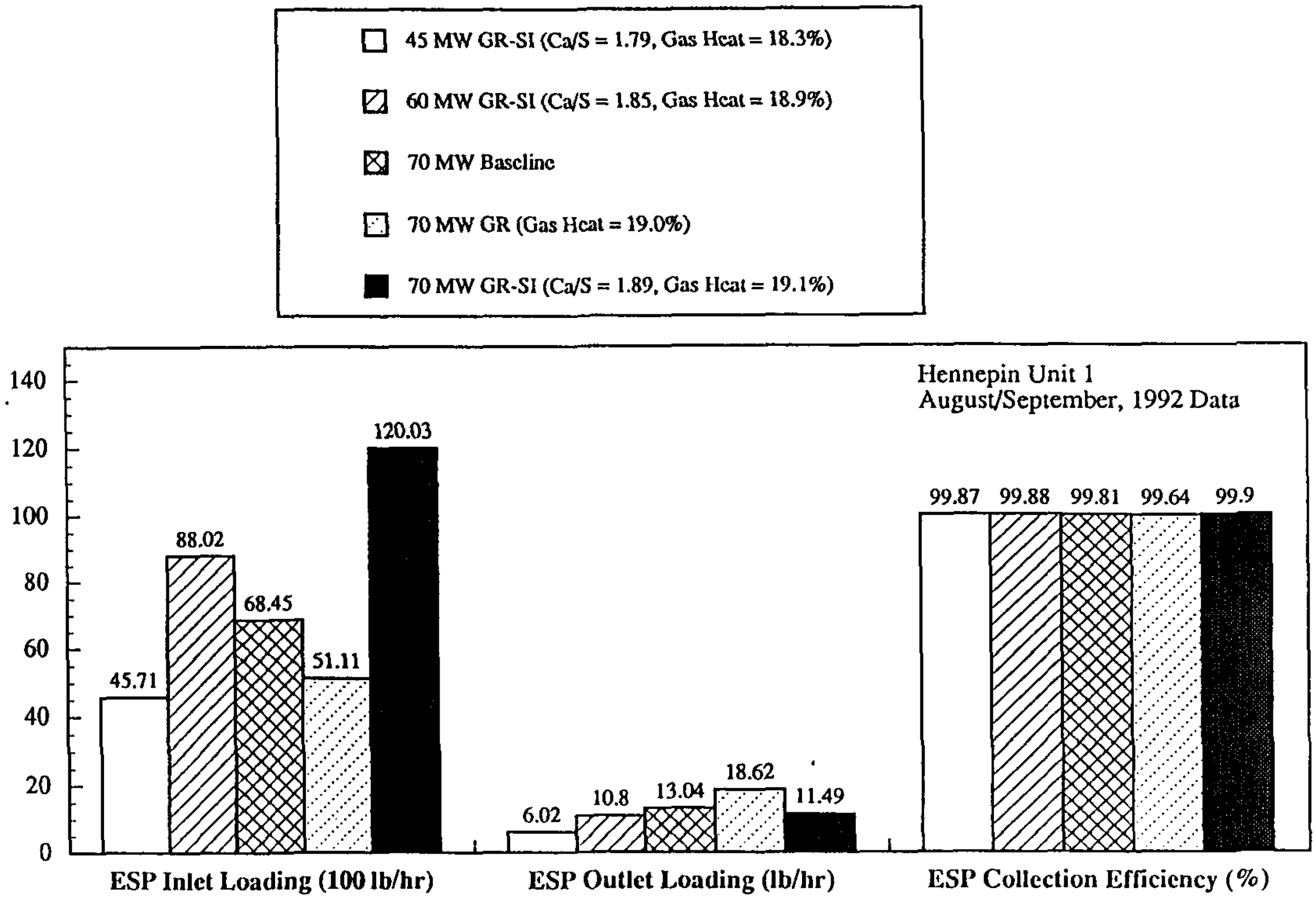


Figure 10-19. Particulate loading at the ESP inlet and outlet and collection efficiency (April, 1992 Data)

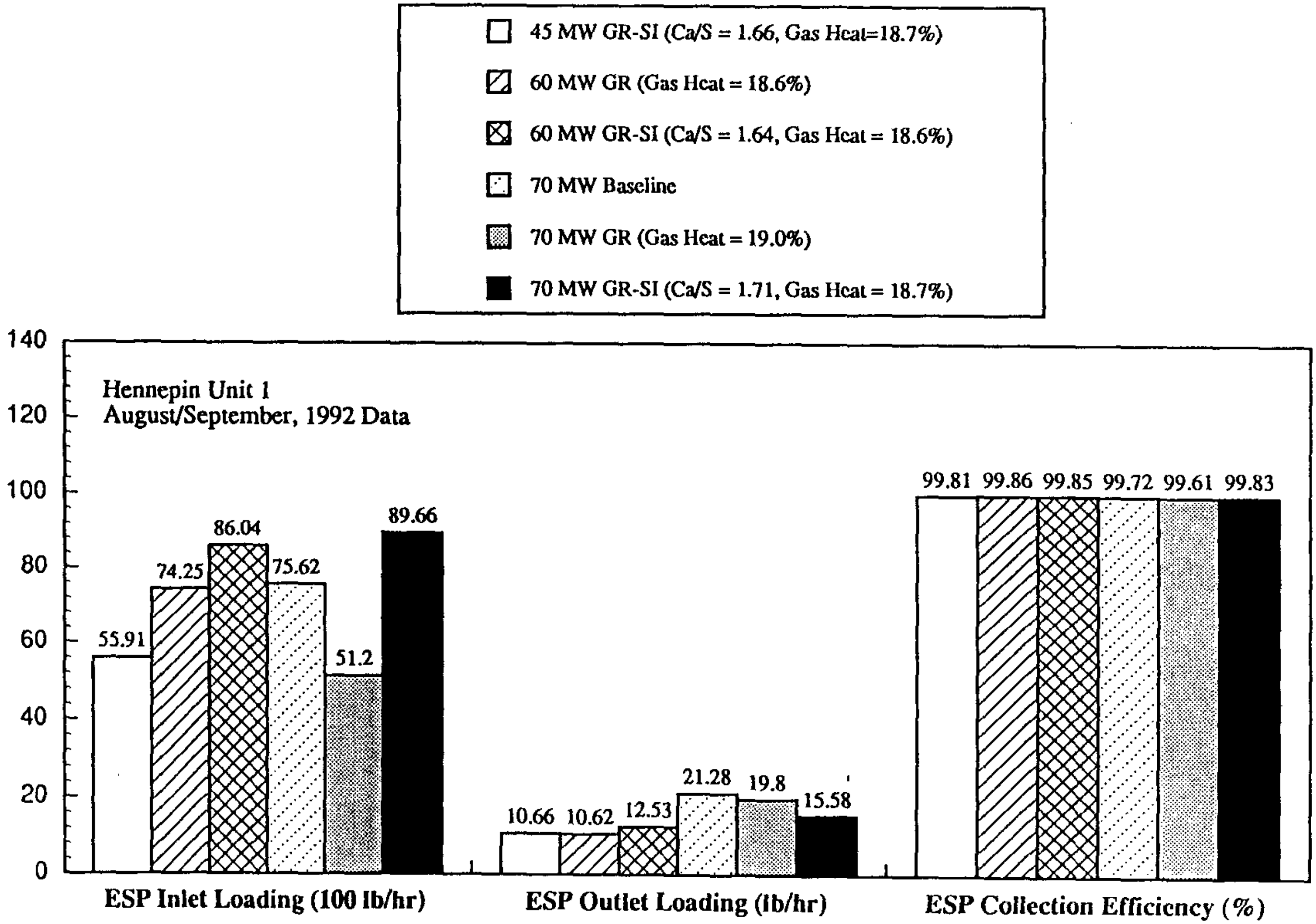


Figure 10-20. Particulate loading at the ESP inlet and outlet and collection efficiency (August/September, 1992 Data)

Figure 10-21 shows the overall mass collection efficiency as a function of the flue gas temperature, measured at the ESP outlet. Gas temperature was reduced in the humidification duct, from the air heater outlet temperature of 350°F (177°C), to a range of 272°F (133°C) to 287°F (142°C). This resulted in enhanced particulate matter capture from that under baseline in which the ESP outlet gas temperature ranged from 307°F (153°C) to 322°F (161°C). Under full load GR-SI operation, the mass collection efficiency ranged from 99.77 to 99.90%, compared to the full load baseline range of 99.58 to 99.81%. One of the impacts of humidification was to increase the SCA of the ESP. The SCA of the Hennepin precipitator varied from 232 ft^2/ 1000 acfm (45.7 m^2/ m^3/s) at 70 MW_e to 380 ft^2/ 1000 acfm (74.8 m^2/ m^3/s) at 45 MW_e. The strong impact of SCA on collection efficiency is a typical characteristic of ESP performance.

10.4.2 Particulate Matter Size

The size of particulate matter into the ESP may have a significant effect on the mass collection efficiency achieved. This is due to differences in migration velocity of particles with different diameters resulting in different collection efficiencies. The particle size distribution data are presented in Figures 10-22 through 10-25 for the April 1992 and August/September 1992 ESP performance tests. Each figure illustrates a series of data for samples collected at the ESP inlet duct with a Mark V - Five Stage Series Cyclone and at the ESP outlet duct using a Mark III - University of Washington type cascade impactor. All ESP inlet samples, over the load range, had mass mean diameters (MMD) greater than 10 microns except for a single sample at 45 MW_e which showed an MMD of approximately 3 microns. This may be an abnormal datum point since other tests at 45 MW_e showed MMD greater than 10 microns. A possible cause may have been an overly fine mill product.

Figures 10-22 and 10-23 show that the size distribution of particle samples at the ESP inlet are very similar for Baseline, GR, and GR-SI operation at 70 MW_e for particle diameters greater than 7 microns. For particle diameters under than 7 microns, GR samples had a larger fraction of particles in the 2 to 7 micron range compared to baseline and GR-SI

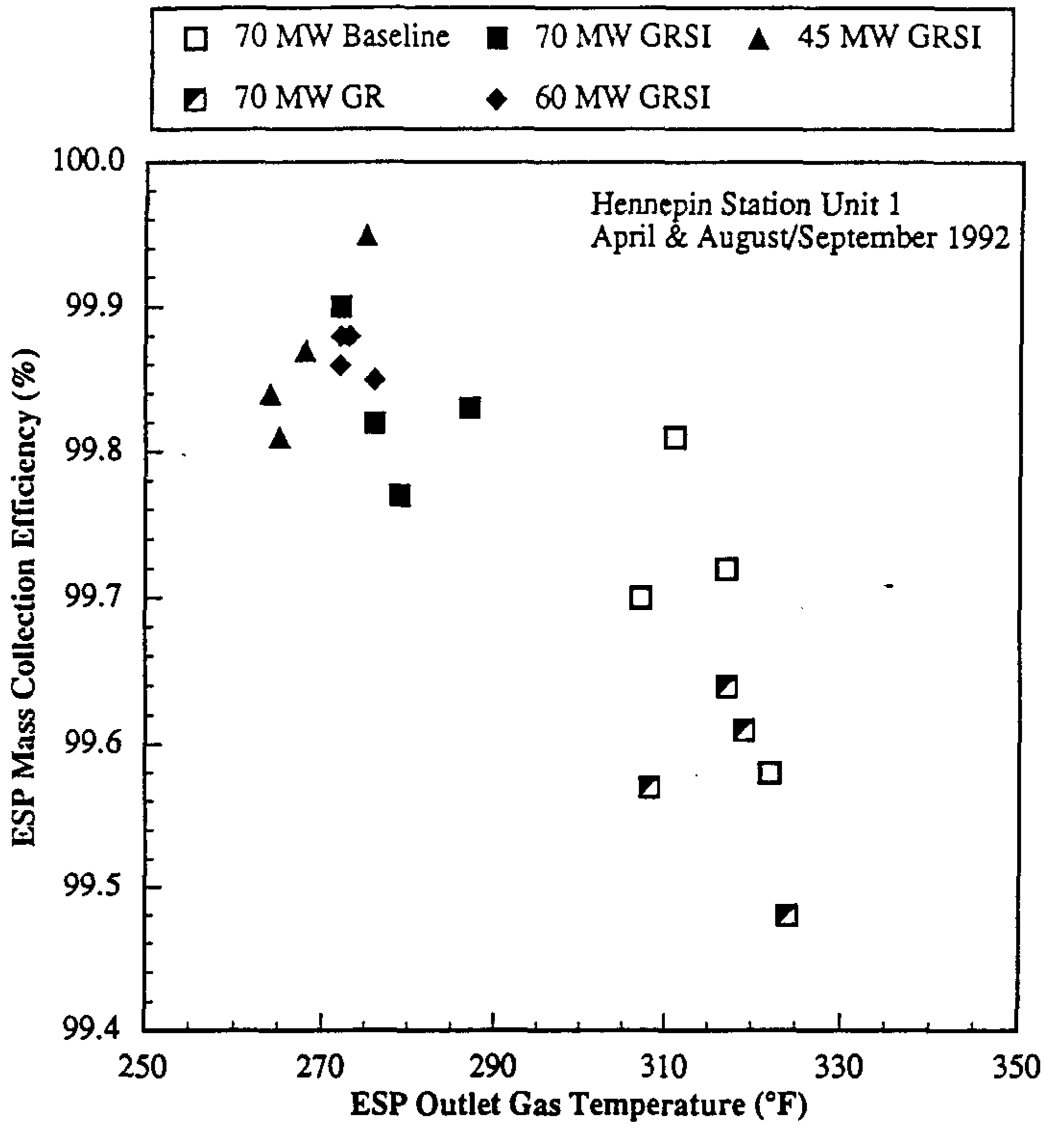


Figure 10-21. ESP mass collection efficiency as a function of flue gas temperature

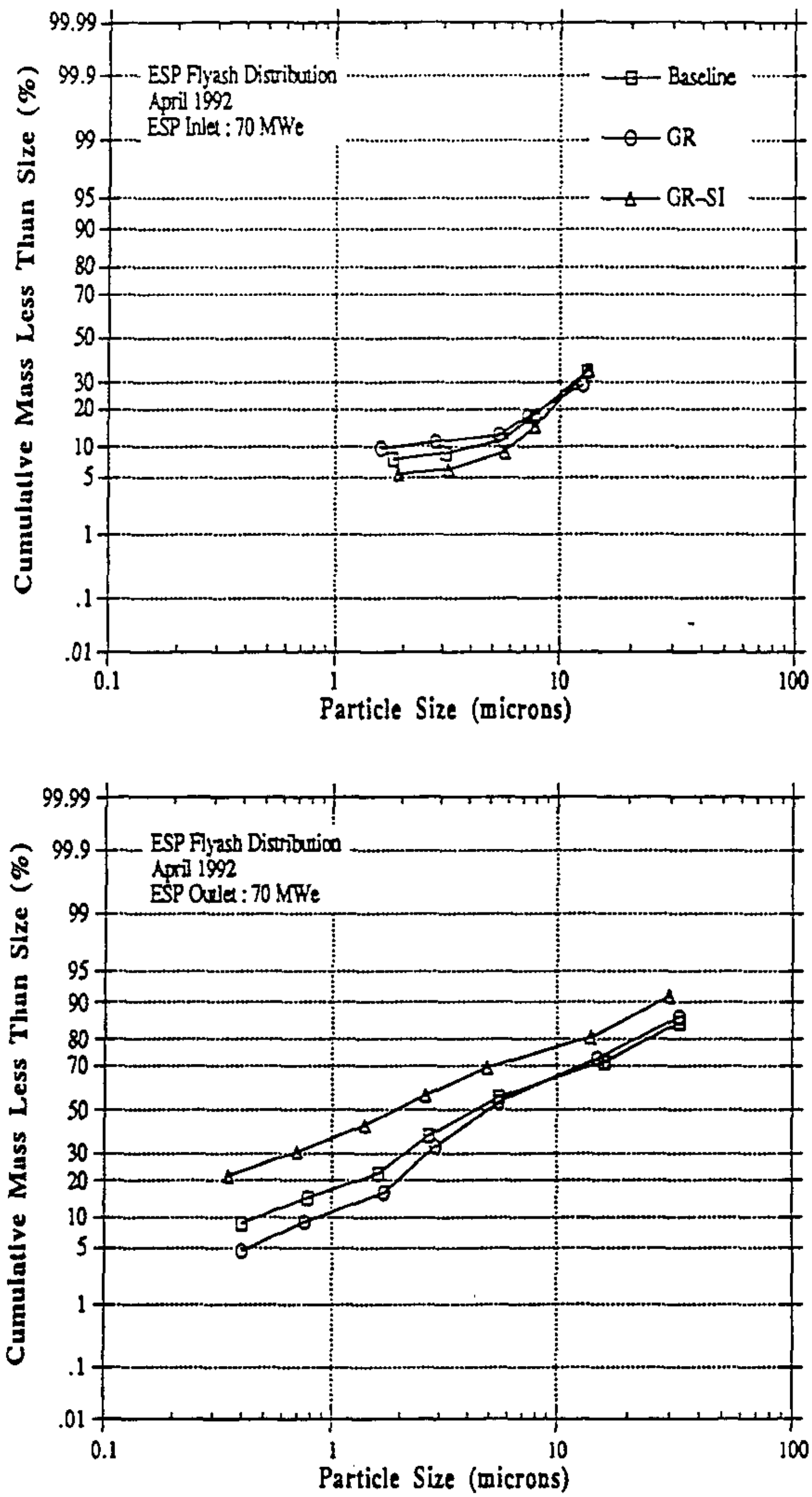


Figure 10–22. Particle size distribution for April, 1992 70 MW_e tests

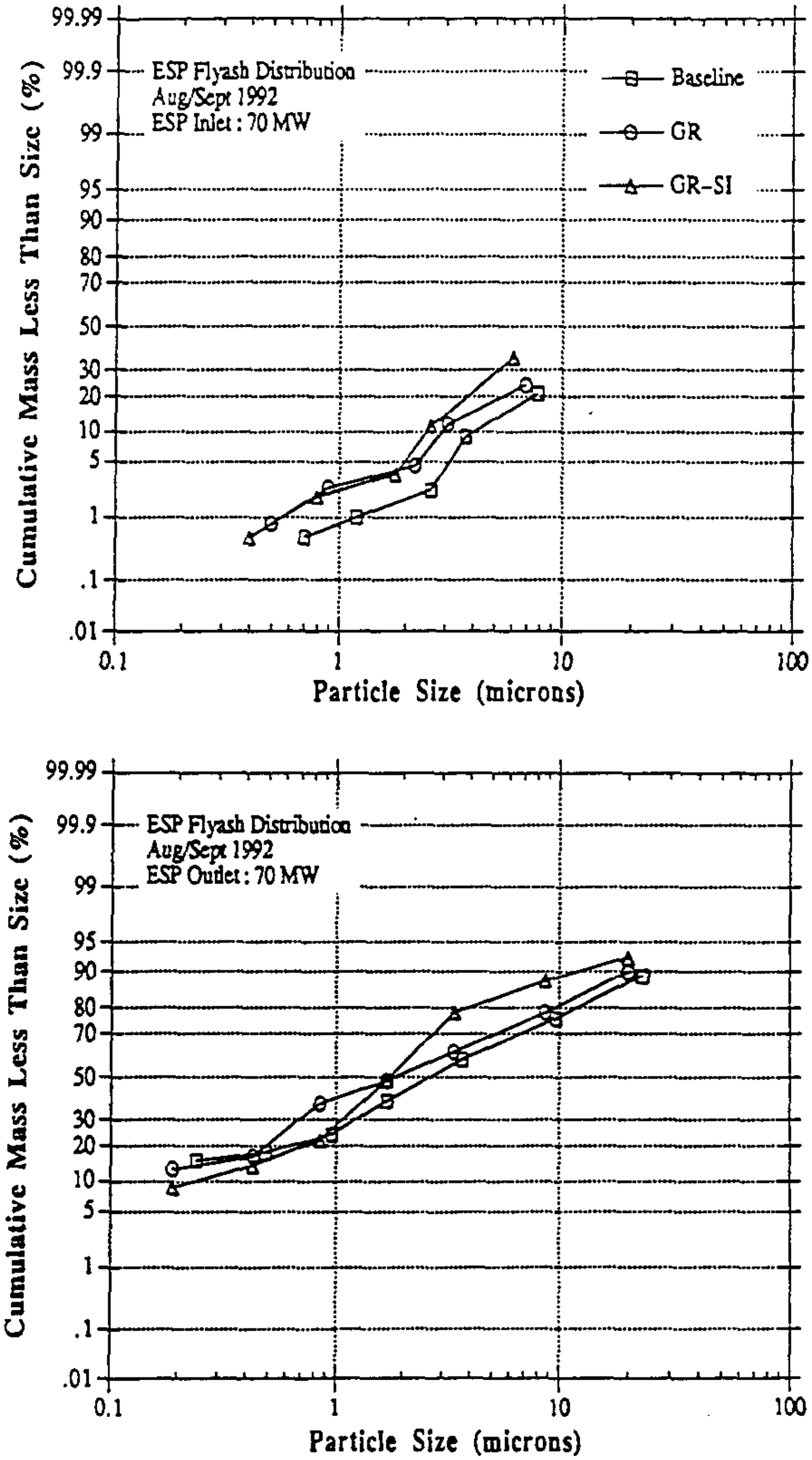
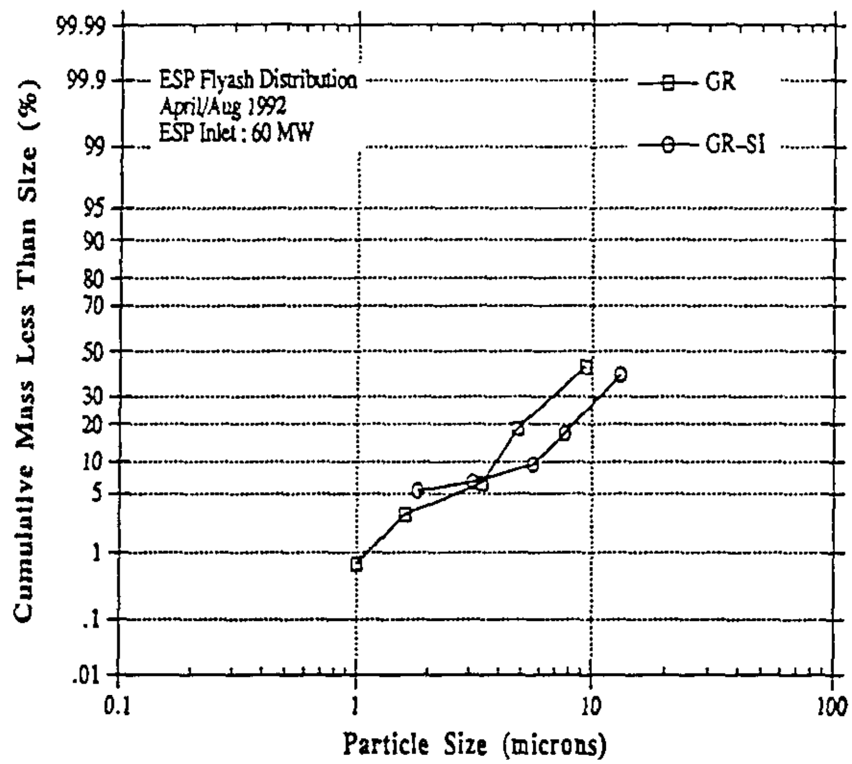


Figure 10–23. Particle size distribution for Aug/Sept 1992 70 MW_e tests



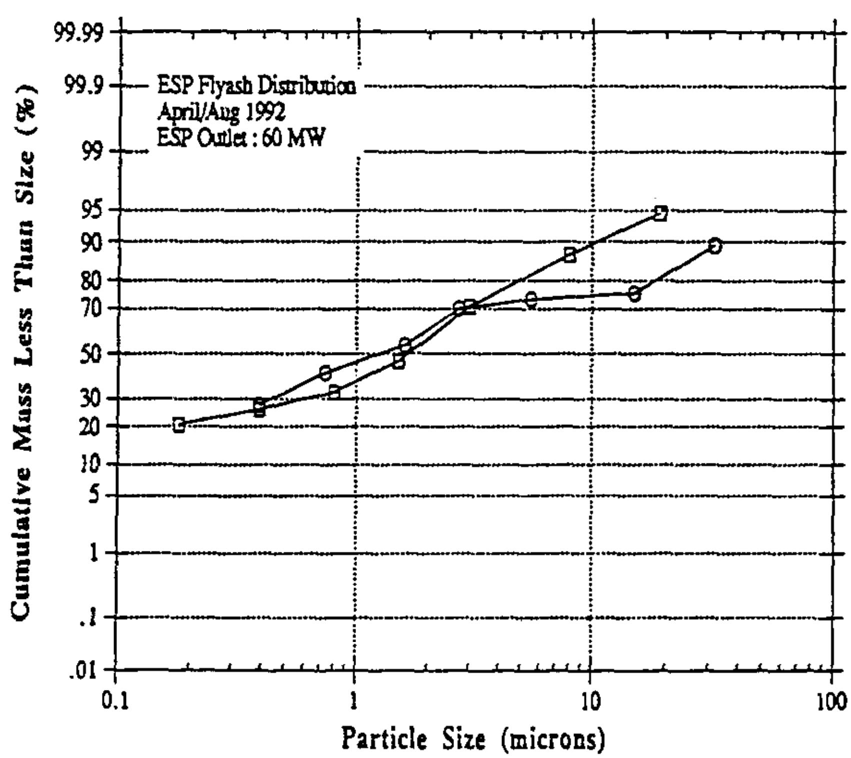
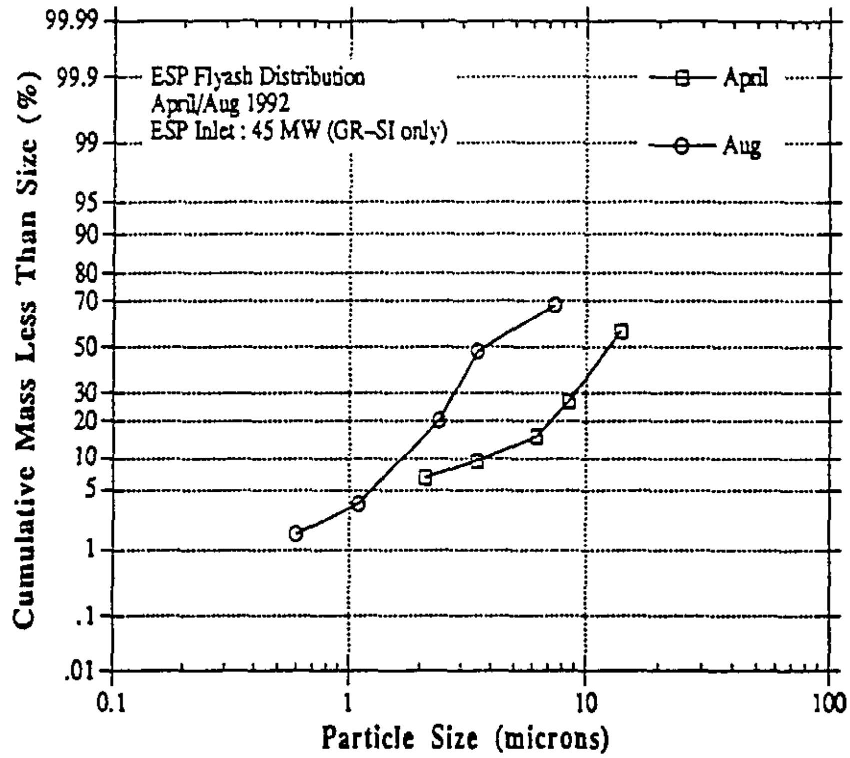


Figure 10–24. Particle size distribution for April/Aug 1992 60 MW_e tests



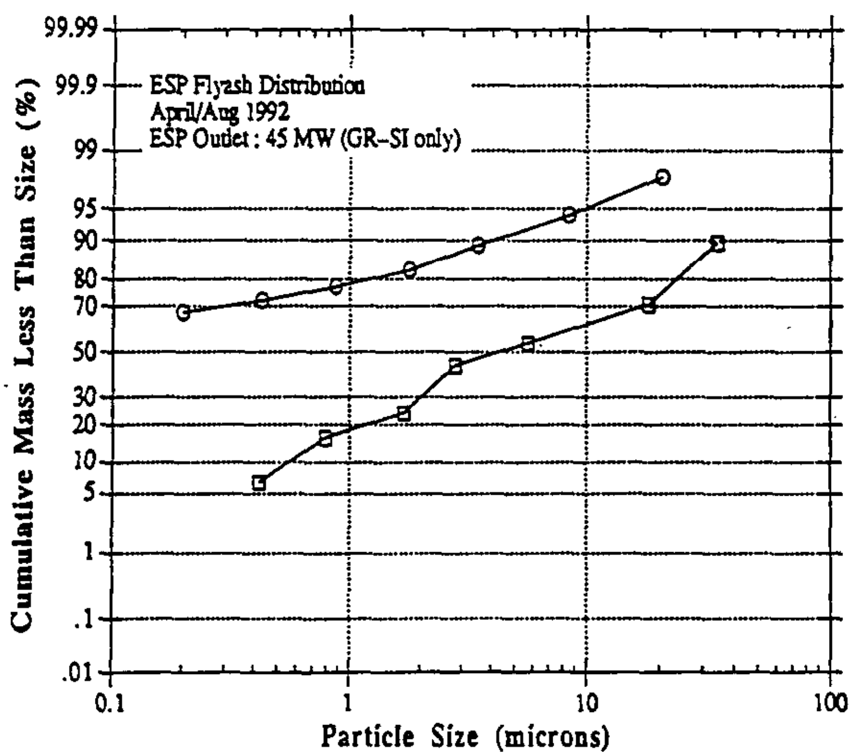


Figure 10–25. Particle size distribution for April/Aug 1992 45 MW_e tests

samples. The outlet data showed that GR-SI samples had an MMD of 2 microns compared to the 5 micron MMD for GR and baseline samples. The second test series showed more uniformity of the three samples with an approximate MMD of 2 microns. Sampling at the ESP outlet showed that during full load GR-SI operation, 75 to 90% of the particulate matter was under 10 microns, while during full load GR and baseline operation, 65 to 80% was under 10 microns.

