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ENHANCING THE USE OF COALS BY GAS REBURNING-SORBENT INJECTION

Quarterly Report No. 6

For the Period

September 1, 1988 to November 30, 1988

Prepared for:

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Gas Resea.·ch Institute

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LEGAL NOTICE

ABSTRACT

The objective of this project is to demonstrate gas reburning-sorbent injection (GR-SI) emission control technology on three pre-NSPS coal-fired utility boilers in Illinois. The project goals are to achieve NO_x and SO_x emission reductions of 60 percent and 50 percent, respectively. Work on Phase 1, Design and Permitting, commenced on June 5, 1987.

During this quarter, work progressed on all tasks of the project. Revised cost and milestone schedules for Phase 1 have been approved by the funding organizations. The next meeting of the Participants Committee has been scheduled for January 19, 1989 in Chicago. One subcontract remains to be completed, with a starting date of this boiler review effort in December. Phase 1 baseline test reports and Phase 3 test plans are in preparation and will be completed in December. Process design studies on boiler characterization, isothermal flow modeling, thermal performance analysis, process specification, and electrostatic precipitator enhancement have been completed for all three units for testing GR-SI technology. Project engineering work has been completed on the wall fired unit, and is moving towards completion on the tangentially and cyclone fired units. The bid package for the wall fired unit will be sent out in December, with proposals due to EER on January 18, 1989. Work on the Environmental Information Volumes (EIVs) has been completed, including the ACH survey that was conducted in November at CILCO's wall fired Edwards Unit 1. DOE has completed the Environmental Assessment (EA) of the cyclone fired unit and is now completing that for the wall fired unit, based on EER's EIV submissions. Other environmental reports, such as site-specific waste disposal plans, have been reviewed and agreed upon with the host utilities, and the Environmental Monitoring Reports required by DOE have been drafted. Permitting assistance is now being provided to the host utilities for GR-SI modifications and operations. In the area of technology transfer, two papers have been presented on the project during this quarter, and the second meeting of the Industry Panel has been scheduled for January 18, 1989 in Chicago.

Key Words

SO_x	Ash	Emission
SO_2	Coal	Control
NO_x	Gas	Boiler
NO	Sorbent	Precipitator
		Flue Gas

1.0 SUMMARY

The objective of this project is to evaluate and demonstrate a cost effective emission control technology for acid rain precursors, oxides of nitrogen (NO_x) and sulfur (SO_x), on three coal fired utility boilers in Illinois. The units selected are representative of pre-NSPS design practices: tangential, wall, and cyclone fired. The specific objectives are to demonstrate reductions of 60 percent in NO_x and 50 percent in SO_x emissions, by a combination of two developed technologies, gas reburning (GR) and sorbent injection (SI).

With GR, about 80-85 percent of the coal fuel is fired in the primary combustion zone. The balance of the fuel is added downstream as natural gas to create a slightly fuel rich environment in which NO_x is converted to N_2. The combustion process is completed by overfire air addition. SO_x emissions are reduced by injecting dry sorbents (usually calcium based) into the upper furnace, at the superheater exit or into the ducting following the air heater. The sorbents trap SO_x as solid sulfates and sulfites, which are collected in the particulate control device.

This project will be conducted in three phases at each site: (1) Design and Permitting, (2) Construction and Startup, and (3) Operation, Data Collection, Reporting and Disposition. Technology transfer to industry will be accomplished through the formation of an industry panel. Phase 1 of the project commenced on June 5, 1987 and includes five tasks as follows:

- Task 1 - Project Management
- Task 2 - Process Design
  - Subtask 2.1 - Host Site Characterization
  - Subtask 2.2 - Process Specification
- Task 3 - Project Engineering
- Task 4 - Environmental Reports, Permitting, Plans and Design
- Task 5 - Technology Transfer

During this quarter, work continued on all Phase 1 tasks.

In Task 1, Project Management, close coordination of all project activities continued. The professional liability issue for RAMCO's review of EER's designs and plans on the tangentially fired unit is expected to be settled in December. The revised cost plan and milestone schedule for Phase 1 extending the work until March 1989 was submitted to the project funding organizations on November 13. Verbal approval has been obtained to proceed with the revised schedule and Phase 1 costs. Arrangements have been made for a meeting of the Participants Committee to be also attended by representatives of the Senior Review Committee on January 19, 1989 in Chicago, following the Industry Panel meeting to be held there the previous day.

In Task 2, Process Design, work continued on both subtasks. In subtask 2.1, Host Site Characterization, the baseline test reports and the Phase 3 test plans are in preparation. The technical work on subtask 2.2, Process Specification, has been completed. The specifications for injector nozzles for the cyclone fired Lakeside unit have been revised to take into account space and mixing constraints. For the tangentially fired Hennepin unit, humidification was selected as the technique for precipitator enhancement. Final reports on process design for each host unit are in preparation.

In Task 3, Project Engineering, working in close coordination with Black and Veatch, EER's Architect/Engineer subcontractor, design work has been completed on the wall fired Edwards unit and bid packages to construction firms have been scheduled to be sent out about mid-December. Work is in progress on the engineering design for the tangentially fired Hennepin unit and the cyclone fired Lakeside unit. Bid packages for these boilers will be mailed out during the next quarter.

In Task 4, all work on the preparation of the Environmental Information Volumes (EIVs) has been completed and the EIV final draft submitted to DOE. The archaeological survey for the Edwards pipeline was carried out during November. EER is providing assistance to DOE for converting the Lakeside and Edwards EIVs into Environmental Assessments, required for NEPA approval. Other activities in Task 4 focused on the methods of ash disposal. Dry disposal at remote sites has been selected for Edwards and Lakeside, while Hennepin will utilize wet disposal into a new, lined ash pond.

In Task 5, Technology Transfer, a paper was presented on the project at the Fifth Pittsburgh International Coal Conference and at the 1988 AIChE Annual Meeting. Preparations have been made to hold the second meeting of the Industry Panel in Chicago at GRI's offices on January 18, 1989.

2.0 INTRODUCTION

Clean Coal Technology implies the use of coal in an environmentally acceptable manner. Coal combustion results in the emission of two acid rain precursors: oxides of sulfur (SO_x) and oxides of nitrogen (NO_x). This clean coal technology project will demonstrate a combination of two developed technologies to reduce both NO_x and SO_x emissions: gas reburning and calcium based dry sorbent injection. The demonstrations will be conducted on three pre-NSPS utility boilers representative of the U.S. boilers which contribute significantly to the inventory of acid rain precursor emissions: tangentially fired, wall fired, and cyclone fired units.

Gas reburning is a combustion modification technique that consists of firing 80-85 percent of the fuel corresponding to the total heat release in the lower furnace. Reduction of NO_x to molecular nitrogen (N_2) is accomplished via the downstream injection of the remaining fuel requirement in the form of natural gas (which also reduces the total SO_x emissions). In a third stage, burnout air is injected at lower temperatures in the upper furnace to complete the combustion process without generating significant additional NO_x.

Dry sorbent injection consists of injecting calcium based sorbents (such as limestone, dolomite, or hydrated lime) into the combustion products. For sulfation of the sorbent to $CaSO_4$, an injection temperature of about 1230°C is optimum, but calcium-sulfur reactions can also take place at lower temperatures. Thus, the sorbent may be injected at different locations, such as with the burnout air, at the exit from the superheater, or into the ducting downstream of the boiler with H_2O added for humidification. The calcium sulfate or sulfite products are collected together with unreacted sorbent by the particulate collection device, usually an electrostatic precipitator or bag filter.

The specific goal of this project is to demonstrate NO_x and SO_x emission reductions of 60 percent and 50 percent, respectively, on three coal fired utility boilers having the design characteristics mentioned above. Host Site Agreements have been signed by EER and three utility companies in the State of

Illinois: Illinois Power Company (Test Site A, Hennepin Unit 1, 80 MW tangentially fired boiler in Hennepin), Central Illinois Light Company (Test Site B, Edwards Unit 1, 117 MW front wall fired boiler in Bartonville), and City Water Light and Power (Test Site C, Lakeside Unit 7, 40 MW cyclone fired boiler in Springfield). Alternate host sites would be utilized in the event that unforeseen problems develop with any of the above tests.

Co-funding for this project is provided by the Gas Research Institute (GRI) and the State of Illinois Department of Energy and Natural Resources (ENR)--the other Funding Participants. GRI and ENR are responsible for funding approximately one-third and one-sixth, respectively, of the total project costs.

To achieve the objectives of the project, it will be conducted in the following three phases at each host site.

Phase 1: Design and Permitting
Phase 2: Construction and Startup
Phase 3: Operation, Data Collection, Reporting and Disposition

Phase 1 of the project is being conducted in parallel for test sites A, B, and C over a period of 15 months. For this reason, quarterly reports will be issued during Phase 1, combining the work done related to all three sites. Starting with Phase 2, which will consist of a staggered schedule of eight months duration for each Test Site, separate reporting will be instituted to cover the work done at each site. This practice will be continued for the remainder of the total project schedule of 54 months, which includes the Phase 3 work at each site.

During the last quarter of Phase 1, Design and Permitting, work continued on each task of the project. The principal objectives of the work performed during this quarter were as follows:

- Meet with DOE and GRI on September 30 to discuss cost and schedule.
- Manage and coordinate all project tasks.

- Continue established communication patterns with co-funders, host utilities, subcontractors, and consultants.
- Complete subcontract/consultant negotiations.
- Review environmental reports to help ensure timely acceptance by DOE.
- Complete baseline test reports.
- Prepare Phase 3 draft test plan.
- Issue gas reburning, overfire air, and sorbent injection nozzle configuration specifications for Lakeside Unit 7.
- Complete thermal performance analyses for all three host sites.
- Specify ESP enhancement strategies for all sites.
- Prepare the Preliminary Design Report for Edwards.
- Adjust EER and Black & Veatch engineering schedules and manpower estimates to account for continued delays in NEPA approval for Edwards and Lakeside Stations.
- Complete Hennepin Station engineering and prepare general construction specifications.
- Prepare Hennepin bid package for review with IP and solicit bids for GR-SI application to Unit 1.
- Complete all engineering for Edwards Station and start preparation of general construction specifications for bid package.
- Complete 25 percent of mechanical project engineering for CWLP Lakeside Station, including:
  a) General arrangement drawings for all sorbent injection, gas reburn, and FGR equipment.
  b) Finalize with CWLP the source of natural gas for the GR process and prepare layout drawing of piping route from supply point.
  c) Finalize selection of sorbent storage in new silo or existing coal bunker.
- Finalize control philosophy and P&I drawings for Lakeside Station. Provide Black & Veatch with motor list.
- Complete power supply design for Lakeside Station and all engineering for Edwards Station.
- Coordinate monthly engineering review meetings with hosts and appropriate subcontractors.

- Arrange for host utility personnel to visit Richmond Power & Light to inspect operating sorbent injection system.
- Submit Edwards Station Final Draft Environmental Information Volume.
- Complete Archaeological, Cultural, Historical Survey of natural gas pipeline route at Edwards Station; submit as Appendix to Edwards EIV.
- Submit Lakeside Station Final Draft Environmental Information Volume.
- Evaluate and select GR-SI ash management options for all three host sites.
- Compile and submit Environmental Monitoring Plans for all three host sites.
- Continue relevant contacts with the industrial, government, and academic communities.
- Present a technical paper at the Pittsburgh Coal Conference in September.
- Plan and conduct the second Industry Panel meeting.
- Continue development of the commercialization plan.

3.0 PROJECT DESCRIPTION

Within the three phases of the project, the following tasks will be performed to demonstrate the cost effective control of NO_x and SO_x emissions from pre-NSPS coal fired utility boilers:

PHASE 1: DESIGN AND PERMITTING

Task 1 - Project Management

- Coordination of all Participant and subcontractor efforts
- Coordination with the three host site and alternate host sites
- Planning and scheduling all tasks
- Monitoring all technical efforts
- Keeping DOE, GRI, and ENR fully informed of project status
- Continual review of relevant ongoing technical developments

Task 2 - Process Design

Subtask 2.1 - Host Site Characterization

- Establishment of the condition of each host site, including field evaluations.

Subtask 2.2 - Process Specification

- Preparation of GR-SI process designs, aiming at 60% and 50% reduction in NO_x and SO_x, respectively.
- Continuing bench scale tests to define key process parameters.

Task 3 - Project Engineering

- Preparation of site specific detailed engineering designs, construction plans and schedules, cost estimates, startup plans and Phase 3 test plans.

Task 4 - Environmental Reportings, Permitting, Plans and Design

- Preparation of relevant environmental data for obtaining NEPA approval.

- Preparation of Environmental Monitoring Plan.
- Assistance to host sites in obtaining environmental permits.

Task 5 - Technology Transfer

- Formation of an Industry Panel for technology transfer.
- Arrangement of Panel meetings on (1) process design and (2) detailed engineering design and plans for Phases 2 and 3.

PHASE 2: CONSTRUCTION AND STARTUP

Task 1 - Project Management

- Continuation of Phase 1 project management activities.
- Arrangement of project review meetings at approximately the 20 and 100 percent completion points for each site.

Task 2 - Installation and Checkout

- Installation of the emission control and auxiliary equipment.
- Checkout of functional operation of all components.

Task 3 - Technology Transfer

- Continuation of technology transfer activities initiated in Phase 1.
- Meetings with Industry Panel to review installations and plans.

Task 4 - Restoration

- Decision on disposition of test equipment if project is discontinued: to be retained by host sites or removal and restoration work.

PHASE 3: OPERATION, DATA COLLECTION, REPORTING AND DISPOSITION

Task 1 - Project Management

- Continuation of Phases 1 and 2 project management activities.
- Conducting final project review at conclusion of project.

Task 2 - Technology Demonstration

Subtask 2.1 - Optimization Testing

- Evaluation of effects of process variables on emission control performance.
- Determination of operating conditions for optimum overall performance.

Subtask 2.2 - Evaluation of Alternative Coals and Sorbents

- Evaluation of performance of alternative coals and sorbents:
  - High and medium sulfur coals, with consideration of cleaned and run-of-mine coals.
  - Selection of sorbents from high calcium and dolomite limestones, hydrated limestones and limes.

Subtask 2.3 - Long-Term Testing

- Operation of GR-SI equipment under optimized conditions for approximately one-year duration at each host site.
- Measurement of emission control system performance.
- Determination of boiler impacts.

Task 3 - Evaluation of Demonstration Results

- Analysis of test data.
- Preparation of guideline manuals for application of GR-SI technology, including design recommendations, cost projection and comparisons with competing technologies.

Task 4 - Restoration

- Disposition of GR-SI equipment installation:
  - To be retained by host site or removal and restoration work.

Task 5 - Technology Transfer

- Continuation of technology transfer activities from Phases 1 and 2.
- Meeting with Industry Panel at one host site to review results obtained there and plans for other two host sites.
- Meeting with Industry Panel at completion of project.

4.0 PROJECT STATUS

Work has continued on all tasks of Phase 1 of this project. This section of the report provides details of the work performed during the quarter September through November, 1988.

4.1 Task 1 - Project Management

Monthly and special reports were submitted as stipulated by the reporting requirements of the Cooperative Agreement. Revised milestone schedule and cost plans have been prepared and submitted to the Project Participants for approval on October 13, 1988. The period of performance of Phase 1 is now projected to last until March 1989.

Project management has been actively involved in the continuing coordination and review of environmental reports submitted to DOE, with particular emphasis on the Environmental Information Volumes (EIVs) to provide the information base needed for DOE's preparation of Environmental Assessments of the Edwards and Lakeside project sites for obtaining NEPA approval. (As reported previously, NEPA approval has already been obtained for the Hennepin project site.) As discussed in section 4.4 of this report, all of these documents have been submitted to DOE, with the one exception of the ACH report for Edwards. The ACH survey was completed during November and submission of a report on its findings is imminent.

The subcontract with RAMCO for review work on the tangentially fired boiler of Illinois Power at Hennepin could not be initiated, because of administrative matters related to insurance/liability issues. RAMCO's work on the project is expected to start in December.

As will be discussed in section 4.5 of this report, the second meeting of the Industry Panel has been scheduled for January 18, 1989 in Chicago. A joint meeting of the Participants Committee and the Senior Review Committee is planned for the following day, January 19, 1989, also in Chicago. The Industry Panel meeting will have as its focus the review of EER's GR-SI designs and Phase 3 test plans for the three host sites, while the second meeting will review the progress achieved in Phase 1 and issues related to technology and cost management strategies for Phase 2 and 3, schedule of completing Phase 1 and transition into Phase 2 and approval procedures. The target schedule of initial project events is shown in Table 4.1-1.

