DVORSCAK
MTCI 10050-F
Paralegal
Leda

DOE/PC/90155--T18

DEVELOPMENT AND TESTING OF COMMERCIAL-SCALE, COAL-FIRED COMBUSTION SYSTEMS: PHASE III

FINAL REPORT

We have no objection from a patent standpoint to the publication or dissemination of this material.
Mark Dvorscak 5-14-96
Office of Intellectual Property Counsel
DOE Field Office, Chicago
Date

For:

U.S. Department of Energy
Pittsburgh Energy Technology Center

Under:

DOE Contract No. DE-AC22-90PC90155

By:

MANUFACTURING AND TECHNOLOGY CONVERSION INTERNATIONAL, INC.
P.O. Box 21, Columbia, Maryland 21045-0021

MARCH 1996

"US/DOE Patent Clearance is not required prior to the publication of this document."

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

MASTER

DISCLAIMER

EXECUTIVE SUMMARY

Coal was once the predominant fuel for the industrial, commercial and residential sectors for process and steam generation purposes through the 1940s. In the post-war era, coal was replaced by the cleaner and more convenient energy sources such as oil, natural gas and electricity. This decline in the use of coal in these sectors can be partially attributed to a lack of competition from advanced coal-fired systems that are easy to use, reliable, efficient, economical, and environmentally acceptable. In particular, ease-of-use, reliability, and environmental factors for coal in comparison with natural gas or electricity are detrimental in these sector's acceptance of coal. Market analyses performed for the Department of Energy, however, indicated that a coal-based system that provides competitive levels of capital and O&M cost, performance, ease of operation, and reliability at the 1 to 10 MMBtu/hr firing rate can displace as much as 2.0 quads of gas and oil within the commercial, residential, and light industrial sectors. Based on these and similar studies that indicated a large potential for significantly increased coal-firing in the commercial sector, the U.S. Department of Energy's Pittsburgh Energy Technology Center (PETC) sponsored a multi-phase development effort for advanced coal combustion systems. This Final Report presents the results of the last phase (Phase III) of a project for the development of an advanced coal-fired system for the commercial sector of the economy.

The project performance goals for the system included dual-fuel capability (i.e., coal as primary fuel and natural gas as secondary fuel), combustion efficiency exceeding 99 percent, thermal efficiency greater than 80 percent, turndown of at least 3:1, dust-free and semi-automatic dry ash removal, fully automatic start-up with system purge and ignition verification, emissions

performance exceeding New Source Performance Standards (NSPS) and approaching those produced by oil-fired, commercial-sized units, and reliability, safety, operability, maintainability, and service life comparable to oil-fired units. The program also involved a site demonstration at a large facility owned by Striegel Supply Company, a portion of which was leased to MTCI. The site, mostly warehouse space, was completely unheated and the advanced coal-fired combustion system was designed and sized to heat this space.

Three different coals were used in the project, one low and one high sulfur pulverized Pittsburgh No. 8 coal, and a micronized, low volatile, bituminous coal. The sorbents used were Pfizer dolomitic limestone and an Anville lime.

A series of preliminary, natural gas fired tests were performed to provide an evaluation of performance, to identify the key operating variables and their ranges, and to establish operating conditions for the proof-of-concept system tests. A combustor with a single tailpipe design that incorporated a 90° turn to facilitate vertical flow into the boiler was chosen. This design was chosen based on the preliminary system test results for three different tailpipe configurations because heat losses were reduced and combustion performance improved.

The configuration was later further modified to meet the target NO_x emissions goals. A coal reburn section and a char burnout section were added to reduce NO_x formation. The final arrangement selected appeared to provide the optimal balance of system components, i.e., utilization of the pulse combustor design, minimization of the space requirement, good mixing of coal, steam, and combustion products in the reburn section, and sufficient residence time in the char burnout section.

After modifications were completed, one set of shakedown tests with natural gas was carried out. The firing rate of the combustion system ranged between 1.36 and 5.32 MMBtu/hr. The thermal efficiency of the boiler was between 80 and 82 percent. The emissions performance of this combustor on natural gas was excellent with NO_x and CO below 30 ppm and negligible TUHC. In this modification, 78 percent of the surface area of the combustion chamber was changed from fully water-cooled mode to radiative cooling. The maximum temperature of the combustion chamber surface during the test was 1350°F, within the safe operating limit for the 304 stainless steel chamber.

Another series of tests was initiated. The main fuel used in these tests was low-sulfur Pittsburgh No. 8 coal. The total firing rate ranged from 3 MMBtu/hr to 5.4 MMBtu/hr. The natural gas support did not exceed about 15 percent. The effect of firing rate on temperatures at various locations was negligible. The temperatures in the combustion chamber and at the end of the tailpipe were similar to those with natural gas. The temperature of the radiantly-cooled chamber metal surface reached 1552°F, 200°F greater than during the gas-fired test. This was attributed to the radiant contribution from the burning coal particles. NO_x ranged from 250 to 400 ppm, SO_x ranged from 550 to 670 ppm, CO ranged from 160 to 400 ppm, and the hydrocarbon emissions were below 30 ppm. The frequency remained at 56 Hz and the sound pressure level registered 175-176 dB, an indicator of very stable pulsed coal-combustion.

More than 100 hours of screening tests were performed to characterize the system. The parameters examined included coal firing rate, excess air level, ash recycle rate, coal type, dolomitic limestone feed rate, and steam injection rate.

These tests indicated that some additional modifications for coal burning in the system were required.

The total firing rate ranged between 4.88 and 5.34 MMBtu/hr with variations in excess air levels. The auxiliary fuel (natural gas) support ranged from 5 to 15 percent including the pilot burner (1.5 percent). The parameters varied include primary zone stoichiometry and secondary air injection rate and in turn the excess air level, ash recycle rate, and steam injection into the combustion chamber. The temperature in the combustion chamber ranged from 2045 to 2327°F and that at the tailpipe exit ranged from 1923 to 2273°F. The carbon monoxide emissions ranged between 66 and 130 ppm, and NO_x emissions ranged between 550 and 800 ppm, all corrected to 3 percent O_2. The sound pressure level in the combustion chamber averaged out at about 176 Db and the frequency, 58 Hz. The thermal efficiency was low and ranged between 68 and 75 percent. The unburned carbon loss was significant (13 to 16%) and was much more than anticipated. In order to improve the combustion efficiency of coal, an ash recycle approach was then incorporated.

Several modifications to the system were explored and implemented. The number of blades in the swirler was cut from 12 to 6 to reduce the pressure drop through the swirler. A section of pipe was added at the entrance to the partition disk to trap the unburned coal particles in the end section and increase the residence time for burnout. An insulation layer was added around the radiation shield to reduce the heat loss from the Morrison tube and increase the temperature in the Morrison tube to promote char burnout. The bottom section of the tailpipe was lined with 2.5" thick refractory that replaced the cooling water circuit. The intent was to maintain the temperature of the char particles and eliminate any quenching by the water cooling circuit.

The proof-of-concept (system) tests at steady-state for the next stage of development were intended to determine combustion efficiency, sulfur capture efficiency, gaseous and particulate emissions, thermal efficiency and turndown ratio of the system as a function of several variables. The parameters to be investigated included: pulse combustor firing rate (1.5 to 5 MMBtu/hr), reburn fuel type (natural gas, coal), and reburn fuel firing rate (0.5 to 1 MMBtu/hr), multiple air staging, Ca/S molar ratio (1.5 to 3), fuel type (natural gas, 3 different coals), and sorbent type (lime and dolomite).

Two shakedown tests were performed, one with gas only and another with coal feed into the pulse combustion chamber. The firing rate in the gas test was 4 MMBtu/hr, sound pressure level (SPL) in the combustion chamber was 177 dB, and temperatures in the combustion chamber, first and second cyclones, were 2240°F, 2230°F and 2100°F, respectively. In the test with coal feed, the total firing rate was 5 MMBtu/hr and SPL in the combustion chamber was 176 dB. The temperatures in the above cited locations were 2400°F, 2456°F and 2357°, respectively. During the second test, 10 SCFM of natural gas was injected near the end of the tailpipe to examine NO_x reduction. The NO_x in the flue gas decreased from 567 to 283 ppm with gas injection.