Particulate samples collected during 60 MW_e GR and GR-SI operation, shown in Figure 10-24, had similar MMDs. The MMD at the ESP inlet was greater than 10 microns for the GR and GR-SI samples. At the outlet, the MMD was less than 2 microns for both samples.

Particulate samples from 45 MW_e operation were taken only during GR-SI operation, and two cases are shown in Figure 10-25. The size distribution measured in August indicated smaller particles both entering and exiting the precipitator. The MMDs at the inlet were 10 microns and 3.5 microns for April and August samples, respectively. The MMDs at the outlet were 4 microns and less than 0.2 microns for April and August samples, respectively. Differences in size distribution may have been caused by inconsistent mill fineness, due to the burner turndown at the lower load. No particulate samples under baseline operation at 60 MW_e or 45 MW_e were collected for comparison.

The full load collection efficiencies for PM_{10} particles were 99.3%, 99.1%, and 99.7% during baseline, GR, and GR-SI operation, respectively, as shown in Figure 10-26. These were slightly lower than the overall mass collection efficiencies for each case. This trend is typical of ESPs, which have a lower collection efficiency for particles in the 0.1 to 1 micron range. The PM_{10} emissions remained virtually unchanged, as evident in the following data from full load tests during August 1992.

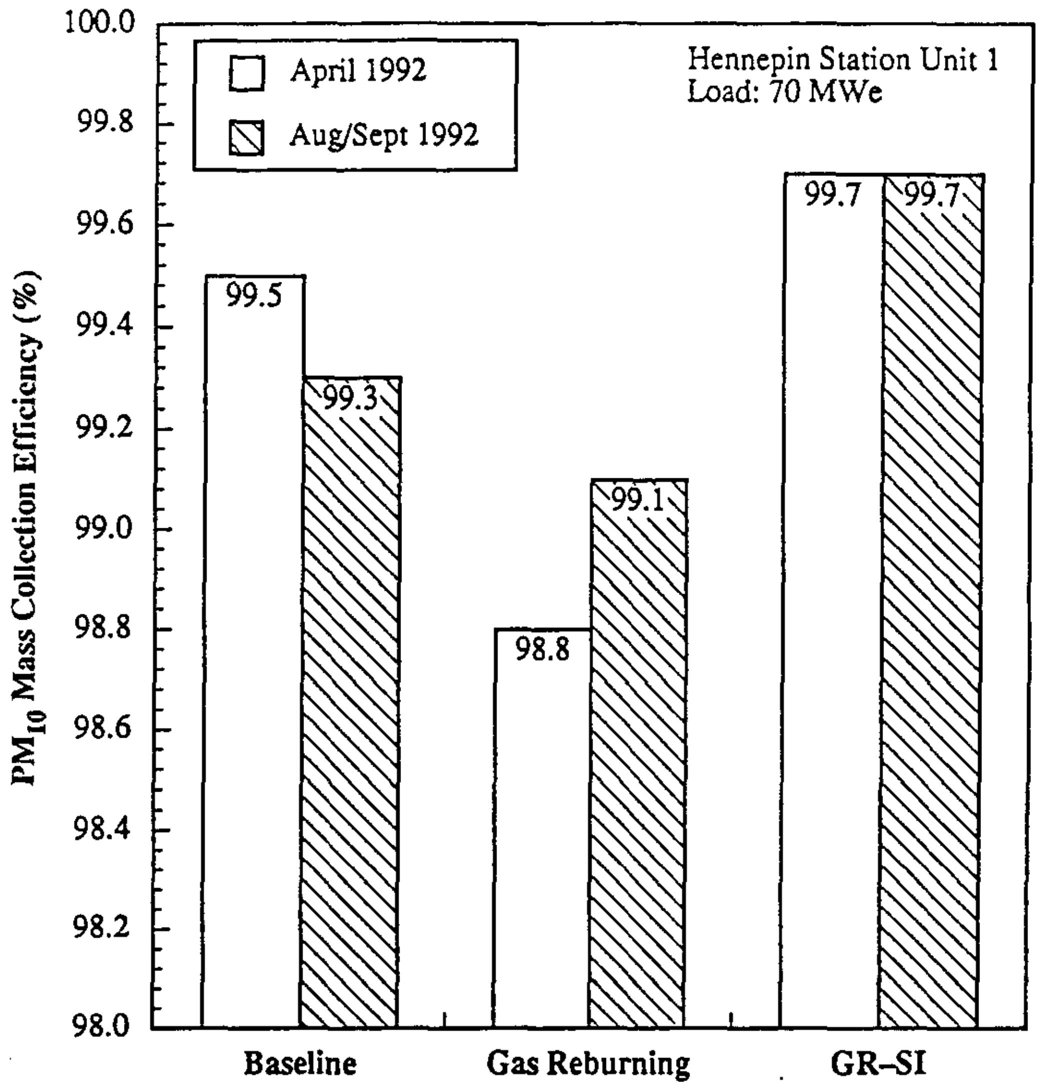


Figure 10-26. PM_{10} mass collection efficiency

Operation	ESP Outlet PM_{10} (%)	ESP Outlet PM_{10} Loading (lb/hr)
Baseline	77	16.4
GR	80	15.8
GR-SI	89	16.6

10.4.3 Fly Ash Resistivity

In-situ resistivity measurements were made in March 1992 through the ESP inlet ports. Figure 10-27 shows the resistivity measurements for 70 MW_e operation. The measurements were made with a point-to-plane resistivity probe. The method entails creating an electric field between an electrode and a grounded collecting plate. As the flue gas passes between the electrode and the collecting plate, a Voltage-Current (V-I) curve is obtained, first with a "clean" plate then with a "dirty" plate. The resistivity is calculated from the difference between the two V-I curves and the thickness of the fly ash layer on the "dirty" plate.

Under baseline and GR operation, the fly ash resistivity was in the area of the mid 10^{10} ohm-cm at temperatures of about 330°F (166°C). This is typical for fly ash from bituminous coal with a sulfur content of about 3%. Under GR-SI, the measurements indicated resistivities ranging from 6×10^{10} ohm-cm at 180°F (82°C) to 6×10^{11} ohm-cm at 300°F (149°C). The variation in resistivity appeared to be due primarily to the temperature. Good to excellent precipitation of the ash-sorbent mixture can be expected for a resistivity of 6×10^{10} ohm-cm, which was confirmed by particulate loading measurements.

10.4.4 Electrostatic Precipitator Inlet Duct Temperature Distribution

Variations in flue gas temperature at the ESP inlet may affect the resistivity of the fly ash and may, in turn, lead to premature sparking in some areas of the precipitator. It is generally believed that a good flow distribution will produce a good temperature distribution.

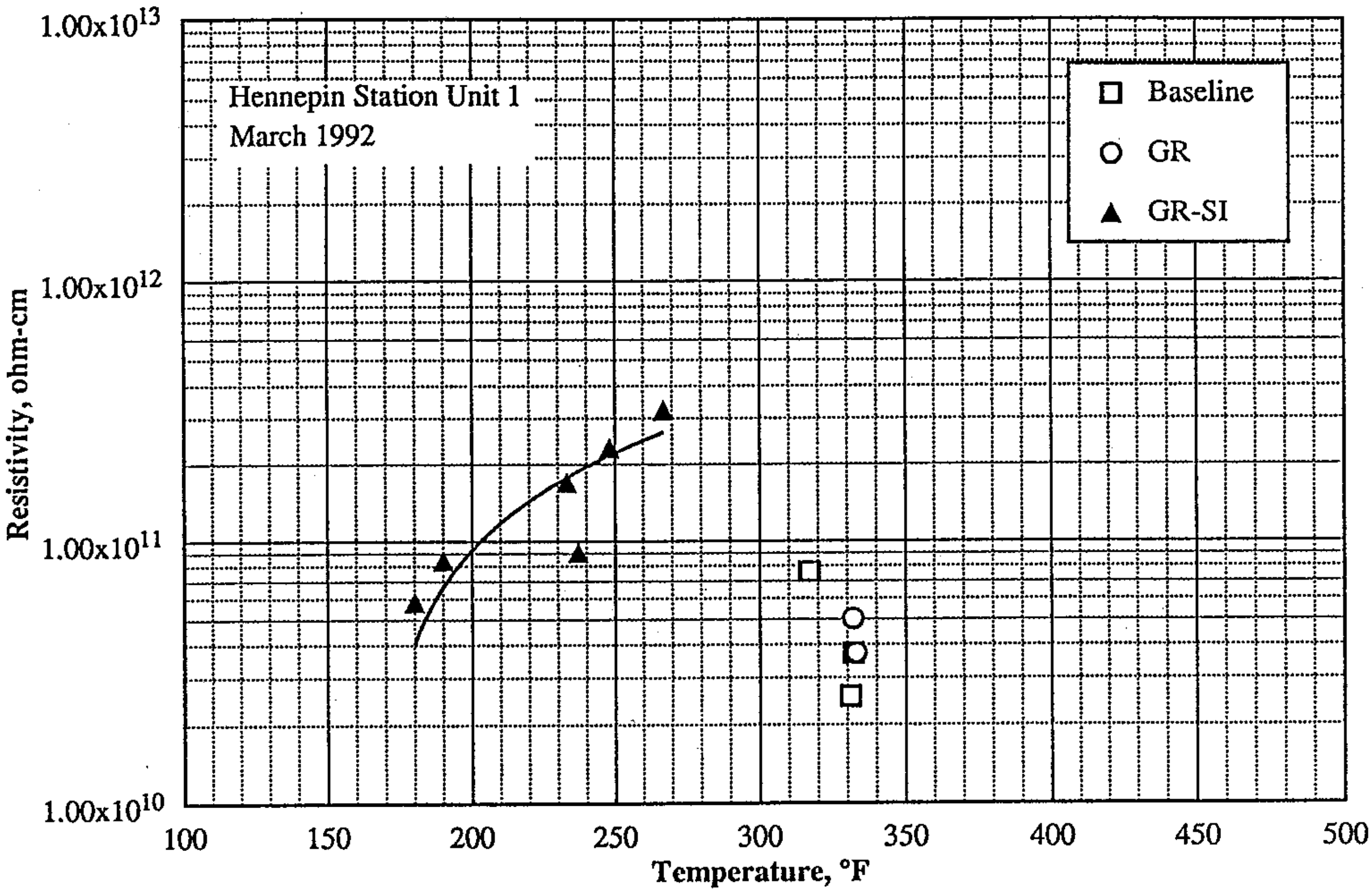


Figure 10-27. In–situ resistivity measurements during sorbent injection by the V–I method

Data were collected at 60 MW_e and 45 MW_e to determine the variations in flue gas temperature at the ESP inlet.

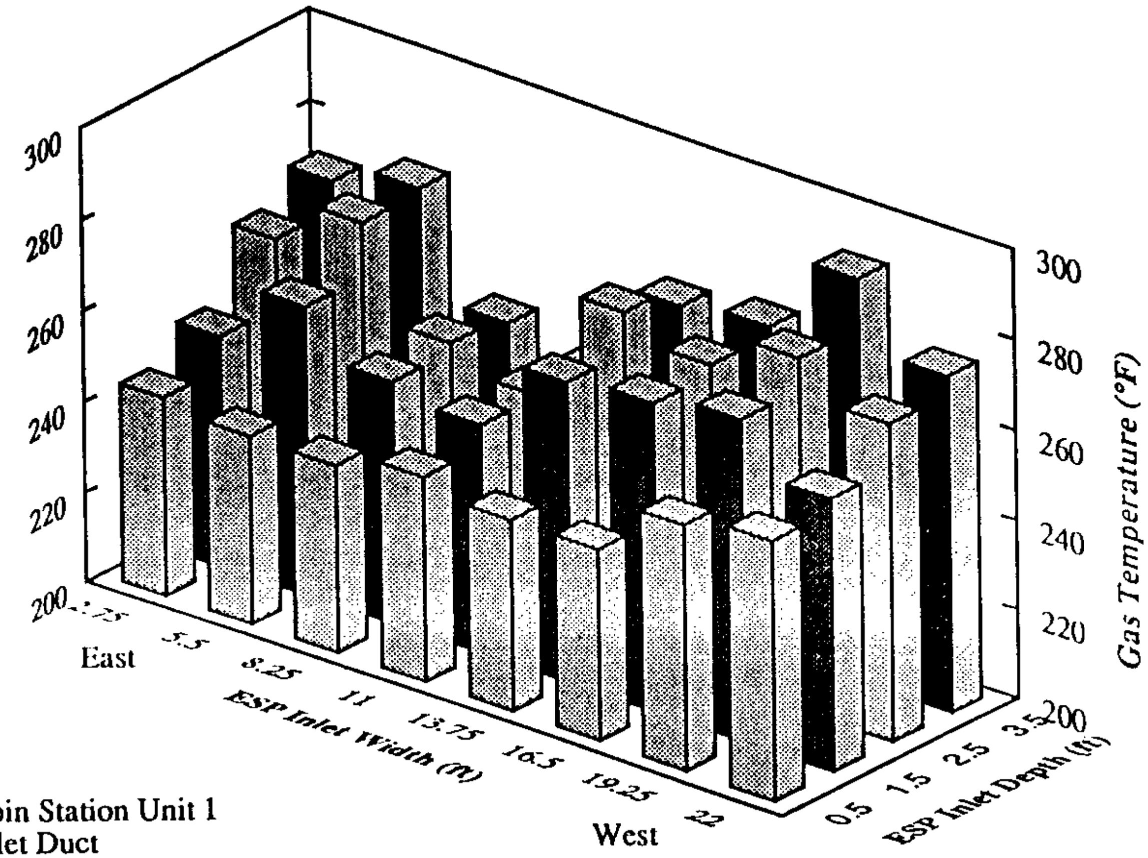
Figures 10-28 and 10-29 present data for the two operating cases mentioned above. At 60 MW_e, the minimum temperature measured was 242°F (117°C) while the highest was 290°F (143°C). The average temperature in the east duct was 256°F (124°C), with a standard deviation of 12°F (6.7°C). The average temperature in the west duct was 267°F (131°C), with a standard deviation of 13°F (7.2°C). Although the standard deviations were not large, there were some locations with high temperatures, typically in the center of each duct, near west and the back walls. The low-load case, illustrated in Figure 10-29, shows the reverse of the trend shown previously (i.e. higher temperatures in the east duct).

Each profile has an area where the flue gas temperature exceeded 285°F (141°C). These high temperature zones produced high-resistivity "hot spots" in the inlet field of the ESP. Since the Hennepin ESP contains only one bus section for the entire inlet cross section, sparkover at high resistivity "hot spots" could have dominated power levels for the entire inlet field. Nevertheless, the particulate tests showed that humidification was highly effective in enhancing ESP performance.

10.4.5 Electrostatic Precipitator Inspections

Proper ESP performance was vital to the success of the GR-SI demonstration. It was determined early in the long-term testing phase that success of the program would depend on the operation of the ESP during extended continuous SI. For this reason, several inspections were scheduled to recommend changes to the mechanical and electrical operating conditions. The inspections were also conducted to determine if GR-SI had negatively impacted operation of the ESP.

The inspections identified key elements which would degrade ESP performance. ESP power levels and automatic voltage controller response to sparking was observed with specific



Hennepin Station Unit 1
ESP Inlet Duct
Dimensions: 25' Wide x 4' Deep
GR-SI Operation
Load: 60 MWe
Average Temperature: 262°F
26 August 1992: Run #2

Figure 10-28. ESP inlet duct temperature profile for a 60 MWe test

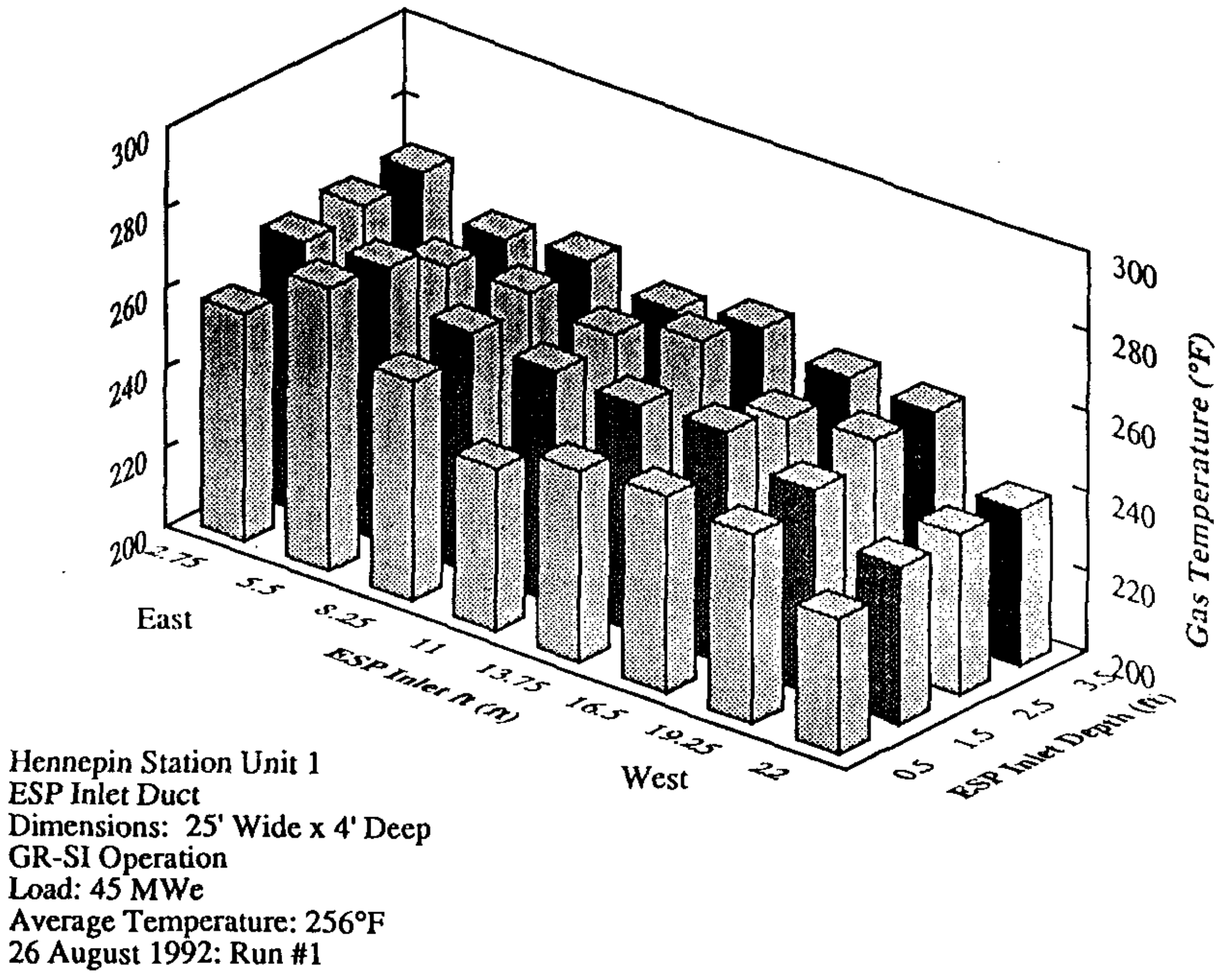


Figure 10-29. ESP inlet duct temperature profile for a 45 MWe test

attention to the "D" or inlet field, which had the greatest dust loading. Power levels recorded during the inspections are shown in Table 10-3. A downward trend is apparent with power levels being the lowest on August 28, 1992.

To explain the downward trend in power levels, a full mechanical inspection of the ESP was performed. It was verified that all the rappers and vibrators were working. All rappers were cycling once every 3.5 minutes. Each rapper was rapidly fired three times in turn during the cycle. Rapping intensities were all about equal with the exception of two Joy Western type replacement rappers which were not hitting as hard as the original rappers. A few rappers were slightly out of plumb but this had little effect on the impact energy as felt from the vibrations on the ESP roof. Reduced electrical clearances due to the swinging of the D, C, and B fields' lower high voltage frames may have also contributed to the lower power levels observed. Installation of anti-sway insulators was recommended to plant management.

10.4.5.1 Collector Plate Deposits

Deposits on collector plates ranged from 1/8 inch (0.3 cm) to 3/8 inch (1.0 cm) in thickness throughout most of the ESP. These collector plate deposits were light grey and had a popcorn-like modular texture. The texture of the deposits may have been caused by the wetting of the ash layers during humidification, or excursions through the dew point experienced while the boiler cycled off and on. The high resistivity sorbent-rich dust on the collector plates was thought to contribute to the poor power levels. The inlet field was, therefore, power-off rapped for about 1-1/2 hours. When re-energized, the inlet field current levels had increased from approximately 110-140 to 211 mA. In order to improve rapping effectiveness and restore power levels, the residual deposits on the ESP collector plates were cleaned by grit blasting.

Scouring of the top 4 to 6 feet (1.2 to 1.8 m) of the inlet field was observed. This resulted in patches of bare metal on collector plates on the first and second collector plate panels

TABLE 10-3. OBSERVED ESP POWER LEVELS

Date		Field			
		D	C	B	A
3/16/92	KW	21 - 25	38	45	41
	KVDC	35 - 39	42	41	36
3/23/92	KW	32	41	50	41
	KVDC	40	40	41	36
8/28/92 Prior to Adjust.	KW	5.4	12	34	38
	KVDC	30	33	37	36
8/28/92 After Adjust.	KW	9	41	35	38
	KVDC	30	34	39	38
8/28/92 After Humid.	KW	25	28	38	42
	KVDC	41	40	38	39

across the top of the ESP inlet field. This type of scouring is typical for high gas velocities. It should be noted that this type of bottom entry inlet plenum is prone to high gas velocities at the top of the ESP. This is especially true in units designed prior to 1978 when the Industrial Gas Cleaning Institute changed the guidelines for ESP gas flow distribution and model studies.

10.4.5.2 Emitter Wire Deposits

Emitter wire deposits ranged from the light dust on the outlet fields to 3/8 inch (1 cm) diameter deposits on the upper third of the inlet field. Again, the deposits were considered to be normal and were not expected to have a negative effect on ESP performance.

10.4.5.3 Collector/Emitter Alignment

Collector plate to emitter wire clearances were checked randomly throughout the ESP in February 1992. A, B, and C fields were, for the most part, $\pm$ 3/8 inch (1 cm) from perfect alignment. The only performance limiting alignment problem observed was in the D field where a 1 inch (2.5 cm) misalignment existed in the second passageway from the southeast. This misalignment was primarily from a bowed collector plate. Further inspection of the ESP in August 1992 showed that the alignment in the A, B, and C fields remained approximately the same but D field misalignment was worse than in the prior inspection. Horizontal bows in the B-line or lower plate stiffener on the fourth collector plate reduced emitter wire to collector plate clearances. This will result in a reduction of field voltage of about 25% when the field is spark limited.

10.4.5.4 Controller Settings

At each inspection, controller settings were checked and compared with the recommended settings from the original inspection in February, 1992. Table 10-4 shows the controller settings as found on 28 August 1992 and the recommended settings. After re-adjustment, the

TABLE 10-4. ESP CONTROLLER SETTINGS

Automatic Voltage Control Setting (As Found)				28 August, 1992
Parameter	Field			
	D	C	B	A
PTC	On	On	Off	On
Slow Ramp (sec)	5	5	5	5
Fast Ramp (sec)	20	20	20	20
Quench Cycles	1	1	1	1
Spark Setback (%)	15	15	15	15
Spark Setback (%)	5	5	2	5
PV Limit (%)	100	100	100	100
PA Limit (%)	100	100	85	85
Automatic Voltage Coltrol Setting (Readjusted)				28 August, 1992
PTC	On	On	On	On
Slow Ramp (sec)	1	2	2	2
Fast Ramp (sec)	10	10	10	20
Quench Cycles	1	1	1	1
Spark Setback (%)	3	5	5	15
Spark Setback (%)	1	1	1	5
PV Limit (%)	100	100	100	100
PA Limit (%)	100	100	85	85

spark rate of the inlet field increased from 12 sparks per minute to 55 sparks per minute which is much closer to the target spark rate of 60 sparks per minute. In addition, adjusting the "D" field controller increased the precipitator current from about 210 mA to 300 mA. After the controls were readjusted, humidification of flue gas commenced, then current levels on the inlet field increased to 624 mA initially and then settled at 750 mA.

10.5 Impacts of GR-SI on Tubewall Wastage

To determine the extent of tubewall wastage due to GR-SI, ultrasonic thickness (UT) measurements were made at approximately 4,000 points in the boiler. These were conducted at three times: in December, 1988, prior to GR-SI start-up, in September, 1990 and in October, 1992 to determine the impact of long-term GR-SI operation. These are summarized in the table below. The measured tube thicknesses from the three tests were compared to determine the extent of tube wastage in several areas of the boiler, including the furnace and convective pass. Metallographic examinations for decarburization were carried out on sixteen tubewall samples, taken in 1990 and 1992.

Date	Significance of UT Measurement
1988	Initial Baseline
1990	Final Baseline - Simultaneous GR-SI Installation
1992	After GR-SI Testing

No increase in tubewall wastage over baseline wastage was determined. Generally, measured wastage rates over the two year GR-SI evaluation were either less than the baseline wastage rate or within the tolerance for the measurement. At some locations there was an apparent increase in wastage over the 1990 to 1992 period, but the 1990 measurements were higher than 1988 measurements. In many areas of the boiler a decrease in wastage rate or even an apparent increase in tubewall thickness (due to measurement inaccuracy) were determined. In two specific regions of the primary superheater, tubewall thicknesses were below the flag-point thickness in each of the three tests. The low readings in these areas can not be attributed to GR-SI, since they were measured before the demonstration. Metallographic examinations found no evidence of decarburization in the 16 tubewall samples.

10.5.1 Tube Measurement Procedures

Specific areas were targeted where high rates of corrosion or erosion are possible. Approximately the same number of points were tested during the three test periods with the distribution of points tested in 1988 shown below:

Boiler Area	Number of Readings
Furnace Walls	644
Furnace Screens	552
Secondary (pendant) Superheater	252
Reheater	720
Convection Pass Rear Walls	183
Primary (horizontal) Superheater	1,584
Economizer	216
Total	4,151

In addition to the above, measurements near the retrofitted SI and reburning ports were made in 1990 and 1992.

Preparation of the surface was by wire-brush in the 1988 test and by sand blasting in the latter two tests. The equipment used included: Krautkramer USL-48 Ultrasonic Flaw Detectors, KB Aerotech Transducers, and Natrasol mixed with water as the couplant. The ultrasonic unit was calibrated using a step-wedge made of SA-106, Grade B material with thickness variations of 50 mils (1.3 mm), over the range of 50 to 300 mils (1.3 to 7.6 mm). Measurements were taken at the center of the tube and at each side, at each location. In some cases, specific areas or tubes were not accessible for measurement during the latter tests, due to installation of tube shielding after the initial test.

10.5.2 Measurement Accuracy

The measurement accuracy is $\pm$ 5 mils (0.13 mm), i.e. the measurements are within $\pm$ 5 mils of the actual tubewall thicknesses. There are several possible sources of inaccuracy in the measurements. One source of inaccuracy results from measurement of tubewall thickness at points proximate to the original location, but not at precisely the same point. The measurement locations were denoted through distances from specific points in the boiler. Therefore, in repeating the measurements at two-year intervals, it is likely that measurements were taken at points near the original point, but not at precisely the same location. Significant variation in tubewall thickness with position along the same tube has been determined.

Another source of inaccuracy is in the preparation of the surface, since two methods of surface preparation were used. Wire-brush preparation is done by hand; therefore, the extent of this preparation will vary with the person applying the technique. In general, any surface preparation results in some error in the measurements. When a new or newly cleaned steel tube is initially exposed to combustion products, accelerated wastage occurs as an oxide layer forms on the surface. The wastage rate then decreases as the oxide layer acts to protect the tubewall. When a surface is repeatedly cleaned for thickness measurements, the tubewall may experience significant wastage in the period after cleaning. As a result, the wastage rate measured over a short time interval will reflect (in part) the accelerated wastage immediately following cleaning. Therefore, tubewall wastage rates calculated during baseline operation (1988 - 1990) and during GR-SI operation (1990 - 1992) are impacted by the surface preparation.