4.2 Task 2 - Process Design

4.2.1 Subtask 2.1 - Host Site Characterization

A report was drafted on the Phase 1 baseline testing of Edwards Unit 1. The internal review process of the report on Hennepin Unit 1 has been completed and final revisions are being made. Laboratory data reduction on the Lakeside Unit 1 baseline tests has been completed and the report will be drafted in December.

Work has started on the Phase 3 test plan for Edwards Unit 1, which is the first unit scheduled to be tested. The plan will include a 30-day period of continuous baseline data-taking prior to testing GR-SI. Precipitator efficiency will be measured before and after the outage in which the GR-SI system and precipitator upgrades are installed. After the outage and baseline period, GR will be optimized without SI. Then SI will be optimized and the system tested for one week of continuous operation. Tests of an alternate sorbent (hydrated lime from a different source) and of alternate coals (two different blends of the coals presently used) will follow. Finally, a high-sulfur coal blend will be burned in a 12-month demonstration in which data on emissions and boiler operation will be taken continuously.

Considerable attention has been given to the subject of determining rates of tube wastage during the GR-SI demonstration, as well as during baseline conditions. Normal rates of tube wastage in pulverized-coal-fired utility boilers are in the range of 0.001 to 0.003 in./year. This is too small a rate to be measured by ultrasonic testing (UT) over a period of a year. Ultrasonic testing is accurate to approximately 0.008 in., and is suitable for predicting tube failure but not for short-term measurements of normal wastage rates.

Table 4.1-1. Phase 1 Target Dates
(1989 dates)

	NEPA APPROVAL	BID PACKAGE OUT	COST PROPOSALS IN	PROJECT EVALUATION REPORTS DRAFTS	HOST SITE AGREEMENTS	PHASE OVERLAP APPROVAL	PHASE 2 APPROVAL
CILCO Edwards Unit 1 (Wall)	2/20	12/18	1/18	1/30	3/1	4/1	5/15
IP Hennepin Unit 1 (Tangential)	In	1/28	2/28	1/30	4/1		5/15
CWLP Lakeside Unit 7 (Cyclone)	2/15	3/1	4/1	1/30	4/1		5/15

Extensive ultrasonic testing surveys will be made a) before startup of the GR-SI system, b) after approximately four months of testing, and c) after seven months of the one-year demonstration period. If excessive tube wastage is determined, further GR-SI testing will be curtailed.

4.2.2 Subtask 2.2 - Process Specification

4.2.2.1 Introduction

The overall objective of the Process Specification subtask of the project is to develop detailed conceptual design specifications for the application of gas reburning and sorbent injection to each of the host utility boilers. The activities necessary to develop the process specification include the identification of operational and performance characteristics for each boiler, and a series of design studies to identify the optimum conditions for the application of gas reburning and sorbent injection, and to develop specific design criteria. The activities are divided into a number of sub-elements which include:

- Boiler Characterization - Compilation of all available structural, operational, and performance data to permit evaluation of each boiler for reburning and sorbent injection application. Additional current data are obtained in a baseline field test program as part of subtask 2.1.

- Isothermal Modeling - Construction of isothermal physical flow models and validation of bulk and detailed flow field structure against available full scale information. The flow field data are used as inputs into the furnace heat transfer model. The isothermal models are used to develop the characteristics of the reburn gas, burnout air, and sorbent injectors necessary to produce adequate mixing of the reactant streams. Injector designs are optimized via detailed measurements to define mixing characteristics for the full operating range.

- Thermal Performance Analysis - Application of 2D and/or 3D furnace heat transfer and boiler performance codes for analysis of thermal performance characteristics of each unit over the nominal operating range. A range of possible reburning and sorbent injection applications will be identified based on boiler thermal characteristics, process requirements and available access. The thermal effects of reburning and sorbent injection will be analyzed to select arrangements which have minimal effects on boiler performance. Then the detailed process design will be specified and detailed thermal analyses will be conducted for the full retrofit situation.

- Process Specification - Coupling of heat transfer and flow analyses with process models to develop predictions of NO_x and SO_2 reductions for a range of process variable parameters. This includes further optimization of process and design parameters. Detailed design specifications will be developed for process application, including injector characteristics, injector locations, reactant flow rates, stoichiometries, etc.

- Electrostatic Precipitator (ESP) Performance Enhancement - The injection of sorbent into the upper furnace (or flue gas duct) will increase the inlet particulate loading for the existing ESP. Further, currently available laboratory and field data indicate that sorbent injection processes can result in fly ash with high electrical resistivity, making it difficult or impossible to collect in an ESP. Some form of ESP performance enhancement will therefore be needed for at least two of the three demonstration sites. Potential enhancement technologies will be identified, and systematic, site-specific studies will be conducted to evaluate the various technologies in terms of their predicted performance, impacts on plant performance and operation, and cost. Through discussions with the utilities, enhancement technologies for each site will be selected, and detailed designs will be developed in Task 3.

4.2.2.2 Wall-Fired Boiler

Thermal performance computer model runs utilizing EER's 2-dimensional furnace heat transfer and combustion model in conjunction with a boiler performance model of the Edwards #1 boiler were completed during the quarter. A brief summary report describing the full-load baseline and nominal GR-SI cases was prepared and forwarded to Riley Stoker Corporation--EER's boiler subcontractor for the Edwards unit--for analysis and comment.

2D Heat Transfer Model. Thermal performance in the furnace and radiative heat exchanger section is predicted using a 2 dimensional steady state heat transfer model (referred to hereafter as the "2D code"). In this code an axisymmetric cylindrical grid is used to represent the furnace. The grid is divided axially and radially into zones, providing for spatial resolution of heat transfer quantities.

The heart of the computational technique is the radiation model. The model uses a semistochastic approach to track radiative beams proceeding through processes of emission, gas-phase attenuation, surface absorption and reflection, until all energy in each beam is absorbed (within a prescribed numerical tolerance). Convective heat transfer is also calculated. Heat transfer surfaces include water walls and distributed heat exchangers.

The flow field is not calculated but is prescribed as an input. The prescription allows for specification of velocity profiles, recirculation patterns, and turbulent exchange between zones. In practice, specified flow fields are generally based on isothermal flow observations, and on experience in modeling similar boilers.

Combustion is modeled by allowing reactants (char particles, and pockets of coal volatiles or natural gas) to move randomly, with probabilities weighted by the turbulent flow vectors. Char particles react according to an Arrhenius rate law. Volatile packets are assigned statistically distributed lifetimes, and each packet reacts completely at the end of its assigned lifetime.

Figure 4.2-1 illustrates the geometrical representation of the Edwards boiler for the 2D code. Figure 4.2-1a shows a schematic of the region to be modeled, including key features such as heat exchanger banks and mass inlets. This schematic has been divided into 29 layers, roughly following the direction of flow from bottom to top. These layers correspond to the 29 axial layers in Figure 4.2-1b, which shows a cross-section of the axisymmetric cylindrical grid used in the 2D code. This grid is also divided into 4 radial layers.

For the region of the furnace between the hopper and the arch (layers 3 through 16), the length and radius of the grid are set to match both the volume and wall surface area of the full-scale unit. For other layers, the volume is matched but the surface area of the grid wall is supplemented by adding heat exchanger surface area. Thus, the total volume and surface area of the grid approximately match that of the actual boiler in the region shown in Figure 4.2-1a.

Cases Run. The thermal behavior of Edwards Unit 1 has been studied to examine the effect of Gas Reburning (GR) and Sorbent Injection (SI) on its performance. The results of three cases are reported here: Baseline (no GR/SI), GR only, and GR/SI. All three cases are run at the same thermal input, approximately corresponding to full load operation. Table 4.2-1 summarizes key parameter variations between these cases.

Case 1 (Baseline) is run under conditions using a coal blend with 15 percent high sulfur (Illinois Bituminous), and 85 percent low sulfur (Kentucky Bituminous) coal, typical of current operation. Cases 2 (GR only) and 3 (GR/SI) are run with a 57 percent high sulfur, 43 percent low sulfur coal blend, corresponding to GR/SI design conditions.

All three cases are run with approximately the same exit stoichiometry, but the local stoichiometries vary in Cases 2 and 3, running slightly fuel lean at the coal burners and slightly fuel rich at the natural gas injectors. The actual stoichiometries used correspond to the GR design specifications.

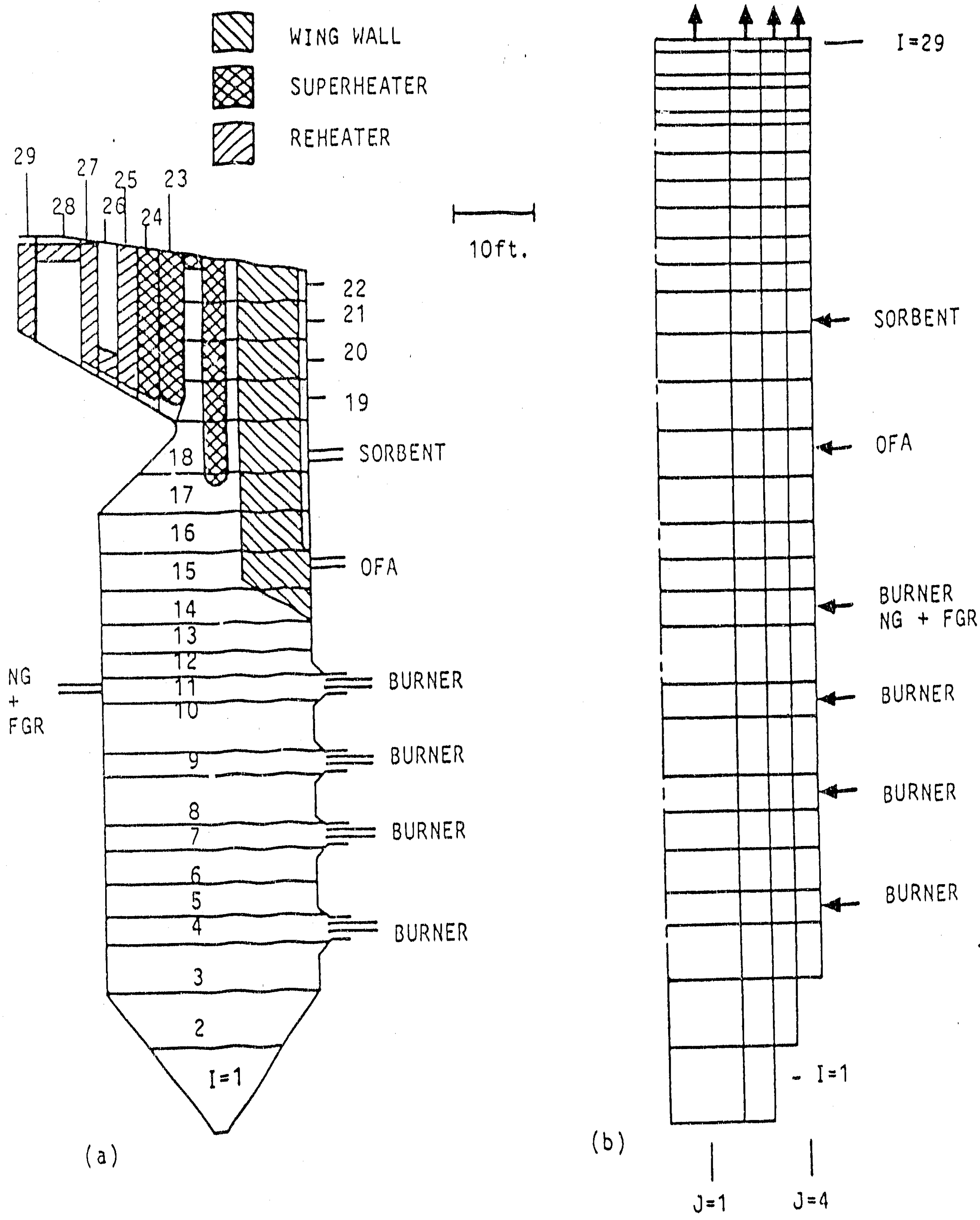


Figure 4.2-1 Edwards Boiler Goemetry in 2D Heat Transfer Code.
(a) Division into Layers; (b) Cylindrical Grid.

Cases 2 and 3 also introduce Flue Gas Recirculation (FGR). Recirculation of 6 percent of the total flue gas includes FGR for cooling out-of-service burners in the reburning zone, as well as FGR for enhancing natural gas (NG) mixing.

Case 3 differs from Case 2 in the use of sorbent, as well as the diversion of 3 percent of the total combustion air flow from the over-fire air (OFA) ports to the sorbent injection nozzles for use as sorbent carrier air (CA). The flow rate of sorbent is set using the design calcium-to-sulfur molar ratio (Ca/S).

TABLE 4.2-1 EDWARDS UNIT #1 AT FULL LOAD

Case No.	GR/SI Included?	Coal Blend (High S/Low S)	Stoichiometric Ratio Burner	NG+FGR	Exit	% FGR	% CA	Ca/S
1	No (Baseline)	15 / 85	1.185	1.185	1.185	0.	0.	0.
2	GR only	57 / 43	1.1	0.9	1.185	6.	0.	0.
3	GR/SI	57 / 43	1.1	0.9	1.186	6.	3.	1.594

<u>2D Code Results</u>. Figures 4.2-2 through 4.2-4 show outputs of interest from the 2D heat transfer code. Each figure shows a plot of an output variable as a function of axial distance, for Cases 1 and 3.

If Case 2 were included in these plots, it would very nearly coincide with the curve for Case 3, over most of the plot range. This is not surprising, as the relative impact of introducing sorbent injection is small compared to that for the introduction of gas reburning. Most of the profile variations between Cases 2 and 3 are in the region of the over-fire air and sorbent injection ports, due to the mass flow differences at these locations.

In each of these plots, the independent variable is <u>projected</u> vertical distance along the grid axis. The "projected distance" is the same as the height above the hopper bottom in the actual boiler (Figure 4.2-1a) for axial layers 1 through 16. Because of the shape distortions in zones 17 through 29, the coordinate used for these layers is the distance on the grid scaled down by the same factor as used for layers 3 through 16. Key elevations are