Analysis of the test results indicated incomplete burnout of the reburn char in the secondary cyclone. This was attributed to the relatively high fraction of larger particles (> 74 microns) in the pulverized coal used as reburn fuel and the limited residence time (< 0.5 sec) in the char burnout section. Modifications to increase residence time and retention of reburn char particles in the second cyclone to maximize combustion efficiency were incorporated.

Three separate coal-fired tests were performed at different firing rates (3.63, 4.73 and 5.78 MMBtu/ hr). Ash samples taken from the stack during the tests were analyzed and indicated that the combustion efficiency in the pulse combustor in these tests now exceeded 98.8 percent. Air staging in char burnout section was expected to further improve combustion efficiency. At the highest firing rate of 5.78 MMBtu/hr, reburn coal at an 18.2 percent ratio was fed into the system at a location just beyond the combustor tailpipe. The NO_x emissions in the stack decreased from 513 to 145 ppm. To confirm test repeatability and system performance, another test was run at 4.02 MMBtu/hr total firing rate with a reburning coal ratio of 10.4 percent. A NO_x reduction to 167 ppm was achieved.

Three additional tests were also performed to determine SO_x emissions reduction in the flue gas. Coal reburning was not used during any of these tests. Instead, the reburning coal feeder and injector were used to feed classified Anville lime (Sorbent B) into the tailpipe. For the three different Ca/S molar ratios (7.6, 11.3 and 15.1) tested, sulfur capture efficiencies were 87, 90.7, and 94.4 percent, respectively. Lower Ca/S feed ratios could not be tested due to rotary valve feeder limitation.

The sound pressure level had a tendency to increase slightly with firing rate and ranged from 175 to 177 dB but frequency was stable in the range of 64 - 68 Hz. The efficiency of the boiler increased with firing rate from about 80 percent at low firing rate to 85 percent at 5.8 MMBtu/ hr. Flue gas emissions data were taken during the test with high sulfur coal (3.18%) but without sorbent feed. The oxygen level was sustained at about 2 percent and total hydrocarbons were in the range of 20 to 30 ppm. The NO_x data (< 200 ppm) reflected the effect of reburning coal on NO_x reduction. CO emissions were on the order of 260 ppm for this test. Air staging was considered for implementation as a method for reducing the CO and THC even further.

With the new sorbent feed system and a test that included both reburning coal and sorbent feed, the SO_2 emissions dropped from 1.5 to 1.2 lb/ MMBtu when the Ca/S molar feed ratio increased from 0 to 2.2. The total firing rate of the boiler was about 6 MMBtu/hr with about 14 percent of the total heat generated by reburning coal. NO_x emissions dropped from 0.7 to 0.2 lb/MMBtu with reburning. Beyond a variation in reburning coal ratios of 12 percent, the NO_x emissions were relatively flat at about 0.2 lb/MMBtu. Coal reburning did increase the CO level from 20 to 100 ppm. Sorbent feed and coal reburning did not have any effect on THC emissions which were below the typical 4 ppm value.

In preparations for the 48-hour qualification test, the combustor was partially dismantled and inspected. Some slag was found in the coal reburning section. A review of previous test data showed that the temperature in this section was higher than anticipated. Some refractory was removed from the inlet of the coal-reburning section and a 10-inch diameter and 16-inch long S.S. 310 pipe were installed at the inlet to sustain the same flow pattern. The extension of the tailpipe was radiantly cooled. A short test was performed to check the system after modifications. Test data showed that NO_x emissions in the flue gas were surprisingly lower than before and met the target goal even *without coal reburning*.

The demonstration test of the commercial unit was planned to heat the building and evaluate the heating capability of the unit. Steam from the commercial boiler passed through 5-inch piping to two air rotation units. Each air rotation unit consisted of a steam condenser, two fans and a filter. The baghouse, ID fan, coal bin, coal feeder and stack were located outside the building. A nominal 1,000 hours of demonstration was considered a reasonable goal to qualify the system for commercial application. Such variables as type of coal and steam load were changed during the demonstration test. The results continued to verify the good combustion and emissions performance of the system. The temperature in the combustion chamber was about 2300°F, the same as in the previous tests. In fact, all the data were similar to those reported earlier, indicating good repeatability.

In the period from January to June of 1995, a total of 1,020 hours of demonstration testing was conducted on the system at different conditions in accordance with the approved demonstration test plan. Except for some minor modifications, no changes were made in the system during this period. Main coal and gas were injected into the pulse combustion chamber. Reburning coal, when used was injected after the tailpipe. Secondary air was supplied into the pass between the coal reburn and char burnout sections. Sorbent (Anville lime) was injected at the entrance to the Morrison tube of the boiler. Six series of tests were conducted and the performance is summarized below.

A 48-hour, full load, low-sulfur coal test with no reburning coal was performed on the system on January 11 and 12, 1995. The NO_x level was below 0.3 lb/MMBtu during the test without reburning. The test demonstrated good combustion (higher than 99%) and thermal efficiencies (higher than 82%) of the commercial system. At Ca/S molar ratio of 1.67, SO_x emissions level was below 1.2 lb/MMBtu.

An 84-hour partial (75%) load test was performed on the commercial unit. The low-sulfur Pittsburgh No. 8 coal was injected into the coal reburning section for NO_x reduction at about 16 percent of total firing rate. Anville lime was injected at the inlet to the Morrison tube for SO_x reduction. The test demonstrated good combustion and emission performance of the system. The reburning coal and reduction in air supply into the pulse combustion chamber reduced NO_x emissions to the 0.19 lb/ MMBtu level. The baghouse temperature appeared to be stable indicating that pulsations kept the boiler tubes clean and there was no fouling problem. The test demonstrated good combustion efficiency of the commercial unit: 99.2 percent. Thermal efficiency was higher than 80 percent. At Ca/S molar ratio, SO_x emissions were reduced to about 0.8 lb/MMBtu.

An additional 360 successive hours of testing were performed on the commercial system. The test was configured to simulate operation under normal commercial application and consisted of alternating 12-hour periods of full and partial load subtests. The test demonstrated repeatability of data obtained in previous full and partial load tests performed on the system. No reburning coal was fed during the full load test. In the partial load test, reburning coal was fed into the coal reburning section at about 16 percent of total firing rate. This measure allowed improvement of the emission performance of the system. These tests were conducted with the low-sulfur Pittsburgh #8 coal containing 1.23 percent sulfur. Combustion efficiency in the test was, again, no lower than 99 percent, and thermal efficiency was higher than 82 percent. At the same Ca/S molar ratio of about 1.6, sulfur capture efficiency in the partial load test was higher (about 31%) which was attributed to longer residence times.

The site demonstration test series was completed by an additional 288-hour test. This test was performed with a Pittsburgh #8 coal containing higher sulfur content (3.18%), and the test consisted of alternating 12 hour periods of full and partial load subtests. As in the previous tests, the emissions performance of the system during full load periods was good without reburning coal. However, during the partial load periods, coal (16% of the total firing rate) was fed into the reburning section to reduce NO_x emissions. The high sulfur coal required rather high lime feed rate (Ca/S molar ratio of between 5 and 6) for SO_x reduction to the 1.2 lb/MMBtu level.

The full load firing rate was generally in the 6.0 to 6.3 MMBtu/hr range, while the partial load firing rate typically spanned the 4.5 to 4.7 MMBtu/hr range. The unit was not run at lower loads because NO_x emissions goal of 0.3 lb/MMBtu could not be met at firing rates less than 3 MMBtu/hr. Consequently, turndown was limited to between 2/3 and 3/4 of full load. The combustion efficiency was on the order of 99 percent and meets the project target goal. Sulfur capture efficiency increased with Ca/S molar feed ratio. Calcium utilization was low due to the relatively large particle size (about 67 percent above 150 μm diameter) and short residence time (about 260 ms) in the 1500 to 2000°F temperature window for sulfur capture. Thermal efficiency was in the 80 to 85 percent range and exceeded the project target goal. The CO emissions were for the most part less than 0.1 lb/MMBtu, NO_x emissions were on the order of 0.3 lb/MMBtu, and SO_2 emissions were on the order of 1.2 lb/MMBtu. The NO_x and SO_2 emissions met the project target goals, while the CO emissions were low but did not have a specified target goal.