10.5.3 UT Measurement Results

Figure 10-30 shows the UT measurement locations. The UT data were evaluated to determine the following:

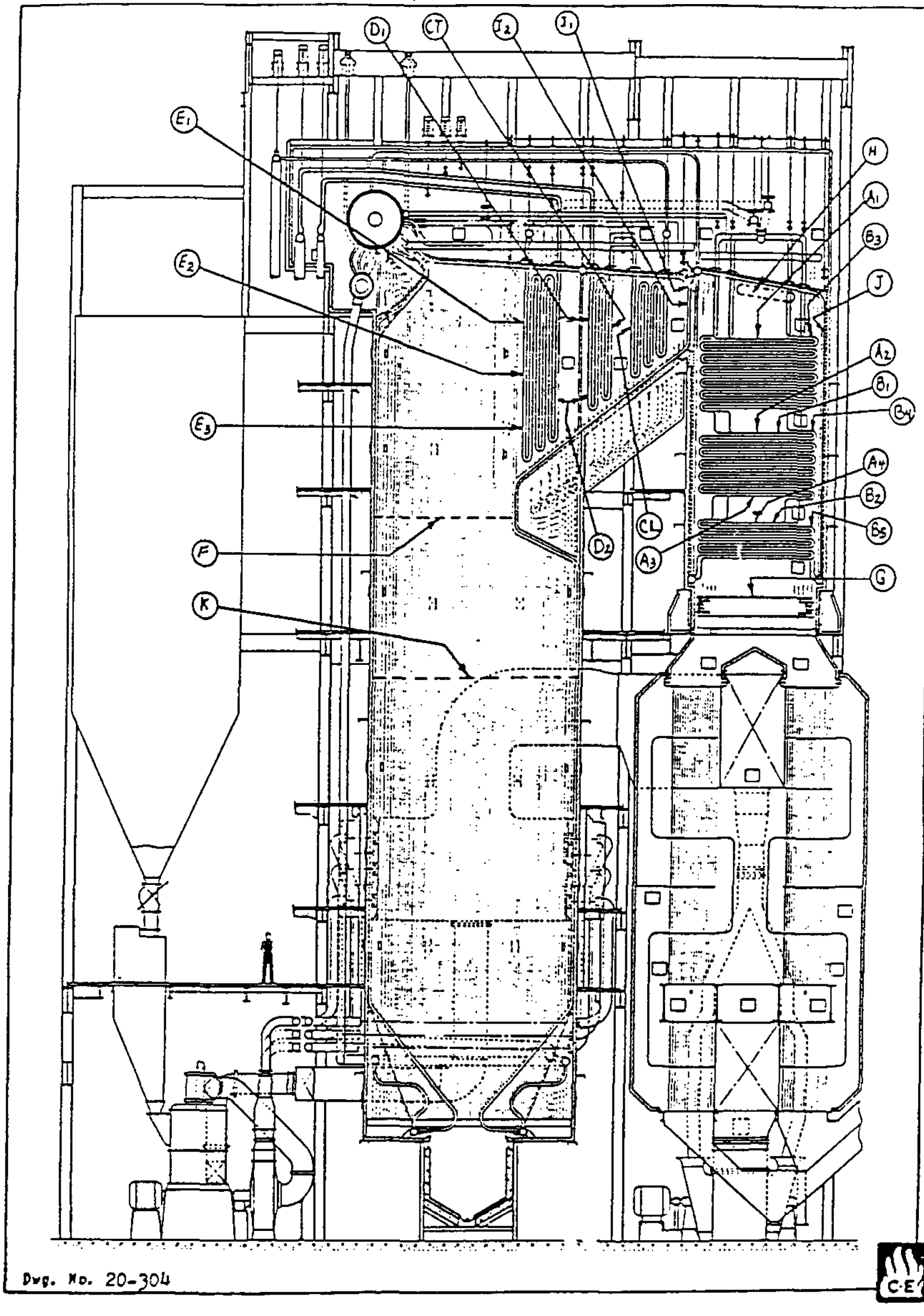


Figure 10–30. Ultrasonic Thickness measurement locations

1. Areas where tube thickness was beneath that required for normal safe operation.

2. Tube wastage rates during baseline and GR-SI operation

3. Areas where tube wastage rates changed during GR-SI testing

4. Projected life of the tubes under continued baseline and GR-SI operation

Table 10-5 presents an analysis of tube thickness based on structural considerations. The information presented includes the results of the UT tests and the "flag point" thickness. The flag point thickness is the minimum acceptable tube thickness based on structural considerations. It is defined as 85% or 70% of the original tube thickness specification for steam or water cooled tubes, respectively. Only two areas had any tubes thinner than the flag point thickness at the end of the GR-SI testing (Nos. 3 and 4 adjacent to Primary Superheater Sootblower 15). As shown in Table 10-5, a significant number of these tubes were also thinner than the flag point at the beginning of the GR-SI testing in 1990. In fact, the number of tubes thinner than the flag point actually decreased slightly for No.3 (due to measurement area). This suggests that the tube wastage is due to the operation of Sootblower 15 rather than GR-SI.

Table 10-6 presents the UT results accounting for the variation in original tube thickness and UT measurement errors. In 1953 when Hennepin Unit 1 was erected, the tubes were specified to have a minimum wall thickness. The tolerance on thickness was + 22%. Table 10-7 lists the minimum thickness, the tolerance and the average thickness (minimum plus 1/2 of the tolerance). The average results of the UT measurements are also shown. Since the UT instrument had a nominal accuracy of +/- 5 mils, the range of thickness was also calculated and is shown in the Table 10-6.

TABLE 10-5 ULTRASONIC THICKNESS MEASUREMENTS AT HENNEPIN UNIT 1

No	Loc.	Description	Elev. (Inch)	Tube ODxMW (In.xIn.)	Flag Point (Mils)	*Lowest** Reading 1988 (Mils)	*Lowest* Reading 1990 (Mils)	*Readings* Below FP 1990	*Lowest* Reading 1992 (Mils)	*Readings* Below FP 1992
1	A1	Primary Superheater at Sootblower 11	6834	2.125x0.188	160	190	200	0	186	0
2	A2	Primary Superheater at Sootblower 13	6704	2.125x0.180	153	190	200	0	192	0
3	A3	Primary Superheater at Sootblower 15	6620	2.125x0.165	140	100	95	73	89	68
4	A4	Primary Superheater at Sootblower 15	6582	2.125x0.165	140	90	100	75	90	132
5	B1	Primary Superheater at Sootblower 13.10	6704	2.125x0.180	153	185	190	0	191	0
6	B2	Primary Superheater at Sootblower 15.10	6582	2.125x0.165	140	160	150	0	127	2
7	B3	Primary Superheater Bends	6838	2.125x0.188	160	180	185	0	177	0
8	B4	Primary Superheater Bends	6704	2.125x0.180	153	165	170	0	169	0
9	B5	Primary Superheater Bends	6578	2.125x0.165	140	145	150	0	140	0
10	C	Reheater at Sootblower 9 - Front	6864	2.125x0.134	114	135	155	0	123	0
11	C	Reheater at Sootblower 9 - Rear	6864	2.125x0.134	114	130	140	0	116	0
12	D1	Screen at Sootblower 5	6861	3.000x0.280	196	270	260	0	223	0
13	D1	Reheater at Sootblower 5	6861	2.125x0.165	140	180	130	3	159	0
14	D2	Secondary Superheater at Sootblower 7	6747	2.125x0.313	266	320	310	0	332	0
15	D2	Reheater at Sootblower 7 - Rear	6747	2.125x0.165	140	170	180	0	177	0
	E1	*Secondary Superheater @ Sootblower 1*	*6861*	2.125x0.203	173	215	215	0	NA	NA
	E1	Screen @ Sootblower 1	6861	3.000x0.280	196	250	265	0	NA	NA
16	E2	Secondary Superheater Screens	6787	3.000x0.280	196	280	255	0	286	0
17	E3	S. S. Screens at Sootblower 3	6711	3.000x0.280	196	210	190	1	212	0
18	F	Furnace Wall - Front	6592	3.000x0.280	196	280	260	0	287	0
19	F	Furnace Wall - Left	6592	3.000x0.280	196	270	275	0	299	0
20	F	Furnace Wall - Right	6592	3.000x0.280	196	280	270	0	302	0
21	F	Furnace Wall - Arch (Rear)	6592	3.000x0.280	196	270	250	0	283	0
22	G	Economizer Outlet - Left Side	6481	2.000x0.165	115	175	170	0	165	0
23	G	Economizer Outlet - Right Side	6481	2.000x0.165	115	170	170	0	164	0
24	H	Economizer Outlet - Left Side	#	2.000x0.165	115	170	170	0	163	0
25	H	Economizer Outlet - Right Side	#	2.000x0.165	115	175	170	0	170	0
26	K	Furnace Wall - Left	6374	3.000x0.280	196	260	275	0	288	0
27	K	Furnace Wall - Right	6374	3.000x0.280	196	265	280	0	271	0
28	K	*Furnace Wall - Front*	6374	3.000x0.280	196	275	260	0	276	0

*: Tube Center Minima (Tube Center Minimum Slightly Varied From Tube Side Minimum)

#: Economizer Outlet -- 12 in. below roof slope

TABLE 10-5 ULTRASONIC THICKNESS MEASUREMENTS AT HENNEPIN UNIT 1 (CONTINUED)

No	Loc.	Description	Elev. (Inch)	Tube ODxMW (In.xIn.)	Flag Point (Mils)	Lowest* Reading 1988 (Mils)	Lowest Reading 1990 (Mils)	Read. Below FP 1990	Lowest Reading 1992 (Mils)	Read. Below FP 1990
29	K	Furnace Wall - Rear	6374	3.000x0.280	196	285	270	0	279	0
30	SI	Sorbent Injection Openings - Left	6636	3.000x0.280	196		275	0	271	0
31	SI	Sorbent Injection Openings - Right	6636	3.000x0.280	196		280	0	283	0
32	SI	Sorbent Injection Openings - Port 1	6636	3.000x0.280	196		300	0	301	0
33	SI	Sorbent Injection Openings - Port 2	6636	3.000x0.280	196		335	0	321	0
34	SI	Sorbent Injection Openings - Port 3	6636	3.000x0.280	196		300	0	290	0
35	SI	Sorbent Injection Openings - Port 4	6636	3.000x0.280	196		290	0	286	0
36	R	Reburner Openings - Port 1	6246	3.000x0.280	196		280	0	276	0
37	R	Reburner Openings - Port 2	6246	3.000x0.280	196		275	0	273	0
38	R	Reburner Openings - Port 3	6246	3.000x0.280	196		290	0	213	0
39	R	Reburner Openings - Port 4	6246	3.000x0.280	196		280	0	274	0

*: Tube Center Minima (Tube Center Minimum Slightly Varied From Tube Side Minimum)

TABLE 10-6 MEAN TUBE THICKNESS DATA AND TOLERANCES

No	Loc. No.	Description	Tube Specs in 1953 (Mils)			Mean Thickness Measurements (Mils)			Thickness Range Accounting for tolerance (initial tube thickness and UT tolerance)							
			Min. Wall	Tol.	Mean Wall				1953		1988		1990		1992	
						1988	1990	1992	Min.	Max	Min.	Max.	Min.	Max.	Min.	Max.
1	A1	Primary Superheater at Sootblower 11	188	41	209	200	219	205	188	229	195	205	214	224	200	210
2	A2	Primary Superheater at Sootblower 13	180	40	200	207	217	216	180	220	202	212	212	222	211	221
3	A3	Primary Superheater at Sootblower 15	165	36	183	135	137	147	165	201	130	140	132	142	142	152
4	A4	Primary Superheater at Sootblower 15	165	36	183	132	123	129	165	201	127	137	118	128	124	134
5	B1	Primary Superheater at Sootblower 13.10	180	40	200	206	208	218	180	220	201	211	203	213	213	223
6	B2	Primary Superheater at Sootblower 15.10	165	36	183	184	201	193	165	201	179	189	196	206	188	198
7	B3	Primary Superheater Bends	188	41	209	213	206	203	188	229	208	218	201	211	198	208
8	B4	Primary Superheater Bends	180	40	200	185	188	190	180	220	180	190	183	193	185	195
9	B5	Primary Superheater Bends	165	36	183	166	167	167	165	201	161	171	162	172	162	172
10	C	Reheater at Sootblower 9 - Front	134	29	149	150	168	139	134	163	145	155	163	173	134	144
11	C	Reheater at Sootblower 9 - Rear	134	29	149	147	160	149	134	163	142	152	155	165	144	154
12	D1	Screen at Sootblower 5	280	62	311	311	298	317	280	342	306	316	293	303	312	322
13	D1	Reheater at Sootblower 5	165	36	183	195	169	182	165	201	190	200	164	174	177	187
14	D2	Secondary Superheater at Sootblower 7	313	69	347	341	329	348	313	382	336	346	324	334	343	353
15	D2	Reheater at Sootblower 7 - Rear	165	36	183	188	192	190	165	201	183	193	187	197	185	195
16	E2	Secondary Superheater Screens	280	62	311	306	292	321	280	342	301	311	287	297	316	326
17	E3	S. S. Screens at Sootblower 3	280	62	311	266	258	288	280	342	261	271	253	263	283	293
18	F	Furnace Wall - Front	280	62	311	307	299	316	280	342	302	312	294	304	311	321
19	F	Furnace Wall - Left	280	62	311	306	307	332	280	342	301	311	302	312	327	337
20	F	Furnace Wall - Right	280	62	311	300	303	330	280	342	295	305	298	308	325	335

TABLE 10-6 MEAN TUBE THICKNESS DATA AND TOLERANCES (CONTINUED)

No	Loc. No.	Description	Tube Specs in 1953 (Mils) Min. Wall	Tol.	Mean Wall	Mean Thickness Measurements (Mils) 1988	1990	1992	Thickness Range Accounting for tolerance (initial tube thickness and UT tolerance) 1953 Min.	1953 Max	1988 Min.	1988 Max.	1990 Min.	1990 Max.	1992 Min.	1992 Max.
21	F	Furnace Wall - Arch (Rear)	280	62	311	312	288	328	280	342	307	317	283	293	323	333
22	G	Economizer Outlet - Left Side	165	36	183	189	182	180	165	201	184	194	177	187	175	185
23	G	Economizer Outlet - Right Side	165	36	183	186	184	177	165	201	181	191	179	189	172	182
24	H	Economizer Outlet - Left Side	165	36	183	184	181	178	165	201	179	189	176	186	173	183
25	H	Economizer Outlet - Right Side	165	36	183	184	179	180	165	201	179	189	174	184	175	185
26	K	Furnace Wall - Left	280	62	311	299	310	318	280	342	294	304	305	315	313	323
27	K	Furnace Wall - Right	280	62	311	300	307	314	280	342	295	305	302	312	309	319
28	K	Furnace Wall - Front	280	62	311	300	289	308	280	342	295	305	284	294	303	313
29	K	Furnace Wall - Rear	280	62	311	302	286	316	280	342	297	307	281	291	311	321
30	SI	Sorbent Injection Openings - Left	280	62	311		285	283	280	342	N.A.	N.A.	280	290	278	288
31	SI	Sorbent Injection Openings - Right	280	62	311		295	294	280	342	N.A.	N.A.	290	300	289	299
32	SI	Sorbent Injection Openings - Port 1	280	62	311		328	328	280	342	N.A.	N.A.	323	333	323	333
33	SI	Sorbent Injection Openings - Port 2	280	62	311		344	337	280	342	N.A.	N.A.	339	349	332	342
34	SI	Sorbent Injection Openings - Port 3	280	62	311		314	310	280	342	N.A.	N.A.	309	319	305	315
35	SI	Sorbent Injection Openings - Port 4	280	62	311		304	298	280	342	N.A.	N.A.	299	309	293	303
36	R	Reburner Openings - Port 1	280	62	311		297	297	280	342	N.A.	N.A.	292	302	292	302
37	R	Reburner Openings - Port 2	280	62	311		296	294	280	342	N.A.	N.A.	291	301	289	299
38	R	Reburner Openings - Port 3	280	62	311		313	312	280	342	N.A.	N.A.	308	318	307	317
39	R	Reburner Openings - Port 4	280	62	311		309	304	280	342	N.A.	N.A.	304	314	299	309

Table 10-7 shows the tube wastage rates calculated from the tube thickness data in Table 10-6. The wastage rates were calculated over the various periods by dividing the tube wastage (the difference in tube thicknesses at the beginning and end of the period) by the duration and expressing the results as mils/year. The range of thicknesses for each measurement (accounting for the initial tube tolerances and UT instrument accuracy) was used to establish minimum, mean and maximum tube wastage rates.

Based on the time of the measurements, there are three baseline periods and one GR-SI operating period. The three baseline periods are compared below:

- 1953 - 1988 Baseline This is the period prior to the program. The initial tube thickness is based on the tube specifications and has a relatively large uncertainty (29 to 62 mils). The final tube thickness is based on the UT measurement in 1988. While the thickness uncertainty range is large, the duration is long and the net range of uncertainty in tube wastage rate is only 1.11 to 2.06 mils/yr. However, the coal characteristics and unit operating conditions have varied over this period and may not be representative of current operation.

- 1988 - 1990 Baseline This is the 21 month period between the first two UT measurements where the system was operating in the baseline mode. While the large uncertainty in initial tube thickness is significantly reduced, the short duration increases the range of uncertainty in tube wastage rate to 11.43 mils/yr. Also, the tube cleaning in 1988 exposed fresh metal resulting in accelerated wastage as discussed previously. This additional wastage is only averaged over a 21 month period as opposed to 35 years for the 1953 - 1988 baseline. However, this operating period should be representative of current unit operation.

- 1953 - 1990 Baseline This baseline period may be used as an alternate to the other two for the limited number of areas which were not measured in 1988.

TABLE 10-7 CALCULATED TUBE WASTAGE RATES

No	Loc.	Description	Calculated Wastage Rates (Mils/Yr)												GR-SI Wastage Relative to Baseline Period		
			1953-1988			1988-1990			1953-1990			1990-1992					
			Baseline			Baseline			Baseline			GR-SI Operation					
			Dur.=	420	Mon.	Dur.=	21	Mon.	Dur.=	441	Mon.	Dur.=	25	Mon.			
	No.		Min.	Mean	Max.	Min.	Mean	Max.	Min.	Mean	Max.	Min.	Mean	Max.	53-88	88-90	53-90
1	A1	Prim. Sup. SB 11	(0.49)	0.24	0.98	(16.70)	(10.98)	(5.27)	(0.99)	(0.29)	0.41	2.33	7.13	11.93	Inc.	Inc.	Inc.
2	A2	Prim. Sup. SB 13	(0.92)	(0.21)	0.50	(11.15)	(5.43)	0.28	(1.13)	(0.46)	0.22	(4.69)	0.11	4.91	In Tol.	In Tol.	In Tol.
3	A3	Prim. Sup. SB 15	0.72	1.38	2.04	(6.85)	(1.13)	4.58	0.63	1.26	1.89	(9.84)	(5.04)	(0.24)	Growth	Growth	Growth
4	A4	Prim. Sup. SB 15	0.80	1.46	2.12	(0.30)	5.41	11.13	1.02	1.65	2.28	(7.82)	(3.02)	1.78	In Tol.	In Tol.	In Tol.
5	B1	Prim. Sup. SB 13.10	(0.88)	(0.17)	0.54	(7.12)	(1.41)	4.31	(0.91)	(0.23)	0.44	(9.49)	(4.69)	0.11	In Tol.	In Tol.	In Tol.
6	B2	Prim. Sup. SB 15.10	(0.69)	(0.03)	0.63	(15.09)	(9.38)	(3.66)	(1.11)	(0.48)	0.15	(0.96)	3.84	8.64	In Tol.	Inc.	In Tol.
7	B3	Prim. Sup. Bends	(0.85)	(0.12)	0.62	(1.78)	3.94	9.65	(0.62)	0.07	0.77	(3.59)	1.21	6.01	In Tol.	In Tol.	In Tol.
8	B4	Prim. Sup. Bends	(0.27)	0.43	1.14	(7.92)	(2.21)	3.51	(0.37)	0.31	0.98	(5.65)	(0.85)	3.95	In Tol.	In Tol.	In Tol.
9	B5	Prim. Sup. Bends	(0.16)	0.50	1.17	(6.73)	(1.01)	4.70	(0.20)	0.43	1.06	(4.70)	0.10	4.90	In Tol.	In Tol.	In Tol.
10	C	Reheat SB 9 - Front	(0.61)	(0.05)	0.52	(15.50)	(9.78)	(4.07)	(1.05)	(0.51)	0.03	8.79	13.59	18.39	Inc.	Inc.	Inc.
11	C	Reheat SB 9 - Rear	(0.51)	0.05	0.61	(12.98)	(7.26)	(1.55)	(0.84)	(0.30)	0.24	0.27	5.07	9.87	In Tol.	Inc.	Inc.
12	D1	Screen SB 5	(1.03)	(0.01)	1.01	1.82	7.53	13.25	(0.62)	0.35	1.32	(13.96)	(9.16)	(4.36)	Growth	Growth	Growth
13	D1	Reheater SB 5	(0.99)	(0.33)	0.33	9.13	14.84	20.56	(0.23)	0.40	1.03	(11.33)	(6.53)	(1.73)	Growth	Growth	Growth
14	D2	Sec. Sup. SB 7	(0.94)	0.18	1.31	1.14	6.86	12.57	(0.57)	0.50	1.57	(13.92)	(9.12)	(4.32)	Growth	Growth	Growth
15	D2	Reheat SB 7 - Rear	(0.80)	(0.13)	0.53	(7.98)	(2.26)	3.45	(0.87)	(0.24)	0.39	(4.11)	0.69	5.49	In Tol.	In Tol.	In Tol.
16	E2	Sec. Sup. Screens	(0.89)	0.14	1.16	2.29	8.00	13.71	(0.46)	0.51	1.49	(18.72)	(13.92)	(9.12)	Growth	Growth	Growth
17	E3	S. S. Screens SB 3	0.26	1.28	2.30	(1.14)	4.57	10.29	0.46	1.44	2.41	(19.20)	(14.40)	(9.60)	Growth	Growth	Growth
18	F	Furn. Wall - Front	(0.90)	0.12	1.14	(1.41)	4.30	10.02	(0.66)	0.32	1.29	(12.75)	(7.95)	(3.15)	Growth	Growth	Growth
19	F	Furn. Wall - Left	(0.87)	0.15	1.17	(6.24)	(0.52)	5.19	(0.86)	0.12	1.09	(17.03)	(12.23)	(7.43)	Growth	Growth	Growth
20	F	Furn. Wall - Right	(0.70)	0.32	1.34	(7.67)	(1.95)	3.76	(0.76)	0.21	1.19	(17.58)	(12.78)	(7.98)	Growth	Growth	Growth

TABLE 10-7 CALCULATED TUBE WASTAGE RATES (CONTINUED)

No	Loc. No.	Description	Calculated Wastage Rates (Mils/Yr)												GR-SI Wastage Relative to Baseline Period		
			1953-1988			1988-1990			1953-1990			1990-1992					
			Baseline			Baseline			Baseline			GR-SI Operation					
			Dur.= 420 Mon.			Dur.= 21 Mon.			Dur.= 441 Mon.			Dur.= 25 Mon.					
			Min.	Mean	Max.	Min.	Mean	Max.	Min.	Mean	Max.	Min.	Mean	Max.	53-88	88-90	53-90
21	F	Furn. Wall - Arch (Rear)	(1.07)	(0.05)	0.98	8.02	13.74	19.45	(0.37)	0.61	1.58	(23.68)	(18.88)	(14.08)	Growth	Growth	Growth
22	G	Econ. Outlet - Left	(0.83)	(0.17)	0.49	(1.71)	4.00	9.71	(0.60)	0.03	0.66	(3.84)	0.96	5.76	In Tol.	In Tol.	In Tol.
23	G	Econ. Outlet - Right	(0.74)	(0.08)	0.58	(4.57)	1.14	6.86	(0.65)	(0.02)	0.61	(1.44)	3.36	8.16	In Tol.	In Tol.	In Tol.
24	H	Econ. Outlet - Left	(0.69)	(0.02)	0.64	(4.00)	1.71	7.43	(0.57)	0.06	0.69	(3.36)	1.44	6.24	In Tol.	In Tol.	In Tol.
25	H	Econ. Outlet - Right	(0.69)	(0.02)	0.64	(2.86)	2.86	8.57	(0.52)	0.11	0.74	(5.28)	(0.48)	4.32	In Tol.	In Tol.	In Tol.
26	K	Furn. Wall - Left	(0.70)	0.33	1.35	(11.76)	(6.04)	(0.33)	(0.95)	0.02	1.00	(8.85)	(4.05)	0.75	In Tol.	In Tol.	In Tol.
27	K	Furn. Wall - Right	(0.71)	0.31	1.33	(9.55)	(3.83)	1.88	(0.86)	0.11	1.09	(8.41)	(3.61)	1.19	In Tol.	In Tol.	In Tol.
28	K	Furn. Wall - Front	(0.72)	0.30	1.32	0.66	6.37	12.09	(0.39)	0.59	1.56	(14.05)	(9.25)	(4.45)	Growth	Growth	Growth
29	K	Furn. Wall - Rear	(0.78)	0.25	1.27	3.33	9.05	14.76	(0.31)	0.66	1.64	(18.95)	(14.15)	(9.35)	Growth	Growth	Growth
30	SI	Sorb. Inj. - Left	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(0.27)	1	1.68	(3.92)	0.88	5.68	N.A.	N.A.	In Tol.
31	SI	Sorb. Inj. - Right	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(0.54)	0.43	1.40	(4.40)	0.40	5.20	N.A.	N.A.	In Tol.
32	SI	Sorb. Inj. - Port 1	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(1.43)	(0.45)	0.52	(4.88)	(0.08)	4.72	N.A.	N.A.	In Tol.
33	SI	Sorb. Inj. - Port 2	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(1.88)	(0.90)	0.07	(1.36)	3.44	8.24	N.A.	N.A.	In Tol.
34	SI	Sorb. Inj. - Port 3	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(1.07)	(0.09)	0.88	(2.64)	2.16	6.96	N.A.	N.A.	In Tol.
35	SI	Sorb. Inj. - Port 4	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(0.79)	0.18	1.15	(1.84)	2.96	7.76	N.A.	N.A.	In Tol.
36	R	Reburn - Port 1	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(0.59)	0.39	1.36	(5.03)	(0.23)	4.57	N.A.	N.A.	In Tol.
37	R	Reburn - Port 2	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(0.57)	0.41	1.38	(3.81)	0.99	5.79	N.A.	N.A.	In Tol.
38	R	Reburn - Port 3	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(1.02)	(0.05)	0.93	(4.33)	0.47	5.27	N.A.	N.A.	In Tol.
39	R	Reburn - Port 4	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	(0.92)	0.05	1.03	(2.41)	2.39	7.19	N.A.	N.A.	In Tol.

The range of uncertainty for this baseline period is comparable to the 1953 - 1988 period. However, the cleaning of the tubes in 1988 may have accelerated wastage by exposing fresh surface to oxidation.

It should be noted that many of the calculated wastage rates were negative. Since there is no known mechanism whereby metal would be deposited on the tubes to increase their thickness during normal operation, it can be concluded that the negative measurements are due to errors. In some cases all three wastage rates (minimum, mean and maximum) were negative. This suggests that there were errors greater than the uncertainty in initial tube thickness and UT measurement error. Examples include measurement of the wrong tube or tube replacement sometime during the period.

The tube wastage rates for the three baseline period and the GR-SI operating period were compared to determine the relative changes. Table 10-7 shows this comparison using the following definitions:

- Confirmed Increase (Inc.) The minimum tube wastage rate during the GR-SI period exceeded the maximum tube wastage rate during the baseline.

- Confirmed Decrease (Dec.) The maximum tube wastage rate during the GR-SI period was less than the minimum during the baseline.

- Inconclusive -- Within Tolerance Range (In. Tol.) The range of tube wastage rates during the GR-SI period was within the baseline range.

- Inconclusive -- Apparent Growth (Growth) The maximum tube wastage rate was measured as negative (tube thickness increased) during the GR-SI period. This is due to measurement error.

As shown in Table 10-7, most of the results were inconclusive either due to tube growth during the GR-SI period or measurements within the tolerance range. There were no confirmed cases of decreased wastage during the GR-SI period.

There were a few cases of confirmed increases in tube wastage during the GR-SI period. However, close examination of those cases reveals that this appears to be a result of a high tube thickness measurement in 1990, at the beginning of the GR-SI period which caused a high calculated wastage rate for GR-SI and a negative wastage rate for the baseline period(s).

10.5.4 Furnace Waterwall Wastage

Furnace wall thickness measurements were taken at three locations: near the reburning ports (elevation 6246 in.), near the SI ports (elevation 6636 in.), and at each wall at elevation 6374 in. (Area K). Potential tubewall wastage due to reducing conditions in the reburning zone was of concern. Since the OFA is injected at elevation 6369 in., only the measurements near the reburning ports may be used to give an indication of the tube wastage due to reducing conditions. As shown in Table 10-7, the mean rate of wastage during GR-SI operation at the reburning ports ranged from -0.23 to 2.39 mils/yr (-0.0058 to 0.0607 mm/a). Considering the tolerance in the wastage rate during this period, no significant tubewall wastage in this area, over the GR-SI period, is apparent.

The tube thickness measurements at the SI ports also show only minor rates of wastage. As shown in Table 10-7, mean tubewall wastage rates in these area range from -0.08 to 3.44 mils/yr (-0.0020 to 0.0876 mm/a). A small rate of tube wastage due to erosion of the surface from the injected sorbent may be expected in this area. The measured rates of tube wastage are similar to those measured at the reburning ports and are considered insignificant.

Measurements taken at each furnace wall at elevation 6374 in. indicate that 1992 measurements are larger than 1990 measurements. The mean tubewall thicknesses were 7 to

30 mils (0.18 to 0.76 mm) larger in 1992 than those measured in 1990. Therefore, the tube wastage over the GR-SI period in this area is considered insignificant.