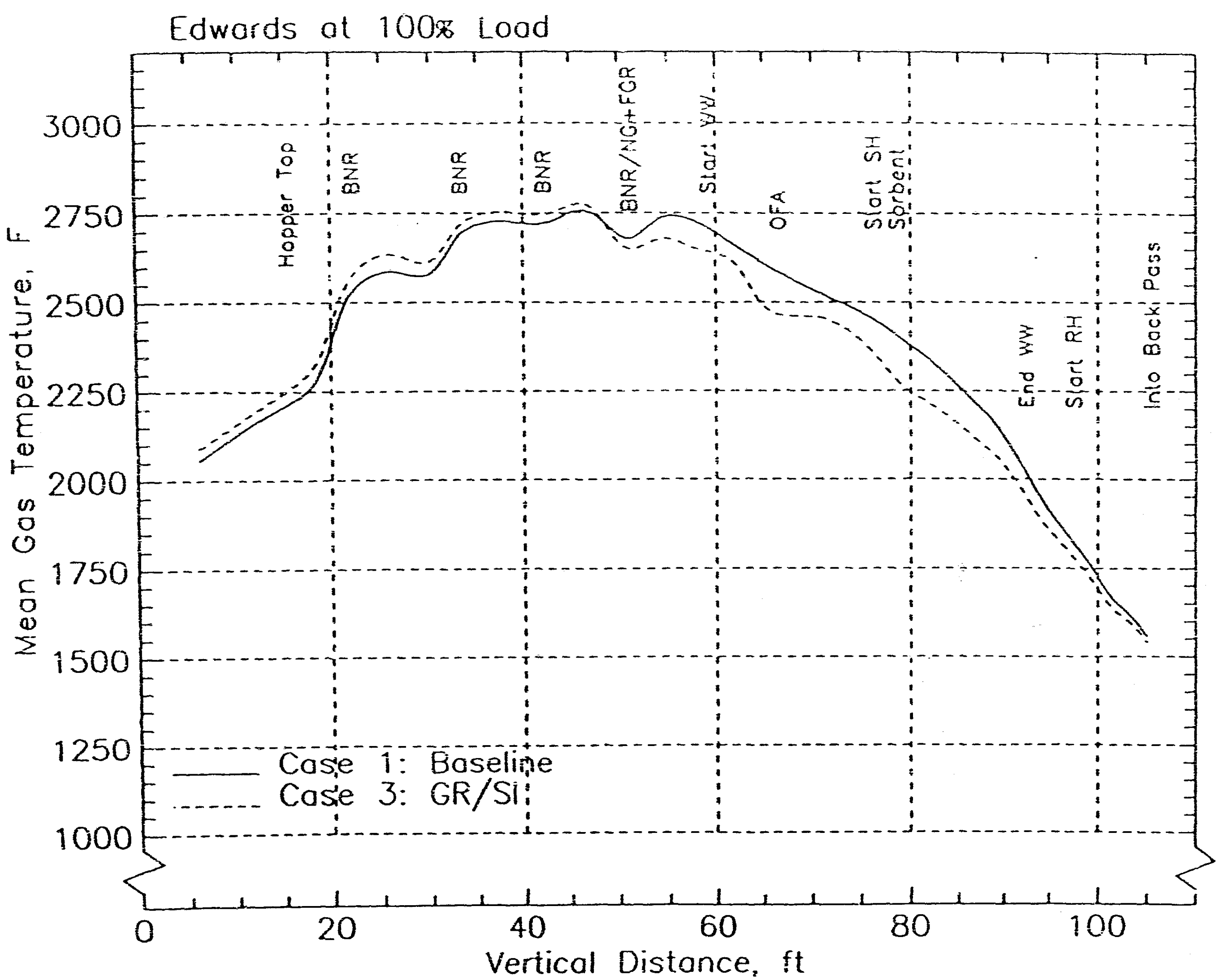


Figure 4.2-2. Mean Gas Temperature Profile

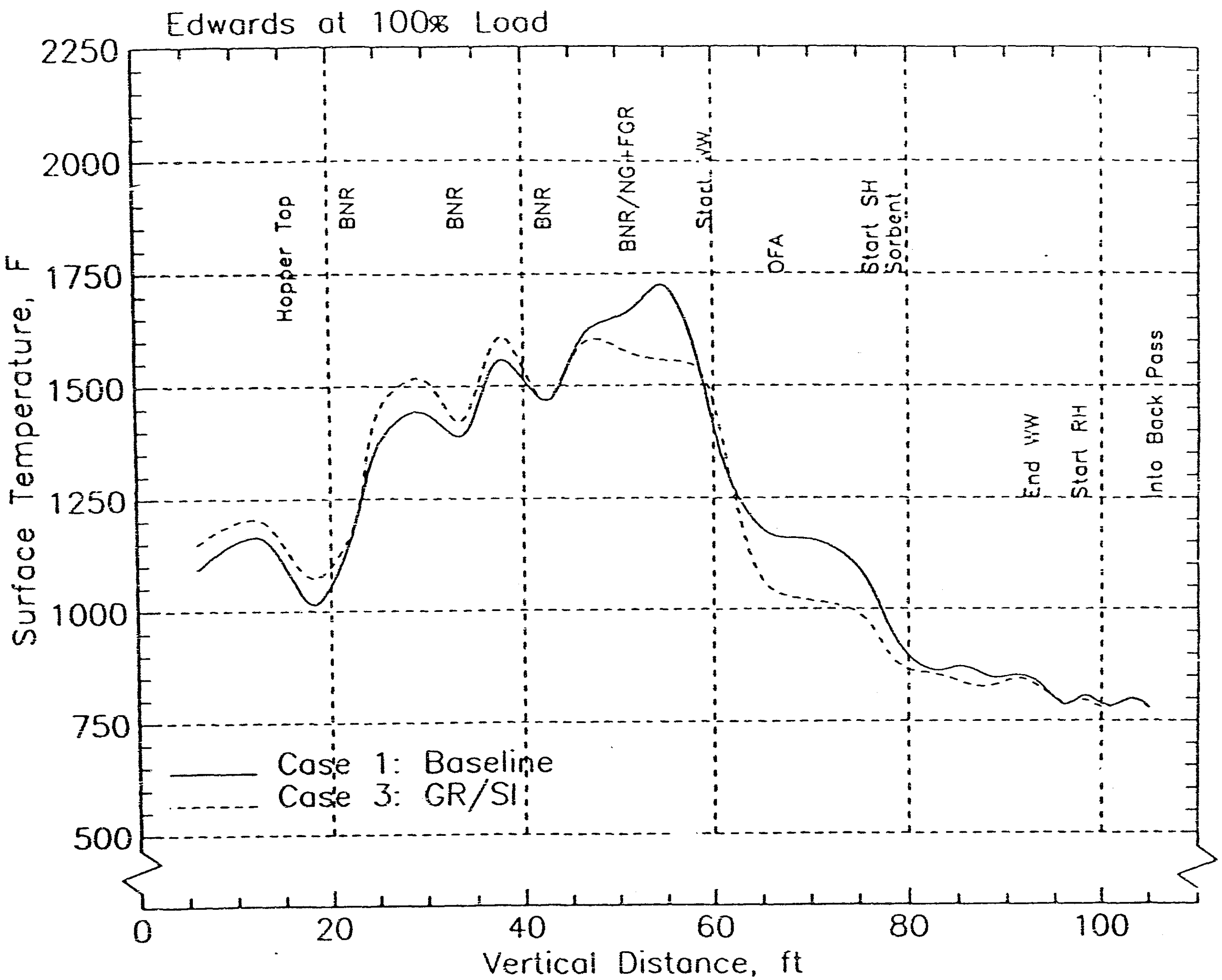


Figure 4.2-3. Surface Temperatures of Ash Deposits

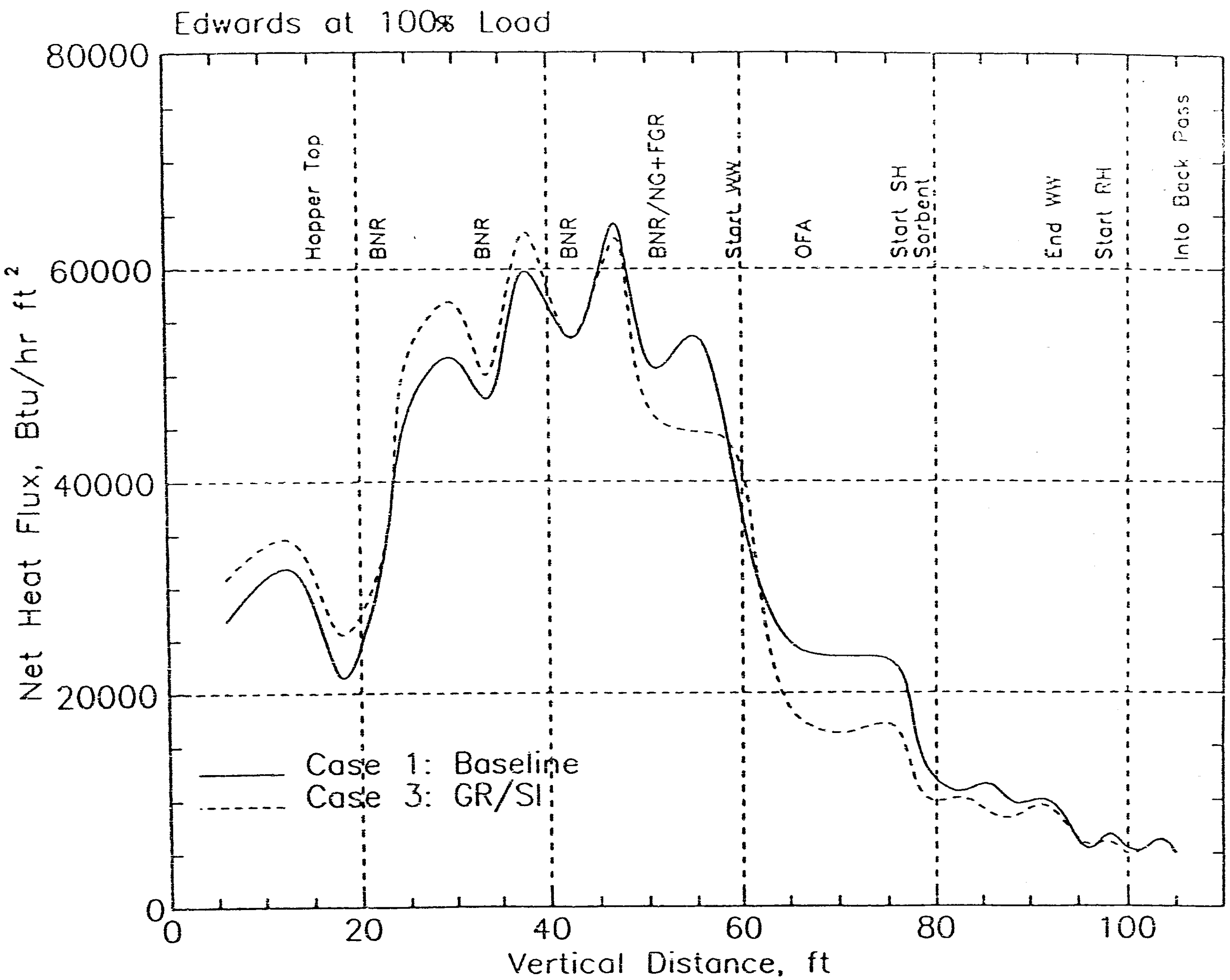


Figure 4.2-4. Net Heat Flux to the Wall

labelled to aid in interpreting the plots (note that in these labels, "WW" stands for "wing walls").

Figure 4.2-2 shows the profile of mean gas temperature through the boiler. The mean gas temperature in each axial layer is an average of the temperature of the radial zones in that layer, weighted by the flow profile. Furnace temperatures during gas reburning are slightly higher in the lower portion of the furnace, where the stoichiometric ratio is slightly lower than for the baseline case. From the natural gas/flue gas recirculation ports upward, the temperature drops for the gas reburning cases, primarily due to the impact of flue gas recirculation. There is also a dip in temperature at the introduction of over-fire air, and at the introduction of sorbent carrier air for Case 3.

Figure 4.2-3 shows the surface temperature of ash deposits along the cylindrical wall of the model. Surface temperatures are also calculated for horizontal wall surfaces and for heat exchanger surfaces, but these are not included in the plot. Note that the peak surface temperature for Case 3 is less than that for Case 1. This result is due to the introduction of flue gas recirculation near the location of the Case 1 peak surface temperature.

Figure 4.2-4 shows the net heat flux to the wall. The local minima at burner locations are due to the treatment of the burners as uniform mass sources around the perimeter of the cylindrical model. For the GR/SI case, slightly higher peak fluxes are seen around the lower coal burners, due to a somewhat larger thermal input and lower stoichiometry at those burners, compared to baseline operation. Above the natural gas/flue gas recirculation port, the heat flux tends to be slightly lower, partly due to flue gas recirculation, the reduced thermal input at the natural gas level, and the introduction of overfire air.

Boiler Performance Model. The 2D heat transfer code calculates heat fluxes to walls and heat exchangers in the domain shown in Figure 4.2-1a, but does not calculate the heat balance for the steam side. A separate program, referred to here as the Boiler Performance Model or the Boiler Code, is run following the 2D code, to calculate the steam side heat balance for all heat exchange surfaces.

For boiler sections which are not included in the domain of the 2D code, such as the back pass heat exchangers, the boiler code calculates a heat balance for both the gas and steam side. For these sections, the gas side heat balance is convective only; radiation is neglected. Heat transfer coefficients for tube banks are calculated based on geometry and flue gas properties; heat transfer coefficients for walls are user-specified. The user must also specify the thickness of ash deposits; ash conductivity is calculated by the program as a function of temperature.

For boiler sections which are included in the domain of the 2D code, such as the high temperature superheaters, it is not necessary to recalculate the gas side heat balance as this has been done in the 2D code. For these sections, the heat flux to the wall is set by the 2D code results. Other information, such as flue gas composition, is also passed from the 2D code.

Boiler Code Results. Table 4.2-2 lists the primary outputs from the Boiler Code for the three cases considered. These include steam mass flows, steam temperatures, heat fluxes, and gas side temperatures from the exit of the 2D code domain. These prediction allow a comparison of the relative performance changes when gas reburning and sorbent injection are introduced.

Not all of the data in Table 4.2-2 is calculated by the Boiler Code. Some values, such as steam inlet temperatures, are set from input values. Other values are determined by the 2D code, including the gas side temperature into the back pass. Portions of the heat transfer to steam are partially determined by the 2D code, as explained previously.

The flue gas temperature from the air heater was calculated apart from the boiler code, based on specified air inlet and outlet temperatures and the boiler code result for the flue gas temperature exiting the economizer. In this calculation solids were excluded from the flue gas heat balance. Air

Table 4.2-2 Edwards Boiler Performance at 100% Load

ITEM.	Case 1 Baseline	Case 2 GR only	Case 3 GR/SI
Back Pass Split Ratio			
Percent of Flue Gas to SH side	76.9	79.2	78.7
Steam Mass Flows (klb/hr)			
Into Economizer	784.6	766.9	768.3
SH Attemperation Spray	57.7	66.9	62.7
Exit Superheater	842.3	833.8	831.0
Reheater	743.2	735.7	733.3
Steam Side Temperatures (^oF)			
Into Economizer	406.	406.	406.
Exit Economizer	447.	453.	453.
Into Primary Superheater	633.	633.	633.
Exit Primary Superheater	800.	834.	829.
SH Attemp. Spray Water	406.	406.	406.
Into Secondary Superheater	728.	736.	738.
Exit Secondary Superheater	1000.	1000.	1000.
Into Low Temp. Reheater	645.	645.	645.
Exit Low Temp. Reheater	788.	787.	790.
Exit High Temp. Reheater	1000.	1000.	1000.
Heat Transfer to Steam (MBtu/hr)			
Economizer	35.3	39.2	39.2
Waterwall	560.6	543.2	544.3
Primary Superheater	162.6	178.1	175.4
Secondary Superheater	167.8	156.4	154.9
Low Temp. Reheater	57.2	56.1	57.0
High Temp. Reheater	82.9	82.4	81.2
Gas Side Temperatures (^oF)			
Into Back Pass	1538.	1535.	1522.
Exit Primary Superheater	861.	881.	877.
Exit Low Temp. Reheater	681.	678.	680.
Exit Economizer	708.	726.	723.
Exit Air Heater	320.	344.	343.

Table 4.2-3 Boiler Efficiency

	Case 1 Baseline	Case 2 GR Only	Case 3 GR/SI
Heat Loss (%)			
Dry Gas	4.85	5.30	5.28
Moisture from Fuel	0.67	0.95	0.95
Moisture from Combustion	3.68	5.15	5.15
Combustible in Refuse	0.50	0.93	0.96
Radiation	0.25	0.25	0.25
Unmeasured	1.50	1.50	1.50
Total Losses	11.45	14.08	14.09
Gross Efficiency (%)	88.55	85.92	85.91

leakage was also excluded from the control volume, and this is reflected in the predicted flue gas exit temperature.

One parameter affecting inputs which is listed explicitly in Table 4.2-2 is the "Back Pass Split;" that is, the percentage of flue gas which is directed down each side of the back pass. By design, this split is adjustable in order to control reheat temperature. In running the boiler code, the same approach has been used--the split between the two sides has been set to match the design reheat temperature of 1000°F.

In comparing the results in Table 4.2-2, note that the major change is between Cases 1 and 2, while the introduction of sorbent injection in Case 3 causes relatively little change. The gas reburning cases show higher intermediate steam temperatures, lower steam flow rates, and higher gas temperatures than for the baseline case.

Boiler Efficiency. Table 4.2-3 lists boiler efficiency calculations for all three cases, based on the ASME standard heat loss method, as described n the "ASME Test Form for Abbreviated Test" (PTC 4.1-a and 4.1-b). Heat exchange through the air heater is considered.

For this calculation, heat losses are calculated based on 2D and Boiler Code inputs and outputs. The exceptions are radiation losses and unmeasured losses, which are taken from the boiler design (the latter is taken as the "manufacturer's margin").

Table 4.2-3 shows that the major change in efficiency occurs between Cases 1 and 2, with a lesser change between Cases 2 and 3. The largest heat loss change is in the loss due to moisture from combustion of hydrogen. This change is due to the large hydrogen content of the natural gas compared to the coal. There is also a composition difference due to the different coal blends used for Cases 1 and 2.

The next largest change is in the heat loss due to dry gas. This is due to the higher gas exit temperatures calculated for Cases 2 and 3.

The heat loss due to moisture in fuel is higher for Cases 2 and 3 due to the higher moisture content of the 57/43 coal blend compared to the 15/85 coal blend.

The heat loss due to combustible in refuse is higher for Cases 2 and 3 due to the higher fraction of unburnt fixed carbon in those cases.

EER's thermal performance analysis of the Edwards GR-SI system continues, and preparation of the final process design report has begun.

4.2.2.3 Tangentially-Fired Boiler

Thermal performance work on the Hennepin Unit 1 GR-SI system also continued during the period. The results of this work will be summarized in subsequent reports. Much of the work associated with the Hennepin unit concerned the selection of an ESP performance enhancement strategy to mitigate the anticipated deleterious effects of applying GR-SI. This work is summarized below. Finally, preparation of the final process design report for the Hennepin unit has begun.