The results and basic conclusions from the demonstration test period indicated that the system could be started with a single button computer control and brought on-line automatically to full-load. The control system was repeatedly able to automatically purge the boiler, start the pilot, bring the combustion chamber up to its preset temperature on natural gas, feed the coal, modulate the coal feed to maintain steam pressure, and regulate the reburn coal (if necessary) and sorbent feeds to meet emissions goals.

The system required support gas of about 15 percent of its total firing to maintain stable pulse combustion. Environmental performance was on target at full load but required reburn coal injection at part load. Total unburned hydrocarbon emissions were always below 10 ppm @ 3% O_2 and mostly below 4 ppm. The combustor boost pressure was significant but varied with load to 10 inches of water at full load. There was very little fouling of fire tubes as indicated by the stable baghouse inlet temperature during each series of tests.

With the completion of the site demonstration testing, a visual inspection of the commercial unit was performed. The air plenum, coal reburning section, char burnout section, and back door of the boiler were opened and/or disassembled for inspection. No significant change was observed in the inspected areas. Several small cracks in the refractory were found in the coal reburning and char burnout sections. These are considered normal and relatively innocuous. No fouling was found in the boiler tubes except in two tubes at the very bottom of the boiler; a small amount of ash was deposited at the bottom of these tubes restricting about 20 percent of the tube opening. The coal/gas injector was disconnected and removed from the pulse combustion chamber. The injector was substantially in its original condition except for a slight warping of the impactor plate. A thicker plate with gusset reinforcement is stipulated for future applications.

An estimate of the MTCI pulse coal combustion system capital cost turned out to be approximately $128,000 which exceeded the target range of the U.S. commercial boiler market sector but remained below the costs in the European and Far East market sectors. Note that the MTCI system is multi-fuel (gas, coal and oil) capable and is designed to meet stringent emissions standards. The capital cost projections were based on an after-tax payback period of five years which typically could correspond to a pre-tax payback period of three to three and one-half years.

A problem, however, arises in that pulverized coal may not be available in many of the potential market areas overseas. Either the system would then have to include a pulverized or the user would have to pay a premium to obtain pulverized coal. The differential fuel cost for breakeven ranges between $4 and $4.50 and suggests that many countries in Europe and the Far East are possible candidates for this technology. Of course, the system proposed here is a high-end system with top-of-the-line controls and sophisticated feed systems. The capital cost could be significantly reduced by simplifying the instrumentation and controls, substituting a blower for the electric air compressor, and fabricating/acquiring off-the-shelf components overseas. Consequently, the potential exists for marketing this technology abroad if engineering and fabrication are tied to the local demands and market drivers.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF FIGURES
(CONT'D)

LIST OF FIGURES
(CONT'D)

LIST OF FIGURES
(CONT'D)

LIST OF FIGURES
(CONT'D)

LIST OF FIGURES
(CONT'D)

LIST OF TABLES

LIST OF TABLES
(CONT'D)

SECTION 1.0
INTRODUCTION

Coal once was the predominant fuel for the industrial, commercial and residential sectors for process and steam generation purposes through the 1940s. In the post-war era, coal was replaced by the cleaner and more convenient energy sources such as oil, natural gas and electricity.

Coal utilization in the sectors cited above declined from 11 million short tons in 1973 to 9 millon short tons in 1984. The Energy Information Administration (EIA) of the U.S. Department of Energy (DOE)[1] projected a further decline to 7 million short tons by 1995 in spite of the prevailing cost differentials among the different energy sources. For example, in 1974 the price of coal and natural gas were equivalent, with oil costing about four times as much and electricity about nine times as much. In 1984, the price of coal declined somewhat from its 1974 peak but the price per MMBtu of gas was three times as much as coal, that of oil was 4½ times, and that of electricity was 11 times.[2] Projected[3] price differentials in 1995 are comparable to those of 1984. In spite of these large cost differentials between coal and other energy sources, the coal use in the industrial, commercial and residential sectors has decreased and is projected to decrease further.

This decline in the use of coal can be partially attributed to a lack of competition from advanced coal-fired systems that are easy to use, reliable, efficient, economical, and environmentally acceptable. In particular, ease-of-use and reliability factors for coal in comparison with natural gas or electricity are negatively affecting the acceptance of coal. Market analyses performed by Burns and Roe[4] and MTCI, however, indicate that a coal-based system that provides competitive levels of capital and O&M cost, performance, ease of operation, and reliability at the 1 to 10 MMBtu/hr firing rate can displace as much as 2.0 quads of gas and oil within the commercial, residential, and light industrial sectors. A successful coal-fired system will lessen the nation's dependence on foreign oil, open up new markets for the large reserves of domestic coal that are currently being underutilized and help export new coal-based technology which will, in turn, enhance the U.S. coal supplier position in exporting into the world markets.

Based on studies which indicated a large potential for significantly increased coal-firing in the commercial sector, the U.S. Department of Energy's Pittsburgh Energy Technology Center (PETC) sponsored the development of advanced coal combustion systems.[5] Phase III of this program has now been completed and is being presented in this Final Report.

1.1 BACKGROUND

In a prior related program,[6] a tandem slagging pulse coal combustion system was developed and optimized at the laboratory-scale (2 MMBtu/hr) for firing dry coal fuels. The system exhibited 99+ percent combustion efficiency and greater than 90 percent ash rejection efficiency. The combustor did effectively burn both pulverized and micronized coals without support gas. Volumetric heat release rates of up to 3.6 MMBtu/hr/ft^3 were achieved when firing dry coal. When coal-water slurry (CWS) fuels were fired, varying amounts of support gas were required depending on the slurry used. This requirement of support gas was attributed to the combustor and slurry injection system not being optimized with respect to CWS firing. Flue gas carbon monoxide emissions ranged from 15 ppm to 1328 ppm, depending on the test conditions. A strong correlation with oxygen content was observed. These values were considered nonproblematic at the time since complete burnout was expected during the residence times provided in an actual boiler retrofit application. In these tests, nitrogen oxide emissions were between 400 and 600 ppm. These values are in the range of typical staged slagging combustors. Sulfur capture by sorbents such as lime and limestone were also investigated. Due to operation at high temperature for slagging, sulfur capture was not as good as anticipated. However, when the sorbent was injected into a lower temperature zone at about 1600°F, effective sulfur capture was obtained (78%). The data were consistent with the equilibrium relationship between SO_2 and lime. Subsequently, the combustion system was integrated with a boiler and tests were performed with CWS fuels. Subsequent work involved scale-up first to 3.5 - 6 MMBtu/hr firing rate, boiler integration and extensive testing with CWS, followed by pilot-scale (15 MMBtu/hr) coal combustor development.

1.2 PROJECT OBJECTIVES

The overall objective of this program is to successfully demonstrate an efficient, economical, environmentally acceptable, and commercially configured coal-fired pulse combustion system. The program comprises the following six tasks:

Task 1: Design, Fabricate, and Integrate Components

Task 2: Perform Preliminary System Tests

Task 3: Perform Proof-of-Concept System Tests

Task 4: Evaluate Economics/Prepare Commercialization Plan

Task 5: Conduct Site Demonstration

Task 6: Decommission Test Facility

The system performance goals include dual-fuel capability (i.e., coal as primary fuel and natural gas as secondary fuel), combustion efficiency exceeding 99 percent, thermal efficiency greater than 80 percent, turndown of at least 3:1, dust-free and semi-automatic dry ash removal, fully automatic start-up with system purge and ignition verification, emissions performance exceeding New Source Performance Standards (NSPS) and approaching those produced by fuel oil-fired commercial-scale units, and reliability, safety, operability, maintainability, and service life comparable to oil-fired units. The system performance goals stipulated by PETC are summarized in Table 1-1.

TABLE 1-1:

SPACE AND WATER HEATING FOR COMMERCIAL BUILDINGS: SYSTEM PERFORMANCE GOALS

Primary Fuel:(1),(2)	Coal-water fuel or dry powder
Secondary Fuel:	Natural gas or petroleum fuels
Ignition:	Fully automatic start-up with system purge and ignition verification
Turndown Ratio:	3:1
Reliability/Safety:	Comparable to oil-fired commercial boilers
Thermal Efficiency:	> 80%
Combustion Efficiency:	> 99%
Routine Operating/Maintenance Labor:	Less than one dedicated man-hour per day and an additional two man-hours per week
Ash Removal:	Dust-free and automatic or semiautomatic
Scheduled Maintenance:	$\leq$ twice a year
Service Life:	Overall system $\geq$ 20 years
Emissions:(3)	1.2 lb $SO_2/10^6$ Btu 0.3 lb $NO_x/10^6$ Btu 0.03 lb particulates/10^6 Btu

(1)The coal(s) must be economically recoverable and have sufficient reserves to support a coal-water fuel industry that supplies the proposer-defined application(s) and geographic market sector(s).