The useful life of tubewall areas may be calculated with respect to the length of time required for the mean tube thickness to be reduced from the 1992 mean thickness to the flag-point wall thickness. Using the wastage rates calculated from the three periods (1953 - 1988, 1988 - 1990, 1990 - 1992) the useful life of each area with respect to continued baseline and GR-SI operation may be determined. The highest furnace waterwall wastage rate calculated is 3.44 mils/yr (0.088 mm/a) in the area around SI Port 2. The mean thickness measured in 1992 was 337 mils (8.56 mm). Considering the time required for the mean tubewall thickness to reach the flag-point of 196 mils (4.98 mm), the useful life of this section is up to the year 2033. Therefore the useful life of the area of the furnace waterwall which shows greatest wastage is longer than the projected end of the unit life in the year 2023.

10.5.5 Convective Pass Wastage

In the convective passes, tube wastage due to erosion is possible; therefore extensive measurements were taken. Erosive wastage of waterwall tubes has been attributed to three parameters: the amount of particulate matter (i.e. particulate loading), abrasiveness of the particulate matter, and the velocity of the particulate matter. During GR-SI operation, the particulate loading through the unit was increased to twice the baseline levels. But the injected sorbent is relatively soft, therefore less abrasive than normal fly-ash. Of the three parameters listed above, the most important parameter is the velocity of the particulate matter along the tube surface. Two factors affect the upper furnace gas velocity: the gas density and the total mass flow, which is dependent on the level of excess O_2. Higher gas temperature results in a reduction in the density which leads to velocity increase, but the more significant impact is due to the total mass of gas flow. During GR-SI operation, the unit is operated under reduced excess oxygen levels relative to baseline operation; therefore the velocity of the gas and particulate matter is reduced in comparison to normal operation.

Overall, the GR-SI process was not expected to significantly increase the erosion wastage of the convective sections.

Two areas have been of concern from the earliest (1988) measurements, due to mean tubewall thickness below the flag-point. These are areas A3 and A4, the horizontal primary superheater tubes near sootblower 15. The flag-point tube thickness in these areas is 140 mils (3.56 mm). During each of the three tests the lowest readings in these areas were consistently below 140 mils (3.56 mm). In the 1988 inspection, the lowest tubewall thickness in Area A3 was 100 mils (2.54 mm) and in Area A4 was 85 mils (2.16 mm). In 1990 tests, the lowest tubewall thickness in Area A3 was 95 mils (2.41 mm), with 73 readings below the flag-point, while the lowest tubewall thickness in Area A4 was 100 mils (2.54 mm), with 75 readings below the flag-point. The 1992 measurements showed lowest readings in Area A3 of 89 mils (2.26 mm), with 68 readings below the flag-point, while the lowest reading in Area A4 was 90 mils (2.29 mm), with 132 readings below the flag-point. The number of readings below the flag-point include measurements at all three locations (i.e. center and each side). These results are compared, as follows, where MWT denotes the original minimum wall thickness:

Test Period	Area	MWT (Mils)	Flag Point (Mils)	Readings below FP	Lowest Reading (Mils)
1988	A3	165	140	> 50	100
1988	A4	165	140	> 50	85
1990	A3	165	140	73	95
1990	A4	165	140	75	100
1992	A3	165	140	68	89
1992	A4	165	140	132	90

The mean tubewall thicknesses measured in 1992 were larger than those measured in 1990. In Area A3 the mean tubewall thickness was 10 mils (0.25 mm) larger in 1992 than 1990, with the mean difference in Area A4 of 6 mils (0.15 mm) over the same period. Corrective action in these areas has been necessary since the 1988 measurements. The 1990 UT report recommended placement of protective shields, sootblower inspection, and possibly tubewall replacement. No increased wastage in these areas due to GR-SI has been determined.

There are three other areas where the measured lowest tubewall thickness was below the flag-point in at least one of the three tests. These are areas B2 (Primary Superheater at Sootblower 15.10), D1 (reheater at Sootblower 5), and E3 (superheater screens at Sootblower 3). In Areas D1 and E3, the lowest tubewall thickness was below the flag-point in 1990 measurements, but the 1988 and 1992 lowest wall thickness were above this value. The lowest tubewall thickness was below the flag-point in Area B2 in 1992 measurements, but exceeded the flag-point in the other tests. These results are summarized below:

Area	MWT (Mils)	Flag-Point (Mils)	1988	1990	1992	Readings Below FP 1990	Readings Below FP 1992
			Lowest Reading				
B2	165	140	160	150	127	0	2
D1	165	140	180	130	159	3	0
E3	280	196	210	190	212	1	0

A lack of consistency is apparent in these readings. The lowest readings in Areas D1 and E3 exceeded the flag-point in 1992, but not in 1990. The mean tubewall thicknesses measured in the three tests are all above the minimum wall thickness, as indicated below:

Area	MWT (Mils)	Flag-Point (Mils)	1988	1990	1992
			Mean Reading (Mils)		
B2	165	140	184	201	193
D1	165	140	195	169	182
E3	280	196	266	258	288

Since only a few points were below the flag-point and since all of the mean tubewall thicknesses measured in 1992 are above the minimum wall thickness (in two of the three cases the 1992 mean measurements were higher than the 1988 mean measurements) no excessive tube wastage is believed to have occurred in these areas. At least 72 readings were taken in each of these areas during each of the three tests.

In only a few areas were the GR-SI wastage rates greater than the baseline wastage rate plus baseline wastage rate tolerance from the period 1953 to 1988. The cases are summarized below with the useful life of each area. The wastage rate is defined as the latter measurement minus the earlier measurement divided by the time period. Therefore a reduction in wall thickness would result in negative values of the wastage rate and an apparent increase in wall thickness would be positive.

Area ID	1992 Avg. (Mils)	FP (Mils)	Useful Life (Yr) Continued GR-SI	Useful Life (Yr) Continued Baseline
A1	205	160	1998	2180
B2	193	140	2006	indeterminate:(wastage > 0)
B3	203	160	2028	indeterminate (wastage > 0)
C-Front	139	114	1994	indeterminate (wastage > 0)
C-Rear	149	114	1999	2692
D2-Rear	190	140	2064	indeterminate (wastage > 0)
G-Left	180	115	2060	indeterminate (wastage > 0)
G-Right	177	115	2010	indeterminate (wastage > 0)
H-Left	178	115	2036	indeterminate (wastage > 0)

Only in a few cases would continued GR-SI operation result in a decrease in the useful life of a section below the 2023 date (the projected life of the unit). But, with continued baseline operation, the useful life will be extended beyond the 2023 date in every case.

If the baseline wastage rate from the 1988 to 1990 period is used the following results are obtained:

Area ID	1992 Avg. (Mils)	FP (Mils)	Useful Life (Yr) Continued GR-SI	Useful Life (Yr) Continued Baseline
A1	205	160	1998	indeterminate (wastage > 0)
B2	193	140	2006	indeterminate (wastage > 0)
B3	203	160	2028	2003
C-Front	139	114	1994	indeterminate (wastage > 0)
C-Rear	149	114	1999	indeterminate (wastage > 0)
D2-Rear	190	140	2064	indeterminate (wastage > 0)
G-Left	180	115	2060	2008
G-Right	177	115	2010	2046
H-Left	178	115	2036	2029

In the two cases where continued baseline operation would result in a reduction in the useful life below 2023, continued GR-SI operation would correspond to a longer useful life. These data inconsistencies show the difficulties in using this method to determine the useful life of a tubewall section.

10.5.6 Metallographic Examination

Metallographic examination of sixteen tubewall samples for decarburization was carried out. Eight samples were obtained from 1990 and eight from 1992 to determine the impact of GR-SI operation on the tubewall microstructure. The microstructure of SA192 steel usually consists of randomly dispersed ferrite and pearlite. Decarburization would be indicated by the presence of a layer of ferrite. Examination of the internal and external surfaces found no evidence of decarburization.

10.6 Chimney Inspection

The chimney, which receives flue gas from both Units 1 and 2, was inspected on two dates, in 1990 and 1992. Both the external structure and the internal lining were examined for wastage and deposits. GR-SI results in the injection of sorbent into the unit which may accumulate at locations at the base of the chimney or on the lining of the chimney. The GR-SI process also could result in a difference in the flue gas temperature from the two units, which may impact deposition or wastage. The purpose of the inspections was to determine the impacts of GR-SI on the rate of particulate matter deposition and wear of the lining. Table 10-8 summarizes the findings during the two inspections and impacts of GR-SI operation on the chimney. An increase in the amount of matter accumulated on the lining of the chimney was observed, but no other significant changes were evident.

The April 1990 inspection found the chimney to be in good condition. The hoppers at the base of the chimney were found 1/2 full at the time of inspection. Some fly ash deposition was noted in the top 80 feet of the chimney. The mortar along the brickwork was found to be in good condition, with a maximum wastage of approximately 1/2 inch (1.3 cm) throughout the length of the chimney. At the point of inspection, the brickwork where the east breeching (Unit 2) connects to the East and West Quadrants was found to be deteriorated and International Chimney was contracted to repair the area by applying a gunited material. The external structure was found in good condition, but the cast iron cap required removal due to safety problems and was replaced with a 6 inch (15 cm) concrete cap.

The October, 1992 inspection showed little change in the condition of the chimney, except the increase in the amount of fly ash on the lining. Throughout the length of the chimney, fly ash accumulation was found to be 1 to 3 inches (2.5 to 7.5 cm). Again, the hopper at the bottom of the chimney was found to be approximately 1/2 full at the time of inspection and the mortar on the inside of the chimney was found to have a maximum wear of 1/2 inch (1.3 cm). On the exterior, some cracking of the brickwork was found in the top 20 feet. The only recommendation made after the post-GR-SI inspection was that the build-up of fly ash "should be removed".

TABLE 10-8. SUMMARY OF CHIMNEY INSPECTION RESULTS

	April 1990	October 1992	Change
fly ash in bottom hoppers	1/2 full	1/2 full	no change
fly ash on lining	some accum. in top 80 ft.	1-3 in.	increase
mortar wear	1/2 in. maximum	1/2 in. maximum	no change
breeching connections	worn (repaired)	intact	no change
chimney cap	6 in. concrete cap installed	good condition	no change
external brickwork	tuckpointing repairs	cracking top 20 ft.	minor change

11.0 ENVIRONMENTAL IMPACTS AND PERMITTING CONSIDERATIONS

During the year-long GR-SI demonstration, environmental impacts were evaluated. The primary waste product from GR-SI operation is a high calcium solid waste, which is a mixture of coal ash, spent sorbent, and unreacted sorbent. During nominal GR-SI operation this solid waste is produced at a rate approximately twice the rate of normal fly ash production. An evaluation of several alternative solid waste handling methods was undertaken and sluicing the ash to a new pond was initially selected. This would have created a new water discharge stream requiring permitting changes and additional environmental monitoring. Following completion of Phase I (Design and Permitting) of the project, it was decided to sluice the ash directly to the existing pond and to use CO_2 injection to control the pH to an acceptable range (6 to 9), as required by the state EPA's National Discharge Elimination System (NPDES) Permit Regulation. The selection of CO_2 as the acidic agent fit the specific needs of this project; other agents, such as H_2SO_4, may be used. Another area of concern in applying GR-SI was a possible increase in emissions of PM_{10} (particulate matter with an aerodynamic diameter less than 10 microns), even though the design evaluation predicted that total particulate matter emissions would not increase, due to application of flue gas humidification. Other potential emission increases were in nitrous oxide (N_2O) emissions and other combustion products (e.g. CO). To ensure that the water quality and air quality were acceptable, an extensive environmental monitoring program was put into effect. The environmental measurements were outlined in an Environmental Monitoring Plan (EMP), prepared by EER and distributed to project sponsors.

Environmental monitoring was conducted during each Phase of the project to determine pre-project (baseline) environmental impacts of operating Hennepin Unit 1 and impacts due to GR-SI. The monitoring during Phases I (Design and Permitting) and II (Construction and Start-Up) was limited to compliance monitoring of coal analyses, ash sluice system water analysis, and emissions monitoring (NO_x, O_2, CO) to develop a GR-SI system design basis. The Hennepin Station has been operating under two permits issued by the Illinois Environmental Protection Agency (IEPA). The air emissions source permit limits emissions of SO_2 while the NPDES Permit regulates the pH, oil and grease, and total suspended solids (TSS) in the water discharged to the Illinois River. The compliance monitoring was continued in Phase III (Operation, Data Collection, Reporting and Disposition) and was supplemented with other measurements. These included monitoring of gaseous emissions NO_x, SO_2, CO, CO_2, and hydrocarbons, N_2O, particulate loading and size distribution, fly ash resistivity, and opacity.

Permitting requirements were considered with respect to the original pre-project permits issued by the IEPA and modifications required to construct the GR-SI system and evaluate its performance. A permit to construct was granted by the IEPA, which addressed a range of issues including a return to pre-project emissions. This was of concern because of the potential application of New Source Performance Standards (NSPS) or Prevention of Significant Deterioration (PSD) provisions of the Clean Air Act Amendments (CAAA) to the unit.

11.1 Environmental Monitoring

Environmental monitoring was conducted in each phase of the project. The purpose of the monitoring was to ensure that GR-SI operation was conducted in an environmentally acceptable manner and to obtain a data base of environmental parameters for consideration in future application of the GR-SI technology. The monitoring in Phases I and II entailed compliance monitoring of ash sluice discharge water, coal analyses, and limited emissions characterization for the purposes of GR-SI process design. The measurements are shown in Table 11-1. The Phase III monitoring was directed primarily at obtaining a full range of measurements to verify process efficiency and any impacts on gaseous or liquid discharges. The supplementary measurements are shown in Table 11-2. The measurements of NO_x and SO_2 emissions were of primary importance to verify that project target emissions reductions were met. Other measurements were used to characterize combustion efficiency, ESP performance, and other pollutants which were of concern in applying GR-SI to a coal fired unit. EPA reference methods were used to verify the accuracy of continuous emissions

TABLE 11-1. HENNEPIN UNIT 1 COMPLIANCE MONITORING

AIR EMISSION SOURCE OPERATING PERMIT

MEASUREMENT	SAMPLE TYPE	FREQUENCY	LOCATION
Coal composition sulfur, ash, Btu, moisture	24 hour composite	Daily	Coal hoppers

NPDES PERMIT

MEASUREMENT	SAMPLE TYPE	FREQUENCY	LOCATION
Flow Rate	Single reading estimate	Once/wk	Existing ash pond discharge
pH	Grab sample	Once/wk	Existing ash pond discharge
Total Suspended Solids	24 hour composite	Once/wk	Existing ash pond discharge
Oil and Grease	Grab sample	Twice/mo	Existing ash pond discharge

TABLE 11-2. SUPPLEMENTAL EMISSIONS MONITORING

MEASUREMENT		SAMPLE TYPE	LOCATION
PHASE I			
Preliminary	NO_x	Continuous (7E)	Economizer Inlet
	O_2	Continuous (3A)	Economizer Inlet
	CO	Continuous (10)	Economizer Inlet
PHASE II			
No measurement			
PHASE III			
Baseline	NO_x	Continuous (7E)	Econ Outlet or Stack Breeching
	SO_2	Continuous (6C), Method 6	Econ Outlet or Stack Breeching
	CO	Continuous (10)	Econ Outlet or Stack Breeching
	CO_2	Continuous (3A) Method 3	Econ Outlet or Stack Breeching
	O_2	Continuous (3A) Method 3	Econ Outlet or Stack Breeching
	Particulate	Method 17	ESP Inlet
	Particulate	Method 5	ESP Outlet
	Particle Size Distribution	Cascade Impactors	ESP Inlet and Outlet
	Resistivity	Cyclonic flow probe	ESP Inlet
	Velocity	Method 2	ESP Inlet
	Opacity	In-situ optical	Stack Breeching
	N_2O	Extractive	Stack Breeching
Parametric	NO_x	Continuous (7E)	Econ Inlet or ESP Outlet
	SO_2	Continuous (6C)	Econ Inlet or ESP Outlet
	CO	Continuous (10)	Econ Inlet or ESP Outlet
	CO_2	Continuous (3A)	Econ Inlet or ESP Outlet
	O_2	Continuous (3A)	Econ Inlet or ESP Outlet
	HC	Continuous (25A)	Econ Inlet or ESP Outlet
	Particulate	Method 17	ESP Inlet
	Particulate	Method 5	ESP Outlet
	Particle Size Distribution	Cascade Impactors	ESP Inlet and Outlet
	Resistivity	Cyclonic flow probe	ESP Inlet
	Velocity	Method 2	ESP Inlet
	Opacity	In-situ optical	Stack Breeching
	N_2O	Extractive	Stack Breeching

TABLE 11-2. SUPPLEMENTAL EMISSIONS MONITORING (CONTINUED)

Long Term Operation	NO_x	Continuous (7E)	Stack Breeching
	SO_2	Continuous (6C), Method 6	Stack Breeching
	CO	Continuous (10)	Stack Breeching
	CO_2	Continuous (3A), Method 3	Stack Breeching
	O_2	Continuous (3A), Method 3	Stack Breeching
	HC	Continuous (25A)	Stack Breeching
	Particulate	Method 17	ESP Inlet
	Particulate	Method 5	ESP Outlet
	Particle Size Distribution	Cascade Impactors	ESP Inlet and Outlet
	Resistivity	Cyclonic flow probe	ESP Inlet
	Velocity	Method 2	ESP Inlet
	Opacity	In-situ optical	Stack Breeching
	N_2O	Extractive	Stack Breeching

measurements.

11.2 EHSS Impacts

The environmental, health, safety, and socioeconomic (EHSS) impacts of the GR-SI demonstration were evaluated. The environmental impacts of GR-SI, which are discussed in subsequent sections, were minor and no significant deleterious air or water pollution problems were detected.

Health concerns for Hennepin Station employees due to applying GR-SI are limited to two areas: noise created by operation of GR-SI equipment and handling of sorbent. The GR-SI system includes four fans. Noise level data on three of the four are available indicating that they have a noise level below that considered an audiometric hazard of 85 decibels, at the fan casing. Data on noise created by operation of the other fan were not available, but in comparison to a background of operating noise, this was expected to be a relatively small source of noise pollution. Areas in the plant which have a noise level exceed OSHA standards are placarded, indicating excessive noise. The other health concern is from handling of the sorbent. The sorbent is an alkaline material and is known to be an irritant. The sorbent handling system used to convey the sorbent to the silo is a dustless system designed to limit fugitive dust emissions. The silo vent is equipped with a fabric filter to prevent dust emissions. The sorbent transmission system was also designed to prevent any dust emissions. In addition, specific handling techniques were developed in case project or IP personnel were required to directly handle the sorbent. This includes use of goggles and dust masks, which have been successfully applied to sorbent handling at EER's Santa Ana Test Facility.

Socioeconomic impacts were evaluated at the initiation of the project. The impact of the GR-SI demonstration on the region surrounding the Hennepin Station was determined to be minor. The project required delivery of two truckloads of sorbent per week, but the transportation route was planned along a major highway and not along small residential streets. The additional truck traffic is very minor compared to the heavy traffic on nearby Interstate Highway 180. Economic impacts to the area were expected to be minor. A majority of the personnel needs for the GR-SI demonstration at Hennepin were met by EER personnel, based at the Orrville, OH office. This included the Phase II construction manager and the Phase III GR-SI testing personnel. Some support, particularly in Phase II, was provided by local personnel. The use of local personnel and purchased materials had small positive impacts on the local economy.

Energy and material requirements are considered part of the socioeconomic impacts. Full load GR-SI operation resulted in an auxiliary power increase of approximately 300 kW, which is 0.4% of the generating capacity of Unit 1. This has a negligible impact on the electric energy availability in the area. A reduction in coal usage was due to firing 18% gas and to a reduction in capacity factor from approximately 62 to 34%. These resulted in a reduction in coal usage by Unit 1 from 184,000 to 98,000 tons/year (167,000 to 89,000 tonne/a). The capacity factor reduction was demand related and did not result from this project. The full load GR-SI design natural gas consumption is 2240 scfm (1.06 Nm^3/s) and the average natural gas consumption over the long-term testing period was 1930 scfm (0.91 Nm^3/s). Continuous utilization of natural gas at a rate of 2240 scfm (1.06 Nm^3/s) resulted in a total annual consumption of 1180 MSCF (33,410,000 Nm^3). Capacity exists to deliver 3,400 billion SCF (96.3 billion Nm^3) of natural gas annually to the U. S. market over current consumption; therefore the gas utilization was a small percentage of the available natural gas.

11.2.1 Water Quality

The quality of water discharged by the Hennepin Station is regulated by the NPDES permit. A modified permit was issued by the Illinois Environmental Protection Agency (IEPA) on June 2, 1989. It specifies discharge limits and monitoring requirements for the following sources of discharged water:

Stream Number	Discharge Stream
001	Condenser Cooling Water
001 (a)	Boiler Blowdown
001 (b)	Intake Screen Backwash
001 (c)	Roof Drain Discharge
003	Ash Lagoon #2 and #4 Discharge
005	Ash Lagoon #3 Discharge
005(a)	Chemical Metal Cleaning Waste Treatment System Effluent

The GR-SI demonstration project significantly impacts only Stream No. 005, which contains the bottom ash and fly ash transport water from Unit 1. This was estimated to be 0.35 million gallons per day (MGD) (1.32 million liters per day [MLD]), but was expected to increase to 0.69 MGD (2.61 MLD) during-full load GR-SI operation. The permit specifies the frequency and type of sampling required to verify that the following maximum discharge limits are not exceeded:

pH	Minimum: 6	Maximum: 9
Total Suspended Solids (TSS)	Average: 15.0 mg/l	Maximum: 30.0 mg/l
Oil and Grease:	Average: 15.0 mg/l	Maximum: 20.0 mg/l

The permit also specifies limits of thermal impacts on the main river water. A maximum temperature rise of 5°F (3°C) above the natural temperature and maximum temperatures of 60 to 90°F (16 to 32°C), depending on the month, are also specified.

Application of GR-SI to Hennepin Unit 1 was expected to change the nature and quantity of ash produced, but the expected impacts on the sluice water makeup were expected to be minor. The GR-SI ash is fully characterized in the following section. Only a minor impact on the total suspended solids was expected, since the sorbent size (mean particle diameter of 5 microns) is small and the sorbent has a lower settling rate. But with proper retention time in the pond, any increase in total suspended solids was expected to be limited. Injection of CO_2 was used to bring the pH to the acceptable range, and no impact on the oil or grease level was expected. Some increase in sulfates was expected since the spent sorbent sluiced is mostly $CaSO_4$.

The compliance monitoring conducted by IP during long-term GR-SI testing indicated no discharge from the ash pond. The existing pond is unlined, resulting in flow into the ground instead of discharge to the Illinois River. During the first quarter of 1992, eight sluice water samples were taken during baseline operation and five during GR-SI operation. The pH of all samples was in the range of 6 to 9.

Supplemental analyses of ash sluice water were conducted. Samples taken during baseline operation as well as the long-term testing period were analyzed and the results are shown in Table 11-3. The results indicate low metals content, with most metals not detected. Moderate levels of sulfates, Fe, and CaO were detected. The sluice water concentrations are not required to conform to the limits stated above since those apply to water discharged to the Illinois River and no discharge took place during the long-term testing period.

Supplemental monitoring of groundwater was also conducted. The groundwater sampling data for sulfite, sulfate, nitrate as nitrogen, nitrite as nitrogen, total dissolved solids, boron, chloride, etc. are presented in Table 11-4. The groundwater concentration standards depend on the classification. Class I and Class II groundwater have standards for total dissolved solids (TDS) of 1200 mg/l and sulfate of 400 mg/l. Application of GR-SI to the unit potentially increases sulfate concentration in the water discharged, due to sluicing of solid $CaSO_4$. Elevated groundwater concentrations of sulfates, relative to the standards, were measured in some of the wells.

11.2.2 GR-SI Ash Characteristics

Operation of GR-SI results in an increase in the quantity and a change in the makeup of the ash produced. Under nominal operation at full load, approximately 7,000 lb/hr (0.9 kg/s) of sorbent is injected. The sorbent reacts with flue gas SO_2 and moisture to produce calcium

TABLE 11–4. GROUNDWATER ANALYSES

Sample Date	Well #	Water Level	pH	Temp °C	SO_3 mg/l	TDS mg/l	B mg/l	SO_4 mg/l	NO_2 mg/l	Cl mg/l	NO_3 mg/l	Ca mg/l	Mn mg/l
2/5/92	W1	446.21	7.3	12.5	<0.5	700	5.1	95	0.02	52.0	<.05	110	130
2/5/92	W2	446.52	8.6	13.5	<0.5	990	14.0	450	0.02	69.2	0.1	160	23
2/5/92	W3	447.98	7.2	13.2	<0.5	600	3.4	480	0.02	36.2	0.1	100	230
2/5/92	W4	446.72	7.8	12.9	<0.5	820	5.0	190	0.02	66.6	<.05	140	98
2/5/92	W5	446.52	7.3	12.1	<0.5	410	1.7	120	0.02	27.8	8.2	89	<5
2/5/92	W5rep	——	——	——	<0.5	410	2.0	90	0.02	27.6	9.0	87	<5
8/25/92	W1	444.73	7.4	14.4	<0.5	730	5.9	260	0.02	51.7	<.05	100	120
8/25/92	W2	445.28	8.8	14.1	<0.5	800	13.0	320	0.02	87.7	<.05	130	1400
8/25/92	W3	445.44	7.4	14.9	<0.5	750	5.0	250	0.02	50.6	0.1	130	120
8/25/92	W4	445.35	7.3	14.4	0.6	870	6.7	350	0.02	61.3	<.05	130	120
8/25/92	W5	444.99	7.4	12.9	<0.5	410	1.5	77	0.02	23.6	8.3	74	<5
8/25/92	W1rep	——	——	——	<0.5	720	5.6	240	0.02	52.2	0.1	100	110
11/17/92	W1	447.97	7.4	12.9	<0.5	738	6.4	280	0.02	53.8	<.05	98	100
11/17/92	W2	448.23	8.9	12.6	<0.5	824	12.5	402	0.02	81.3	0.1	108	17
11/17/92	W3	448.40	7.4	12.5	<0.5	663	4.4	241	0.02	39.8	<.05	87	460
11/17/92	W4	448.36	7.3	12.5	0.6	867	7.5	395	0.02	60.0	<.05	110	63
11/17/92	W5	444.99	7.9	11.1	<0.5	418	1.8	73	0.02	26.1	8.4	77	<5
11/17/92	W3rep	——	——	——	<0.5	696	4.7	239	0.02	43.1	<.05	87	540
2/2/93	W1	449.51	7.1	12.9	<0.5	609	4.6	230	0.02	43.2	<.05	87	140
2/2/93	W2	449.61	7.1	12.1	<0.5	1048	12.2	560	0.02	87.4	<.05	88	26
2/2/93	W3	450.23	7.1	12.1	<0.5	639	4.8	250	0.02	39.5	<.05	170	230
2/2/93	W4	449.99	7.1	12.9	<0.5	868	7.4	400	0.02	60.2	<.05	96	92
2/2/93	W5	449.71	7.0	11.5	<0.5	395	1.6	76	0.02	24.8	8.0	78	<5
2/2/93	W3rep	——	——	——	<0.5	610	5.1	230	0.02	45.3	<.05	89	130
5/18/93	W1	448.23	7.0	14.0	<0.5	720	5.6	270	0.02	52.4	<.05	94	140
5/18/93	W2	448.18	8.6	15.1	<0.5	920	11.4	420	0.02	77.2	1.0	130	25
5/18/93	W3	449.00	7.2	14.2	<0.5	690	4.6	260	0.02	42.0	<.05	91	270

TABLE 11–4. GROUNDWATER ANALYSES (Continued).