4.2.2.4 Cyclone Fired Boiler

Isothermal flow model studies of the Lakeside Unit 7 boiler were completed during the reporting period. The objectives of these studies were to identify natural gas, overfire air, and sorbent injection nozzle configurations and operating conditions yielding effective mixing of the respective jets with the furnace gases, and to characterize the furnace gas flow field before and after application of GR-SI.

A 1/8-scale plexiglass model of the Lakeside unit was used for the studies. The cyclone furnace outlets were scaled geometrically, and the inlets were scaled to yield the same axial to tangential momentum ratio as provided by the full-scale cyclones at Lakeside. The convection pass tube banks were modeled to yield the correct pressure loss coefficients.

Before injector studies could begin, it was important to verify that the furnace flow field obtained in the model was in substantial agreement with velocity measurements from the field. This was particularly important at Lakeside due to the very complicated, 3-dimensional upper furnace temperature and flow fields. It was also difficult to make a comprehensive assessment for Lakeside since there are very few water-wall penetrations available in its pressurized furnace for making the needed velocity measurements.

A comparison between model and full-scale boiler flow field results under full load conditions is provided by Figure 4.2-5. The velocity measurements were made by traversing the furnace with a special velocity probe through ports C and D (Figure 4.2-7). The probe is also equipped with a high velocity thermocouple, and the corresponding full-load temperature measurements are indicated in Figure 4.2-8). The large uncertainties in velocity indicated in the figure for measurements made near the center of the full-scale furnace are indicative of an unstable flow field in that region. The complicated nature of the furnace flow field is illustrated in Figure 4.2-6. As the furnace gases exit the primary furnace, most of the flow is concentrated in the rear corners and along the back wall.

This provided a very difficult situation for injecting reburning gas, overfire air, and sorbent into the furnace and obtaining good mixing and dispersion. The short upper furnace gas-phase residence time in the cyclone unit just compounded the problem. Considerable effort--including repeating some of the field measurements during the Baseline Tests in August, 1988--went into the development of the following injector specifications:

Reburning Gas. Natural gas is injected above the primary furnace in such a manner as to reduce the overall stoichiometry in the reburning zone to about 0.9. This creates a variety of hydrocarbon fragment free radicals which react with the NOx species present--effectively destroying a large percentage of the NOx created in the cyclones. To take full advantage of the limited upper furnace residence time, the gas must be quickly dispersed and intimately mixed with the furnace gases. Extensive isothermal flow model testing was required to optimize the natural gas injector configuration for

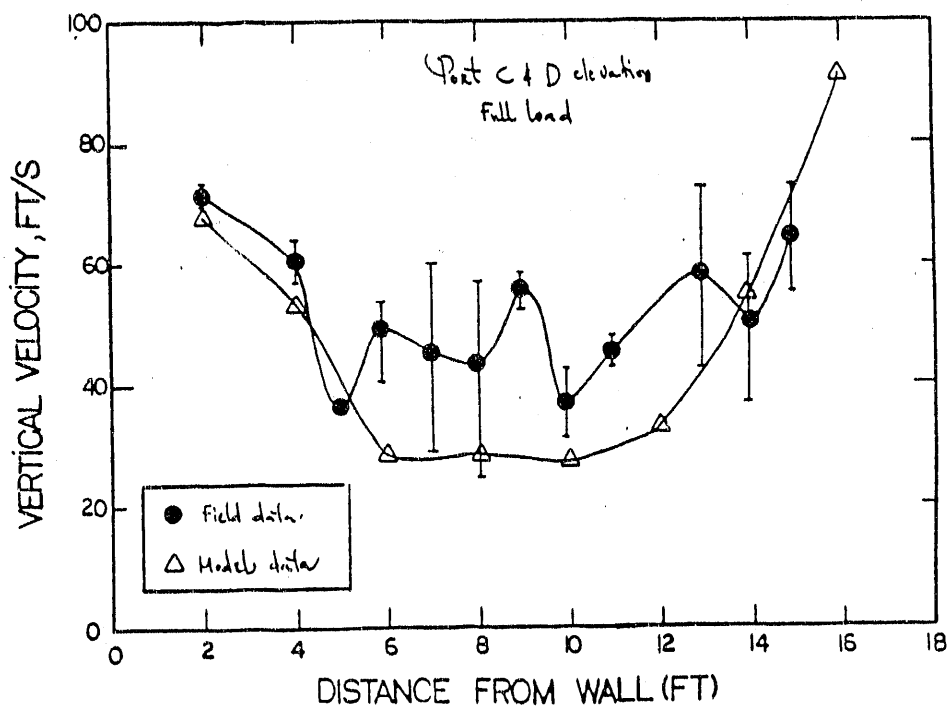


Figure 4.2-5 Model and Full-Scale Velocity Fields

Figure 4.2-6
MODEL VELOCITY FIELD

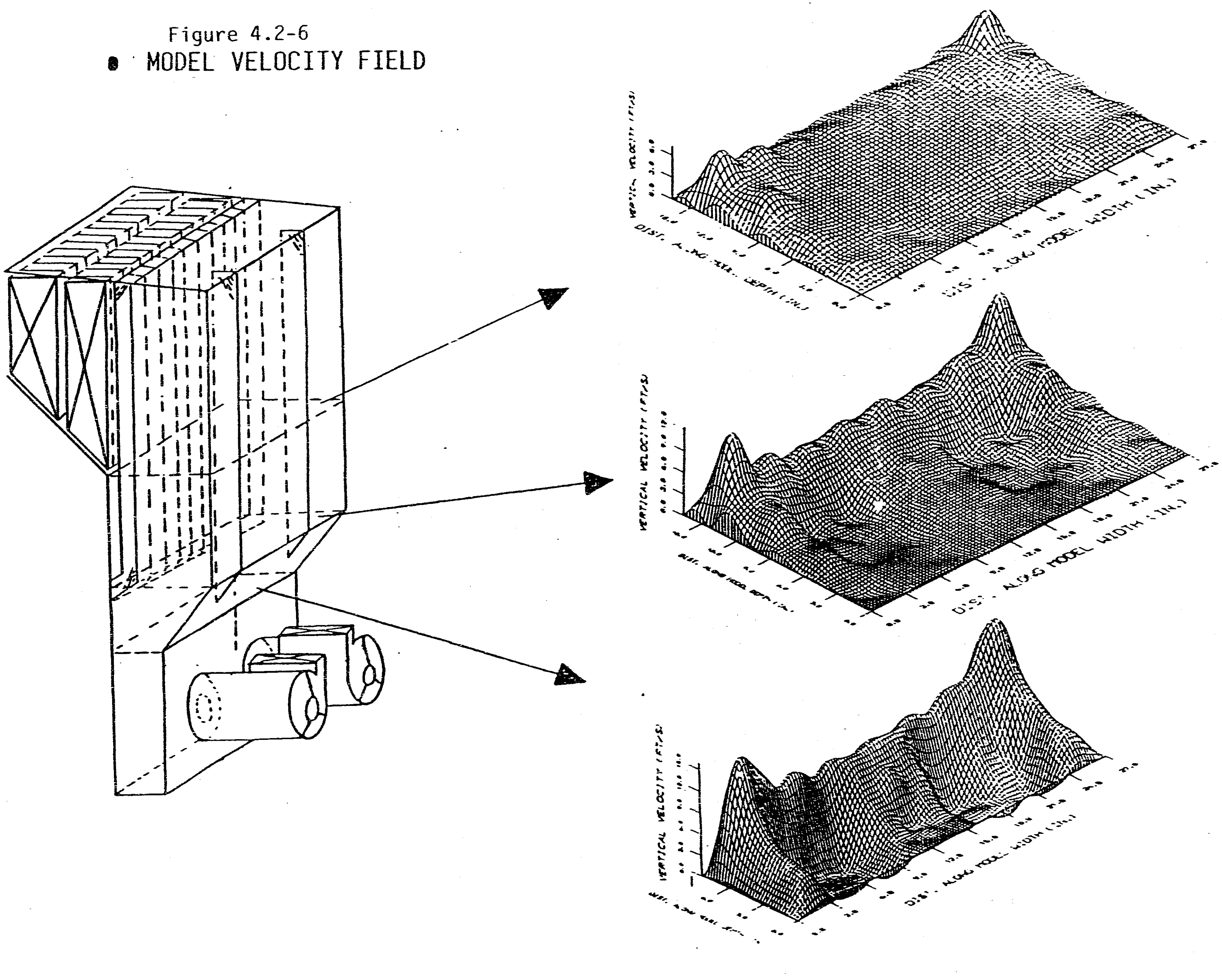
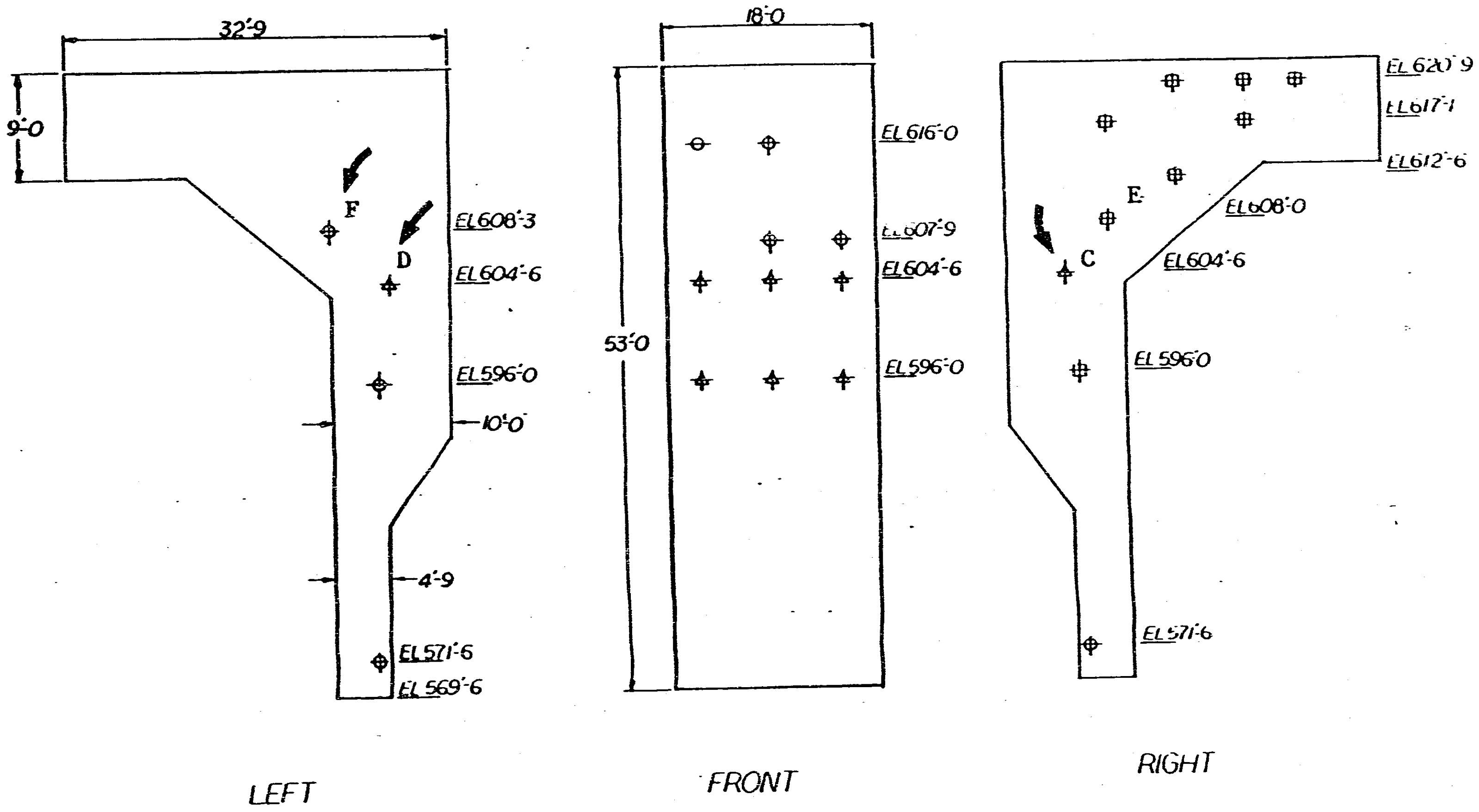
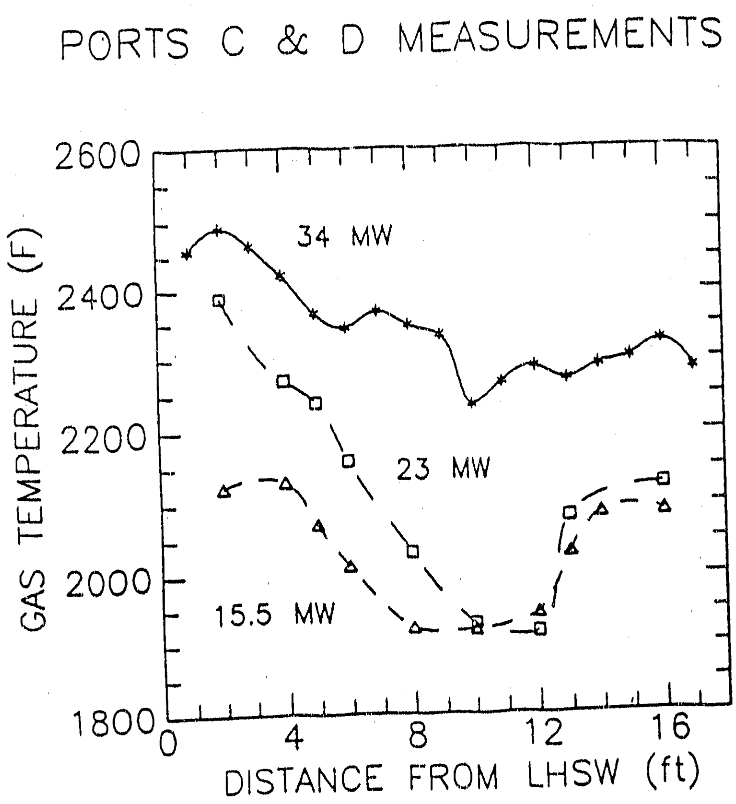


Figure 4.2-7

LOCATION OF SAMPLING PORTS





Figu~e 4.2-8 Furnace HVT Measurements

Lakeside. Promising configurations were first identified through visualization studies wherein the injected streams are made visible using smoke or neutrally-buoyant soap bubbles. Dispersion measurements were then made using tracers to quantitatively compare the candidate configurations. Selection of the final GR nozzle configuration was primarily based on how quickly the natural gas was dispersed and mixed with the furnace gases, the absence of entrainment of the gas down into the primary furnace, and, to a lesser extent, the ease at which the system could be retrofitted to the boiler.

The reburning gas will be injected from the side and rear (to accommodate the high velocity furnace gas flow near the rear wall) walls of the furnace at EL 585'-8" (see Figure 4.2-9) using the configuration shown in Figure 4.2-10. Natural gas will be supplied through a 1-inch ID tube to each nozzle. Recirculated flue gas will be supplied to six of the nozzles to improve penetration and mixing. The flue gas and natural gas will mix inside the injectors and enter the furnace through 5 1/2-inch ID nozzles. At full load, the flue gas flow through the reburning gas injectors will amount to about 5 percent of the total flue gas flow. Injection velocity will vary with boiler load as indicated in Figure 4.2-11.

Overfire Air. In order to complete the combustion process in the furnace, overfire air (OFA) will be injected downstream of the reburning zone. The air must be injected at an elevation yielding adequate residence times in both the reburning and burnout zones, and must be injected in a manner which achieves good dispersion and rapid mixing with the furnace gases while avoiding entrainment of the air down into the reburning zone.

Overfire air will also be injected through the rear wall of the furnace through six nozzles at EL 597'-7" (see Figure 4.2-12). The air will enter through 3 pairs of nozzles of different diameters. The OFA injection velocity will vary with boiler load as indicated in Figure 4.2-13.