(2)The 1986 PRDA that initiated Phases I and II characterized the fuel as having a mineral matter content less than 1 lb/10^6 Btu and a sulfur content of 0.5 lb or less/10^6 Btu. These restrictions do not apply here; however, it is emphasized that in order to meet the emissions specifications listed and limit the user's ash-handling requirements, it is assumed that some coal beneficiation will be necessary.

TABLE 1-1:

SPACE AND WATER HEATING FOR COMMERCIAL BUILDINGS: SYSTEM PERFORMANCE GOALS (CONT'D)

(3) There are wide variations in state and local air pollution control regulations for commercial-scale space-heating systems. In addition, these regulations are all subject to change. Therefore, the aforementioned emissions specification chosen as the goal for this RFP are those that are anticipated to be achieved based on the present state of development of coal-cleaning, combustion, and flue gas cleanup technologies. However, for coal-fired systems to become environmentally and hence commercially acceptable, emissions levels will ultimately need to be comparable to those produced by fuel oil-fired commercial-scale units, viz.:

0.4 lb $SO_2/10^6$ Btu
0.2 lb $NO_x/10^6$ Btu
0.02 lb particulates/10^6 Btu

In summary, the system should be designed to enable further emission reductions, e.g., via advanced flue gas treatment, to be readily applied when necessary.

SECTION 2.0

PROJECT DESCRIPTION

2.1 DESIGN, FABRICATE, AND INTEGRATE COMPONENTS

The objective of the project was to design, develop and demonstrate a commercial-scale space-heating system that was capable of meeting the performance goals listed in Table 1-1.

The specific objectives were to:

- Develop a pulse combustor design concept based on MTCI's past experience that is most appropriate for this application.
- Design the pulse combustion system, categorize components, and develop specifications for the combustion and space heating systems.
- Fabricate and/or procure components.
- Perform component integration.

The program involved the site demonstration of the system so that its size was based on site requirements. A large facility owned by Striegel Supply Company, a portion of which was leased to MTCI, was chosen as the host site. The site, mostly warehouse space, was unheated and it was proposed to heat this space with the advanced coal-fired combustion system. The floor plan of this warehouse was approximately 26,500 sq.ft. and the height was approximately 40 ft. Heating load calculations[7] for this structure indicated a design load of about 4.2 MMBtu/hr. Therefore, the combustion system design corresponds to a firing rate of 5 MMBtu/ hr. The major components of this system are:

- Coal Receiving, Storage and Transfer,
- Sorbent Receiving, Storage and Transfer,
- Combustion, Heat Recovery and Emissions Control,
- Solids Collection and Disposal, and
- System Controls.

The fuel and sorbent preparation step is left out due to economic and aesthetic reasons and limited real estate typically available for system installation.

The make-up and anticipated performance of the above-cited components are discussed next starting with fuel selection.

2.1.1 FUEL

Advanced coal-fired combustors generally use coal prepared in one of the following forms:

- Dry Pulverized Coal (DPC),
- Dry Ultrafine Coal (DUC), and
- Coal-Water Mixture (CWM).

Dry, pulverized coal is conventional ground coal that typically has a product fineness of 70 percent through a 200-mesh sieve and less than 3 percent surface moisture. The technology and infrastructure for preparation, handling, transportation and storage of DPC is well-established. Storage requires proper design and care in view of the potential for fire and explosion. This is the most inexpensive of the three forms. Dry, ultrafine coal is a product of an integrated process comprising grinding, drying and beneficiation. It is a fine powder with low ash and sulfur content and is more expensive than DPC. The technology for DUC preparation has been developed but the infrastructure for DUC preparation, handling, transportation and storage is almost non-existent. Coal-water mixture is a mixture of pulverized coal and water with some chemical additives which enhance stability and flow characteristics. It is cheaper and safer to transport and store than DPC and DUC. The technology for CWM preparation has been developed but the infrastructure for CWM preparation, handling, transportation and storage is at its infancy due to soft market conditions for CWM.

The availability of CWM fuel is rather limited and therefore it will not be considered initially for this application. MTCI test results[6,8,9,10] show that pulse combustors can burn both DPC and DUC efficiently (>99% carbon conversion) and without gas support. DPC, however, is more economical to burn and boasts a more mature technology and infrastructure as compared to DUC. The high combustion intensity and the oscillating flow field achieved in pulse combustion permit the use of pulverized rather than ultrafine coal without any performance penalty. Furthermore, the propensity to capture sulfur and particulates at the temperature regime before the combustion products enter the second pass of the boiler encourages the use of the less expensive unbeneficiated coal.

A coal preparation plant consisting of coal unloading, handling and pulverization is relatively expensive to install and operate for small-scale applications (<50 MMBtu/hr). Capital cost will be significant and specialized/experienced personnel will be required for operation and maintenance. Therefore, already prepared dry pulverized coal was used in this application. Pittsburgh No. 8 was the primary design fuel. A total of three different coals were used in this program. Table 2-1 presents analyses of the two types of Pittsburgh No. 8 coal (low sulfur and high sulfur) used. Figure 2-1 shows the size distribution of the low sulfur Pittsburgh No. 8 coal. The third coal tested was a micronized, low volatile, bituminous coal. The micronized coal is similar to a dry ultrafine coal. The analysis of this coal is given in Table 2-2. For the purposes of this report, the three coals will be referred to as coals A, B, and C as identified in Tables 2-1 and 2-2.

2.1.2 SORBENT

Since it was proposed to use unbeneficiated coals, it was necessary to inject sorbent for sulfur capture and meet emissions requirements. The sorbent could be either limestone or dolomite. Again, to minimize capital and operating costs, two pulverized sorbents were procured for the tests. The sorbents selected were Pfizer dolomitic limestone and Anville lime. Tables 2-3 and 2-4 present analyses of the two sorbents. The lime is much coarser than standard grind pulverized stone as the data in Table 2-4 indicates.

TABLE 2-1:

ANALYSIS OF COALS A AND B

	COAL A	COAL B
	LOW SULFUR PITTSBURGH NO. 8	LOW SULFUR PITTSBURGH NO. 8
ULTIMATE		
Moisture, %	1.72	3.40
Carbon, %	80.43	68.90
Hydrogen, %	4.98	4.76
Nitrogen, %	1.36	1.20
Sulfur, %	1.23	3.18
Oxygen, %	4.90	9.66
Ash, %	5.38	8.93
PROXIMATE		
Moisture, %	1.72	3.40
Fixed Carbon, %	56.35	50.30
Volatile, %	36.55	37.30
Ash, %	5.38	8.93
Higher Heating Value, Btu/lb	14073	12470