Sample Date	Well #	Water Level	pH	Temp °C	SO_3 mg/l	TDS mg/l	B mg/l	SO_4 mg/l	NO_2 mg/l	Cl mg/l	NO_3 mg/l	Ca mg/l	Mn mg/l
5/18/93	W4	448.84	7.2	14.4	<0.5	850	7.7	430	0.02	69.6	<.05	110	120
5/18/93	W5	448.53	7.3	11.6	<0.5	450	1.8	130	0.02	38.0	6.1	81	<5.0
5/18/93	W2rep	——	——	——	<0.5	910	11.6	470	0.02	76.6	1.2	120	27
8/17/93	W1	448.22	7.4	14.2	<0.5	790	5.8	300	0.02	56.6	<.05	92	130
8/17/93	W2	448.27	8.9	13.3	<0.5	920	9.7	490	0.02	70.2	1.0	92	16
8/17/93	W3	448.78	7.3	13.5	<0.5	850	4.9	320	0.02	52.8	<.05	78	870
8/17/93	W4	448.77	7.4	14.2	<0.5	900	7.6	430	0.02	73.0	<.05	94	130
8/17/93	W5	448.47	7.3	11.8	<0.5	610	2.5	240	0.02	56.2	3.8	83	<5.0
8/17/93	W5rep	——	——	——	<0.5	611	2.3	230	0.02	56.4	4.1	94	<5.0
Average		447.73	7.5	13.1	<0.5	717	6.0	286	0.02	53.7	3.7	102	210

TABLE 11-3. SLUICE WATER ANALYSES

(BASELINE OPERATION)

24 hour Composite Samples Sampling Period		From: 8:30 7/20 To: 8:30 7/21			From: 8:30 7/22 To: 8:30 7/23		
Parameter	Units	Method	MDL	Result	Method	MDL	Result
Arsenic [As] (total)	mg/l	SW6010	0.1	ND	SW6010	0.2	ND
Barium [Ba] (total)	mg/l	SW6010	0.003	0.022	SW6010	0.1	4.2
Cadmium [Cd] (total)	mg/l	SW6010	0.007	ND	SW6010	0.1	ND
Chromium [Cr] (total)	mg/l	SW6010	0.025	ND	SW6010	0.2	1.6
Lead [Pb] (total)	mg/l	SW6010	0.085	ND	SW6010	0.2	ND
Selenium [Se] (total)	mg/l	SW6010	0.2	ND	SW6010	0.5	ND
Silver [Ag] (total)	mg/l	SW6010	0.01	ND	SW6010	0.2	ND
Iron [Fe] (total)	mg/l	SW6010	0.017	0.18	SW6010	0.34	1100
Manganese [Mn](total)	mg/l	SW6010	0.003	ND	SW6010	0.1	3.2
Mercury [Hg] (total)	mg/l	SW7470	0.0005	ND	SW7470	0.001	ND
Boron [B] (total)	mg/l	SW6010	0.25	8.56	SW6010	0.5	ND
Calcium Oxide	mg/l	SW6010	0.3	110	SW6010	0.5	1800
Copper [Cu] (total)	mg/l	SW6010	0.012	ND	EPA200.7	0.2	0.8
Nickel [Ni] (total)	mg/l	SW6010	0.034	ND	EPA100.7	0.2	1.25
Zinc [Zn] (total)	mg/l	SW6010	0.004	ND	EPA200.7	0.2	6.46
Total Dissolved Solids (Filt. Residue)	mg/l	EPA160.1	5	620	EPA160.1	5	1100
Total Suspended Solids (Non-Filt Residue)	mg/l	EPA160.2	5	5600	EPA160.2	5	20000
Sulfate	mg/l	EPA375.4	5	230	EPA375.4	5	390
Oil and Grease (grav)	mg/l	EPA413.1	2	ND	EPA413.1	2	ND
pH (lab)	SU	SW9040	--	9.21	---	---	---

MDL: Method Detection Limit

ND: Not detected at a concentration greater than or equal to the MDL

TABLE 11-3. ASH SLUICE WATER ANALYSES (CONTINUED)
(LONG TERM DEMONSTRATION PERIOD)

Date	1/6/92	1/6/92	1/7/92	1/8/92	1/9/92	1/9/92
Test	----	----	BL	BL	GR	GR
pH	11.08	11.61	11.28	11.15	11.11	11.30
Dissolved Solids (mg/l)	1500	1200	2100	1400	2800	3800
Suspended Solids (mg/l)	5500	10000	5000	4500	2000	1400
Sulfates (mg/l)	480	390	780	500	670	530
Oil, Grease (mg/l)	ND	ND	ND	ND	ND	ND
Metal (mg/kg)						
As	ND	ND	ND	ND	ND	ND
Ba	5.9	3.8	9	5.6	5.4	4.4
Cd	ND	ND	ND	ND	ND	ND
Cr	ND	ND	ND	ND	ND	ND
Pb	ND	ND	ND	ND	ND	ND
Se	ND	ND	ND	ND	ND	ND
Ag	ND	ND	ND	ND	ND	ND
Fe	450	320	780	530	360	330
Mn	5.4	3.6	8.0	4.5	5.0	3.9
Hg	ND	ND	ND	ND	ND	ND
B	50	30	74	50	54	40
CaO	74	53	110	66	1600	1200

sulfate and calcium sulfite. Over the long-term GR-SI demonstration period the average calcium utilization was 24%, with the remainder of the sorbent passing through as unreacted lime (CaO).

Changes in ash characteristics were evaluated by firing coal representative of the normal supply at the Hennepin Station in a pilot scale test furnace, under conditions designed to simulate baseline and GR-SI conditions. The ash produced was then evaluated for characteristics shown in Table 11-5. The ash analyses were compiled in a document entitled "Pilot Scale Ash Characterization Test Report for IP Hennepin Station, Unit 1." The results of ash characterization with respect to composition, pozzolanic activity (compressive strength in a cement mix), temperature rise upon addition of water, and leaching properties are summarized below.

The baseline ash contained approximately 55% silica, 21% alumina, 12% ferric oxide, and various other materials and trace minerals. The GR-SI ash was approximately 42% calcium oxide and 6% sulfur trioxide (calcium sulfate), indicating that the fly ash/sorbent mixture was approximately 50% sorbent, 28% silica, 11% alumina, and 6% ferric oxide. The high CaO content influences several characteristics including pozzolanic activity and temperature rise upon addition of water.

The pozzolanic activity was evaluated by two tests, a 7-day and 28-day test. The evaluation involves replacement of 35% of a cement mixture with the material to be tested. The results of the 7-day test indicate a compressive strength of 505 psi (3480 kPa). The 28-day test results are presented as a percentage of the control (pure cement case). The extended test hardness was 127% of the control, i.e. 27% stronger than pure cement. Therefore, the fly ash/sorbent mixture has cementitious properties, hardening to a very strong material.

Another characteristic affected by the high CaO content is the temperature rise upon addition of water. The baseline ash showed a temperature rise of only 0.5°C (0.9°F) upon addition of water, while addition of water to the GR-SI ash resulted in a temperature increase of 9°C

TABLE 11-5. ASH ANALYSIS PARAMETERS.

PARAMETER	METHOD	SAMPLES ANALYZED BL	SAMPLES ANALYZED GR-SI
Temperature Rise on Addition of Water	ASTM D4326	X	X
Sulfate	ASTM D1757		X
Phenols	Std Methods for Water and Wastewater (SMWW) Method 510		X
Sulfide	SMWW 427		X
Chloride	SMWW 407C		X
Cyanide	SMWW 412		X
Total Organic Carbon	ASTM D429		X
Chemical Oxygen Demand	ASTM D1252		X
EP Tox - Metals, pH	Ref: EPA SW-846	X	X
Paint Filter Test	Ref: EPA SW-846		X
Specific Gravity	ASTM C188, C618		X
Apparent Loose Density	ASTM C110-85, Section 15	X	X
Apparent Packed Density	ASTM C110-85, Section 16	X	X
Fineness	ASTM 430, C618		X
Temperature Rise on Addition of Water	ASTM C110-85, Section 10	X	X
Pozzolanic Activity	ASTM C311, C618		X
Increase of Drying Shrinkage	ASTM C311, C618		X
Autoclave Expansion	ASTM C151, C618		X
Water Requirement	ASTM C311, C618		X
Settling Rate of Water	ASTM C110-85, Section 9	X	X

BL: Baseline

TABLE 11-6. RCRA EP CHEMICAL CHARACTERIZATION.

Concentration (mg/l)	BASELINE ASH	GR-SI ASH	EPA HAZARD LEVEL
Arsenic	<0.1	<0.1	5.0
Barium	<0.2	<0.2	100.0
Cadmium	0.08	<0.01	1.0
Chromium	1.26	0.14	5.0
Hexavalent Chromium, Cr^{+6}	<0.2	<0.4	---
Lead	<0.05	<0.05	5.0
Mercury	<0.0005	<0.0005	0.2
Selenium	<0.1	<0.1	1.0
Silver	0.02	0.08	5.0
Sample Weight (g)	100.02	100.04	
Volume of 0.5 N acetic acid required for pH adjustment (ml)	200	400	
Volume of deionized water added to the extract (ml)	1800	1600	
Final volume of the extract (ml)	2000	2000	
Initial pH	10.44	12.22	12.5
Final pH	4.86	12.14	

RCRA: Resource Conservation and Recovery Act

(16°F). The weight ratio of water to ash in these evaluations was approximately 4:1, which is significantly less than the 17.6:1 used in sluicing the ash. Therefore, the actual water temperature rise is significantly less than specified by the test.

The leaching characteristics of the ash were evaluated through an EPA EP toxicity test. The metal content and the limits requiring classification as a hazardous material, are presented in Table 11-6. Both the baseline and GR-SI ashes have metal contents far below the EPA hazard level. Reductions in leaching of cadmium and chromium from GR-SI ash relative to baseline ash were measured. It would be expected that the GR-SI ash has a lower content of the metals tested for than baseline fly ash since the sorbent is over 90% calcium hydroxide.

11.2.3 Gaseous Emissions

The IEPA limits gaseous emissions of SO_2 to 17,050 lb per hour (2.15 kg/s), from Units 1 and 2. Compliance monitoring of coal analyses is required; an SO_2 level below 6.0 lb/10^6Btu (2580 mg/MJ) indicates compliance. During the first three quarters of 1992, the coal sulfur contents were: Quarter 1 -- 5.26 lb/10^6Btu (2,260 mg/MJ), Quarter 2 -- 5.30 lb/10^6Btu (2,280 mg/MJ), Quarter 3 -- 5.32 lb/10^6Btu (2,290 mg/MJ). GR-SI operation results in reduction in emissions of SO_2, NO_x, CO_2, HCl, and HF, while maintaining CO emissions generally below 100 ppm. Over the long-term GR-SI testing period, the average emissions and reductions from Unit 1 were:

Emissions (lb/10^6Btu)					Reduction From Baseline (%)				
SO_2	NO_x	CO_2	HCl	HF	SO_2	NO_x	CO_2	HCl	HF
2.510	0.246	189	0.017	0.00010	52.7	67.3	7.8	73.0	97.0

All of the above were measured emissions, with the exception of the CO_2 emissions rate which was calculated based on natural gas and coal composition. The HCl and HF emissions and reductions are the median of measured data during GR-SI operation.

N_2O emissions were also measured during the first quarter of 1992, under baseline, SI, and GR-SI operation. The average N_2O emissions were: 0.8 ppm (baseline), 1.4 ppm (SI), and 1.6 ppm (GR-SI). These levels are very low, indicating that GR-SI operation was conducted with insignificant emissions of N_2O.

Particulate matter sampling was conducted during baseline, GR, and GR-SI operation. As presented in Section 10, the maximum emissions rate was 0.035 lb/10^6Btu (15.1 mg/MJ), measured under baseline operation. Humidification was successfully applied, resulting in particulate emissions of 0.015 to 0.025 lb/10^6Btu (6.5 to 10.8 mg/MJ) during full-load GR-SI operation. A small increase in the fraction of the PM_{10} was observed for GR-SI emissions. During full-load GR-SI operation the fraction of particulate matter under 10 microns was approximately 75 to 90% of the outlet loading. This may be compared to a baseline PM_{10} loading of approximately 60 to 75% at the ESP outlet. However, since the total mass of particulate emissions are reduced by a small amount [GR-SI Full Load Average: 0.021 lb/10^6Btu (9.1 mg/MJ), Baseline Full Load Average: 0.026 lb/10^6Btu (11.1 mg/MJ)], this change in the fraction of PM_{10} did not increase the total emitted.

11.2.4 Worker Health

Monitoring of noise levels at the site was conducted during GR operation in January, 1992. The noise levels were measured at several locations, near the sootblower air compressor, west of the overfire air duct on the 5th floor, and the sorbent fan area on the 4th floor. The audiometric device used to make the measurements is a product of Bruel & Kjaer, model number 2205. The results indicate that the noise exceeds the Department of Labor's Occupational Safety and Health Administration (OSHA) noise standard of 85 decibels (over an 8-hour period) only near the sootblower air compressor.

Date	Test Location	Test Condition	Noise (db)
1/14/92	Sootblower Air Compressor (In-Service)	GR	99
1/14/92	Fourth Floor, west side of boiler	GR	79

Date	Test Location	Test Condition	Noise (db)
1/14/92	Fifth Floor, west of OFA duct	GR	79

OSHA has also established a total dust standard of 15 mg/m^3 and coal dust standard of 2.4 mg/m^3, above which employees should not be exposed for more than 8 hours. Ambient air sampling was conducted in January, 1992. The results indicate very low dust levels as shown in the following table:

Date	Filter Number	Location	TSP ($\mu g/m^3$)	Plant Contribution ($\mu g/m^3$)
1/14/92	1453	upwind	16.7	5.2
1/14/92	1452	downwind	21.9	
1/18/92	1455	upwind	21.4	1.1
1/18/92	1454	downwind	22.5	
1/21/92	1456	upwind	63.2	Negligible*
1/21/92	1457	downwind	36.2	
1/22/92	1459	upwind	39.5	Negligible*
1/22/92	1558	downwind	20.5	

TSP: Total Suspended Particles

*: High background contribution from neighboring plant facility

Air sampling in several work areas was also conducted. The results indicate that dust levels are below 15 mg/m^3 in all areas with the exception of inside the lime silo. High dust levels would be expected in this location, requiring use of protective dust masks.

Date	Location	Operating Condition	Dust Concentration (mg/m^3)
1/14/92	Inside lime silo	GR	33.8
	Fifth Floor	GR	7.43
1/17/92	Inside lime silo	Baseline	8.14
	Fifth Floor	Baseline	3.22
1/21/92	Inside lime silo	GR-SI	12.6
	Fifth Floor	GR-SI	1.37

While the high dust level inside the lime silo was measured during GR operation, the high dust level may be attributed to GR-SI operation during the previous day.

11.3 Permitting Considerations

An analysis of permitting considerations for the Hennepin Unit 1 GR-SI demonstration project was conducted at the beginning of the project. The analysis focused on determining the necessary permitting changes for installation and operation of the GR-SI system. Several permanent and temporary modifications required consideration, including:

- Temporary reductions in NO_x and SO_2
- Possible temporary increase in PM_{10}
- Possible increase in stack gas temperature
- Discharge of ash/sorbent sluice water
- Permanent humidification capability
- Permanent SI capability

The temporary reductions in NO_x and SO_2 emissions due to GR-SI operation had the potential for application of NSPS or PSD provisions of the CAAA on completion of the program, when the emissions would rise to original levels. Section 60.14 of Title 40 of the Code of Federal Regulations (40 CFR 60.14) states that "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification" necessitating permitting of the facility as a new source. In addition, 40 CFR 52.21 indicates that an increase in NO_x or SO_2 emissions of 40 tpy (36 tonne/a) makes a source subject to PSD provisions of the CAAA. But, since the primary purpose of the retrofit was to control gaseous emissions, it was expected that EPA would rule that the retrofit was not a modification triggering new emissions standards.

A modified permit to construct was issued by the IEPA on May 27, 1992. The permit granted construction of a flue gas humidification system, a sorbent silo with fabric filter, a sorbent surge tank with a fabric filter, a multiclone in the FGR line, and the SI system. The permit also stated the following:

- The construction and operation of the CCT program does not constitute a modification as defined in 40 CFR 60.14. Since the equipment installed has the primary function of reducing air pollutants, under 40 CFR 60.14 (e) (5), it is exempt from being considered a modification

- Annual emissions of particulate matter and PM_{10} during the CCT demonstration program shall not increase more than 24.9 and 14.9 tons (22.6 and 13.5 tonne), respectively, above the pre-CCT demonstration levels. Accordingly, the CCT project does not constitute a major modification for purposes of 40 CFR 52.21.

- The CCT demonstration project shall be limited in operation to one year, provided that this project may be formally extended by the Agency, if necessary, to complete the CCT demonstration program but not to exceed 5 years including time needed to restore the boiler to original operating conditions. The limited operation period classifies the project as temporary.

- As a temporary demonstration project, emissions from this unit during the demonstration project shall not be considered "representative" for the purposes of PSD or NSPS emissions comparisons. Accordingly, removal or discontinued use of the CCT demonstration equipment shall not be considered as a modification for purposes of 40 CFR 52.21. or 40 CFR 60.14.

- Routine actions taken to restore this unit to its pre-CCT demonstration condition and operating at the condition and capability will not subject this unit to the requirements of 40 CFR 52.21 or 40 CFR Part 60.

- The emissions limits, 35 Ill. Adm. Code 212, 214 and 217, which currently apply to this unit shall not change as a result of the construction, removal or discontinued use of the CCT demonstration equipment, as described in the application.

Therefore, a return to pre-project emissions will not trigger application of NSPS or PSD provisions. The permit also required that particulate matter emissions measurements be conducted upon resumption of GR-SI testing. Tests during short-term operation indicated that humidification effectively enhanced ESP performance, resulting in no change in particulate matter emissions and little change in the ESP outlet and stack gas temperature.

The project originally called for construction of a new ash pond for disposal of the ash/spent sorbent. This would have required modification of the NPDES permit as well as additional permitting considerations due to construction in a 100-year floodplain. Due to several factors including prohibitive cost of construction of a new ash pond, sluicing of the GR-SI ash to the original pond was decided upon. A modified NPDES was issued by the IEPA addressing the required handling of GR-SI ash and the required environmental monitoring in case of a discharge to the Illinois River. The permit specified use of CO_2, acetic acid or other chemical to reduce the pH to approximately 9.0. Other, less costly methods of pH reduction were prohibited due to their potential to increase chloride and sulfate levels in the Illinois River and groundwater. Since no discharge to the river occurred during the GR-SI demonstration, the extensive monitoring specified was limited. If a discharge had occurred, two types of testing would have been required: chemical specific testing on a quarterly basis, and biomonitoring of acute toxicity. The chemical specific testing was conducted regularly, even though not required by the conditions of the NPDES Permit. Biomonitoring was not conducted.

12.0 ENGINEERING DESIGN

The GR–SI system at Hennepin Unit 1 is shown in Figure 12–1 . The system provides for injection of natural gas, recirculated flue gas, OFA, and sorbent. This section contains a description of the engineering design of the Hennepin Unit 1 GR–SI system.

The equipment installed consists of a GR system, an SI system, and a humidification system for enhancement of the ESP performance. The total retrofit includes boiler pressure part modifications, duct modifications, and the installation of the GR–SI equipment and piping. The exact injection configurations for the reburning fuel, OFA, and sorbent are highly site specific and are based on detailed engineering studies. These studies include baseline tests to establish general operational parameters, fabrication and testing of a scaled physical model for isothermal tests, and process modeling to develop projections of NO_x and SO_2 removal performance.

Process design work led to the engineering design of the GR–SI system. Figure 12–2 shows the full-load GR–SI process stream material balance at Hennepin Unit 1 used in the engineering design. For appropriate streams the design and maximum flow rates and the basis for the maximum flow rate are listed. The temperature ranges of streams significant to GR-SI are relatively narrow, the pressure ranges for GR process streams are presented in the following section. An energy balance for GR-SI operation at full load is shown in Figure 12-3.

12.1 Gas Reburning System

The GR system provides for injection of natural gas and FGR several feet above the coal burner nozzles and OFA at a higher position. Natural Gas/FGR is injected through four rectangular co–axial injectors located at each corner of the Hennepin boiler furnace above the top burner row. These injectors were designed to fire co-tangentially to the rotating fireball, which is created by the three rows of burner nozzles located immediately beneath. The basic

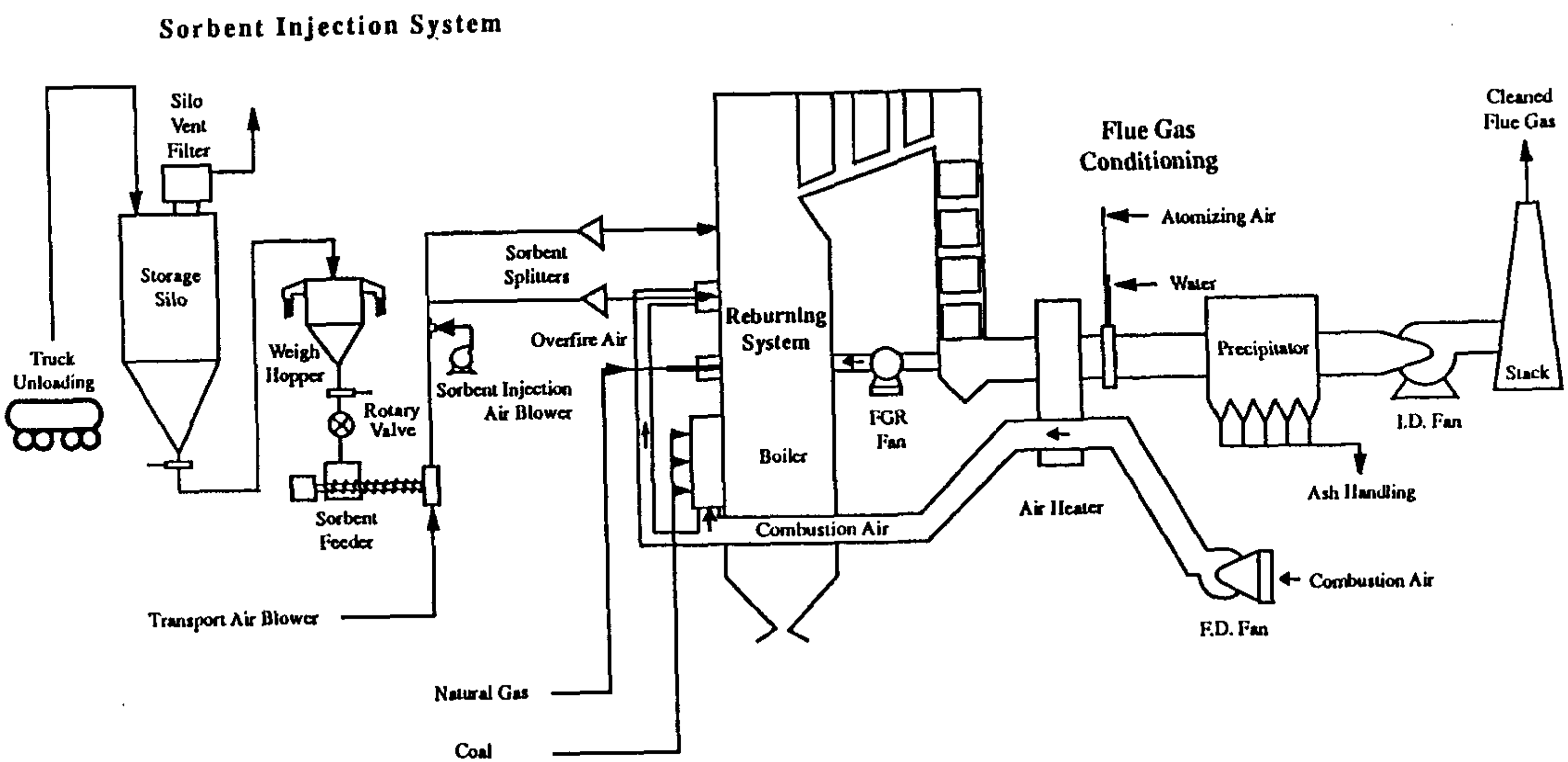
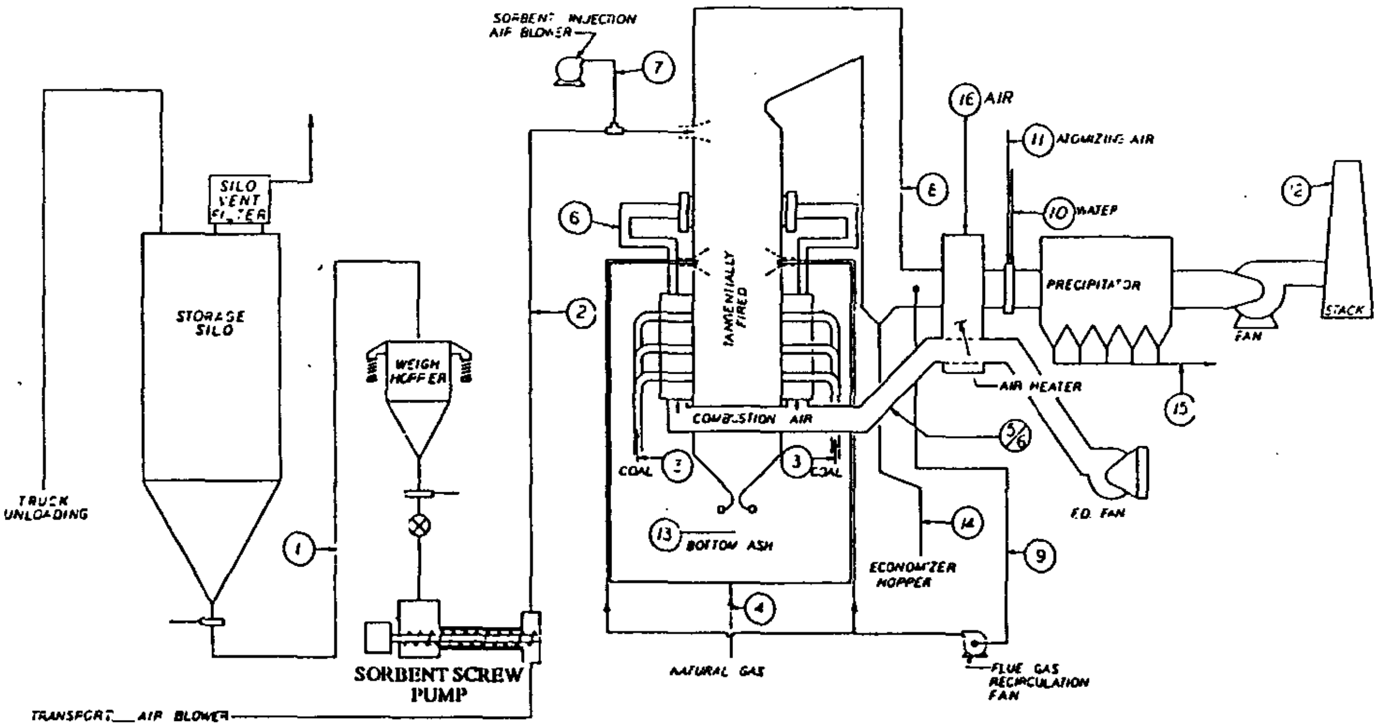


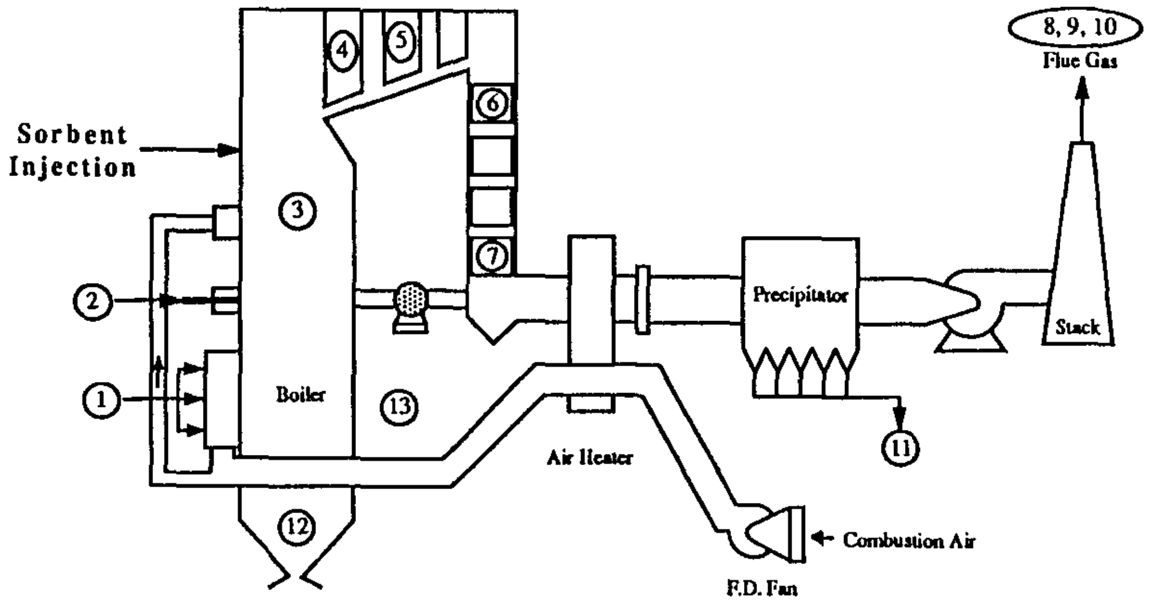
Figure 12-1. Overview of the GR–SI and humidification systems at Hennepin



STREAM NUMBER	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
DESCRIPTION	STORAGE SILO TRANSFER	SORBENT FEED	COAL	NATURAL GAS	COAL COMBUSTION AIR	OVERFIRE AIR	SORBENT INJECTION AIR	FLUE GAS	FLUE GAS RECIR-CULATION	HUMIDI-FICATION WATER	ATOMIZING AIR	STACK GAS	BOTTOM ASH	ECONO-MIZER ASH	ESP ASH	AIR LEAKAGE
GAS SIDE																
AIR LBS/HR		1490			496342	172341	19191				9322					25897
AIR SCFM		325			108230	37577	4187				2034					5647
NATURAL GAS LBS/HR				6284												
NATURAL GAS SCFM				2244												
FLUE GAS LBS/HR								745301	23000			811593				
FLUE GAS SCFM								160820	4925			179298				
SO_2 LBS/HR								1966								
SO_2 LBS/MBTU								2.68								
H_2O LBS/HR										31073						
TEMPERATURE					575°F	575°F	120°F	690°F	690°F	70°F	100°F	195°F				80°F
PRESSURE				15 PSIG	2.0" H_2O	2.5" H_2O	28" H_2O	NEG 5.5" H_2O	34" H_2O	150 PSIG	125 PSIG					
SOLID SIDE																
COAL (COMBUSTIBLES) LBS/HR			49653													
FUEL INERTS LBS/HR			6105										1221	305	4579	
SORBENT LBS $Ca(OH)_2$ /HR	7453	7453														
$CaSO_4$ LBS/HR															2669	
CaO LBS/HR															4541	
TOTAL SOLIDS LBS/HR	7453	7453	55758										1221	305	11789	
MAX DESIGN FLOW LBS/HR	11180	11180		9386		226154	25000		27500	31073	9322				14609	
BASIS		3:1 Ca/S		25% H.I.		25% GAS H.I.	25% TEST BLK		25% TEST BLK	70°F APPROACH	70°F APPROACH				3:1 Ca/S	

* SCFM @ 14.7 PSIA 60°F

Figure 12.2 Full load GR-SI material balance



Full Load GR-SI Heat Energy Balance

No.	Source/ Device	Heat Input (MBtu/hr)	Heat Input (% of total)	Steam Heat Absorption (MBtu/hr)	Steam Heat Absorption (% of input)	Heat Loss (MBtu/hr)	Heat Loss (% of input)
1	Coal*	612.8	81.8				
2	Natural Gas	136.8	18.2				
3	Furnace Water Walls			363.0	48.4		
4	Secondary Superheater			55.7	7.4		
5	Reheat Superheater			68.2	9.1		
6	Primary Superheater			125.6	16.8		
7	Economizer			22.3	3.0		
8	Dry Gas					42.6	5.7
9	Moisture in Fuel					10.9	1.5
10	Moisture from Combustion					38.8	5.2
11	Combustible in Refuse					3.4	0.5
12	Radiation					2.5	0.3
13	Unmeasured					11.2	1.5
Total		749.5	100.0	634.8	84.7	109.4	14.6

*Coal Flow Rate Back Calculated From Energy Balance

Figure 12-3. Full load GR-SI energy balance.

design of the reburning fuel injector assembly is shown in Figure 12-4. Natural gas is injected into an FGR plenum, mixes with FGR, and then is injected into the furnace through four injector assemblies, each containing four rectangular injectors. The injectors were sized according to the required velocity and momentum flux for optimum jet penetration and mixing.