Sorbent Injection. To make maximum use of the available upper furnace residence time, sorbent must be injected at the point where the furnace gases

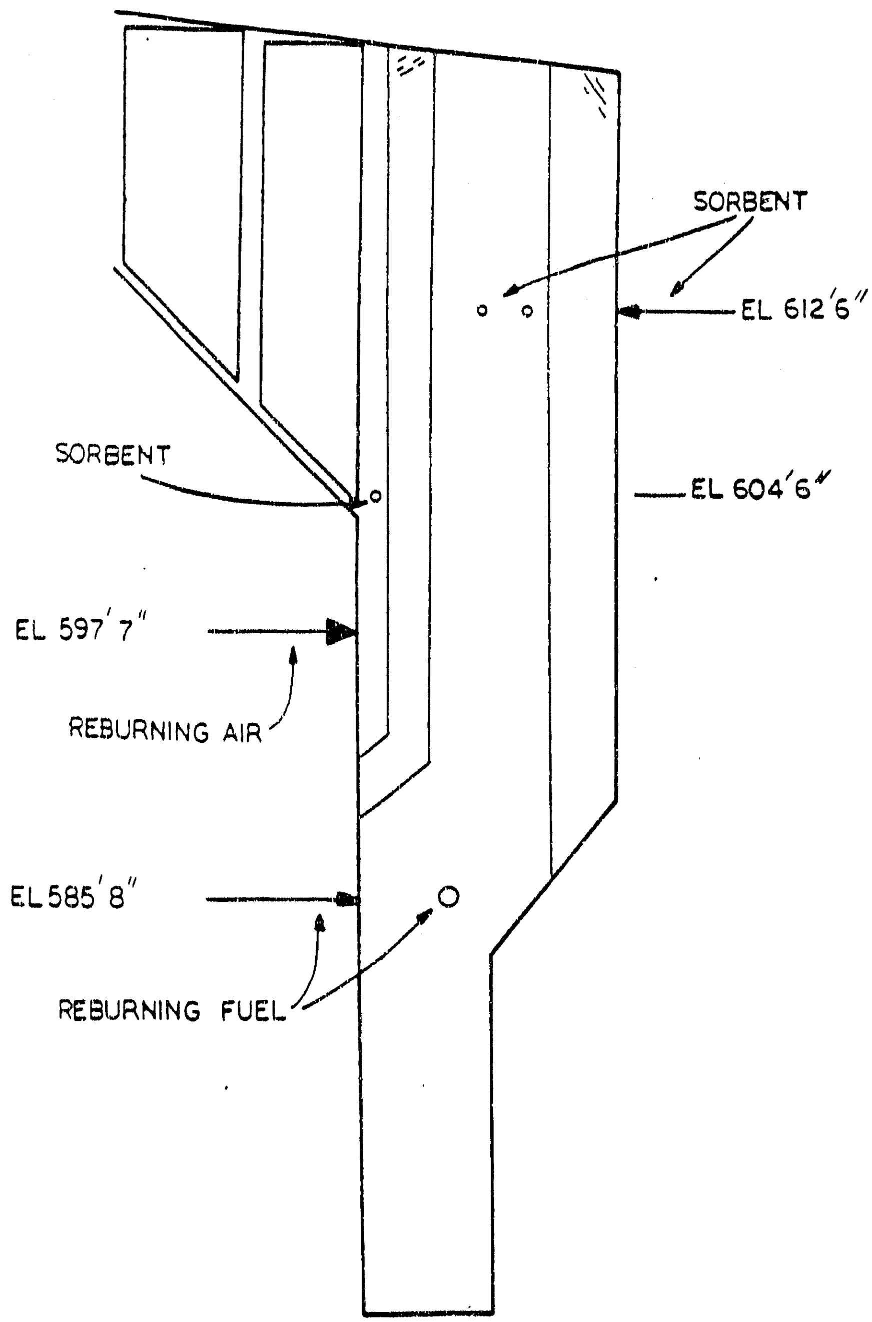


Figure 4.2-9
Injection elevations of the GR-SI system.

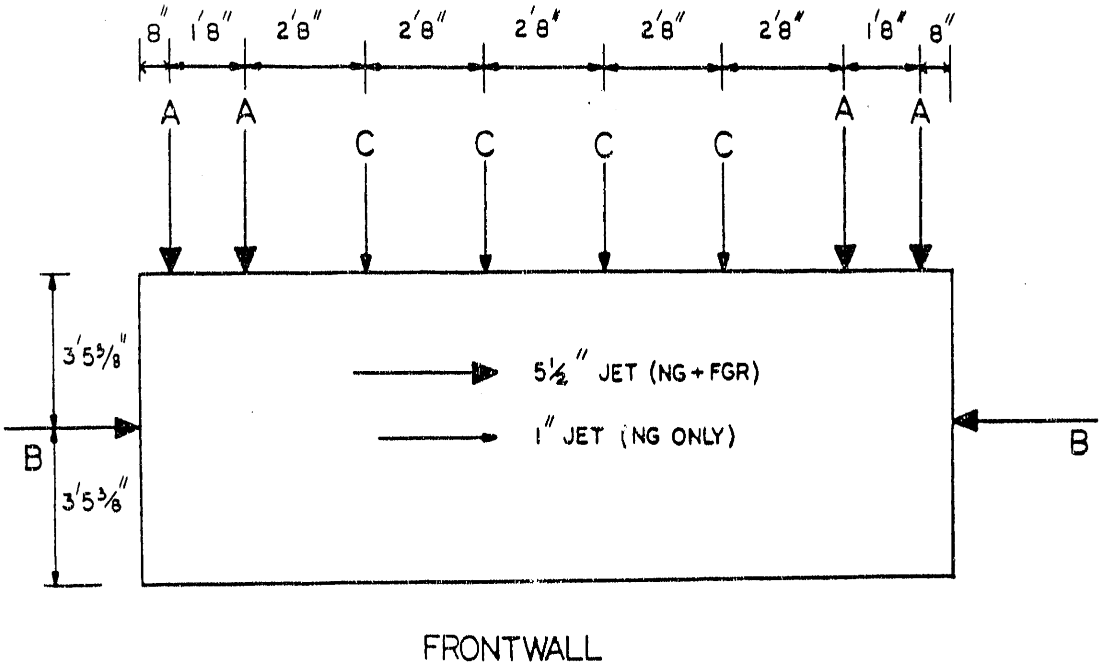


Figure 4.2-10
Plan view of the reburning fuel injection system.

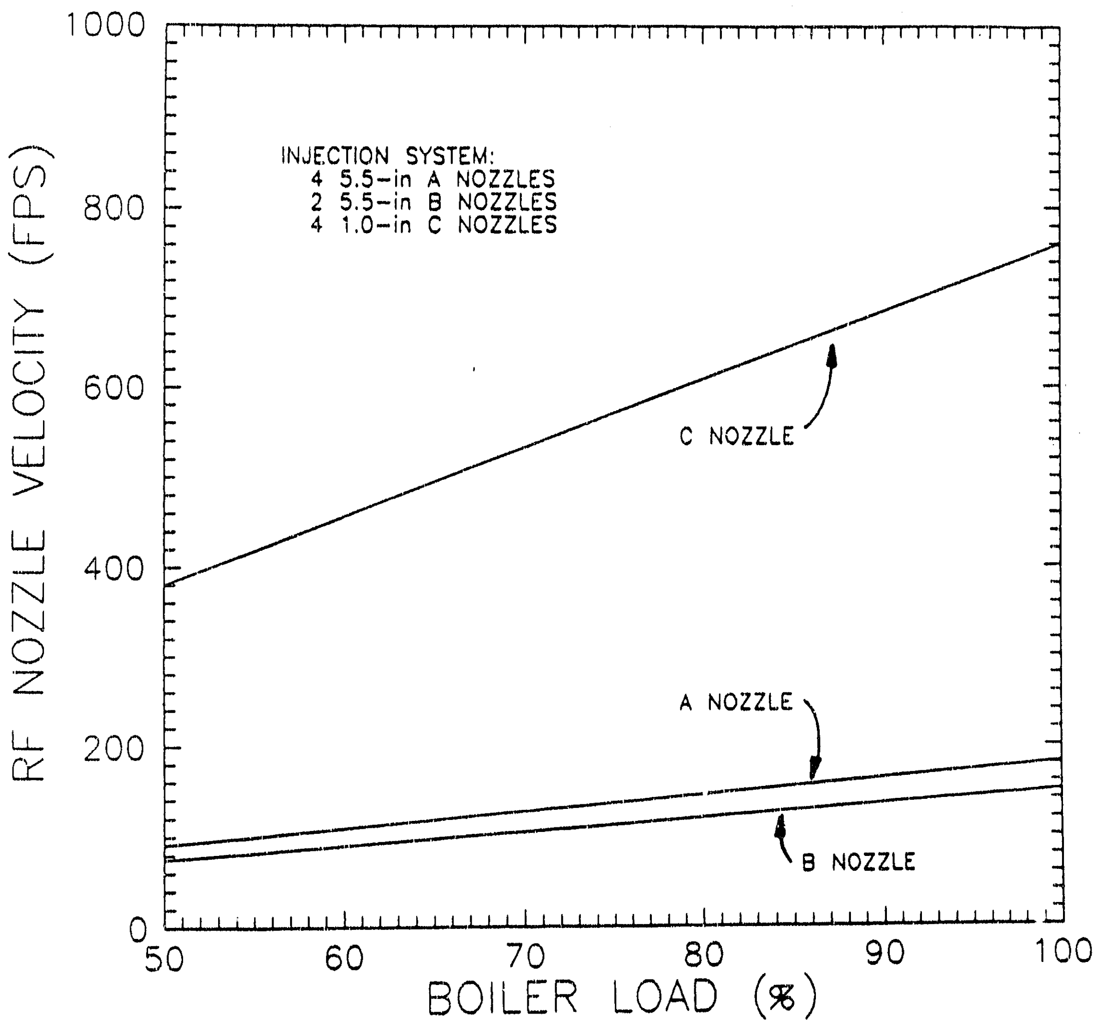


Figure 4.2-11

Variation of reburning fuel nozzle velocity with boiler load.

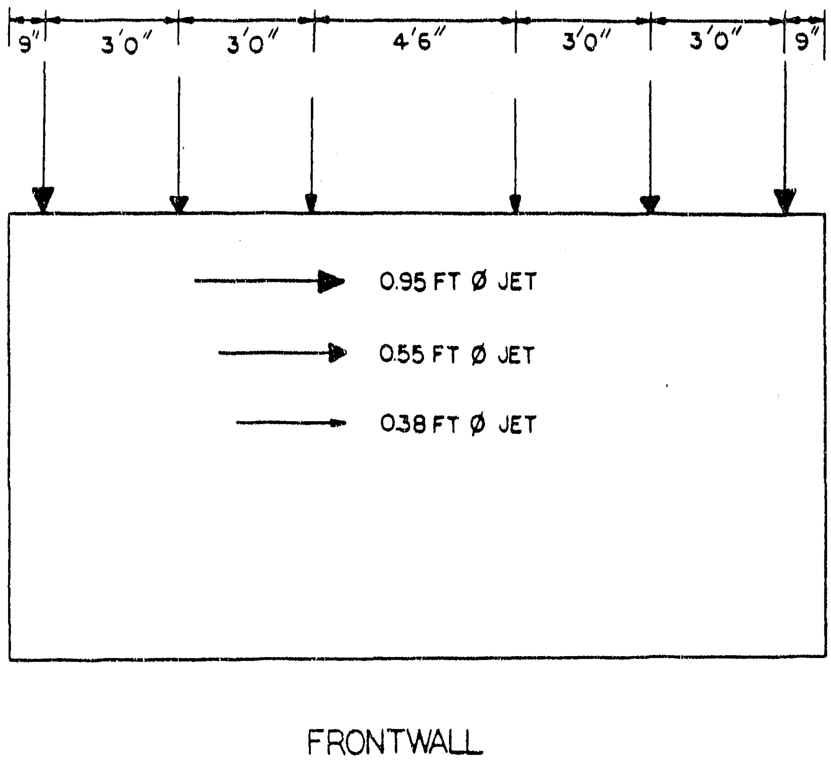


Figure 4.2-12

Plan view of the overfire air injection system.

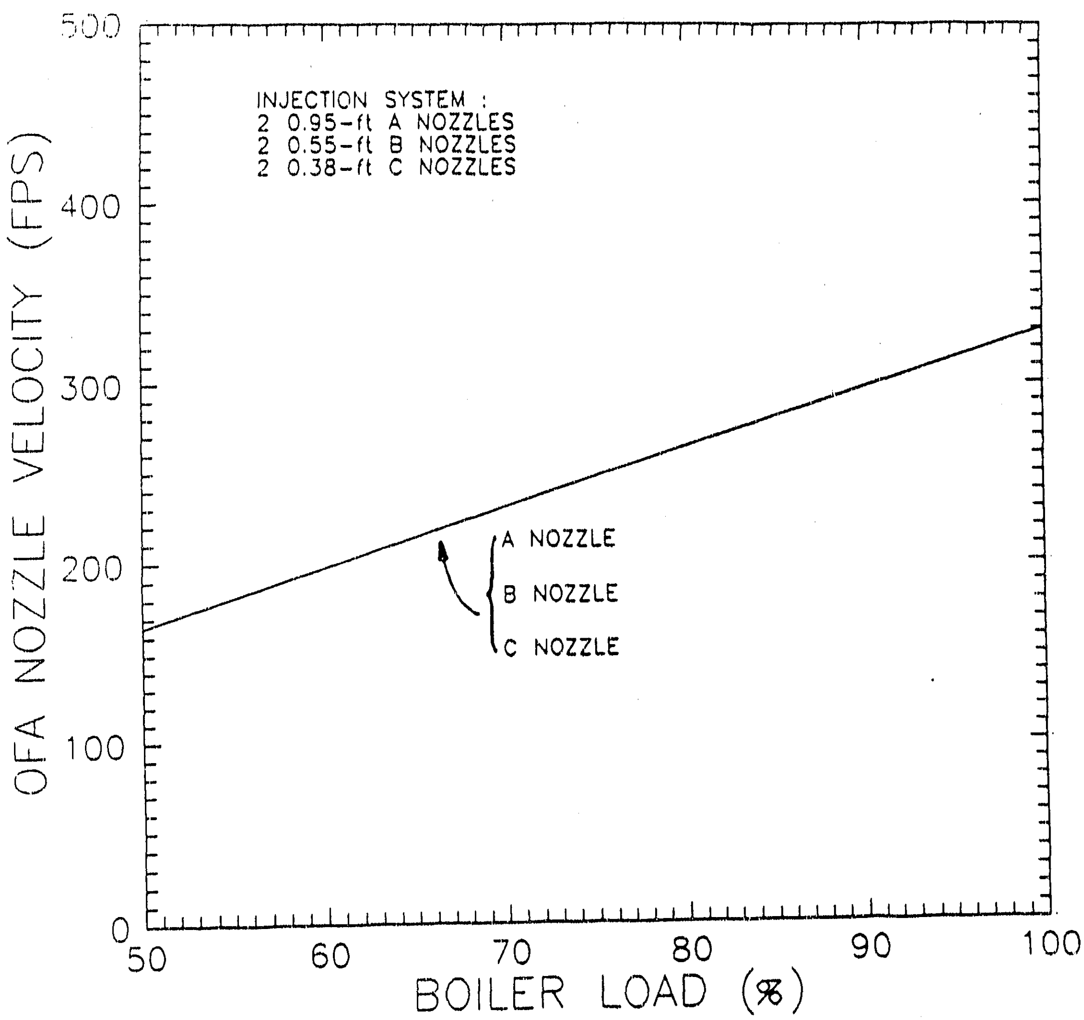


Figure 4.2-13

Variation of overfire air port velocity with boiler load.

have cooled to about 2250°F-- the ideal injection temperature. This location in the Lakeside boiler was identified using furnace temperature measurements made in the field in conjunction with various thermal performance computer model results. Sorbent injection system variables investigated during the isothermal modeling work included the number and location of injection nozzles, the nozzle diameter and injection velocity, and the amount of sorbent transport air to be used.

Sorbent will be injected into the boiler through injectors located on the front and side walls, as indicated in Figures 4.2-9 and 4.2-14. Approximately 5 percent of the total combustion air will enter the furnace as sorbent transport air. Injection velocity will vary as indicated in Figure 4.2-15.

4.2.2.5 ESP Enhancement Studies

Results of the SoRI Study - Hennepin Unit #1. The results of the SoRI computer simulation of the Hennepin Unit 1 ESP under conditions of GR-SI, indicate that there are two potentially viable options for restoring baseline performance. Namely,

- SO_3 conditioning
- humidification of the gas stream

Both of these options have been evaluated with and without an assumed plate area extension, and under different assumptions for electrical conditions.