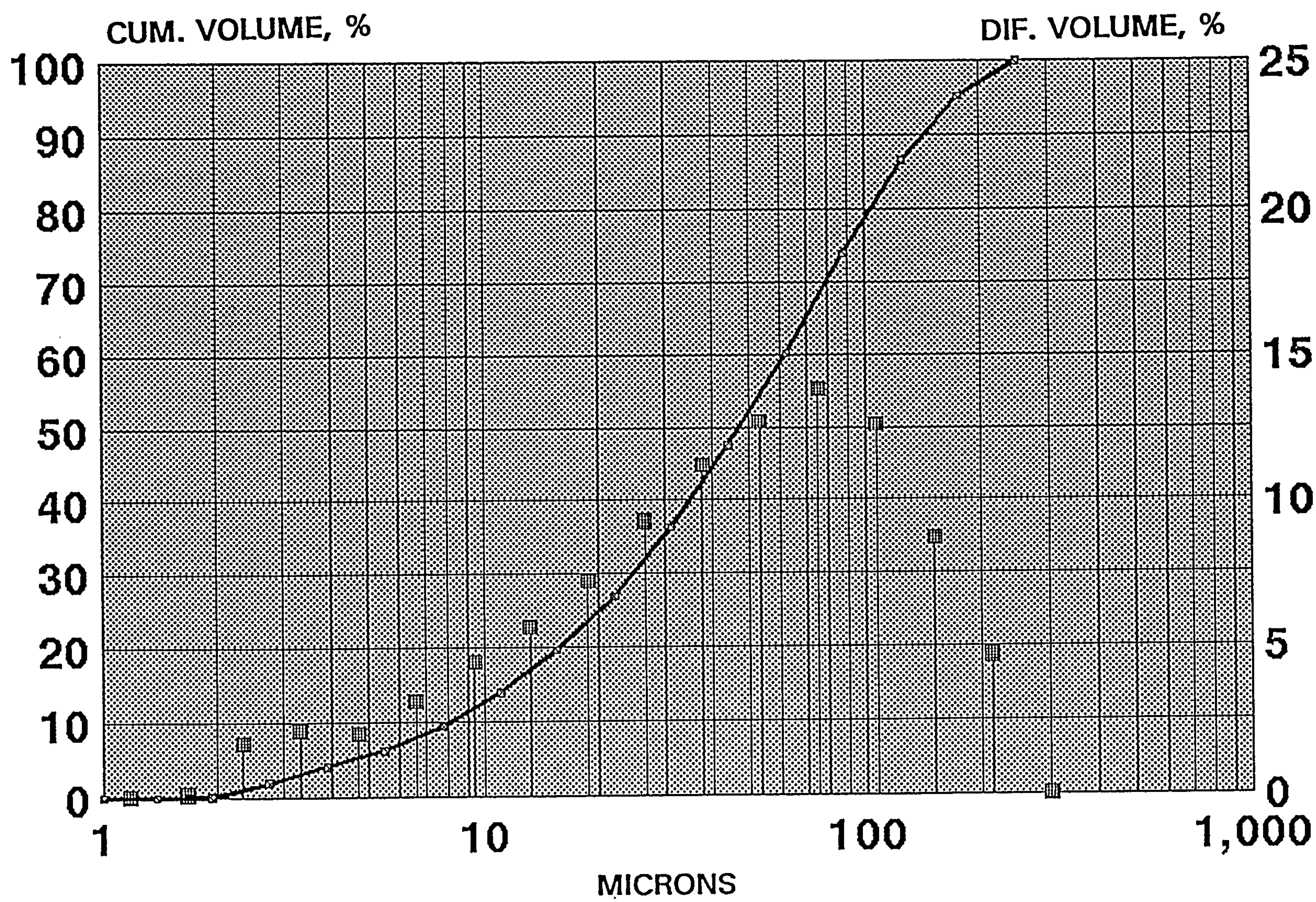


FIGURE 2-1: SIZE DISTRIBUTION OF COAL A

TABLE 2-2:

ANALYSIS OF MICRONIZED COAL

(COAL C)

ULTIMATE ANALYSIS		PROXIMATE ANALYSIS	
MOISTURE	5.00-7.00%	MOISTURE	5.00-7.00%
CARBON	79.00-80.0%	FIXED CARBON	69.90-73.1%
HYDROGEN	4.10-4.30%	VOLATILE	16.50-17.5%
NITROGEN	1.15-1.25%	ASH	5.40-5.95%
SULFUR	0.60-0.70%	Btu/lb	13800-14100
OXYGEN	2.40-2.80%		
ASH	5.40-5.95%		

TABLE 2-3:

ANALYSIS OF PULVERIZED DOLOMITIC LIMESTONE
(SORBENT A)

CHEMICAL COMPOSITION		PHYSICAL PROPERTIES	
	Wt.%	Sieve	Wt.%
$CaCO_3$	55.0	+40	0.8
MgO	43.0	+100	15
SiO_2	0.7	+200	39
Al_2O_3	0.2	+325	63
Fe_2O_3	0.33	thru 325	37
MOISTURE	0.1	Specific gravity	2.88 lb/cu.ft.
		Dry brightness	89
		Bulk density	75-85 lb/cu.ft.

TABLE 2-4:

ANALYSIS OF ANVILLE LIME
(SORBENT B)

CHEMICAL COMPOSITION		SIZE DISTRIBUTION	
	Wt.%	Opening, Microns	Wt.% Below
SiO_2	2.10	45	14.63
Al_2O_3	0.90	75	23.89
Fe_2O_3	0.28	106	29.49
CaO	89.00	150	33.72
MgO	1.25	212	38.24
K_2O	0.16	355	45.77
Moisture	6.31	500	52.80
	100.00	710	60.26
		1180	76.61
		1700	90.17
		2800	100.00

2.1.3 Coal Receiving, Storage, and Transfer

Coal used in the program was acquired pre-packaged in 100-pound sacks, 25 sacks to a pallet and shrink-wrapped. It was stored at MTCI's laboratory storage area on pallets. During the tests, the coal was transported by forklift to the test facility and loaded into the coal bin.

2.1.4 Sorbent Receiving, Storage and Transfer

The pulverized limestone was procured in 55-gallon drums. It was stored in the laboratory storage area, transported to the test facility by forklift, and loaded into the sorbent hopper.

2.1.5 Coal Feed System

The initial coal feed system consisted of a coal bin (80 ft^3 capacity), a rotary valve, and an eductor. The rotary valve gave rise to near square-wave pulse flow of coal and that interfered with the stable operation of the pulse combustor. Then a fluidized bed feed conditioner was installed between the rotary valve and the venturi eductor. While the flow characteristic was satisfactory, moisture accumulation in coal due to weather changes resulted in intermittent plugging of the distributor and affected the reliability of the feed system. Therefore, the fluidized bed feed conditioner was replaced by a screw feeder. The coal feed rate was varied by the speed of the screw (controlled by an adjustable frequency AC drive) and the coal level with the screw feeder box was maintained by a level sensor coupled to the rotary valve motor drive. Figure 2-2 shows a schematic of the coal feed system.

2.1.6 Sorbent Feed System

It was initially attempted to feed the sorbent from a sorbent hopper (20 ft^3 capacity) through a rotary valve to a common eductor for coal and sorbent. A Y-connector was provided to couple the two rotary valves to the common eductor. Two problems were encountered. The rotary valve capacity was found to be much larger than that needed for this unit and the mixture entering the pulse combustor was found to be non-uniform and interfered with the stable operation of the pulse combustor. Also, it was decided to inject sorbent at different