The nominal natural gas input is 136 10^6Btu/hr (39.9 MJ/s), 18% of the full load heat input, and the maximum design gas input is 204 10^6Btu/hr (59.8 MJ/s). These correspond to nominal and maximum flows of 2,240 scfm (1.06 Nm^3/s) and 3,350 scfm (1.58 Nm^3/s), respectively. The natural gas piping and control system was designed to deliver a maximum of 210 scfm (0.10 Nm^3/s) of natural gas to each of 16 injection ports. The natural gas trains, which are identical for each set of injectors, contain flow modulating equipment, a flowmeter, and safety shutoff equipment. Under nominal and maximum design conditions the natural gas pressure at the nozzles is 1.0 psig (6.9 kPa) and 1.8 psig (12.4 kPa), respectively.

One criterion which complicated the design of the gas injection nozzles is unique to tangentially-fired units. The primary method of controlling reheat steam temperature in tangentially-fired units is to control the angle of the burners, thereby moving the fireball in the furnace and affecting the ratio between radiant heat absorption in the furnace waterwalls and convective heat transfer in the tube banks. To maintain this same control ability, the design of the gas injection nozzles incorporated tilt control via a remote operator. The tilting mechanism was located at the exit of the nozzle and is shown schematically in Figure 12-4. The tilting mechanism was removed subsequent to optimization/parametric testing.

The volume of flue gas to be recirculated for injection was set by the required mass flow determined from the flow modeling. The nominal and maximum FGR flows are, respectively, 23,000 lb/hr (2.90 kg/s) and 27,500 lb/hr (3.47 kg/s), corresponding to 10,900 acfm (5.14 m^3/s) and 13,000 acfm (6.14 m^3/s). The injection velocity was critical to achieving rapid mixing with the primary zone gas. To recirculate the flue gas from the flue

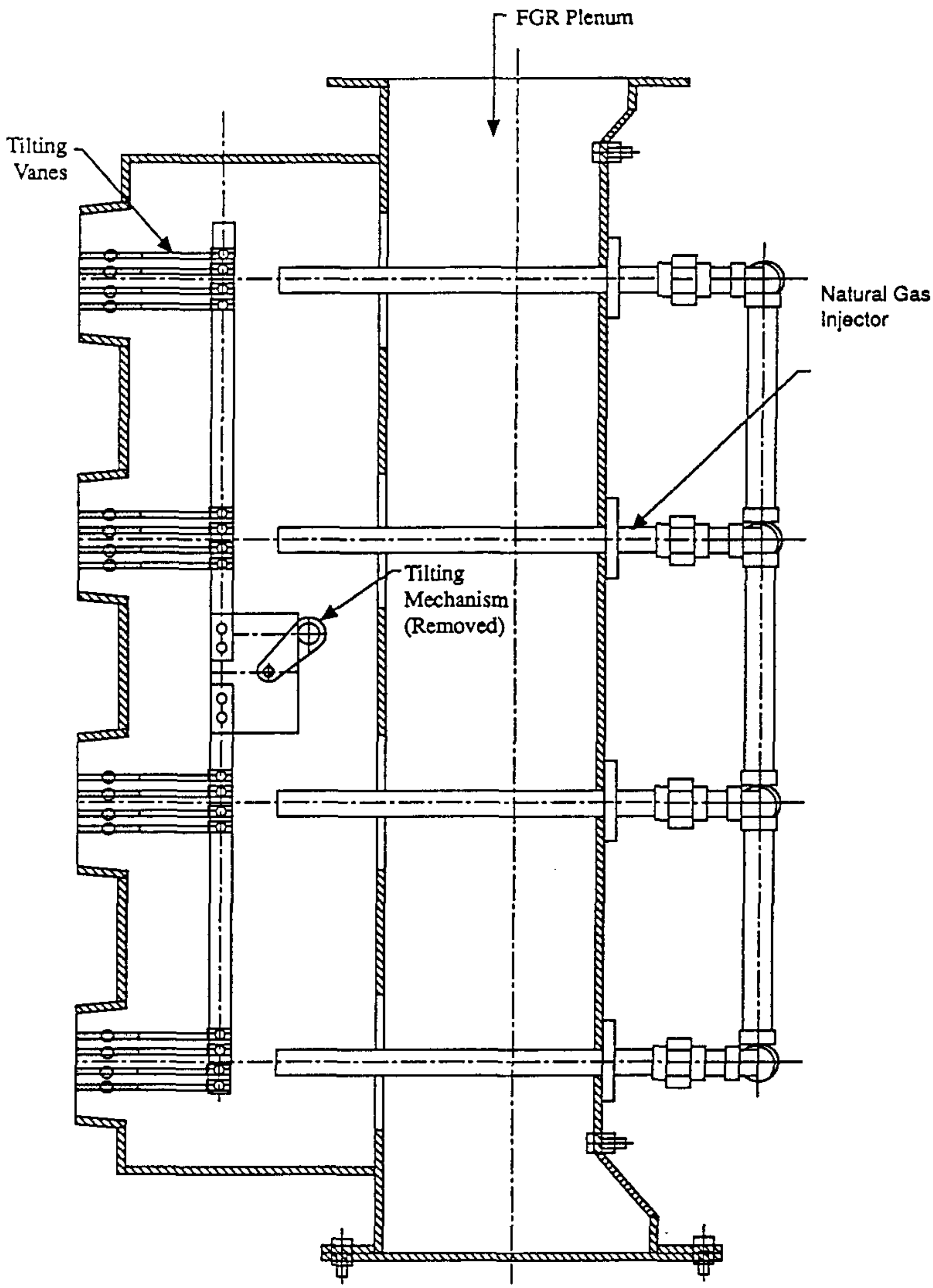


Figure 12-4. Engineering design of the reburning fuel injectors

gas breeching between the economizer and the air heater, a fan was required. The static discharge of the fan was set to provide the needed velocity head for injection plus the duct losses. A static pressure of 34" W.C. (8.45 kPa) is required to inject the FGR at the optimum velocity. To minimize erosion of the FGR fan and injection nozzles, a multiclone dust collection device was incorporated into the design. The tie-in point for the flue gas was selected to be upstream of the air heater. By selecting this point, the amount of oxygen in the flue gas was minimized—prior to air heater leakage—and the degree of quenching in the furnace was reduced. Overall, the FGR injection system consists of a multiclone, a high static fan, control dampers, flow metering, duct work, and injection nozzles.

The flue gas particulate loading at the economizer with GR-SI was expected to be approximately 10 grains/dscf (22.9 g/dscm). Approximately 55% of this is from the injected sorbent and 45% is from the coal ash. The multiclone was designed to reduce the dust loading to approximately 2 grains/dscf (4.6 g/dscm). The FGR injection fan was designed to boost the static pressure from -6" W.C. (-1.5 kPa) to 34" W.C. (8.5 kPa). The maximum FGR flow case of 13,000 acfm has a static pressure rise of 42" W.C. (10.4 kPa).

Preheated combustion air was used as OFA to minimize the temperature quenching effect in the injection zone. Since the GR process has no overall effect on the combustion air flow, but only separates the normal air flow between the burner zone and the OFA zone, the OFA is supplied from the existing FD fan. In addition to specifying the OFA flow, injection configuration and elevation, injection velocity was also critical for optimum penetration and mixing. To meet the required velocity specified for injection, the available velocity head from the existing secondary air ducts was increased. This is accomplished by adjusting the existing coal burner air registers to a more closed position, thereby increasing the back-pressure in the secondary air ducts. This increases the static pressure in the OFA ducts from approximately 2" W.C. (0.5 kPa) to 3" W.C. (0.75 kPa). OFA was injected into the furnace via four rectangular ports located at the four corners of the furnace at an elevation approximately 500 milliseconds downstream of the reburning fuel injection elevation. Four ports inject a nominal rate of 172,000 lb/hr (21.7 kg/s), corresponding to a volumetric flow of 37,600 scfm (17.7 Nm^3/s) of air. The design OFA temperature is 575°F (302°C). The OFA system consisted of tying into the existing secondary air ducts, control dampers, flow metering, duct work, and the injection ports.

12.2 Sorbent Injection System

The SI system at Hennepin Unit 1 provides for sorbent unloading and storage, as well as the upper furnace injection of the sorbent through several injection nozzles. The system was designed to inject sorbent at a Ca/S molar ratio of 1.5 to 3.0, over a range of loads. The sorbent is carried to the site by pneumatically unloaded bulk hopper semi-trailers. It is stored on site in a silo, which has a capacity of 23,300 cubic feet (660 m^3), a three day supply for nominal sorbent use. The sorbent is then transported pneumatically to either the upper furnace injection ports or the low load SI ports (located at the OFA ports). The sorbent plus transport air stream is mixed with the SI air for injection at the design jet velocity. SI is through either six (high load) or four (low load) 3 inch (7.6 cm) coaxial injectors. The properties of one of the sorbents evaluated (Linwood calcitic hydrate) are shown in Table 12-1.

12.2.1 Sorbent Delivery to Silo

The sorbent is delivered to the Hennepin site via pneumatically unloaded truck trailers. The trailers are totally enclosed tankers with a capacity of 20 to 25 tons (18,200 to 22,700 kg). The loaded trailers are weighed on a truck scale to document the total sorbent used in the test program. The trailers are unloaded at a newly installed sorbent silo located near the power plant building. Unloading is accomplished using a truck-mounted blower to convey the sorbent pneumatically via a pipeline into the sorbent storage silo. The sorbent is unloaded at an approximate rate of 12 tph (3.0 kg/s). The blower is capable of supplying air at 15 psi (103 kPa) pressure differential. The silo has a sorbent capacity of 23,300 cubic feet (660 m^3), which is a three-day supply for full-load operation at a Ca/S molar ratio of 2.0.

TABLE 12-1. PROPERTIES OF LINWOOD CALCITIC HYDRATE

Surface Area (cm^2/g)		15.5
Density (g/cm^3)	2.18	
Mass Median Particle Size (microns)	2.88	
Bulk Density (lb/ft^3)		
-- Loose	25	
-- Settled	30	

<u>Analysis (weight percent)</u>

$Ca(OH)_2$	96.20
$Mg(OH)_2$	0.14
$CaCO_3$	1.22
SiO_2	1.66
Fe_2O_3	0.50
Al_2O_3	0.60
SO_3	0.08

Conveying air is vented from the top of the silo through a cartridge baghouse filter equipped with replaceable elements.

12.2.2 Sorbent Transport and Injection

During GR–SI operation, sorbent flow from the conical bottom storage silo is enhanced by fluidizing air slides. An automatic slide gate valve is located between the storage silo and sorbent weigh hopper. The weigh hopper is mounted on four load cells which monitor the sorbent mass in the hopper. The conical bottom of the sorbent weigh hopper also is equipped with fluidizing air slides. A manual slide gate valve is located at the outlet of the sorbent weigh hopper. The sorbent rotary valve feeder is located immediately below the slide gate. Sorbent flows into the variable speed rotary valve feeder and is discharged at a controlled flow rate that is measured by the weigh hopper load cells. The sorbent screw pump conveys the sorbent into the pneumatic transport line. By means of a blower on the clean air plenum of the baghouse, a slightly negative pressure is maintained so that all air leakage is into the feed system. This virtually eliminates fugitive dust emissions.

Transport air is provided by a rotary positive displacement blower which operates at a constant volume output. Excess air at less than design loads is vented to the atmosphere. Transport air is controlled by an arrangement of flowmeters, pressure and temperature sensors, and flow control valves. This blower also provides the air to the fluidizing air slides.

Transport air is delivered to the solids pump where sorbent is fed into the transport line. Sorbent is then pneumatically conveyed to a line diverter valve. The valve directs the flow to either the high-load splitter or the low-load splitter. The high- and low-load splitters divide the sorbent flows into equal outlet streams, six from the high-load splitter and four from the low-load splitter.

The pneumatically conveyed sorbent continues from the splitter to the nozzles on the furnace wall. The SI nozzles utilize a co-axial jet design. Here, the sorbent/transport air blend is mixed with injection air from a SI air fan to produce the required mass flow and nozzle velocities for injection. The transport air/sorbent are introduced into the center of the injection air stream, with mixing taking place in the barrel of the nozzle.

12.2.3 Spent Sorbent/Fly Ash Disposal

SI results in a significant increase in the amount of fly ash generated and a change in its composition. Under nominal GR-SI operation, the unit produces approximately 13,500 lb/hr (1.7 kg/s) fly ash and 1,500 lb/hr (0.2 kg/s) bottom ash, or a total of 15,000 lb/hr (1.9 kg/s). The amount of ash/spent sorbent produced during GR-SI is double the amount from baseline operation, which is approximately 7,500 lb/hr (0.95 kg/s). Operating GR-SI over a one-year period at a capacity factor of 40% is expected to result in the production of 23,000 tons (20,900 tonne) of fly ash. SO_2 is formed from the combustion of the coal and reacts with injected sorbent in the upper furnace to produce calcium sulfate and calcium sulfite. The sorbent, which has a small particle diameter in comparison to fly ash, is carried by the furnace gas with the fly ash through the convective pass, air heater, and duct work to the existing ESP. The fly ash and spent sorbent are collected by the ESP and stored temporarily in insulated hoppers under the ESP. Fly ash and spent sorbent are periodically conveyed from the hoppers to the sluice system and then to the ash pond. The chemical composition of the ash is also different from the baseline cases; the calcium content is much higher. The makeup of the ash is similar to ash produced from firing high calcium western coal. Because the fly ash/spent sorbent mixture is highly alkaline, the system required injection of carbon dioxide (CO_2) to control the pH of the water entering the ash pond within the range of 6.0 to 9.0.

The plant is equipped with a wet ash sluicing system supplied by United Conveyor. The system uses high pressure water and an ejector to create a vacuum. The fly ash is carried from hoppers by a transport air stream and is then mixed with water in the ejector. The mixture flows to an air separator designed to completely mix ash with the water and separate the air. The amount of water used is approximately 25 pounds per pound of ash. The ash is then sluiced to an on-site settling pond. The sluice water is treated with CO_2 to a pH of 6 to 9, before discharge into the Illinois River.

Several upgrades to the original system were required. New tie-ins were required to accommodate the ash collected in the five hoppers in the humidification duct and the multiclone. The hoppers are equipped with screw conveyors and rotary valves and discharge ash into the new ash air conveyor line. The multiclone ash discharges into a new tie in line by a rotary valve. The cementitious nature of the GR-SI fly ash required a new Hydroveyor Ram clean-out device to scrape these deposits. The buildup of ash in the pipe leading to the settling pond is limited by the action of the coarse bottom ash also carried by the pipe.

12.3 Humidification System

The humidification system was designed to cool the flue gas to within 70°F (39°C) of saturation, measured at the precipitator inlet, over a range of boiler loads from a nominal low load of 22 MW_e a to full load of 75 MW_e. A saturation temperature 125°F (52°C) was used. The humidification system was designed to cool the air heater outlet flue gas from 350°F (177°C) to 195°F (91°C), requiring 60 gpm (3.8 l/s) of water at full load. Humidification water is injected into a duct immediately before the flue gas flow into the ESP. Rapid vaporization is required; therefore twin fluid atomization nozzles were used to obtain fine atomization. The design called for water atomization via 34 nozzles with a nominal flow rate of 1.76 gpm (0.11 l/s).

Humidification water is supplied from the plant's service water system. The water is passed through a basket-type strainer to remove debris, such as leaves, twigs, and pipe scale. A motor driven centrifugal water pump boosts the pressure to overcome line losses and elevation head, and provide sufficient water pressure to the atomizing lances. Water flow rate was measured by a vortex-type flowmeter, and controlled by a pneumatically actuated globe valve.

Atomizing air is provided by three screw-type air compressors. Each air compressor is equipped with intake filters, oil and water separators, and aftercoolers. No provision is made for measuring air flow rate. Air pressure is controlled by a pneumatically actuated eccentric disc valve.

Six humidification lances support the atomizing nozzle array, as well as deliver compressed air and water to each nozzle. Each lance was designed to accommodate a maximum of six atomizing nozzles.

Humidification takes place in a horizontal section of the modified flue gas duct just downstream of the air heater gas outlet. This horizontal duct section has been enlarged to provide the required residence time for vaporization prior to any change in direction in the duct route. The humidification duct section terminates with a 90 degree turn upward towards the ESP inlet. The system was designed for complete water vaporization in the humidification duct, so that little or no liquid water can impact on the precipitator fields.

Water droplet impingement and any subsequent ash deposit formation occur on the humidification lances and the vertical wall as the gases make the first turn. For this reason the duct has ash hoppers incorporated in the design downstream of the humidification lances, and one additional hopper below the first 90 degree bend. A screw conveyor is attached to the hopper flange to provide for ash removal. Twelve thermocouples per duct are pad-welded to the duct skin for monitoring temperature.

Water in the flue gas is assumed to be completely vaporized by the time it enters the ESP. A temperature sensor is suspended in the center of the gas stream in a short section of the duct leading to the precipitator inlet. This temperature signal is used by the control system to modulate water flow rate.

12.4 Additional Plant Modifications

Several modifications to the plant system were required. These include a new auxiliary power system, a GR-SI controls system, additional sootblowers in the backpass, and relocation of the induced draft fans to provide for the necessary residence time in the humidification duct.

The power distribution system was designed to provide power and overload/fault protection to all GR-SI components. The power is received from the existing 2300 V Switchgear 1A. The switchgear bus was extended and a watt-hour meter and breaker were installed to meter the GR-SI power usage and to disconnect these loads in case of overload or fault condition. The 2300 V power is transformed by a 1000 KVA transformer to 480 V and delivered to two motor control centers (MCC 1 and MCC 2). The motor control centers service 460 V motors and miscellaneous three-phase, 480 V loads in different areas. Feeder circuit breakers and starters allow isolation of loads from MCC buses and provide overload and fault protection. Two 30 KVA transformers are used to transform power from 460 V to 120/208 V. The power is fed to 120/208 V, 3-phase, 4-wire panelboards. These panelboards distribute power through 20 A circuit breakers to various 120 V, single-phase loads.

GR-SI operation requires control of flow rates of many inputs, including sorbent, sorbent transport air, SI air, natural gas, coal, primary air, etc. A control system was required to modulate these flows and to trip power in the event of equipment malfunction or unsafe conditions. The boiler control system (the original system) is a Leeds and Northrup system which was judged to be obsolete. Therefore several microprocessor-based control systems were evaluated and a Westinghouse WDPF system was selected. The control system included associated controllers, power supplies, input-output cards and terminations, and a table top CRT display with an operator keyboard station. The Westinghouse system interfaces with the Leeds and Northrup Control System by means of hardwired connections, but the integrity of each control system is maintained. The system interface was designed so that during baseline operation (i.e. without GR-SI), the control of the boiler is maintained in the original manner requiring no change in operating procedure.

SI results in significant increase in the particulate matter flow through the upper furnace and backpass. The anticipated increased fouling of heat transfer surfaces necessitated the installation of additional sootblowers. Eight new IK type sootblowers were installed in the convective sections to maintain tube cleanliness/heat transfer. These are the same type as original sootblowers, supplied by Diamond Power Co. The time to complete one full cycle of IK blower operation was doubled from 1 to 2 hours and the number of cycles per shift also was expected to double. Therefore, the time for sootblower operation was expected to increase from 1 to 4 hours per 8 hour shift. The added sootblowers receive compressed air from the original compressed air supply.

The induced draft (ID) fans were relocated to accommodate the necessary residence time of 2.0 seconds in the humidification duct. A breeching, with east-west orientation, carries the flue gas from the ID fans to the stack. The fans were originally located south of this breeching and discharged the flue gas northward. The fans were relocated to the north of the breeching and rotated 180 degrees, discharging the flue gas southward. The fan motors and foundations were replaced and turning vanes were installed at the fan outlet to improve uniformity of gas flow to the stack breeching.

12.5 Design and Equipment Changes

The final GR-SI system had few changes from the original design. The changes were in the following areas: the reburning fuel injector size, reburning fuel injector tilting, number of humidification nozzles in use, the humidification duct configuration, and sorbent injectors in use. The reburning fuel injectors required modification after they were received from the manufacturer. The nozzles were approximately twice the size specified, requiring modification so that the final design had approximately 75% of the original cross-sectional area. The original design specified tilting capability of the reburning fuel injectors to follow the angle of the coal burners. During the optimization/parametric testing evaluation the tilting of the injectors was found to have little impact on the emissions reduction performance. Therefore, the tilting capability of these injectors was removed and the reburning fuel is injected horizontally.

The humidification system required modification in two areas: nozzles in use and duct configuration. The humidification duct has 34 nozzles on six horizontal lances in two parallel ducts. During preliminary testing it was determined that water from the lower two lances (12 nozzles) was not evaporated rapidly. Due to the concern for water droplets entering the ESP, the use of the two lower lances was discontinued and the humidification water is injected through 22 nozzles affixed to the upper four lances. While this resulted in the capacity of the humidification system, the actual water flow required for ESP enhancement was much less than the design flow. Several changes to the humidification duct configuration were required to enhance water vaporization and ash collection, as discussed previously in Section 10. These include installation of the perforated plate and turning vanes at the humidification duct entrance, and two additional hoppers for collection of accumulated ash.

One change from the original design was not in the GR-SI system configuration, but in the operation of that system at low loads. The GR-SI system design specified switching of SI from the upper furnace to the OFA port position at 50% load, due to a shift in the furnace gas temperature profile. Optimization testing results indicate that the six upper furnace ports may be used at reduced loads without loss in sorbent sulfation efficiency; therefore, no switching of injection configuration is necessary.

12.6 Restoration/System Configuration at Project Completion

At the completion of the project, the host site restoration was completed. Illinois Power elected to retain GR capability and to remove the SI and flue gas humidification capability. The major changes were the removal of all SI equipment in the boiler building, the sorbent silo and other equipment outside of the boiler building were retained. The humidification system was removed, the smaller diameter duct was restored. Other equipment removed include the sootblowing system compressor and the GR cooling air fan.

13.0 DESIGN VS. OPTIMIZED PERFORMANCE

The Hennepin GR-SI system was designed for a wide range of natural gas, sorbent, and other process stream inputs for process optimization. In this section the nominal design case for full-load GR-SI operation and projected results are compared to actual and to optimized operating conditions and results. The performance of the GR-SI system is discussed with respect to several parameters including zone stoichiometric ratios and FGR flow. GR performance, evaluated primarily during optimization testing and to some extent during the long-term demonstration, will also be discussed.

13.1 Proposed vs. Actual Performance Comparative Review

An evaluation of the design operating scenario and performance and actual operation and measurements has been undertaken. Overall, the operating conditions under which the long-term demonstration was conducted are very similar to the design case. GR-SI design operation and the actual operating parameters under which the long-term demonstration was conducted are listed below:

	Design	Long-Term Demonstration
Primary Zone Stoichiometric Ratio	1.10	1.09
Reburning Zone Stoichiometric Ratio	0.90	0.91
Exit Zone Stoichiometric Ratio	1.18	1.21
Ca/S Molar Ratio	2.0	1.76
Gas Heat Input (%)	18.0	18.2
FGR (% of Total Flue Gas)	3.0	2.1

Over the long-term demonstration, these conditions resulted in emission reductions in excess of the 60% NO_x reduction and 50% SO_2 reduction goal.

13.1.1 Zone Stoichiometric Ratios

As indicated above, design zone stoichiometric ratios were effectively used to achieve the emissions reduction goals. The primary zone stoichiometric ratio was tested over a wide range, from 1.045 to 1.153. Reduction in primary zone stoichiometric ratio results in reduced NO_x formation in the primary zone, but also in an increase in the lower furnace gas temperature. This results in increased lower furnace heat flux and a potential increase in unburned carbon in ash due to inadequate primary zone O_2 concentration. Therefore, a lower limit for primary zone stoichiometric ratio is established. At high load, the primary zone stoichiometric ratio of 1.07 was typically maintained, while the primary zone stoichiometric ratio was normally above 1.10 at reduced loads.

The design gas heat input of 18% was approached at 18.2%, resulting in an average reburning zone stoichiometric ratio of 0.909. This resulted in NO_x reduction of 67%, exceeding the design goal of 60%. The reburning zone stoichiometric ratio ranged from 0.860 to 0.982 and the gas heat input ranged from 12.1 to 19.7%, during long-term demonstration. Generally, the reburning zone stoichiometric ratio is limited by the amount of reburning fuel injected. As expected, the lower the reburning zone stoichiometric ratio, the greater the reduction in NO_x emissions. The following test results show the general impacts of operation near the design primary and reburning zone stoichiometric ratios (SR_1: 1.10, SR_2: 0.90) and operation at lower stoichiometric ratios:

Date	Steam Flow (lb/hr)	Reburn Gas (%)	Primary Zone SR	Reburn Zone SR	NO_x Emissions (lb/10^6Btu)
3/2/92	544,550	18.5	1.106	0.914	0.276
3/11/92	549,075	18.7	1.090	0.898	0.284
3/26/92	553,423	18.8	1.073	0.885	0.250
10/19/92	547,716	18.2	1.068	0.886	0.252

The coal burner tilt angles for these tests were in the +20 to +25 degree range (upward). As discussed in Section 7, the coal burner tilt angle impacts the NO_x reduction process, with lower burner tilts resulting in higher process efficiency, i.e higher NO_x reduction.

13.1.2 Sorbent Utilization

The predicted sorbent utilization for Marblehead and Linwood hydrated lime was in the 20 to 30% range. This compares well with the 16.5 to 32.5% range and average of 24.1% measured during the long-term demonstration. While the design case Ca/S was 2.0, it was expected that a Ca/S molar ratio of 1.5 and gas heat input of 18% would result in 50% SO_2 emissions reduction. Replacement of 18% coal heat input with natural gas requires an additional reduction of 39% to achieve an overall 50% reduction. This level of SO_2 reduction was expected from a Ca/S of 1.5, requiring a calcium utilization of 26%. During the long-term demonstration, an average gas heat input of 18.2% and sorbent input corresponding to a Ca/S of 1.76 resulted in an average SO_2 reduction of 52.7%. An average calcium utilization of 24% was calculated.

High sorbent utilizations were obtained while injecting sorbent from the upper configuration, even at low loads. It was expected that as the boiler load dropped, the lower SI configuration (located at the OFA air ports) would be used. But parametric test results indicated that the upper configuration may be used over the range of operating loads. Therefore, the sorbent sulfation rates did not significantly drop off with injection temperature.

An evaluation of promoted sorbents showed that the same SO_2 emissions reductions may be obtained at significantly reduced sorbent inputs. Calcium utilizations under optimum conditions exceeded 40%. One of the sorbents also yielded reduction in NO_x (20 to 35%) due to the NO_x reducing property of the proprietary additive.

13.1.3 GR-SI Process Flow Rates

The injection velocity and mixing rate are significant parameters for both reburning and sorbent sulfation processes. For this reason, natural gas and SI require injection/carrier gases. GR is optimized for a mixing time; therefore, the system was designed to inject recycled flue gas at a rate corresponding to 3% of the total flue gas flow. The full-load design case called for an FGR flow of 4,900 scfm (2.3 Nm^3/s), which is 3% of the total full-load flue gas flow of 161,000 scfm (76.0 Nm^3). To minimize the FGR fan power requirement, the system was optimized for minimum FGR flow. During optimization testing, an FGR flow of 2800 scfm (1.3 Nm^3/s), corresponding to 1.7% of the full load flue gas flow, was determined to be optimum. Over the long-term demonstration the FGR flow rate was 2,811 scfm (1.32 Nm^3/s), corresponding to 2.1% of the total flue gas flow rate at the average load of 62 MW_e. The design SI air flow is 4,200 scfm (2.0 Nm^3/s), which is 3% of the total air flow at full load. During the long-term demonstration period, the average SI air flow was 3,600 scfm (1.7 Nm^3/s), which is equal to the design SI air flow at 62 MW_e (long-term testing average load). Therefore, effective NO_x reductions were obtained with less than two-thirds of the design FGR flow rate, while the SI process was carried out with the design injection air flow rate.

13.1.4 Gas and Steam Temperatures

Some differences between the design and actual flue gas and steam temperatures were evident. GR-SI resulted in fouling of the secondary superheater and reheater surfaces and an increase in the economizer outlet gas temperature. The GR-SI process also resulted in essentially no change in the superheater steam temperature. Heat transfer modeling indicated that application of GR-SI at full load was expected to result in an increase in the flue gas temperature at the economizer outlet, from a baseline of 692°F (367°C) to 701°F (372°C), a difference of 9°F (5°C). The economizer outlet gas temperature, which was recorded by the BPMS, increased at full load from a baseline of 651°F (344°C), to 720°F (382°C), a rise of 68°F (38°C).