The study is less favorable for SO_3 conditioning, implying that an additional collecting field might be required to maintain compliance. It is also suggested that SO_3 concentrations of up to 125 ppm might be required to achieve the desired conditioning effect. This conclusion is supported to some extent by recent data obtained by Ontario Hydro. On a 235 MW boiler, SO_3 conditioning was found to be less effective with $Ca(OH)_2$ injection than with $CaCO_3$ injection. For the precipitator with an SCA of 242, 70 ppm of SO_3 was necessary to maintain opacity at 24 percent (compared to a baseline level of

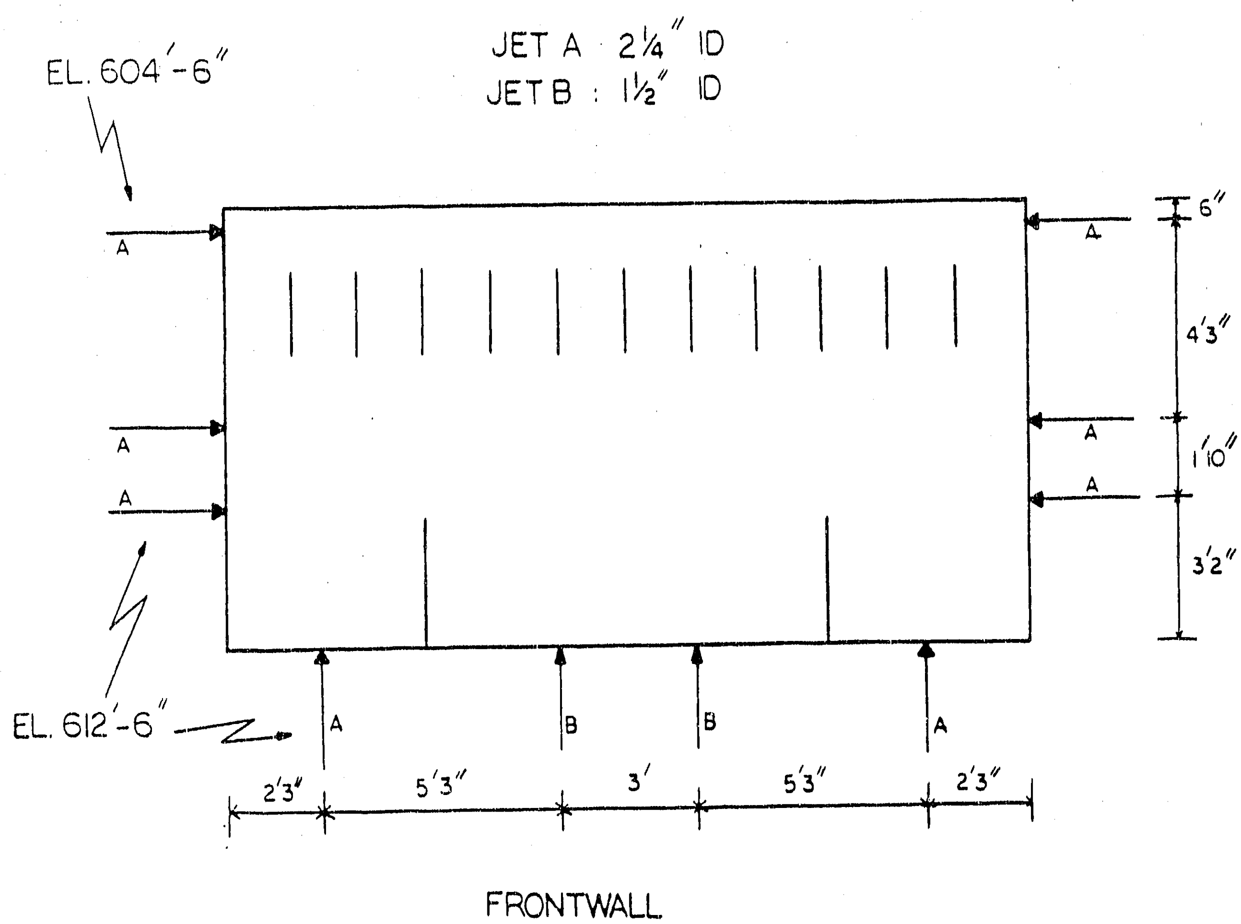


Figure 4.2-14

Plan view of the sorbent injection system.

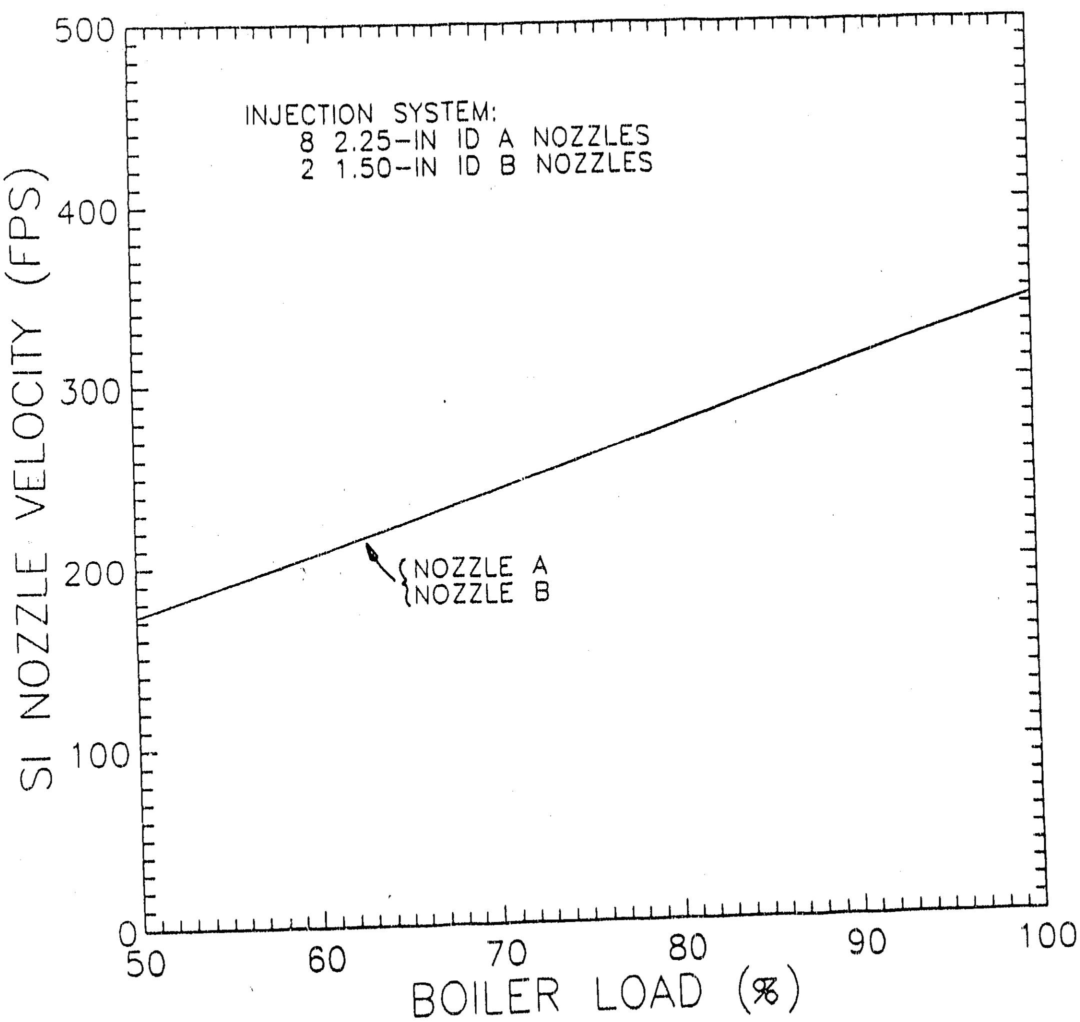


Figure 4.2-15

Variation of sorbent injection velocity with boiler load.

14 percent). The tests were only short term, however, and there appeared to be a decrease in first field power with time.

For flue gas humidification the model projection indicates operation with a reasonable safety margin without the addition of a fifth field. However, it is assumed that humidification to within 70°F of the adiabatic saturation temperature is required to achieve the desired conditioning effect. At the present time, there is little full-scale experience to support this assumption. Recent results from EER's humidification tests at Richmond Power & Light indicate that opacity can be restored by humidification down to a temperature of approximately 280°F (from 325°F), with an SCA of only 198. Observations indicate that the use of humidification eliminated sparking and allowed operation at higher current densities and higher secondary voltages. For all but the inlet field it was possible to approximately double the effective corona power (compared to normal operation) without sparking or back corona.

The SoRI calculations include two assumptions:

- Air heater leakage is minimized. This is important since the calculations indicate that leakage at the current level is equivalent to the loss of one field. To a first approximation performance curves can be extrapolated back to a lower SCA to assess performance at current levels. This suggests that compliance could still be achieved with humidification but not with SO_3 conditioning. Serious consideration should be given to minimizing the air heater leakage. (Since the cost is small compared to a fifth field).

- Calculations are based on sorbent addition at the rate of Ca/S=3. This is an extreme case which will only be encountered occasionally and during shakedown testing. Current predictions indicate that SO_2 removal goals can be met with Ca/S=1.5 or lower. This would reduce the ESP inlet loading from 18.3 lb/10^6 Btu to 12.6 lb/10^6 Btu (compared to 6.87 lb/10^6 Btu baseline), with a corresponding reduction in emissions (see Figure 4.2-16).

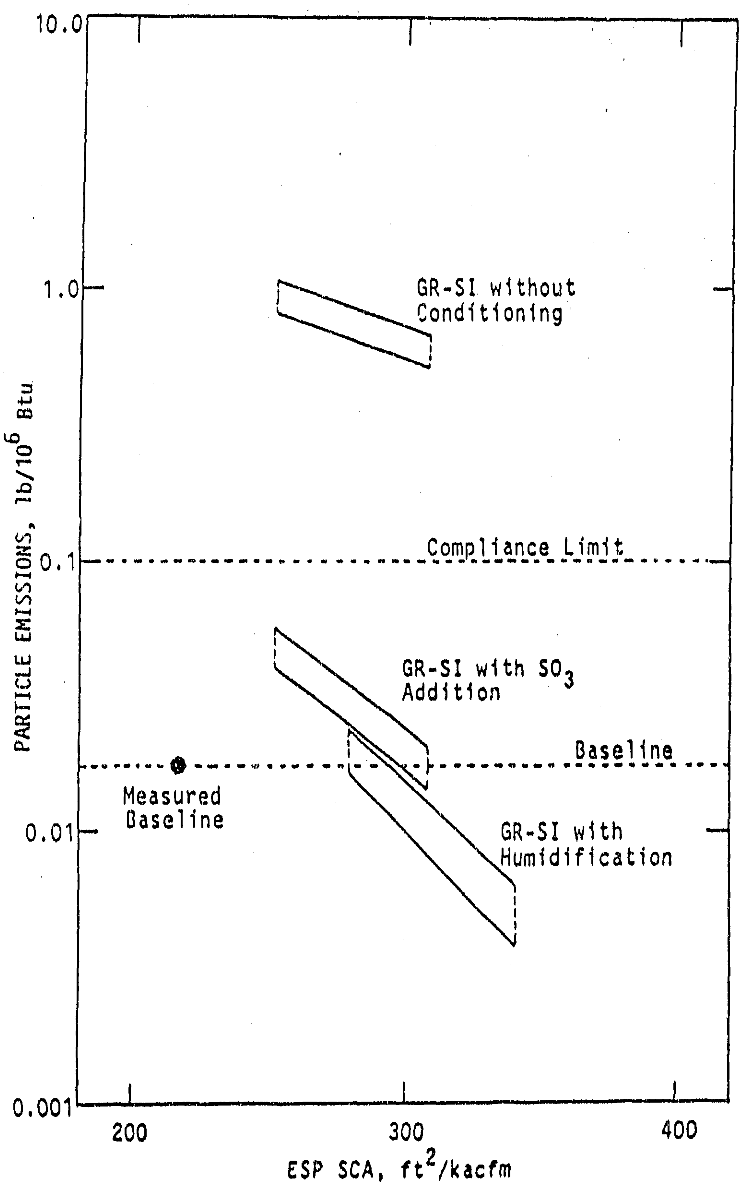


Figure 4.2-16. Predicted Particle Emissions
(SoRI curves modified to reflect expected GR-SI conditions)

EER's recommended approach to ESP enhancement at Hennepin was therefore based on humidification. IP has recently concurred with EER's recommendation. Design recommendations are:

- Humidification system should be designed to achieve a 70°F approach to saturation temperature. However, it should be possible to control the system at lower humidification levels since it is anticipated that this will be adequate in practice.

- Approach duct work should be modified to accommodate the humidification water spray. The design should allow for adequate residence time in a straight duct section to maximize evaporation, and should be located such that the potential for liquid droplet carryover into the ESP is minimized.

- Air heater repairs should be made to minimize the amount of air in-leakage and thus maximize the available SCA of the unit.

Humidification System Design Considerations. Key considerations in the design of a humidification system relate primarily to achieving evaporation of the humidification water spray in a manner that does not compromise operation of the unit. Considerations include:

- Identifying or creating a sufficient section of straight flue gas duct work where residence time is sufficient to allow a high degree of evaporation.

- Identifying duct configurations and nozzle placement which will minimize the impaction of liquid water droplets on duct walls or at bends, and which minimize the potential for water carryover into the ESP itself.

- Identifying operating regimes where the mixing of flue gases with a non-humidified stream will not compromise stack integrity due to dew-point considerations.

Preliminary design considerations have focused on full load (71 MW) operation since this represents a worst case situation. Consideration has also been given to a case where air heater leakage remains approximately at the current level (20 percent) and to a case where the leakage has been reduced (5 percent). Figure 4.2-17 shows the humidification water spray requirements as a function of the approach to adiabatic saturation temperature. For a 70°F approach (approximately 195°F final duct temperature), 67 gpm and 57 gpm of water are required for assumed 20 percent and 5 percent air heater leakage, respectively. At 160°F approach (approximately 280°F duct temperature) the water flow requirement reduces to approximately 23 gpm. This represents the range over which it is anticipated that the humidification system will be required to operate in the Hennepin duct during full load operation.

Calculations for the time required to achieve evaporation of the injected water spray are presented in Figure 4.2-18. The calculation is based upon measured droplet size distributions for a down-fired atomizer with capacity appropriate to this application. Air heater leakage has no impact on evaporation time, but high leakage will significantly impact the time available in a given duct section. At a 70°F approach to saturation approximately 2.5 seconds is required to achieve essentially complete evaporation, while 90 percent evaporation is reached in approximately 0.5 seconds. These figures set some preliminary requirements for necessary total residence time to the ESP, and time available in straight duct sections.

Considering the existing flue gas duct arrangement between the air heater outlet and the ESP inlet, Figure 4.2-19 indicates sections of straight duct work in which the humidification system could be installed. Of these, Section 2 appears to be most appropriate. The residence time in this section (assuming 328°F and 5 percent air heater leakage) is approximately 0.4 sec, with approximately 1.2 sec to the ESP inlet (Sections 2, 3, and 4). However, in 0.4 sec and with a 70°F approach, only 87 percent of the humidification water would be evaporated by the time the gases turned the bend into Section 3. Consequently, some water droplet impaction and ash deposition might be expected at the outside wall of the bend. At the ESP inlet approximately 2