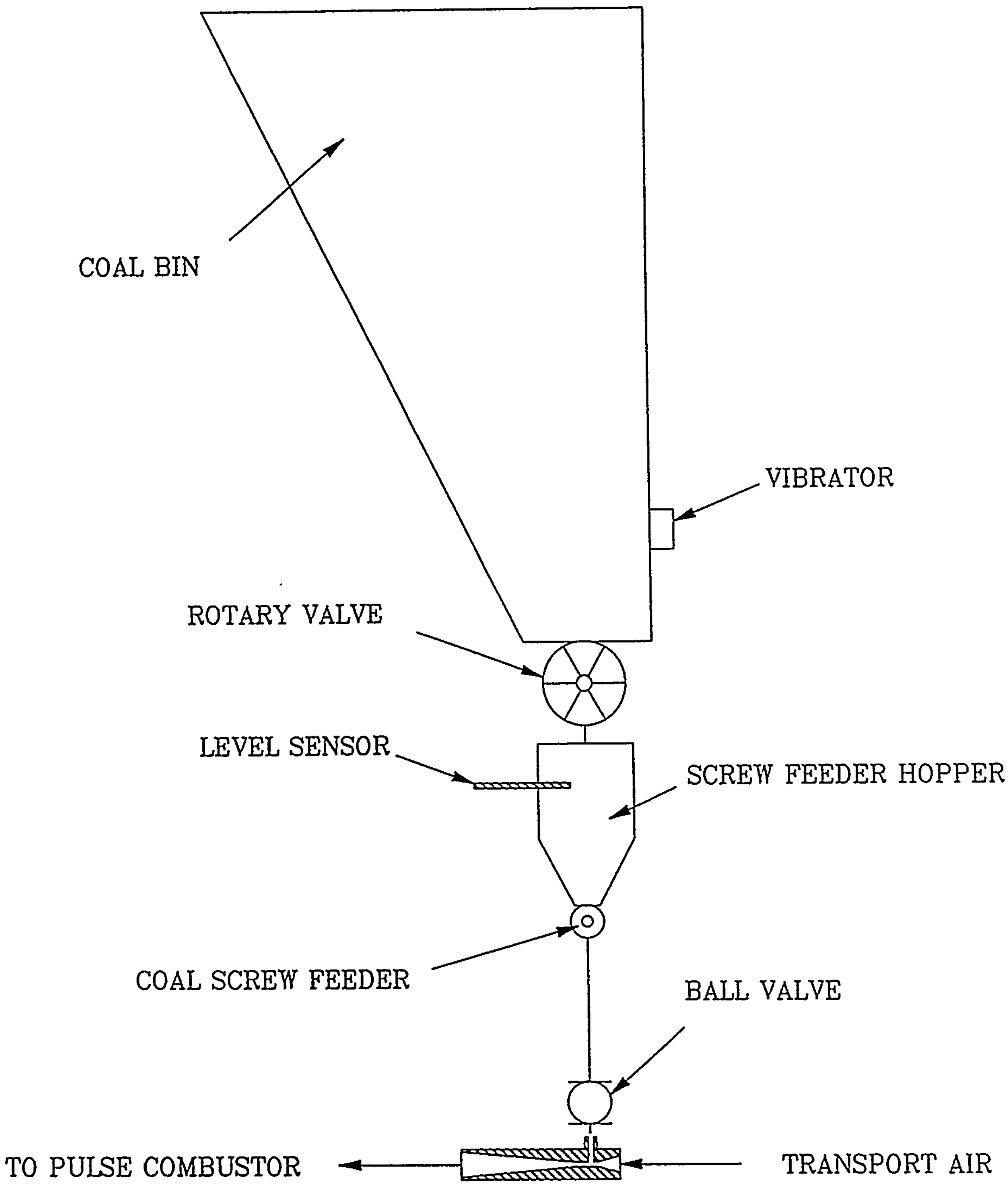


FIGURE 2-2: SCHEMATIC OF THE COAL FEED SYSTEM

locations to examine sulfur capture propensity. Consequently, a separate screw feeder and a venturi eductor were used to feed the sorbent.

2.1.7 Combustion, Heat Recovery and Emissions Control

Steam's ability to give off heat, promote its own circulation, and permit ease of distribution and control in a heating system are advantageous for space heating. Besides, a significant number of steam-heat installations already exist throughout Eastern/Northern United States/Canada and Overseas which present a large retrofit market. Therefore, steam was chosen as the heating medium for this application. Since boilers operating at high pressures (about 30 to 50 psig) typically require an operator to be present in the boiler room at all times and the present application called for minimal operator attention, a low-pressure design was chosen (i.e., 15 psig).

2.1.7.1 Initial Configuration -- A

A schematic of the initially proposed combustion, heat recovery and emissions control system is shown in Figure 2-3. It integrated combustion and heat recovery wherein a pulse combustor is configured with the main fire tube (Morrison tube) found in conventional Scotch boilers.

The different design options considered include:

- Two pulse combustors arranged in a tandem configuration with the combustion chambers and tailpipes constituting the fire tube. The tandem operation is tantamount to a 180 degree phase lag between each unit and results in superposition of acoustic waves and cancellation of fugitive sound emissions, and provides for automatic fuel phasing and supercharging.
- Single pulse combustor with the combustion chamber and tailpipes placed inside a perforated Morrison tube.
- Single pulse combustor with the combustion chamber and tailpipes enclosed by a water jacket and integrated with the Morrison tube.
- A refractory-lined cyclone placed between the Morrison tube and the second pass of the boiler.
- An inertial particle separator-cum-air preheater placed between the Morrison tube and the second pass of the boiler.

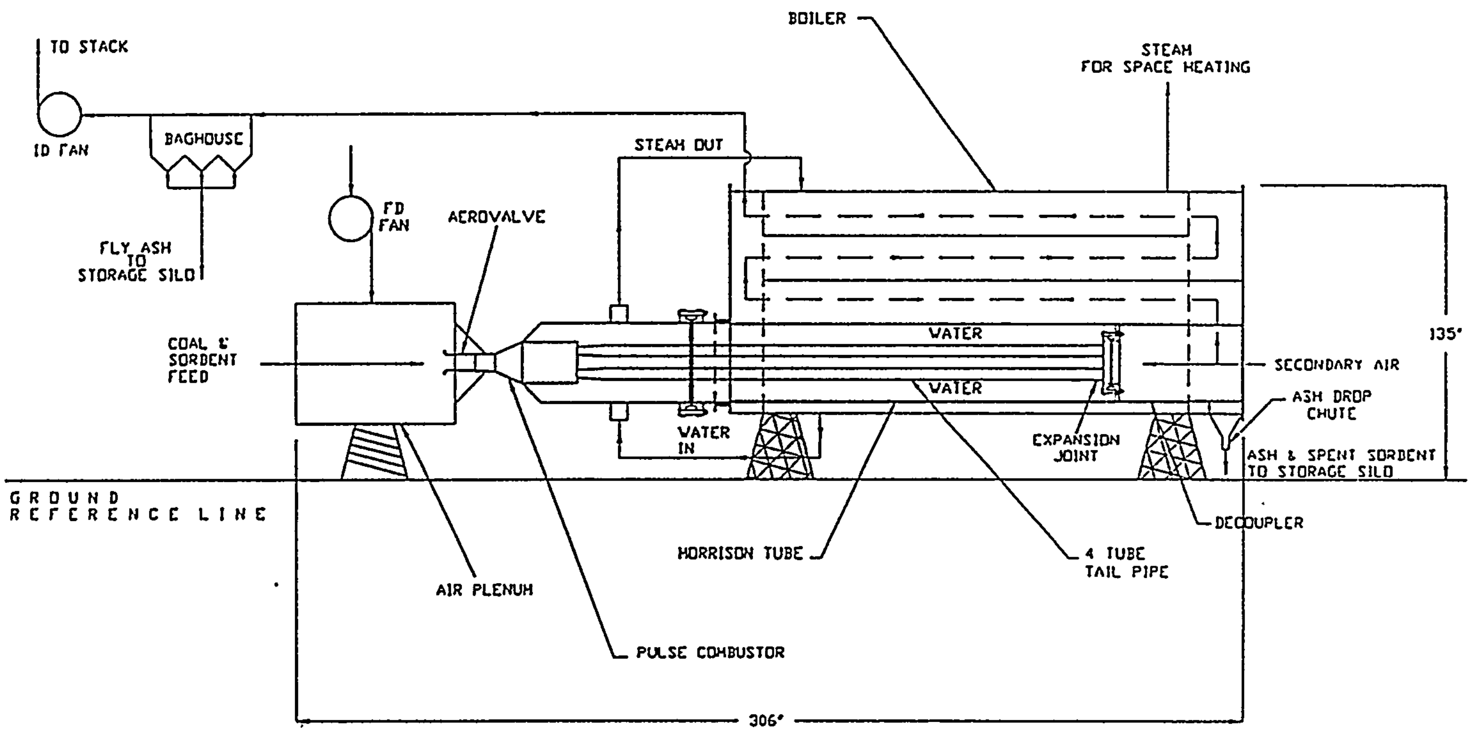


FIGURE 2-3: SCHEMATIC OF THE MTCI COMMERCIAL-SCALE COAL-FIRED PULSE COMBUSTION SYSTEM (CONFIGURATION A)

- An ash dropout chute placed beneath the turnbox at the end of the Morrison tube.

- Sorbent injection at the end of the tailpipe.

- Sorbent injection into the pulse combustion chamber.

Based on cost, space and retrofit considerations and ease of operation and maintenance, the configuration (termed Configuration A) shown in Figure 2-3 was selected. The pulse combustor was integrated with a renovated Cleaver Brooks 125 hp four-pass, fire-tube boiler.

The pulse combustion system was designed using a computer code that was developed by MTCI for scale-up. The code performs mass balance, heat balance, fluid dynamics, heat transfer, materials selection and mechanical design calculations. The input data to the code included the desired firing rate and the fuel specifications. The code generated the dimensions for the components which in turn facilitated the development of component drawings using AutoCad. For operation in the non-slagging mode, a multiple (three) tailpipe arrangement became necessary.