The plant operators typically maintain the superheat and reheat steam temperatures 10°F (6°C) less than the design point of 1005°F (541°C). Superheater and reheater steam temperatures of 993°F (534°C) and 992°F (533°C), respectively, were measured under full-load baseline operation. These may be compared to superheater and reheater temperatures of 994°F (534°C) and 999°F (537°C), respectively under GR, and 995°F (535°C) and 989°F (532°C) under full-load GR-SI. These measurements indicate that main steam temperature did not change, while the reheat steam temperatures were reduced under GR-SI. This reduction in reheat steam temperature was more significant at mid-load and was due to sorbent fouling of this convective heat exchanger.

13.2 Physical Design Limitations

Physical design limitations experienced during the long-term demonstration extended to two areas of operation: sootblowing and humidification. The first area was improved by optimization of sootblowing cycles. Significant fouling of secondary and reheater surfaces, determined from reduction in heat transfer rates during GR-SI operation, required optimization of sootblower operation. Sootblower optimization resulted in reduction in thermal efficiency, increase in boiler exit temperature, and superheater attemperation rate.

During start-up of the humidification system, it was determined that the water from the lowest set of nozzles was not vaporizing rapidly, resulting in significant wall wetting. Therefore, their use was discontinued and humidification was applied with 22 nozzles, a capacity of 38.7 gpm (2.44 l/s) with nominal flow of 1.76 gpm (0.11 l/s) through each. During periods of high load GR-SI operation, water flow reached its capacity. Therefore, an improvement in the humidification configuration or nozzles should result in greater ESP enhancement.

While humidification was applied successfully, especially at low load, some deterioration of ESP performance was apparent during extended full load GR-SI operation. Continuous full load GR-SI operation was limited to 32 hours, due to elevated stack opacity approaching the 30% limit. The stack opacity during this run approximated 15 to 20% when sootblowers were not in operation and 25% while sootblowing, which was conducted 84% of the time.

13.3 Design Lessons from Hennepin GR-SI

During long-term testing, several design features of the Hennepin GR-SI system were noted for their beneficial or adverse impacts on emissions/operations. These include the coal zone residence time, OFA injection velocity, and the sootblowing cycles. Emissions of NO_x were lower when coal burners were tilted downward, as was the case for full-load GR operation but not GR-SI operation. At low load, the OFA injection velocity was insufficient to rapidly mix with reburning zone gas, resulting in elevated CO emissions. The original sootblowing cycles required optimization to reduced boiler exit gas temperature and limit attemperation rates.

One of the design features which appears to impact NO_x emissions is the coal zone residence time. This is a function of the coal burner tilt angles, the reburning fuel tilt angles, and the distance between the reburning fuel injectors and the coal burners. Under full load GR operation, the coal burners were generally tilted downward, while under full load GR-SI operation the burners were tilted upward to maintain reheat steam temperatures. The upward tilting of coal burners resulted in a reduction in the coal zone residence time and reduced the reburning process efficiency. The reburning fuel tilting mechanism, which was removed after optimization testing, allowed the reburning fuel to be introduced into the furnace at the same angle as the coal burners, thereby enhancing zone separation. But reburning fuel injector tilting had only a minor effect on NO_x emissions. NO_x emissions during GR-SI operation were somewhat higher than under GR. The burner tilt angles were generally below -20 degrees (downward) during full load GR operation. Therefore, the impact of the reburning fuel tilting mechanism is limited, while the burner tilt angle appeared to have significant impact on NO_x emissions. This indicates that lower NO_x emissions are obtained when there is greater separation of primary combustion and reburning fuel injection.

Elevated emissions of CO (above 100 ppm) were measured during low load GR-SI operation. While the stoichiometric ratios appeared to show sufficient burnout air for complete combustion, the injection velocity was below that required to rapidly mix with the furnace gas and burn out CO. The design studies showed that a significant drop-off in injection velocity would result from operation at reduced load, i.e. at 50% boiler load (approximately 40 MW_e) the injection velocity drops to 50% of the full load case. Therefore, the mixing rate is significantly reduced at low load, resulting in lower burnout of CO.

Fouling of convective heat transfer sections during GR-SI operation resulted in an increase in the boiler exit gas temperature, lower thermal efficiency, and higher superheater attemperation rates (due to greater heat transfer to the primary superheater). The eight IK sootblowers installed in the convective heat transfer section required optimization. The addition of these sootblowers was expected to result in an increase in sootblowing time to 50%, from the original 12%. In practice an increase in the sootblowing time to 84% was required during full load GR-SI operation to maintain a relatively constant boiler exit gas temperature, constant heat loss efficiency, and reduced superheater attemperation rates.

13.4 Technology Improvements

13.4.1 Humidification Nozzle

During the field test, twin-fluid atomization nozzles designed by EER were tested in the Hennepin humidification duct. The EER nozzles, called VEER-Jet, were effective in reducing wall wetting. This was determined by measurement of duct skin temperature in the east and west duct, when the VEER-Jet nozzles were used in the east duct and the normal Delavan nozzles were used in the west duct. The average duct skin temperature in the east duct was 273°F (134°C) when the water flow in the duct was 12.6 gpm (0.79 l/s), while the average duct skin temperature in the west duct was 251°F (122°C) when the water flow in the west duct was 10 gpm (0.63 l/s). These results are summarized in the table below. The drop size distribution from a scaled down version of the nozzles was obtained using a

Malvern instrument. The Sauter Mean Diameter (SMD) of the drops, as a function of air to water ratio, is shown in Figure 13-1. A SMD of under 25 microns for water flow of 0.8 gpm (0.050 l/s) and air to water ratio of 0.1, is significantly smaller than those from most commercially available nozzles. Therefore, use of VEER-Jet nozzles would permit injection of a greater quantity of water which should allow continuous full load GR-SI operation without a time limit.

Duct	Nozzle	Water Flow (gpm)	Duct Skin Temperature (°F)
East	VEER-Jet	12.6	273
West	Delavan	10.0	251

13.4.2 Sorbent Reactivity

Another area in which the original technology was improved upon is the use of advanced sorbents. SI operation over the load range of 40 to 50 MW_e at Ca/S molar ratio of 1.75 resulted in calcium utilization of 26% for Linwood hydrated lime. The utilization increased to 31% with PromiSORB™ A and 38% with PromiSORB™ B. HSAHL, which is produced by the Illinois State Geological Survey, also showed improved performance, with an average utilization of 34%. PromiSORB™ B utilization was above 40% under a Ca/S molar ratio of 1.5, in the above stated load range. A gas temperature effect evident from operation at high loads and GR operation was evident with these promoted sorbents. The performance of these sorbents at two Ca/S molar ratios is summarized in Figure 13-2. Therefore, use of these advanced sorbents can yield much higher utilization and corresponding SO_2 reductions, in comparison to conventional sorbents.

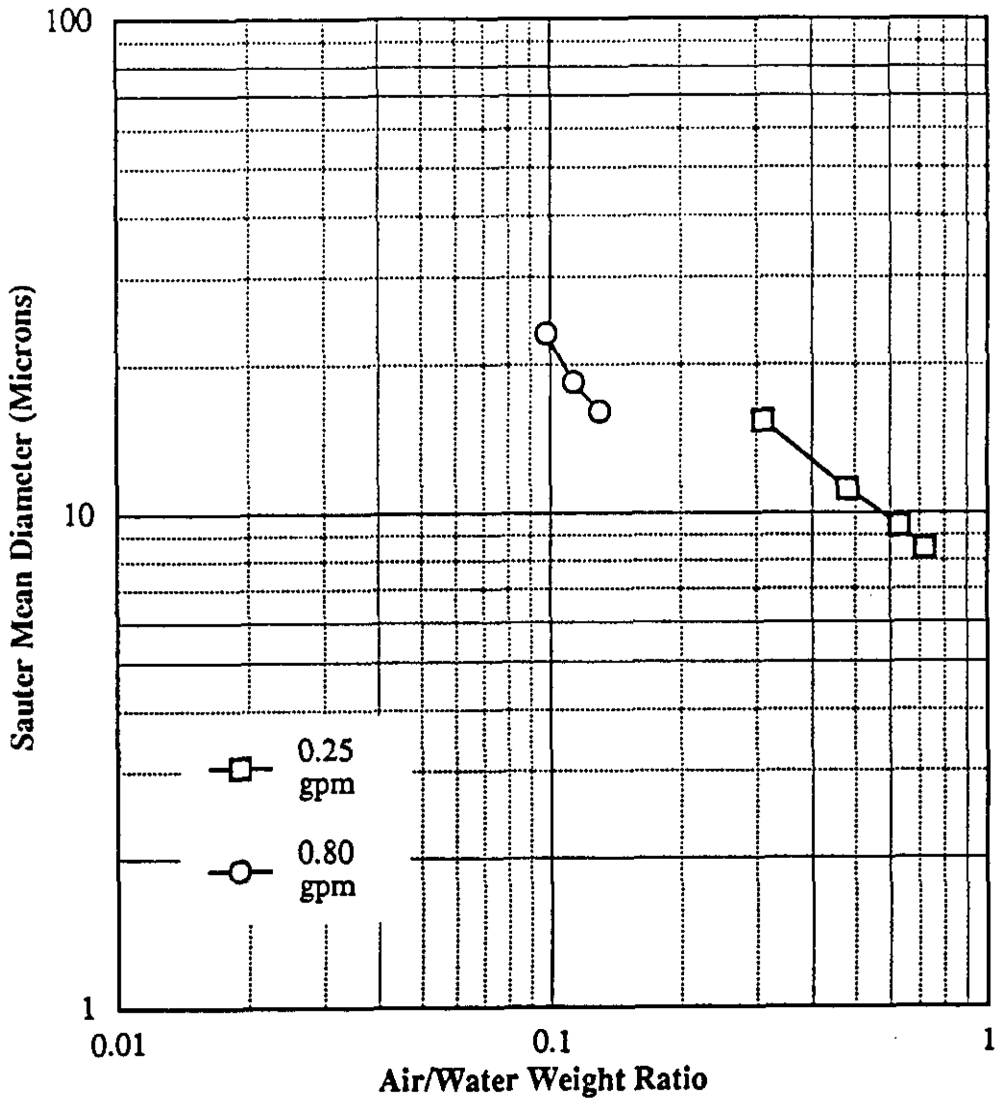


Figure 13–1. VEER–Jet Nozzle performance

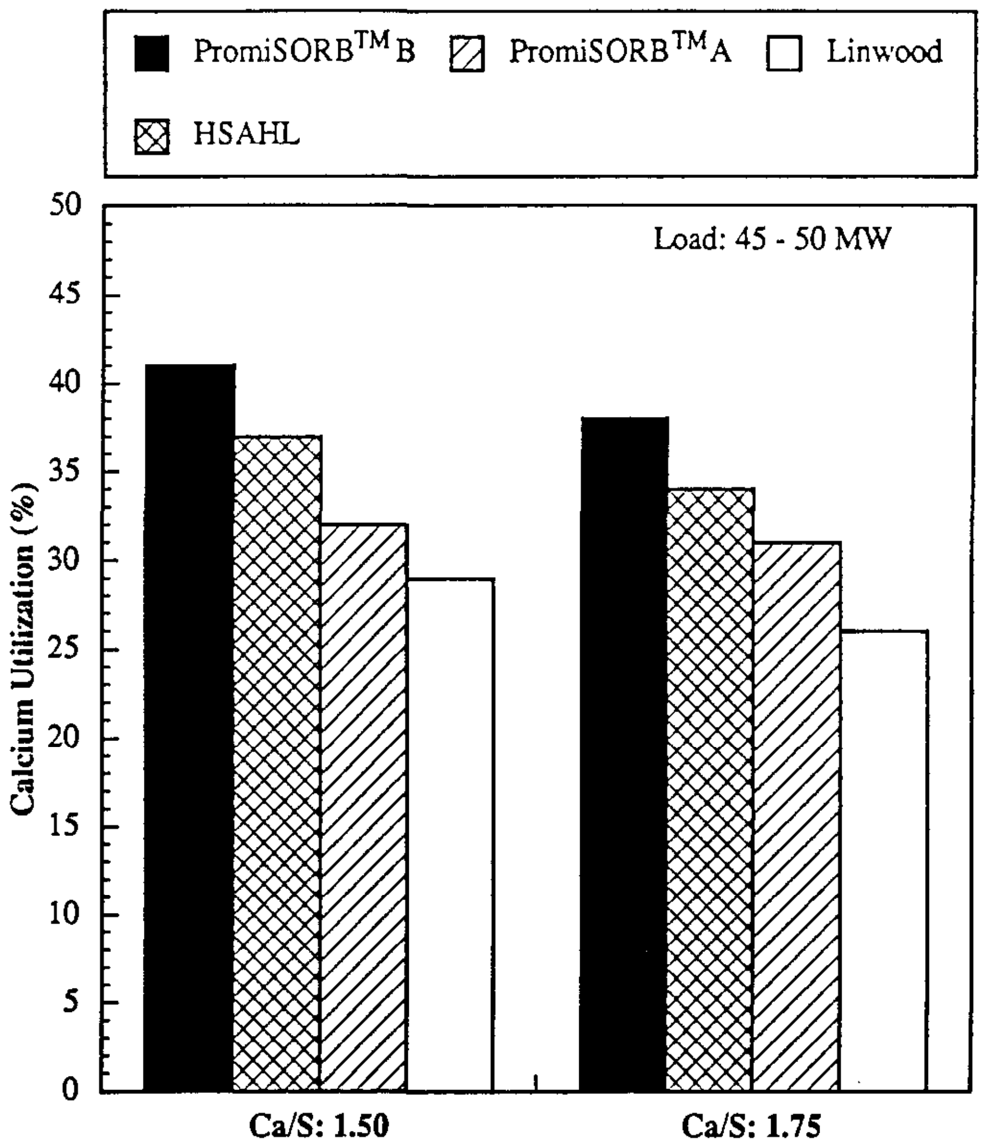


Figure 13-2. Comparison of promoted and unpromoted sorbent utilizations

14.0 CONCLUSIONS AND RECOMMENDATIONS

14.1 Conclusions

GR-SI has been demonstrated to be suitable for application to tangentially fired boilers for reduction of NO_x emissions by 60% and SO_2 emissions by 50%. These reductions, which were the project target levels, were consistently met and exceeded over the year long demonstration. The process also results in reductions in CO_2 and CO emissions. Emissions of HCl and HF, measured during short-term tests, were also significantly reduced. Flue gas humidification has been demonstrated to be suitable for enhancing ESP performance, resulting in particulate matter emissions at or below baseline levels even with the considerable increase in particulate matter entering the ESP. GR-SI has minor impacts on thermal efficiency, resulting in a reduction in efficiency of less than 1.5% and an increase in heat rate of less than 200 Btu/kWh (211 kJ/kWh). The main steam temperature was unaffected by GR-SI; however, a small reduction in reheat steam temperature was measured. No significant impacts on the local environment or unit operation and wear rate were detected.

14.1.1 NO_x and SO_2 control

Reductions of NO_x emissions by 60% and SO_2 emissions by 50% may be obtained with natural gas heat input of 18% and sorbent input corresponding to a calcium/sulfur molar ratio of 1.75. Under these conditions, NO_x emissions of 0.245 lb/MBtu (106 mg/MJ) and SO_2 emissions of 2.51 lb/MBtu (1,080 mg/MJ) were obtained over the year-long demonstration period. These correspond to 67.3% reduction in NO_x and 52.6% in SO_2 from "as found" baseline levels. Under optimum conditions (reduced load with the top mill out of service), NO_x emissions were reduced to 0.179 lb/MBtu (77 mg/MJ). SO_2 emissions as low as 2.01 lb/MBtu (864 mg/MJ) were measured, under optimum GR-SI operation.

NO_x reductions were 55% at 10% gas heat input and increased to 67% at 18% gas heat input. Reductions leveled off in the 12 to 20% gas heat input range. The parameters which appear to most strongly control NO_x emissions are the gas heat input, the coal and reburning zone stoichiometric ratios, the coal burner tilt angle, and the mills in service. Reductions in NO_x emissions were obtained by operation at low primary and reburning zone stoichiometric ratios. During full load GR-SI operation, the coal burner tilt angle also appeared to impact NO_x emissions with lower NO_x emissions measured when the burners were tilted downward. This is due to improved zone separation of the primary combustion and reburning processes. Significant reductions in NO_x emissions were measured when the top mill was out of service, when operating at reduced load.

The parameter which most strongly impacted SO_2 emissions was the sorbent input, or the corresponding Ca/S molar ratio. The calcium utilizations obtained with the primary sorbent evaluated, Linwood hydrated lime, varied significantly and averaged 24.1% over the long-term demonstration. Advanced sorbents, prepared by EER and the Illinois State Geological Survey (ISGS), were evaluated and showed effects due to load and GR. Improved calcium utilizations were obtained at reduced loads and while operating SI, without GR. At a Ca/S molar ratio of 1.75, the performance of three advanced sorbents and the conventional Linwood sorbent may be summarized as follows:

	PromiSORB™ B	HSAHL	PromiSORB™ A	Linwood
SO_2 Capture (%)	66	60	54	46
Calcium Utilization (%)	38	34	31	26

These results were obtained at loads of 40 to 50 MW_e; operation at higher loads resulted in reduced calcium utilizations for advanced sorbents.

14.1.2 Thermal Performance

Operation of GR-SI had relatively minor impacts on thermal efficiency and steam conditions. These included a reduction in thermal efficiency from the baseline of 86.76% to 85.38% at full load and from 86.54% to 85.09% at 45 MW_e. These resulted in an increase in heat rate of 45 to 173 Btu/kWh (47 to 183 kJ/kWh), or 0.4 to 1.7% of the 10,338 Btu/kWh (10,908 kJ/kWh) baseline. Main steam temperature was unaffected by GR-SI, with an average of 995°F (535°C) at full load, compared to 993°F (534°C) under baseline operation. These may be compared to the design steam temperature of 1,005°F (541°C). During full-load GR-SI operation, the secondary superheater steam attemperation rate increased from a baseline of 6,700 lb/hr (0.84 kg/s) to 12,200 lb/hr (1.54 kg/s). A modest increase in the boiler exit gas temperature, due to fouling of superheater and reheater surfaces, was noted. The air heater exit gas temperature increased from 317°F (158°C) to 350°F (177°C), during full load GR-SI. These effects do not significantly impact the emissions control process, steam generation capacity, or availability of the unit.

14.1.3 ESP Enhancement With Humidification

Flue gas humidification was successfully applied to enhance ESP performance during GR-SI operation. Cooling of flue gas to the design approach to saturation of 70°F (39°C) was not required, with satisfactory stack opacity and particulate emissions measured at a 150°F (83°C) approach to saturation. The actual humidification water requirement was 25 to 35 gpm (1.6 to 2.2 l/s), which may be compared to the design requirement of 60 gpm (3.8 l/s). With flue gas humidification, particulate matter emissions of 0.015 to 0.025 lb/MBtu (6.5 to 10.8 mg/MJ) were measured under full-load GR-SI operation. These may be compared to full load baseline emissions of 0.018 to 0.035 lb/MBtu (7.7 to 15.1 mg/MJ). Continuous long-term operation exceeding 55 hours was possible under variable loads, and continuous full-load operation of 32 hours was also achieved with stack opacity within the 30% limit.

14.1.4 Other Impacts of GR-SI on Boiler Operation

Other impacts of the year-long GR-SI demonstration were not significant. Some ash buildup was observed in the cold reheater and primary superheater sections. Increased fouling, especially of the secondary superheater and reheater surfaces, resulted in increased use of sootblowers. However, this did not result in acceleration in tubewall wastage in these areas. The U.T. tubewall thickness data taken indicates that, in most areas, the wastage rate due to GR-SI was either reduced with respect to the baseline rate, or was within the tolerance for the measurement. In some areas where significant wastage rate was calculated during the period 1990 to 1992 (during the GR-SI demonstration), the 1990 thicknesses were significantly larger than 1988 measurements, indicating measurement inaccuracy. Visual inspections of the unit and chimney indicated no significant added wastage due to GR-SI, but some increase in accumulated ash on the inner lining of the chimney.

14.2 Recommendations

The successful commercial demonstration of GR–SI at Hennepin Station Unit 1 indicates that the technology is suitable for widespread commercial application to meet the requirements of the CAAA. The results of this project and those from the GR-SI demonstration at a cyclone fired unit and the GR-Low NO_x Burner demonstration at a wall fired unit indicate that significant efforts should be directed to marketing these technologies.

14.2.1 Application of GR-SI to Other Tangentially Fired Units

Further demonstration of GR-SI, or GR, at other units over a range of boiler sizes, is recommended to assist utilities selecting these technology. The CAAA require that pre-NSPS tangentially fired units limit their NO_x emissions to 0.45 lb/MBtu (194 mg/MJ). The Hennepin GR-SI system has been shown to effectively control NO_x emissions to 0.245 lb/MBtu (105 mg/MJ). This is well under the CAAA Title IV limit of 0.45 lb/MBtu (194 mg/MJ) and is in the range required for Title I.

14.2.2 Application of GR-SI to Other Firing Configurations

Further application to cyclone and wall fired units, over a range of sizes, is recommended to assist utilities in selecting GR-SI and GR-LNB. EER's GR-LNB demonstration project at PSCo's Cherokee Station Unit 3 has shown that reductions of 60 to 72% may be achieved at a wall fired unit, and results from the GR-SI demonstration at CWLP's Lakeside Unit 7 indicate that 60% NO_x reduction and 50% SO_2 reduction may be achieved at cyclone fired units.

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APPENDIX A

GR AND GR-SI OPTIMIZATION TESTING DATA

TABLE A–1. COAL ANALYSES

a) Feeder 1A.

Date	Time	Test ID	ID No.	HHV Btu/lb	C (%)	H (%)	O (%)	N (%)	S (%)	H_2O (%)	Ash (%)
6/15/91	17:00	GR-33a	2803	10,789	60.00	4.05	8.06	1.17	2.80	14.03	9.89
6/17/91	18:30	GR-33a	2813	10,801	59.89	4.04	7.92	1.17	3.02	14.45	9.51
6/18/91	10:45	GR-37c	2829	10,849	60.81	4.11	8.00	1.17	3.01	12.54	10.36
6/19/91	10:45	GR-34b	2845	10,766	59.98	4.04	7.94	1.17	2.99	12.81	11.07
6/20/91	13:30	GR-35d	2844	10,666	59.71	4.01	8.04	1.14	3.05	13.47	10.58
6/21/91	14:30	GR-39c	2871	10,808	60.20	4.03	8.03	1.18	2.78	13.46	10.32
6/22/91	10:30	GR-38b									
6/24/91	14:30	GR-41b	2901	10,760	60.17	4.07	7.85	1.15	2.82	13.90	10.04
6/25/91	10:30	GR-42a	2915	10,843	60.15	4.13	7.98	1.16	2.91	14.05	9.62
7/2/91	4:00	GR-40c									
7/11/91		GR-33a	2963	10,987	60.88	4.20	8.00	1.11	2.99	12.40	10.42
8/2/91		GRSI-1a									
8/14/91		GRSI-3a	1940	10,979	60.71	4.15	8.07	1.13	3.12	12.73	10.09
		Pre–Outage Average :		10,825	60.25	4.08	7.99	1.16	2.95	13.38	10.19
11/18/91		GR-46									
11/25/91		GRSI-15									
12/10/91		GR-44c	2106	10,921	60.39	4.20	7.90	1.09	2.92	12.96	10.54
		Post–Outage Average :		10,921	60.39	4.20	7.90	1.09	2.92	12.96	10.54

TABLE A-1. COAL ANALYSES (CONTINUED)

b) Feeder 1B

Date	Time	Test ID	ID No.	HHV Btu/lb	C (%)	H (%)	O (%)	N (%)	S (%)	H_2O (%)	Ash (%)
6/15/91	17:00	GR-33a	2805	10,757	59.97	4.13	8.07	1.15	3.11	13.24	10.33
6/17/91	18:30	GR-33a	2815	10,896	60.94	4.19	7.92	1.18	2.93	13.17	9.67
6/18/91	10:45	GR-37c	2831	10,542	59.09	3.97	8.18	1.13	2.84	14.12	10.67
6/19/91	10:45	GR-34b	2847	10,886	60.60	4.10	8.06	1.17	3.06	12.37	10.64
6/20/91	13:30	GR-35d	2863	12,160	67.40	4.56	9.15	1.26	3.20	3.88	10.55
6/21/91	14:30	GR-39c	2873	11,911	66.62	4.53	9.03	1.25	3.20	3.35	12.02
6/22/91	10:30	GR-38b	2889	12,056	66.66	4.49	9.19	1.27	3.15	4.50	10.74
6/24/91	14:30	GR-41b	2903	11,897	66.53	4.50	8.78	1.31	3.36	3.99	11.53
6/25/91	10:30	GR-42a	2917	12,211	68.03	4.59	9.00	1.29	3.17	3.70	10.22
7/2/91	4:00	GR-40c	2919	11,954	66.64	4.53	9.08	1.31	2.96	4.20	11.28
7/11/91		GR-33a	2965	10,818	59.79	4.01	8.25	1.11	2.93	13.21	10.70
8/2/91		GRSI-1a	1840	10,895	60.38	4.13	8.08	1.16	2.96	13.11	10.18
8/14/91		GRSI-3a									
		Pre–Outage Average :		11,415	63.55	4.31	8.57	1.22	3.07	8.57	10.71
11/18/91		GR-46	2087	10,307	56.86	3.87	7.77	1.10	2.94	17.30	7.77
11/25/91		GRSI-15	2101	10,254	56.69	3.95	7.34	1.13	2.91	17.47	10.51
12/10/91		GR-44c	2108	10,950	60.62	4.21	7.83	1.14	2.99	12.67	10.54
		Post–Outage Average :		10,504	58.06	4.01	7.65	1.12	2.95	15.81	9.61

TABLE A–1. COAL ANALYSES (CONTINUED)

c) Feeder 1C

Date	Time	Test ID	ID No.	HHV Btu/lb	C (%)	H (%)	O (%)	N (%)	S (%)	H_2O (%)	Ash (%)
6/15/91	17:00	GR-33a	2807	11,616	64.46	4.39	8.66	1.25	3.18	5.04	13.02
6/17/91	18:30	GR-33a	2817	11,971	66.45	4.52	9.04	1.27	3.05	4.81	10.86
6/18/91	10:45	GR-37c	2833	11,978	66.28	4.55	8.87	1.22	3.11	5.61	10.36
6/19/91	10:45	GR-34b	2849	11,821	65.87	4.44	8.81	1.26	3.42	3.86	12.34
6/20/91	13:30	GR-35d	2865	11,939	66.40	4.54	8.87	1.27	3.22	5.22	10.48
6/21/91	14:30	GR-39c	2875	11,809	65.98	4.46	8.87	1.28	3.31	4.74	11.36
6/22/91	10:30	GR-38b	2891	11,949	66.37	4.51	9.00	1.25	3.29	4.24	11.34
6/24/91	14:30	GR-41b	2905	11,742	65.24	4.42	9.00	1.25	3.08	4.85	12.16
6/25/91	10:30	GR-42a									
7/2/91	4:00	GR-40c	2957	12,039	67.34	4.58	8.82	1.28	3.00	4.26	10.72
7/11/91		GR-33a	2967	10,791	59.42	3.98	8.79	1.13	2.82	13.11	10.78
8/2/91		GRSI-1a	1842	10,726	59.33	4.04	7.96	1.14	2.84	14.94	9.75
8/14/91		GRSI-3a									
		Pre–Outage Average :		11,671	64.83	4.40	8.79	1.24	3.12	6.43	11.20
11/18/91		GR-46	2085	10,316	57.23	3.93	7.64	1.04	2.78	16.45	10.93
11/25/91		GRSI-15	2103	10,495	58.18	4.12	7.19	1.09	3.09	15.57	10.76
12/10/91		GR-44c	2110	10,838	59.66	4.15	7.89	1.16	3.15	13.08	10.19
		Post–Outage Average :		10,550	58.36	4.07	7.57	1.10	3.01	15.03	10.63