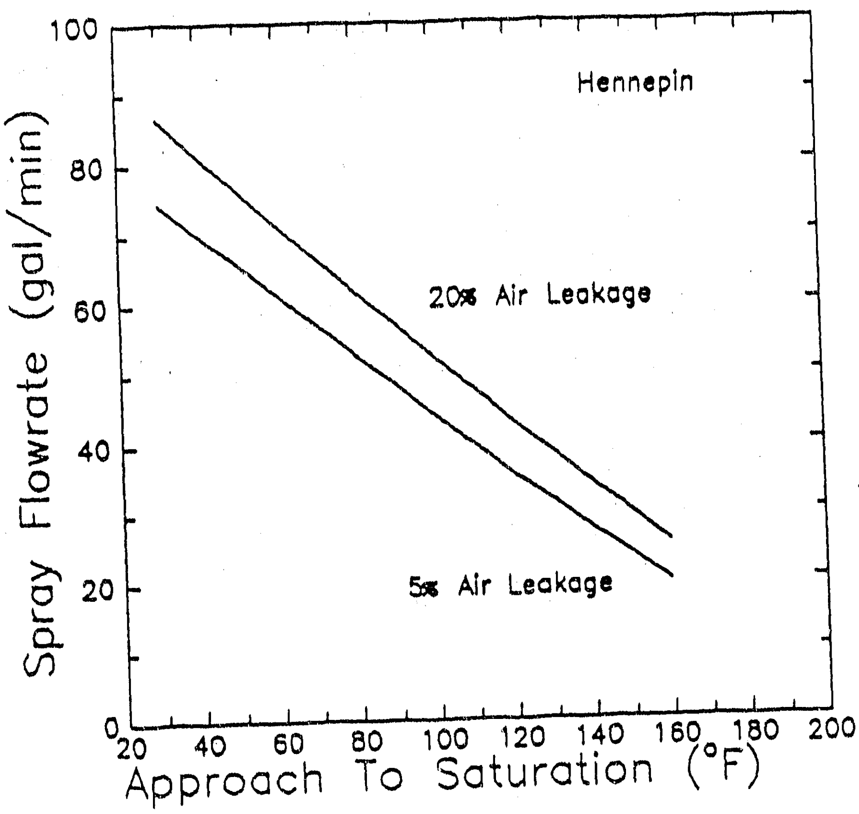


Figure 4.2-17

HUMIDIFICATION WATER REQUIREMENTS
HENNEPIN DUCT -- 71 MW

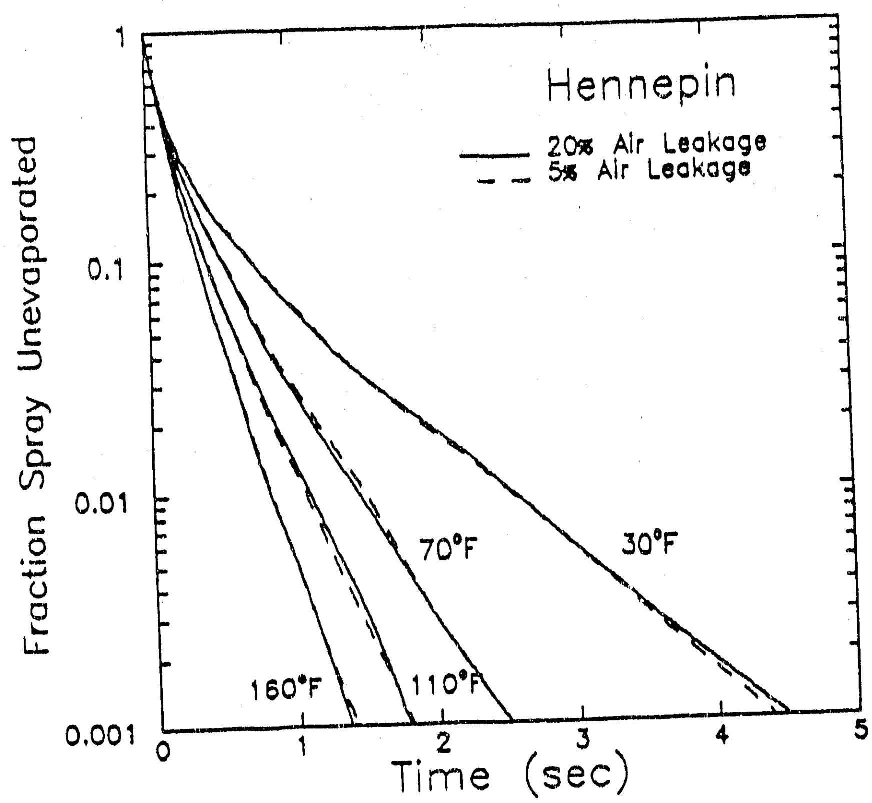
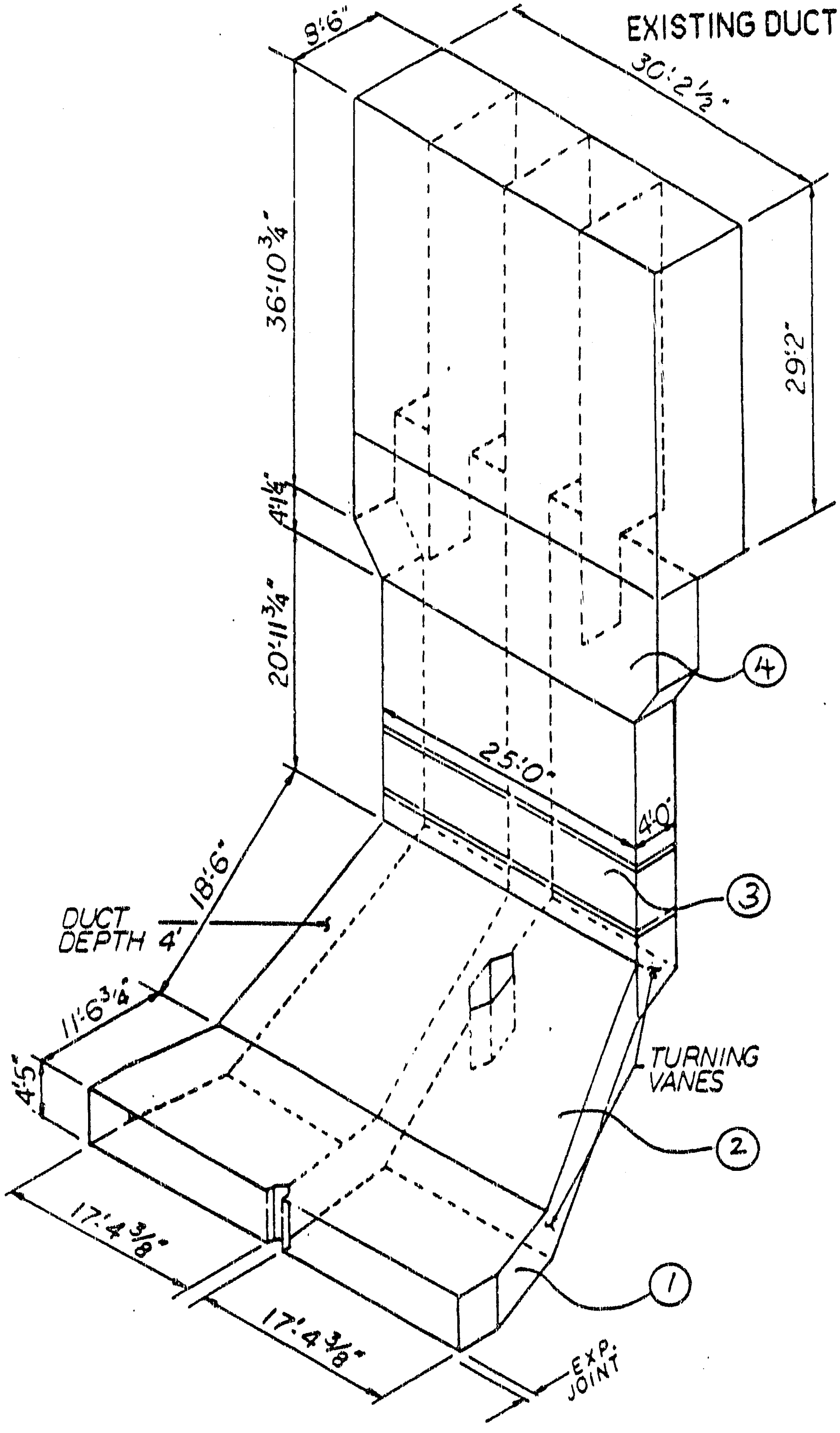


Figure 4.2-18

EVAPORATION CHARACTERISTICS
HENNEPIN DUCT -- 71 MW

Figure 4.2-19

EXISTING DUCT -- HENNEPIN



percent of the water could potentially remain unevaporated. Under more moderate conditions of a 160°F approach to saturation, only 6 percent of the water would remain at the bend and 0.25 percent at the ESP.

From this it can be concluded that the existing duct work at Hennepin would be satisfactory only for moderate levels of humidification (160°F approach or greater), and even then only under constant supervision. A more conservative design, allowing a closer approach to saturation (70°F as a target) will require duct modifications to increase the residence time both in the humidification zone and prior to the ESP.

EER's proposed duct modification is shown in Figure 4.2-20, and involves the incorporation of a new duct section approximately 12 ft high x 26 ft long between the air heater exit and the vertical duct section. Accommodation of such a duct section will require relocation of the ID fans. This duct provides approximately 2.0 sec of residence time in the humidification zone, plus approximately 1 sec to the ESP. For this inlet arrangement evaporation is essentially complete at the end of the horizontal section at humidification levels down to a 70°F approach. Such a duct configuration is considered suitable and sufficiently conservative for the intended application.

Consideration has also been given to the placement of humidification water atomizers in the duct. This is based on atomizers of a nominal 1.7 gpm capacity of the type used in the Richmond system. Thirty-four such atomizers will be required to achieve a 70°F approach to saturation in the Hennepin duct at full load. Figure 4.2-21 shows an example calculated distribution of water mass flux at a plane approximately 2 feet downstream of the atomizer location. This is approximately in the zone where ballistic impaction of water droplets on duct walls is expected to be highest. For this particular atomizer design it is recommended that individual nozzles be placed no closer than 1.5-2 feet from the duct walls to minimize deposition. In the proposed duct section, where nozzle-wall, and nozzle-nozzle spacings are comparatively large, humidification conditions are quite uniform.

Figure 4.2-20 Preliminary Layout for Hennepin Unit 1 Humidification Duct

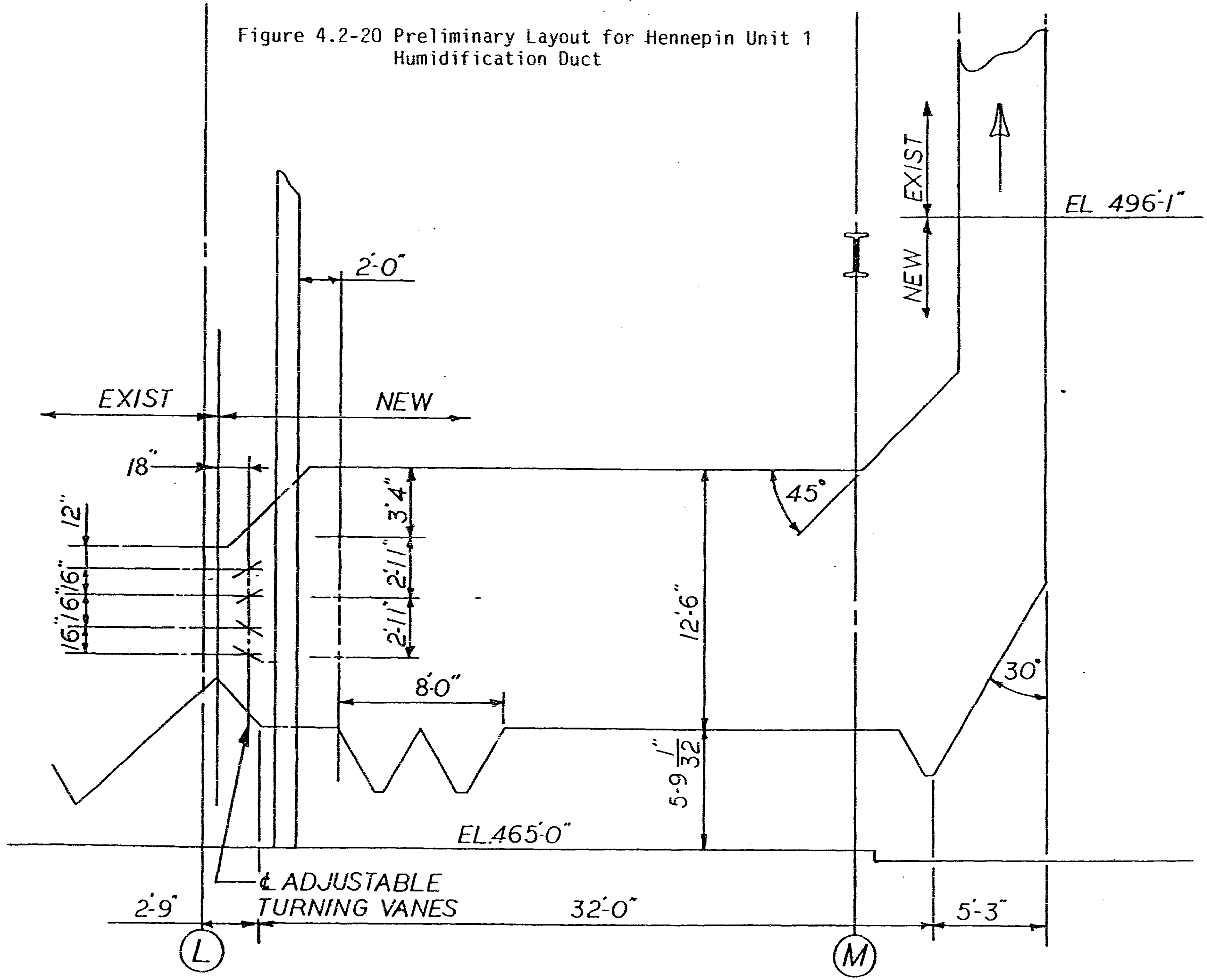
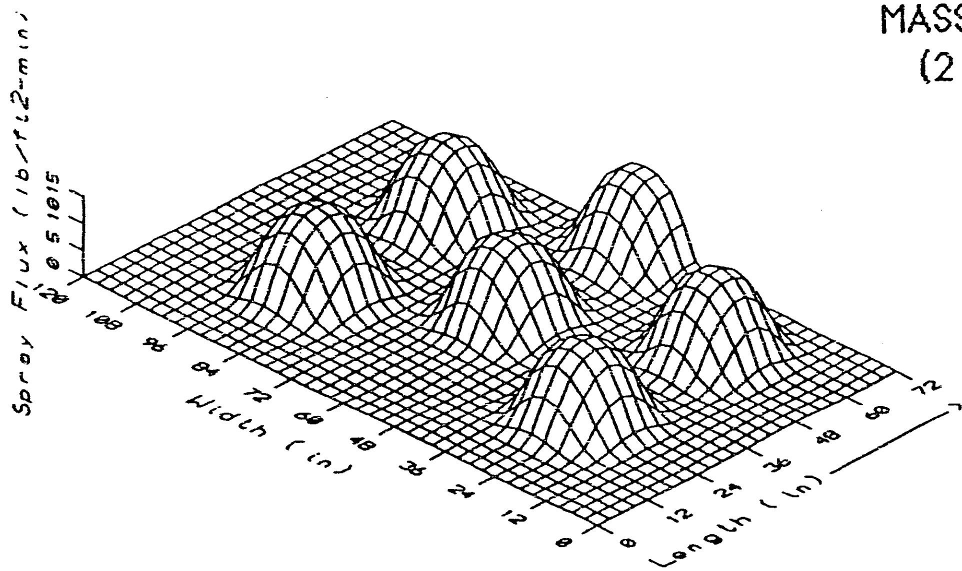


Figure 4.2-21

SPRAY WATER
MASS FLUX DISTRIBUTION
(2 FT FROM NOZZLES)



10-foot duct
staggered nozzles

A final consideration relates to the mixing of the humidified flue gas steam from Unit 1 with the untreated flue gases from Unit 2 which still contain SO_3. The concern here is that the temperature of the mixed steam will be below the acid dew point, raising the possibility for acid condensation and attack of the stack lining. A preliminary analysis of the situation at Hennepin indicates that the flue gas mixture will be well above the acid dew point for virtually all of the expected operating conditions. Operating instructions will be developed--supplemented by stack temperature monitors--to prevent operation outside the safe "window."

4.3 Task 3 - Project Engineering

A significant amount of engineering activity occurred this quarter for each of the three sites. This quarter saw the completion of engineering for Edwards Station and the finalization of the General Construction Specification, Contract Documents and drawings. The specifications, documents, and drawings will be assembled into a bid package covering the mechanical and electrical construction for the GR-SI system installation. The bid package will be released in early December. Also for Edwards Station, the ESP field addition specification was completed and bids solicited. United Conveyor provided EER with a firm cost for refurbishing the existing dry ash handling and storage system.

The Hennepin Station engineering was nearly completed for the natural gas, FGR and sorbent systems while a decision regarding ESP enhancement was not reached until the end of this reporting period. Humidification will be used at Hennepin but requires a major duct modification to provide adequate residence time.

Engineering was started this reporting period for Lakeside Station and has progressed well. Detailed arrangements have been completed and no technical issues have arisen to delay engineering progress.

4.3.1 CILCO Edwards Station

During this reporting period EER and B&V completed engineering for the Edwards unit. Equipment specifications were prepared and suppliers for 90 percent of the equipment selected. To expedite Phase 2 construction, EER, rather than subcontractors, will purchase all major equipment. The general construction specification, prepared by B&V, includes the installation and wiring of all equipment. This specification, together with other EER specifications, 104 drawings, and contract documents, comprise the general mechanical and electrical installation bid package. A bidder's list was generated based on EER, B&V, CILCO, IP, and CWLP experience with construction contractors on previous projects. Forty-seven contractors were invited to receive bid documents.

An Edwards Station auxiliary power supply study was performed by CILCO which determined the existing 4160V system to be overloaded. The GR-SI system will have to receive its power from the 16.8V generating buss. Detailed design of a 16.8KV to 4160V transformer will not be completed until Phase 2. EER will purchase the transformer and has included the installation in the general mechanical and electrical contract work. The transformer will be a long lead item (approximately six months delivery) in Phase 2. For this reason, B&V will prepare a specification for the transformer to enable EER to place an order immediately following authorization to proceed to Phase 2.