The combustion chamber and tailpipes were embedded in water (Figure 2-4). The pulse combustor was designed to operate at 53 Hz with an overall excess air level of 20 percent. Heat balance calculations performed with combustion profiles typically obtained by MTCI in coal-fired pulse combustion indicated about 10 percent heat loss from the combustion chamber and 31 percent heat loss from the tailpipes. The mean temperature in the combustion chamber was estimated to be about 2192°F and was well below the initial ash deformation temperature of the primary design fuel (2525°F). The aerovalve was known to run cooler, relatively speaking, and was therefore not water-cooled. Dry pulverized coal and limestone are injected close to the junction between the aerovalve and the combustion chamber.

Primary air is supplied by a forced draft (FD) fan, through a venturi for flow measurement, to an air plenum. The air plenum acts like a capacitor and seeks to provide primary air to the combustors at approximately constant static pressure. The tailpipes are connected to the Morrison tube which serves as a

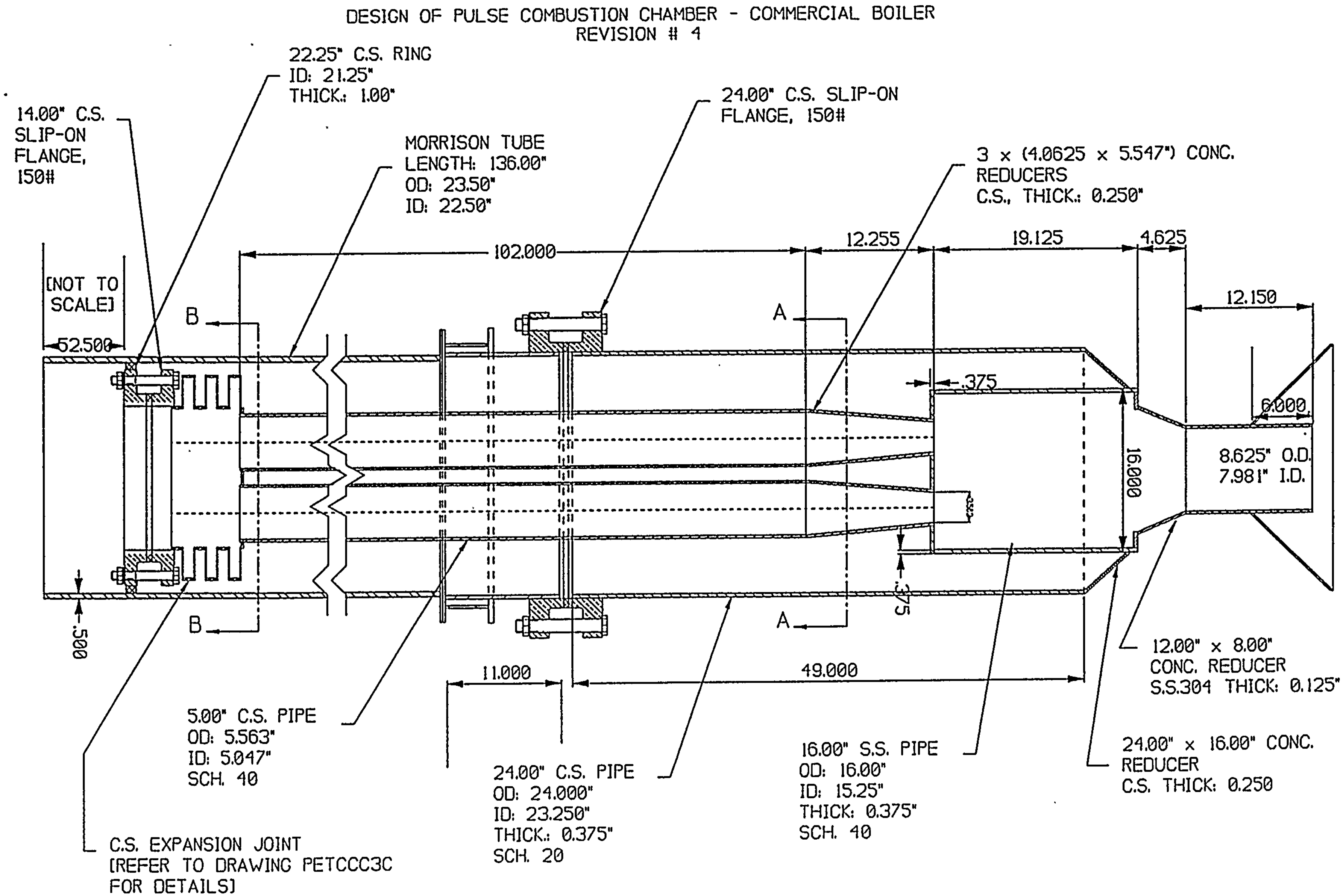


FIGURE 2-4: PULSE COMBUSTOR (DESIGN A)

decoupler. The flue gas from the Morrison tube flows through the second, third, and fourth passes of the boiler, a baghouse and an induced draft (ID) fan on its way to the stack. The ID fan is designed to maintain zero gage static pressure in the decoupler. The pressure boost developed due to pulse combustion will reduce the size, power requirement, and cost of the FD and ID fans.

The combustion system is designed to run in the non-slagging or dry ash rejection mode because of its horizontal orientation and the need to provide a simple and reliable means for ash collection. Non-slagging operation eliminates the need for refractory-lining of the combustion chamber and tailpipe and the attendant maintenance requirement. The operating temperature is lower than that in the slagging mode and offers the potential for reduced NO_x emissions and improved sulfur capture. An ash dropout chute is provided at the end of the decoupler to collect the larger particles (acoustically agglomerated dry ash and spent sorbent) that separate at the turn of the boiler first pass. It is anticipated that the remaining particulate matter will predominantly be carried over through the boiler tube passes into the baghouse where final particulate collection will occur.

Additionally, it was proposed to employ multiple air staging for NO_x emissions control. As such, NO_x emissions are lower in pulse combustion mode than that in conventional combustion. The incorporation of multiple air staging with near stoichiometric or substoichiometric combustion in the chamber and tailpipe, and secondary air addition in the decoupler is expected to lower NO_x emissions.

The process and instrumentation diagrams of the system are given in <u>Figures 2-5</u> and <u>2-6</u> with Figure 2-5 showing the air, fuel and flue gas flows and Figure 2-6 depicting the water and steam flows. The combustion system included FD fan, coal and limestone storage and feed system, natural gas flow regulator, air plenum, pulse combustor, Cleaver Brooks 125-hp four-pass fire-tube boiler, two air rotation units for space heating, make-up water tank, water circulation pumps, baghouse, and ID fan. The combustor was designed for dual-fuel capability with dry pulverized coal as the primary fuel and natural gas as secondary fuel. Pulverized limestone was to serve as the sorbent for sulfur capture. The pulse