TABLE A-2. BOILER BOTTOM ASH SAMPLES ANALYSES

DATE SAMPLED	TIME	SAMPLE NO.	SiO_2 (%)	Al_2O_3 (%)	TiO_2 (%)	Fe_2O_3 (%)	CaO (%)	MgO (%)	K_2O (%)	Na_2O (%)	SO_3 (%)	P_2O_5 (%)	SrO (%)	BaO (%)	MnO (%)	Undet. (%)	Silica Value	Base Acid	Ash Fusion ** Temp. (°F)	Fouling Index
15-Jun-91	18:00	2809	47.05	17.49	0.79	20.90	7.90	1.09	1.79	0.66	1.64	0.40	0.01	0.02	0.15	0.11	61.15	0.50	2,314	0.33
17-Jun-91	10:30	2821	45.82	17.00	0.78	20.99	7.80	1.18	1.90	0.63	2.97	0.33	0.02	0.00	0.15	0.43	60.46	0.51	2,302	0.32
18-Jun-91	12:00	2835	43.99	15.99	0.71	21.70	11.13	1.24	1.76	0.78	2.03	0.42	0.01	0.06	0.18	0.00	56.35	0.60	2,245	0.47
18-Jun-91	15:30	2839	43.85	16.25	0.70	23.05	11.36	1.07	1.60	0.69	0.76	0.42	0.02	0.08	0.15	0.00	55.28	0.62	2,238	0.43
19-Jun-91	11:00	2851	44.40	16.26	0.72	21.79	10.50	1.07	1.64	0.60	2.03	0.52	0.01	0.10	0.16	0.20	57.10	0.58	2,257	0.35
19-Jun-91	13:00	2855	46.55	17.14	0.82	21.40	9.16	1.12	1.78	0.55	0.89	0.42	0.01	0.00	0.16	0.00	59.50	0.53	2,290	0.29
19-Jun-91	18:00	2859	46.49	16.88	0.85	21.86	8.58	1.10	1.73	0.64	1.25	0.44	0.02	0.00	0.16	0.00	59.58	0.53	2,289	0.34
20-Jun-91	13:45	2867	45.71	16.99	0.91	20.46	8.63	1.15	1.74	0.57	1.55	0.32	0.03	0.00	0.16	1.78	60.18	0.51	2,301	0.29
21-Jun-91	11:00	2877	44.74	16.54	0.71	24.16	9.34	1.06	1.55	0.76	0.50	0.37	0.01	0.11	0.15	0.00	56.42	0.59	2,249	0.45
21-Jun-91	15:00	2881	43.62	15.46	0.70	25.71	9.09	1.04	1.51	0.52	1.70	0.37	0.01	0.07	0.17	0.03	54.90	0.63	2,231	0.33
21-Jun-91	17:30	2885	44.61	16.17	0.72	23.21	10.38	1.09	1.55	0.75	0.91	0.34	0.01	0.10	0.16	0.00	56.26	0.60	2,246	0.45
22-Jun-91	10:45	2893	44.05	16.07	0.70	23.71	10.51	1.09	1.54	0.77	0.93	0.36	0.01	0.10	0.16	0.00	55.51	0.62	2,237	0.48
22-Jun-91	14:00	2897	46.50	17.31	0.79	21.32	8.89	1.13	1.70	0.61	1.17	0.33	0.01	0.08	0.16	0.00	59.74	0.52	2,294	0.32
24-Jun-91	11:30	2907	43.78	16.09	0.69	24.35	9.59	1.02	1.51	0.78	1.54	0.37	0.01	0.10	0.17	0.00	55.60	0.62	2,239	0.48
24-Jun-91	16:30	2911	46.29	17.56	0.79	22.36	8.43	1.07	1.67	0.81	0.51	0.28	0.01	0.06	0.16	0.00	59.23	0.53	2,287	0.43
25-Jun-91	11:00	2935	42.29	15.22	0.66	27.27	9.65	0.93	1.44	0.49	1.32	0.43	0.01	0.12	0.17	0.00	52.77	0.68	2,212	0.33
2-Jul-91	2:30	2959	47.28	17.86	0.82	22.06	7.64	1.11	1.78	0.77	0.13	0.38	0.01	0.00	0.15	0.00	60.55	0.51	2,306	0.39
AVERAGE			45.12	16.60	0.76	22.72	9.33	1.09	1.66	0.67	1.28	0.38	0.01	0.06	0.16	0.15	57.68	0.57	2,267	0.38
MAX			47.28	17.86	0.91	27.27	11.36	1.24	1.9	0.81	2.97	0.52	0.03	0.12	0.18	1.78	61.15	0.68	2,314	0.48
MIN			42.29	15.22	0.66	20.46	7.64	0.93	1.44	0.49	0.13	0.28	0.01	0	0.15	0	52.77	0.5	2,212	0.29
STANDARD DEVIATION			1.45	0.75	0.07	1.84	1.14	0.07	0.13	0.10	0.69	0.06	0.01	0.05	0.01	0.43	2.50	0.06	32	0.07

** T250 Temperature

TABLE A-3. ECONOMIZER ASH SAMPLES ANALYSES

DATE SAMPLED	TIME	SAMPLE NO.	SiO_2 (%)	Al_2O_3 (%)	TiO_2 (%)	Fe_2O_3 (%)	CaO (%)	MgO (%)	K_2O (%)	Na_2O (%)	SO_3 (%)	P_2O_5 (%)	SrO (%)	BaO (%)	MnO (%)	Undet. (%)	Silica Value	Base Acid	Ash Fusion ** Temp. (°F)	Fouling Index
15-Jun-91	17:15	2811	38.34	14.31	0.76	25.87	11.46	0.93	1.49	0.63	4.24	0.31	0.02	0.00	0.17	1.47	50.05	0.76	2,190	0.48
17-Jun-91	10:30	2819	38.40	13.67	0.73	27.84	10.99	0.89	1.40	0.61	2.85	0.48	0.02	0.00	0.17	1.65	49.35	0.79	2,183	0.48
18-Jun-91	11:00	2837	37.64	13.21	0.63	28.20	13.12	0.98	1.28	0.54	3.34	0.59	0.01	0.08	0.19	0.17	47.07	0.86	2,168	0.46
18-Jun-91	15:30	2841	39.68	14.36	0.70	25.27	9.25	1.00	1.64	0.76	5.71	0.45	0.01	0.12	0.18	0.87	52.77	0.69	2,209	0.52
19-Jun-91	11:00	2853	38.21	13.34	0.68	25.53	15.21	0.99	1.30	0.50	2.57	0.68	0.02	0.00	0.18	1.09	47.98	0.83	2,174	0.42
19-Jun-91	13:00	2857	31.72	10.52	0.42	30.53	20.36	0.94	1.00	0.38	2.27	1.10	0.01	0.06	0.20	0.49	37.97	1.25	2,900	0.48
19-Jun-91	18:00	2861	36.60	12.55	0.65	27.55	15.82	0.98	1.18	0.47	2.45	0.72	0.02	0.00	0.19	0.82	45.21	0.92	2,156	0.43
20-Jun-91	13:45	2869	37.84	11.93	0.58	28.24	14.60	0.90	1.14	0.52	2.90	0.69	0.02	0.00	0.19	0.45	46.38	0.90	2,160	0.47
21-Jun-91	11:00	2879	40.29	12.24	0.65	26.98	11.53	0.87	1.17	0.53	2.37	0.50	0.02	0.00	0.16	2.69	50.57	0.77	2,186	0.41
21-Jun-91	15:00	2883	35.78	12.07	0.51	28.78	16.05	0.96	1.13	0.72	3.17	0.52	0.01	0.11	0.19	0.00	43.86	0.99	2,150	0.71
21-Jun-91	17:30	2887	34.37	10.92	0.42	28.67	19.57	0.92	0.99	0.70	2.45	0.69	0.01	0.10	0.19	0.00	41.05	1.11	2,150	0.78
22-Jun-91	10:45	2895	34.66	11.83	0.49	28.19	18.68	0.98	1.07	0.68	2.51	0.59	0.01	0.11	0.20	0.00	42.01	1.06	2,150	0.72
22-Jun-91	14:00	2899	32.03	10.70	0.41	32.72	18.92	0.89	0.97	0.68	1.72	0.64	0.01	0.11	0.20	0.00	37.88	1.26	2,150	0.86
24-Jun-91	11:30	2909	41.16	14.46	0.63	23.34	13.71	0.99	1.42	0.81	2.71	0.48	0.01	0.11	0.17	0.00	51.97	0.72	2,201	0.58
24-Jun-91	16:30	2913	45.02	16.35	0.71	21.62	10.32	1.00	1.69	0.88	1.77	0.37	0.02	0.09	0.16	0.00	57.75	0.57	2,261	0.50
25-Jun-91	11:00	2937	40.58	14.51	0.59	23.56	14.56	1.01	1.45	0.90	2.05	0.50	0.01	0.09	0.19	0.00	50.91	0.74	2,193	0.67
2-Jul-91	2:30	2961	37.61	13.33	0.58	26.24	15.72	1.03	1.32	0.74	2.50	0.64	0.01	0.10	0.18	0.00	46.66	0.87	2,165	0.64
AVERAGE			37.64	12.96	0.60	27.01	14.70	0.96	1.27	0.65	2.80	0.59	0.01	0.06	0.18	0.57	47.03	0.89	2,220	0.57
MAX			45.02	16.35	0.76	32.72	20.36	1.03	1.69	0.9	5.71	1.1	0.02	0.12	0.2	2.69	57.75	1.26	2,900	0.86
MIN			31.72	10.52	0.41	21.62	9.25	0.87	0.97	0.38	1.72	0.31	0.01	0	0.16	0	37.88	0.57	2,150	0.41
STANDARD DEVIATION			3.34	1.58	0.11	2.71	3.36	0.05	0.22	0.15	0.96	0.18	0.01	0.05	0.01	0.78	5.34	0.19	177	0.14

** T250 Temperature

TABLE A–4. RESULTS OF THE GAS REBURNING TEST SERIES(AVERAGED OVER THE TEST PERIODS)

Date 1991	Test ID	Load (MWe)	NOx Emiss. (ppm)	NOx Emiss. (lb/MBtu)	CO Emiss. (ppm)	Excess Oxygen (%, wet)	FGR (scfm)	Gas Heat percent of Total	Coal Zone SR	Reburn Zone SR	Exit Zone SR	Burner Tilt (deg)
14-Jun	GR-33A	70	390	0.532	–	–	0	0	1.15	1.19	1.19	-27
15-Jun	GR-33A	70	405	0.552	–	2.20	0	0	1.13	1.18	1.18	-27
17-Jun	GR-33A	70	347	0.473	5	2.20	39	0	1.13	1.13	1.18	-27
17-Jun	GR-33C	70	309	0.421	7	2.50	1	0	1.08	1.08	1.16	-26
17-Jun	GR-33E	70	200	0.273	6	2.30	0	0	0.99	0.99	1.16	-26
17-Jun	GR-33F	70	290	0.395	8	1.50	0	0	1.09	1.09	1.11	-24
17-Jun	GR-33G	70	250	0.341	80	1.00	0	0	1.05	1.05	1.07	-23
17-Jun	GR-33H	70	392	0.534	5	2.30	0	0	1.15	1.15	1.15	-27
18-Jun	GR-37C1	70	247	0.333	6	2.30	7,294	10	1.10	1.01	1.17	-21
18-Jun	GR-37C2	70	224	0.302	3	2.20	7,304	10	1.31	1.20	1.35	-27
18-Jun	GR-37A1	70	208	0.279	5	2.80	7,504	16	1.10	0.94	1.20	-27
18-Jun	GR-37A2	70	202	0.271	2	2.70	7,599	16	1.33	1.14	1.40	-27
18-Jun	GR-37A3	70	226	0.303	6	2.90	6,030	15	1.14	0.98	1.23	-26
18-Jun	GR-37A4	70	378	0.515	8	2.20	3,822	0	1.15	1.15	1.15	2
19-Jun	GR-34B	60	352	0.480	12	2.70	322	0	1.16	1.17	1.19	26
19-Jun	GR-34A	60	358	0.488	8	2.90	1,864	0	1.19	1.20	1.21	0
19-Jun	GR-35A1	60	161	0.215	19	2.10	7,479	19	1.08	0.90	1.16	-1
19-Jun	GR-35A2	60	382	0.521	5	2.70	4,242	0	1.17	1.17	1.18	12
20-Jun	GR-35D	70	188	0.251	20	1.90	7,678	17	1.06	0.89	1.14	0
20-Jun	GR-36A	70	190	0.254	15	2.40	8,000	19	1.11	0.92	1.17	-23
20-Jun	GR-36B1	70	173	0.231	19	2.00	6,911	19	1.08	0.89	1.14	-21
20-Jun	GR-36B2	70	204	0.272	8	2.50	5,015	19	1.12	0.93	1.17	-22
20-Jun	GR-36B3	70	184	0.246	33	1.90	2,544	20	1.07	0.88	1.12	-7
20-Jun	GR-36B4	70	427	0.582	8	2.50	2,503	0	1.16	1.16	1.17	-6
21-Jun	GR-39A	60	364	0.496	9	2.40	577	0	1.12	1.13	1.17	10
21-Jun	GR-39C	60	160	0.214	10	2.20	7,080	19	1.10	0.91	1.17	-13
21-Jun	GR-39B	60	204	0.275	8	2.70	7,239	11	1.10	1.00	1.19	-10
22-Jun	GR-38C1	50	380	0.518	9	2.80	1,907	0	1.17	1.17	1.21	25

TABLE A-4. RESULTS OF THE GAS REBURNING TEST SERIES(AVERAGED OVER THE TEST PERIODS)

Date 1991	Test ID	Load (MWe)	NOx Emiss. (ppm)	NOx Emiss. (lb/MBtu)	CO Emiss. (ppm)	Excess Oxygen (%, wet)	FGR (scfm)	Gas Heat percent of Total	Coal Zone SR	Reburn Zone SR	Exit Zone SR	Burner Tilt (deg)
22-Jun	GR-38C2	50	429	0.585	8	3.10	1,877	0	1.21	1.22	1.23	16
22-Jun	GR-38B1	40	359	0.489	11	3.00	1,886	0	1.16	1.17	1.22	27
22-Jun	GR-38B2	40	408	0.556	9	2.90	1,788	0	1.21	1.22	1.22	27
24-Jun	GR-41A	70	192	0.259	20	1.90	6,896	10	1.07	0.97	1.13	-24
24-Jun	GR-41B	70	154	0.206	23	1.70	6,928	18	1.06	0.88	1.12	-27
24-Jun	GR-41C1	70	166	0.222	18	1.60	5,533	18	1.06	0.88	1.12	-26
24-Jun	GR-41C2	70	413	0.563	9	2.00	5,542	0	1.14	1.14	1.14	-23
24-Jun	GR-41C3	70	361	0.492	9	2.10	80	0	1.09	1.10	1.14	-24
25-Jun	GR-42A	40	296	0.404	11	3.40	233	0	1.19	1.20	1.26	27
25-Jun	GR-42B	40	180	0.245	16	3.40	113	0	0.95	0.95	1.23	27
25-Jun	GR-42C1	40	224	0.305	18	4.60	131	0	0.97	0.98	1.33	27
25-Jun	GR-42C2	40	388	0.529	16	4.20	10	0	1.30	1.31	1.32	27
1-Jul	GR-33A	70	371	0.506	9	2.30	197	0	1.13	1.13	1.16	-21
11-Jul	GR-33A	70	331	0.451	22	2.30	251	0	1.27	1.28	1.31	14
12-Jul	GR-37A	60	161	0.215	31	2.00	8,407	18	1.10	0.91	1.15	-24
16-Jul	GR-40B	40	270	0.364	14	3.30	7,000	11	1.10	1.00	1.24	14
16-Jul	GR-40C	40	220	0.293	13	3.10	6,857	22	1.13	0.90	1.23	14
16-Jul	GR-40D1	40	240	0.321	14	3.50	4,945	17	1.15	0.97	1.25	14
16-Jul	GR-40D2	40	399	0.544	14	3.30	5,770	0	1.21	1.22	1.22	27
16-Jul	GR-40D3	40	331	0.451	14	3.30	5,792	0	1.08	1.08	1.22	21
12-Nov	GR-33A2	70	269	0.367	23	1.97	6	0	1.07	1.08	1.14	-12
13-Nov	GR-42A1	45*	348	0.474	5	2.77	33	0	1.11	1.12	1.19	27
13-Nov	GR-42A2	45*	305	0.416	5	3.37	16	0	1.08	1.09	1.24	27
15-Nov	GR-45B	45	189	0.253	31	2.89	2,647	18	1.07	0.90	1.20	27
15-Nov	GR-45C	45	180	0.241	114	2.84	3,429	18	1.08	0.91	1.20	27
15-Nov	GR-45D	45	177	0.237	55	2.87	4,472	18	1.08	0.90	1.19	27
15-Nov	GR-45E	45	178	0.238	57	2.93	4,752	18	1.08	0.90	1.20	27
19-Nov	GR-46B	45	177	0.236	45	3.05	2,610	18	1.08	0.91	1.21	26

TABLE A–4. RESULTS OF THE GAS REBURNING TEST SERIES(AVERAGED OVER THE TEST PERIODS)

Date 1991	Test ID	Load (MWe)	NOx Emiss. (ppm)	NOx Emiss. (lb/MBtu)	CO Emiss. (ppm)	Excess Oxygen (%, wet)	FGR (scfm)	Gas Heat percent of Total	Coal Zone SR	Reburn Zone SR	Exit Zone SR	Burner Tilt (deg)
19-Nov	GR-46C	45	173	0.231	38	2.97	3,550	19	1.08	0.90	1.20	27
19-Nov	GR-46D	45	162	0.217	108	2.83	4,523	18	1.07	0.90	1.19	27
19-Nov	GR-46E	45	165	0.221	205	2.98	4,721	18	1.08	0.91	1.22	27
21-Nov	GR-46B2	45	150	0.200	3	2.82	2,885	19	1.07	0.90	1.19	-8
22-Nov	GR-46D3	45	171	0.228	41	3.07	4,448	18	1.10	0.92	1.21	26
23-Nov	GR-50A	45	171	0.229	3	2.88	3,016	15	1.08	0.94	1.20	4
23-Nov	GR-50B	45	179	0.241	3	2.95	3,030	12	1.09	0.97	1.20	-2
23-Nov	GR-50C	45	188	0.253	3	2.86	3,054	10	1.08	0.98	1.19	0
7-Dec	GR-44A	70	186	0.249	2	2.84	2,777	18	1.09	0.92	1.19	3
10-Dec	GR-33A1	70	370	0.504	2	2.40	0	0	1.14	1.15	1.16	-23
10-Dec	GR-33A2	70	390	0.532	2	2.30	0	0	1.09	1.10	1.16	22
10-Dec	GR-39A1	60	325	0.443	2	2.93	0	0	1.13	1.14	1.20	3
10-Dec	GR-39A2	60	261	0.356	2	3.04	0	0	1.09	1.10	1.21	2
11-Dec	GR-44C2	70	163	0.218	3	2.99	4,383	18	1.12	0.94	1.21	-6
11-Dec	GR-44B2	70	176	0.235	2	2.97	3,591	18	1.10	0.92	1.20	-6
11-Dec	GR-44A2	70	184	0.246	2	2.88	3,057	18	1.10	0.92	1.20	-6
11-Dec	GR-43A1	70	164	0.219	2	2.20	3,096	18	1.07	0.89	1.15	-6
11-Dec	GR-43B1	70	152	0.203	2	2.26	3,603	18	1.06	0.89	1.15	-6
11-Dec	GR-43C1	70	141	0.188	2	2.18	4,542	18	1.06	0.89	1.15	-6
12-Dec	GR-44A3	70	166	0.222	4	2.77	2,622	18	1.08	0.90	1.19	4
12-Dec	GR-43A2	70	157	0.210	8	2.24	2,653	18	1.09	0.91	1.15	2
12-Dec	GR-51A1	70	206	0.276	2	3.02	2,662	14	1.08	0.94	1.21	1
12-Dec	GR-51A2	70	184	0.247	3	2.91	4,419	14	1.07	0.93	1.20	1
12-Dec	GR-51B	70	207	0.276	3	3.16	4,472	12	1.08	0.97	1.22	1
		AVG	254	0.343	18	2.64	3,278	9	1.11	1.02	1.19	0
		MAX	429	0.585	205	4.60	8,407	22	1.33	1.31	1.40	27
		MIN	141	0.188	2	1.00	0	0	0.95	0.88	1.07	-27

TABLE A-5. RESULTS OF THE GR-SI PARAMETRIC TESTS AT HENNEPIN STATION UNIT NO. 1

Date 1991	Test ID	Load (MWe)	Sorbent Injection Elevation	Gas Heat Input (%)	Plant O2 (%, wet)	NOx Emiss. (lb/MBtu)	SO2 non-GR Baseline (lb/MBtu)	SO2 GR Baseline (lb/MBtu)	SO2 Emiss. (lb/MBtu)	Ca/S Molar Ratio	Total SO2 Reduction (%)	Sorbent SO2 Reduction (%)	Ca Util. (%)	Sorbent Jet Vel. (ft/sec)	Coal Burner Tilt (Deg)
2-Aug	GRSI-1A	45	Lower	17.4	3.20	0.281	5.12	4.12	2.55	2.07	50.27	38.22	18.46	150	13
6-Aug	GRSI-1F	75	Upper	17.5	2.70	0.237	5.02	3.98	1.85	1.96	63.18	53.52	27.31	290	1
6-Aug	GRSI-1D	60	Upper	17.7	3.10	0.269	5.02	3.97	1.76	1.83	64.89	55.67	30.42	300	6
6-Aug	GRSI-1C	60	Lower	17.9	3.10	0.237	5.02	3.97	2.20	1.83	56.11	44.57	24.36	160	-18
7-Aug	GRSI-1G	58	Upper	17.6	3.30	0.310	5.36	4.32	2.08	2.02	61.19	51.75	25.62	300	18
8-Aug	GRSI-1H	60	Lower	17.7	3.60	0.283	5.18	4.17	1.76	2.10	66.00	57.78	27.52	150	-10
9-Aug	GRSI-1IB	70	Upper	15.5	3.30	0.351	5.35	4.29	1.98	2.07	63.01	53.91	26.04	280	-1
9-Aug	GRSI-1IA	70	Upper	15.5	3.10	0.315	5.35	4.29	2.11	2.06	60.49	50.77	24.65	290	2
12-Aug	GRSI-2A	71.5	Upper	15.5	3.20	0.311	5.37	4.27	2.05	2.25	61.75	51.87	23.05	280	-7
14-Aug	GRSI-3C	70	Upper	17.8	2.80	0.261	5.42	4.43	2.86	1.24	47.25	35.53	28.65	240	2
14-Aug	GRSI-3B	70	Upper	17.9	3.10	0.265	5.42	4.43	3.14	1.17	42.09	29.21	24.96	200	-3
14-Aug	GRSI-3A	70	Upper	18.0	2.80	0.278	5.42	4.43	3.20	1.10	40.91	27.75	25.23	150	1
19-Aug	GRSI-4	DIS	Lower	–	3.40	0.241	5.30	4.33	1.83	1.99	65.58	57.82	29.06	150	-8
20-Aug	GRSI-5	DIS	Lower	–	3.60	0.254	5.31	4.37	1.72	2.12	67.60	60.63	28.60	160	-3
21-Aug	GRSI-6BL	65	Lower	17.8	2.50	0.218	5.14	4.13	1.92	1.90	62.59	53.48	28.15	150	-21
21-Aug	GRSI-6BH	65	Upper	17.6	2.50	0.235	5.14	4.13	2.13	1.89	58.64	48.58	25.70	270	1
21-Aug	GRSI-6AL	45	Lower	18.2	2.70	0.191	5.14	4.13	1.94	1.74	62.28	53.07	30.50	160	-2
21-Aug	GRSI-6AH	45	Upper	18.4	3.50	0.313	5.14	4.13	2.03	1.95	60.41	50.73	26.02	280	27
22-Aug	GRSI-7C	65	Upper	17.8	3.20	0.279	5.31	4.35	2.37	2.21	55.43	45.63	20.65	250	12
22-Aug	GRSI-7B	65	Upper	17.6	3.20	0.278	5.31	4.35	2.47	1.79	53.42	43.19	24.13	240	16
22-Aug	GRSI-7A	65	Upper	17.8	3.30	0.282	5.31	4.35	2.66	1.29	49.87	38.84	30.11	240	6
23-Aug	GRSI-8B	65	Upper	17.6	2.90	0.255	5.15	4.11	2.08	2.04	59.62	49.35	24.19	260	15
23-Aug	GRSI-8A	65	Upper	18.0	2.80	0.226	5.15	4.11	2.60	1.73	49.53	36.68	21.20	250	8
26-Aug	GRSI-9D	55	Upper	17.8	2.80	0.254	5.37	4.32	2.49	1.81	53.63	42.34	23.39	280	15
26-Aug	GRSI-9C	55	Lower	17.8	2.90	0.191	5.37	4.32	2.23	1.83	58.53	48.42	26.46	150	-19
26-Aug	GRSI-9B	50	Lower	17.9	2.60	0.263	5.37	4.32	2.47	1.70	54.06	42.86	25.21	150	8
26-Aug	GRSI-9A	50	Upper	18.4	2.90	0.259	5.37	4.32	2.75	1.63	48.81	36.30	22.27	250	27
27-Aug	SI-3C	70	Upper	0.0	3.40	0.515	5.08	5.08	2.35	2.44	53.61	53.61	21.97	240	4
27-Aug	SI-3B	70	Upper	0.0	3.30	0.518	5.08	5.08	2.99	1.76	41.18	41.18	23.40	240	-1
27-Aug	SI-3A	70	Upper	0.0	3.30	0.513	5.08	5.08	3.79	0.96	25.29	25.29	26.34	250	3
28-Aug	GRSI-10B	70	Upper	17.7	2.90	0.285	5.16	4.25	2.25	1.82	56.36	46.93	25.78	250	7
28-Aug	GRSI-10A	70	Upper	18.0	2.80	0.277	5.16	4.25	2.92	1.02	43.47	31.24	30.63	250	1

TABLE A-5. RESULTS OF THE GR-SI PARAMETRIC TESTS AT HENNEPIN STATION UNIT NO. 1

Date 1991	Test ID	Load (MWe)	Sorbent Injection Elevation	Gas Heat Input (%)	Plant O2 (%, wet)	NOx Emiss. (lb/MBtu)	SO2 non-GR Baseline (lb/MBtu)	SO2 GR Baseline (lb/MBtu)	SO2 Emiss. (lb/MBtu)	Ca/S Molar Ratio	Total SO2 Reduction (%)	Sorbent SO2 Reduction (%)	Ca Util. (%)	Sorbent Jet Vel. (ft/sec)	Coal Burner Tilt (Deg)
29-Aug	GRSI-11A	70	Upper	18.0	2.90	0.258	5.33	4.32	2.40	1.78	54.89	44.37	24.93	240	0
15-Nov	SI-6A	45	Upper	0.0	3.83	0.444	5.24	5.24	3.17	1.60	39.49	39.49	24.68	310	24
15-Nov	SI-6A2	45	Upper	0.0	3.87	0.457	5.24	5.24	2.50	1.63	52.31	52.31	32.09	323	27
15-Nov	SI-6A3	45	Upper	0.0	3.59	0.464	5.24	5.24	2.32	1.64	55.74	55.74	33.99	251	27
20-Nov	GRSI-15A	45	Upper	18.7	3.39	0.229	5.24	4.26	2.26	1.83	56.79	46.85	25.60	214	27
20-Nov	GRSI-15B	45	Upper	18.8	3.15	0.204	5.24	4.25	2.08	1.86	60.22	51.01	27.43	280	27
20-Nov	GRSI-15C	45	Upper	19.0	3.21	0.200	5.24	4.24	2.41	1.83	54.02	43.24	23.63	326	27
26-Nov	GRSI-15C2	45	Upper	18.3	3.76	0.225	5.24	4.28	2.68	1.85	48.90	37.45	20.24	266	27
3-Dec	GRSI-15B3	45	Upper	18.3	3.01	0.191	5.24	4.28	2.42	1.76	53.81	43.46	24.69	234	27
3-Dec	GRSI-15C3	45	Upper	18.6	3.14	0.191	5.24	4.26	2.24	2.36	57.18	47.40	20.08	261	27
6-Dec	GRSI-15A3	45	Upper	18.4	2.74	0.199	5.24	4.27	2.42	1.81	53.74	43.31	23.93	183	18
6-Dec	GRSI-19A	45	Upper	12.4	2.96	0.212	5.24	4.59	2.46	1.77	53.07	46.42	26.23	234	18
7-Dec	GRSI-12A1	70	Upper	18.8	2.54	0.171	5.24	4.25	2.90	1.62	44.70	31.90	19.69	243	-3
7-Dec	GRSI-12B1	70	Upper	18.3	2.85	0.183	5.24	4.28	2.58	1.67	50.70	39.66	23.75	244	5
7-Dec	GRSI-12C1	70	Upper	18.5	2.87	0.180	5.24	4.27	2.37	2.06	54.79	44.53	21.62	241	5
12-Dec	SI-5A	70	Upper	0.0	2.90	0.481	5.24	5.24	3.41	1.49	34.84	34.84	23.38	257	3
12-Dec	SI-5B	70	Upper	0.0	3.17	0.546	5.24	5.24	2.97	1.72	43.25	43.25	25.14	253	17
12-Dec	SI-5C	70	Upper	0.0	3.11	0.562	5.24	5.24	2.61	1.96	50.21	50.21	25.62	247	20
14-Dec	GRSI-12A2	70	Upper	18.4	3.09	0.212	5.24	4.27	2.60	1.57	50.38	39.19	24.96	276	6
17-Dec	GRSI-12A3	70	Upper	18.0	2.84	0.238	5.24	4.29	2.51	1.51	52.06	41.53	27.51	273	19
17-Dec	GRSI-12B3	70	Upper	17.6	2.78	0.216	5.24	4.31	2.50	1.71	52.29	42.10	24.62	271	16
17-Dec	GRSI-12C3	70	Upper	18.0	2.91	0.196	5.24	4.29	2.37	1.97	54.66	44.71	22.69	270	5
18-Dec	GRSI-14A	70	Upper	17.9	2.81	0.239	5.24	4.30	2.53	1.69	51.66	41.11	24.33	253	19
18-Dec	GRSI-14B	70	Upper	17.8	2.78	0.233	5.24	4.30	2.31	1.71	55.95	46.41	27.14	200	5
18-Dec	GRSI-14C	70	Upper	17.5	3.29	0.242	5.24	4.32	2.40	1.66	54.13	44.40	26.75	155	-4
			Avg	14.8	3.08	0.285	5.24	4.41	2.44	1.78	53.45	44.77	25.35	238	9
			Max	19.0	3.87	0.562	5.42	5.24	3.79	2.44	67.60	60.63	33.99	326	27
			Min	0.0	2.50	0.171	5.02	3.97	1.72	0.96	25.29	25.29	18.46	150	-21