EER reached agreement with Riley Stoker to perform six tasks. The tasks included: 1) physical assessment, 2) existing operational assessment, 3) process design review and GR-SI thermal performance assessment, 4) EER engineering review, 5) windbox partition design, and 6) Phase 3 test plan review. During this reporting period, tasks 1 and 2 were completed. Task 5 was deleted as EER has opted to design a burner air register shut-off device to avoid partitioning the windbox.

EER has contacted Leeds and Northrup (L&N) in order to identify the interfacing requirements between EER control scheme and the existing L&N control system. L&N has provided EER with a budget price to supply a new CRT console and programming software modifications needed to meet the new GR-SI control requirements.

United Conveyor, as the original equipment supplier, was contacted concerning refurbishing of the existing dry ash handling system. EER completed a review of various ash disposal options for both wet and dry disposal and concluded that dry ash handling and storage with off-site disposal was the most economical method. CILCO concurred with EER's recommendation. United Conveyor was requested to submit a firm proposal for refurbishing the system. EER received their proposal this period.

EER, working with ESP Consultant Clifford Beck, prepared a specification for the addition of one or two fields to the existing Unit 1. EER and its subcontractor Southern Research evaluated the performance of the existing ESP and concluded no method of ESP enhancement would be successful without increased collection plate area. EER has solicited bids from five large ESP manufacturers for the addition of one field with a additional price for a second field. The bids will be received by January 9, 1989.

With additional plate area added, EER and Southern Research have predicted that increased SO_3 injection will reduce particulate emissions to permitted levels. To this end, EER has been working with Wahlco, the original supplier of Edwards' SO_3 injection equipment, to determine the most cost-effective method of increasing the capacity of the equipment from 40 ppm to 100 ppm. After reviewing and rejecting six scenarios offered by Wahlco due primarily to excessive costs, a method has been suggested to increase the output of the existing burner skid by increasing the operating temperature of the system and adding additional pump capacity. Wahlco is currently preparing a firm cost proposal for this option.

4.3.2 IP Hennepin Station

Black & Veatch has been awaiting decisions on ESP enhancement and ash disposal options. After holding several meetings and arranging for plant visits for IP personnel to witness humidification at Richmond Power & Light and Ohio Edison power plants, and an SO_3 injection system at a Dayton Power & Light plant, IP has concurred with EER's recommendation to use humidification for ESP enhancement at the Hennepin Station. The final arrangement selected by EER requires a major flue duct modification and the relocation of the induced draft fans. This arrangement precludes using the space under the existing duct for locating other equipment as originally planned. A new location will be selected during the next engineering review meeting with Illinois Power.

Once EER and IP identify a new equipment location, B&V can proceed with the electrical power design. EER will provide B&V with a duct layout for B&V to detail. Also, EER will have B&V prepare specifications for relocating the I.D. fans.

EER has nearly completed engineering of the natural gas, FGR, and sorbent systems. Arrangement drawings have been completed and detailed drawings are being prepared. The controls and instrumentation engineering is 50 percent complete with the bulk of the work remaining dealing with humidification and preparing instrument location drawings. Westinghouse has been contacted and a quotation received for a microprocessor system which IP is interested in using for several control functions. Leeds & Northrup has also been contacted to quote a lower capacity microprocessor which would meet the project needs only.

EER completed its ash disposal analysis in which various options for wet and dry disposal were evaluated. The analysis revealed that on-site wet disposal is the most cost effective approach. IP responded with several concerns to which EER has just recently responded. If on-site wet disposal is selected, EER will prepare a preliminary design and cost estimate for a disposal pond. A detailed specification for the ash pond will not be prepared until after Phase 2 approval. United Conveyor will be requested to provide a firm price for the ash sluice piping to the new pond.

EER will retain RAMCO as the subcontractor to perform the same basic scope of work for Hennepin that Riley is performing for Edwards (except for windbox modification). Initiation of RAMCO's work is awaiting resolution of insurance issues.

4.3.3 CWLP Lakeside Station

During this reporting period, a final design for injector locations was completed. From this, general arrangement drawings were completed for the natural gas and FGR systems. Physical interferences were encountered with the sorbent injection layout which prompted the process design task to reevaluate the injection arrangement.

Originally, EER had planned on modifying the Lakeside Unit 6 existing coal bunkers for sorbent storage. However, after obtaining budgetary cost information and reviewing future CWLP plans for Unit 6, it was decided to erect a new sorbent silo outside the building.

EER completed an ash disposal study for Lakeside Station and recommended dry off-site disposal due to the inability to economically treat the sluice water for dissolved sulfates. CWLP agreed with EER's recommendation. A specification will be prepared to solicit bids from United Conveyor and Allan Sherman Hoff for the ash handling equipment.

Engineering for the Lakeside controls and instrumentation modifications is approximately 25 percent complete with process and instrumentation diagrams finalized and a preliminary instrument list prepared. Discussions with Westinghouse Controls were initiated to determine the most cost-effective approach for interfacing the required GR-SI controls with the Westinghouse combustion control system which was recently installed at Lakeside.

The power supply point for the GR-SI equipment was selected during this period. A 12.8 KV line near the proposed location for the new ash and sorbent silos will be used.

4.4 Task 4 Environmental Reports, Permitting Plans and Design

4.4.1 Environmental Information Volumes

The Edwards Station final Environmental Information Volume (EIV) was submitted to DOE on September 7. DOE's environmental support contractor, Science Applications International Corporation (SAIC), is currently compiling an environmental assessment (EA) based on the EIV. The EA is complete except for information regarding an Archaeological, Cultural, and Historical (ACH) survey of the proposed natural gas pipeline route to Edwards Station. The ACH field survey required by the Illinois Historic Preservation Agency (IHPA) pursuant to Section 106 of the National Historic Preservation Act of 1966 was conducted on November 9 and 10. The archaeologist who conducted the survey has completed his Statement of Findings, and CILCO personnel expect to receive a copy of the report early in December. CILCO will discuss the ACH results with IHPA and procure official approval for the proposed pipeline route. The ACH results are the final items requiring incorporation into the EA.

The Lakeside Station final EIV was submitted on October 5. SAIC has completed an EA based on the EIV, which they will submit for DOE review at the beginning of December. Approximately two months will be required for review by DOE's Office of Fossil Energy and Assistant Secretary for Environment, Safety, and Health.

As discussed in the last quarterly report, NEPA approval for the GR-SI project at Hennepin Station has already been obtained.

4.4.2 Environmental Monitoring Plan

The Edwards Station Environmental Monitoring Plan (EMP) was forwarded to CILCO during November. The Hennepin and Lakeside EMPs will be submitted for host utility review early in December. All host comments will be incorporated into final draft EMPs to be submitted to DOE in January.

4.4.3 Permitting Plans and Design

Evaluation of the engineering and economic feasibility of various by-product management options were conducted for all three sites.

Three waste management options were considered for Edwards Station:

- wet disposal to a new ash pond
- dry disposal to a new, on-site landfill
- dry disposal to an existing, off-site, permitted landfill

Evaluations of these disposal alternatives established that the most economically attractive option is to handle the GR-SI waste dry (Table 4.4-1). The cost estimates are valid within a margin of $\pm$30 percent; the estimates for both dry disposal options fell within this range and cannot be significantly distinguished economically without more detailed analysis. Environmentally, the lowest risk and least complicated solution is to have the waste disposed of in an off-site landfill. The environmental regulations for this alternative require dust suppression during truck loading and manifesting (if GR-SI ash is classified as a special waste, which was assumed for this worst-case analysis). On the other hand, the environmental requirements for the construction of a new on-site landfill are significant, including a five-foot clay liner and a groundwater monitoring program. The time required to obtain the appropriate permits and to design and construct the facility could impact the project schedule. Equipment modifications for material handling will be required regardless of the option selected. The wet system would require modifications to the hydroveyor to account for GR-SI material properties, and new sluice lines to transport the ash to the new disposal location. A dry handling system is currently in place, but not operational; replacement of some components will be required. In general, the amount of effort required to replace or add equipment is similar for all three options. Based on all of these considerations, EER recommended to CILCO that the GR-SI fly ash produced in Edwards Unit 1 be transported dry to an off-site, permitted landfill. CILCO has informally agreed that engineering design

Table 4.4-1. Comparative Costs for Three GR-SI Ash Management Alternatives at Edwards Station

OPTION	CAPITAL COST	FIRST YEAR OPERATING COST	TOTAL COST
OPTION 1 - Wet handling and disposal into new pond.	$686,700	$173,900	$860,600
OPTION 2 - Dry handling, on-site disposal in new landfill.	$459,600	$ 45,100	$504,700
OPTION 3 - Dry handling, off-site disposal to a permitted facility.	$270,700	$345,900	$616,600

should proceed based on dry, off-site disposal and will provide formal approval in December.

Five waste management options were considered for Hennepin Station:

1-2. Wet disposal to a new on-site ash pond (two sites)
3-4. Dry disposal to a new, on-site landfill (two sites)
5. Dry disposal to an existing, off-site, permitted landfill

Evaluation of these alternatives established that the most economically attractive option is to manage the waste by wet disposal to a new pond. The major disadvantage associated with dry disposal is the high capital cost of installing new dry ash handling equipment. Environmentally, on-site disposal must consider the characteristics of the material being disposed as well as the characteristics and capabilities of the landfill or pond designed to hold the material. Environmental regulations for off-site disposal focus on material characteristics, since the off-site option involves disposal at a landfill which already has been permitted. Based on all these considerations, EER recommended to IP that the GR-SI fly ash produced in Hennepin Unit 1 be sluiced to a new on-site pond, to be constructed solely for the purpose of handling the GR-SI ash. Review comments regarding the disposal alternatives for Hennepin Station were received from IP in the middle of November. The review comments indicated that clay was not available near Hennepin, and that costs for options using clay should include a transportation cost. Information was also provided clarifying the permitting process and suggesting wording changes. The report was modified accordingly and resubmitted to Illinois Power at the end of the month. The costs presented in the revised report are summarized in Table 4.4-2. The most economically attractive option remains wet disposal into a new pond. The costs for on-site dry disposal are no longer lower than off-site dry disposal, however, due to the increased cost of clay. After IP personnel have reviewed the final document, EER and IP will select the waste management method for Hennepin Station.

The waste management options considered for CWLP's Lakeside Station included only dry disposal. Wet disposal of GR-SI ash is not possible at

Table 4.4-2. Summary of Disposal Costs at Hennepin Station

	CAPITAL COST	OPERATING COST	TOTAL COST
Option 1 - Wet ash handling, disposal in new pond at site A	$1,049,400	$87,700	$1,137,100
Option 2 - Wet ash handling, disposal in new pond at Site B	908,600	83,500	992,100
Option 3 - Dry ash handling, new handling equipment, dry disposal in new landfill at Site C	1,823,900	115,900	1,939,800
Option 4 - Dry ash handling, new handling equipment, dry disposal in new landfill at Site B	1,803,500	115,300	1,918,800
Option 5 - Dry ash handling, new handling equipment, dry disposal in permitted off-site landfill	1,313,100	449,200	1,762,300

Lakeside Station due to the fact that any pond discharge enters Sugar Creek and constitutes the majority of the flow in the creek. The GR-SI ash and any resulting effluent are expected to have high sulfate concentrations. To avoid exceeding the Illinois General Use Water Quality Standard for sulfate level in Sugar Creek, it was determined that wet disposal was not an option at Lakeside. Environmental, economic, and engineering factors for two dry disposal options were compared: 1) on-site disposal in the landfill cells designed for scrubber sludge from Dallman Station, and 2) off-site disposal in a permitted landfill. Both options require the installation of dry ash handling equipment. On-site disposal requires upgrading of the existing landfill to meet current regulations, which were not in place during original landfill construction. As shown in Table 4.4-3, the costs for these two disposal options are the same, within the range of accuracy associated with the cost evaluation procedure employed ($\pm$30 percent). The time required to obtain the appropriate landfill modification permits and to implement the required modifications is expected to be much longer than the time required to arrange off-site disposal details. Based on these considerations, EER recommended to CWLP that the GR-SI fly ash produced in Lakeside Unit 7 be transported to an off-site permitted landfill. Based on CWLP's review of the Lakeside waste management report, EER's recommendation (off-site dry disposal) was informally accepted. Formal approval is expected in December.

GR-SI ash samples generated in EER's pilot scale Fuels Evaluation Furnace using coals from the three host sites are currently being analyzed to evaluate a full range of environmental and engineering properties. Battelle Pacific Northwest Laboratories (BPNL) is conducting environmental tests on the ash samples under an agreement with EPRI and the Edison Electric Institute's Utility Solid Waste Activities Group (USWAG). EER is characterizing the engineering properties of the ash, both through in-house analyses and through additional analyses being conducted by Commercial Testing and Engineering Company (CT&E). The CT&E and EER tests have been completed. Test results will be submitted to each host in December. The results from these tests will be used to verify the assumptions used in assessing waste management alternatives and to support the preparation of permit applications. The BPNL test

Table 4.4-3. Summary of Costs for Disposal Alternatives at Lakeside Station

	CAPITAL COST	OPERATING COST	TOTAL COST
Option 1 - Dry disposal on-site in existing landfill	$1,268,600	$55,600	$1,324,200
Option 2 - Dry disposal off-site to a permitted facility	1,192,900	105,300	1,298,200

results are expected in late December or early January. These results will be used primarily in the preparation and support of permit applications.

Copies of all IEPA forms for permitting air emission sources were procured and reviewed. EER will meet with representatives from the Environmental Affairs Divisions of CILCO, IP, and CWLP in December to discuss the permitting approach, and assemble information packages describing the GR-SI project and anticipated permit requirements. The information packages will be submitted to Illinois EPA after review.

4.5 Task 5 - Technology Transfer

During this quarter, technical papers on the project were presented at the following meetings:

- Fifth International Pittsburgh Coal Conference
  Pittsburgh, Pennsylvania
  September, 1988

- 1988 AIChE Annual Meeting
  Washington, DC
  November-December, 1988

The date and location of the second Industry Panel meeting has been finalized. It will be held on January 18, 1989 at GRI's offices in Chicago. EER will present the status of the project, reviewing each task, with particular emphasis on process design and project engineering. The focus of the meeting will be the presentation of the Phase 3 test plans, requesting feedback from the Panel membership.

5.0 PLANNED ACTIVITIES

During the next quarter (December, 1988 through February, 1989) the following work is planned:

5.1 Task 1 - Project Management

- Meet with DOE and GRI on December 15 to discuss costs, schedules, cost management options, and transition into Phase 2.
- Manage and coordinate all project tasks.
- Continue established communication patterns with co-funders, host utilities, subcontractors, and consultants.
- Finalize insurance/liability issues; finalize remaining subcontract.
- Organize and hold Participants Committee meeting in Chicago on January 19, 1989, with invitation to Senior Review Committee to attend.
- Prepare deliverables according to reporting requirements, including draft of Project Evaluation Report.
- Negotiate with host utilities their participation in Phase 2.

5.2 Task 2 - Process Design

5.2.1 Task 2.1 - Host Site Characterization

- Complete baseline test report by end of December, 1988.
- Draft Phase 3 test plans for presentation to co-funders, host utilities, and to Industry Panel at meeting on January 18, 1989 in Chicago.

5.2.2 Task 2.2 - Process Specification

- Complete preparation of final Process Design Reports.

5.3 Task 3 - Project Engineering

- Issue bid package for Phase 2 construction work at Edwards in December; compare proposed costs with EER and Black & Veatch estimates when bids are received on January 18.
- Complete Hennepin engineering design, prepare general construction specification and drawings, and issue bid package by end of February.
- Complete Lakeside engineering design and drawings; work with Black & Veatch to prepare a detailed cost estimate for construction based upon EER design and equipment prices. Issue bid package by March 1.
- Prepare final design reports for all three host sites and submit for co-funders and host site review and approval.

5.4 Task 4 - Environmental Reports, Permitting Plans and Design

- Submit Hennepin and Lakeside Station draft EMPs for host utility review.
- Submit Edwards, Hennepin, and Lakeside Station revised draft EMPs for DOE review.
- Submit Archaeological, Cultural, Historical survey report and Illinois Historic Preservation Agency pipeline authorization letter as Appendix C to Edwards EIV.
- Obtain host utility approval for GR-SI by-product management recommendations at all three sites.

5.5 Task 5 - Technology Transfer

- Present papers on project at 1988 AIChE Annual Meeting in Washington, DC, December 2, 1988 and at 16th Energy Technology Conference in Washington, DC, February 28-March 2, 1989.
- Organize and hold second Industry Panel meeting with a focus on Phase 3 test plans on January 18, 1989 in Chicago.

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