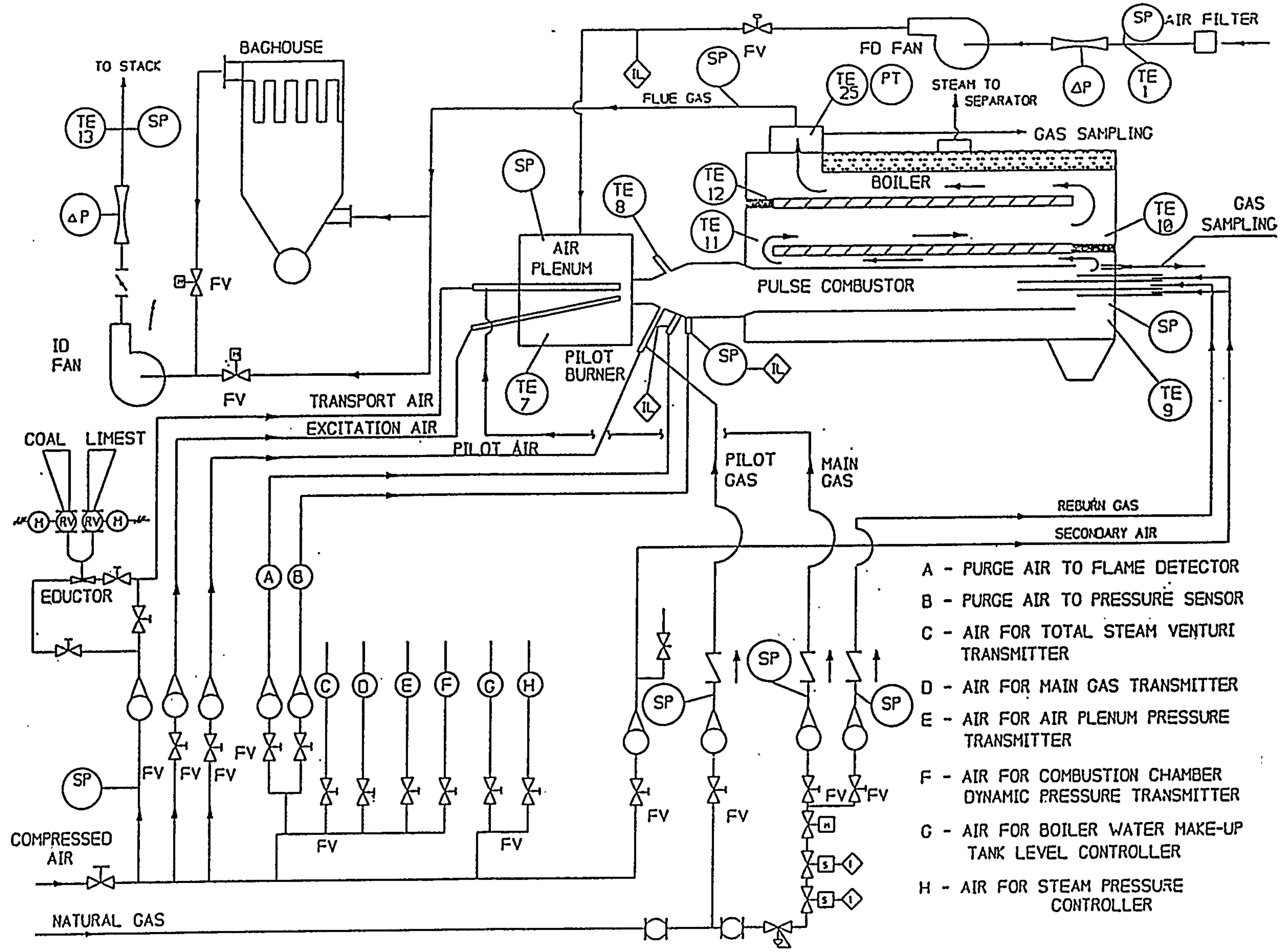


FIGURE 2-5: P&ID OF PULSE COMBUSTION SYSTEM - AIR, FUEL AND FLUE GAS FLOWS

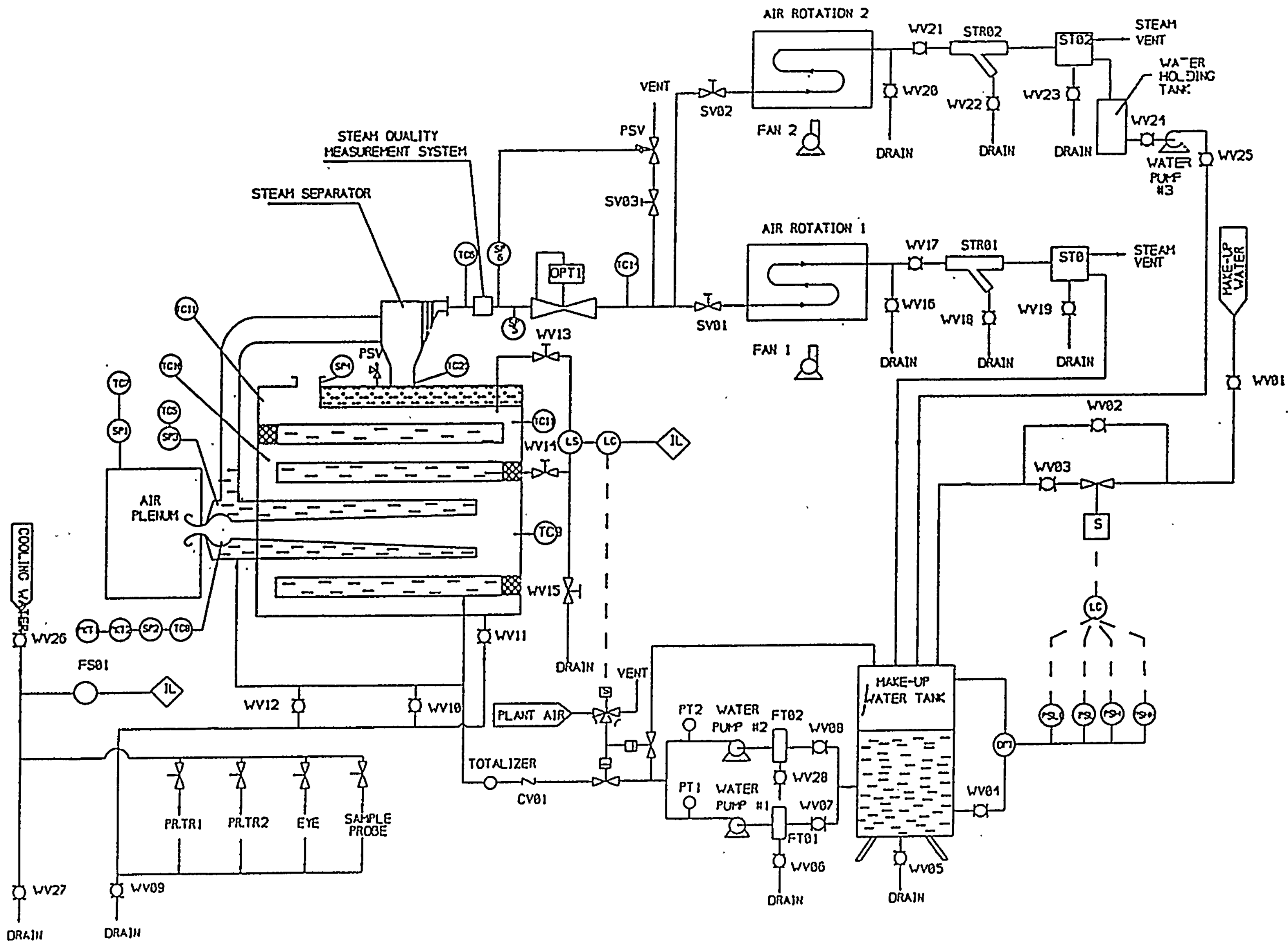


FIGURE 2-6: P&ID OF PULSE COMBUSTION SYSTEM - WATER AND STEAM FLOWS

combustor was integrated with the boiler such that the tailpipes were embedded in water inside the main fire tube (Morrison tube). A computer-based control system was configured to allow fully automatic start-up with system purge and ignition verification. The controls were configured to automatically purge the boiler, start the pilot, bring the combustion chamber up to its pre-set temperature on natural gas, feed the coal and modulate the coal feed to maintain steam pressure. Several safety interlocks were provided to shut down the system in case of unsafe boiler water level, interruption in instrumentation cooling water flow, pilot flame out, and insufficient draft pressure.

A Hewlett Packard spectrum analyzer was to be employed to monitor combustion chamber dynamic pressure. A Horiba/Enertec continuous emissions monitoring system was to be used to sample and analyze flue gas for O_2, CO, CO_2, NO_x, SO_2 and HC. It was also necessary to measure steam quality in order to accurately evaluate boiler thermal efficiency. Since the boiler in this program was configured to operate at low pressure (< 15 psig), throttling calorimeters which are conventionally used for steam quality measurement could not be employed here. Therefore, a special device was designed and fabricated in-house and installed downstream of the steam separator to measure steam quality. During the tests, steam condensation samples and boiler water samples were also collected to facilitate cross-checking with the sodium tracer method typically used in the steam generation industry.

Preliminary system tests (see Section 2.2) were conducted in this configuration.

2.1.7.2 Initial Configuration -- B

The conventional straight tailpipe pulse combustor was seen to require sizable clearance (~ 10 ft.) in front of the boiler for combustion system-boiler integration. In order to cater to retrofit applications where the boiler room is small and accessibility is limited, a compact pulse combustor with a helical tailpipe was designed and fabricated. This combustor was integrated with a home-made steam generator. Figure 2-7 shows the pulse combustor and Figure 2-8 shows the P&ID for this system. It included provisions for gas reburning and air staging.

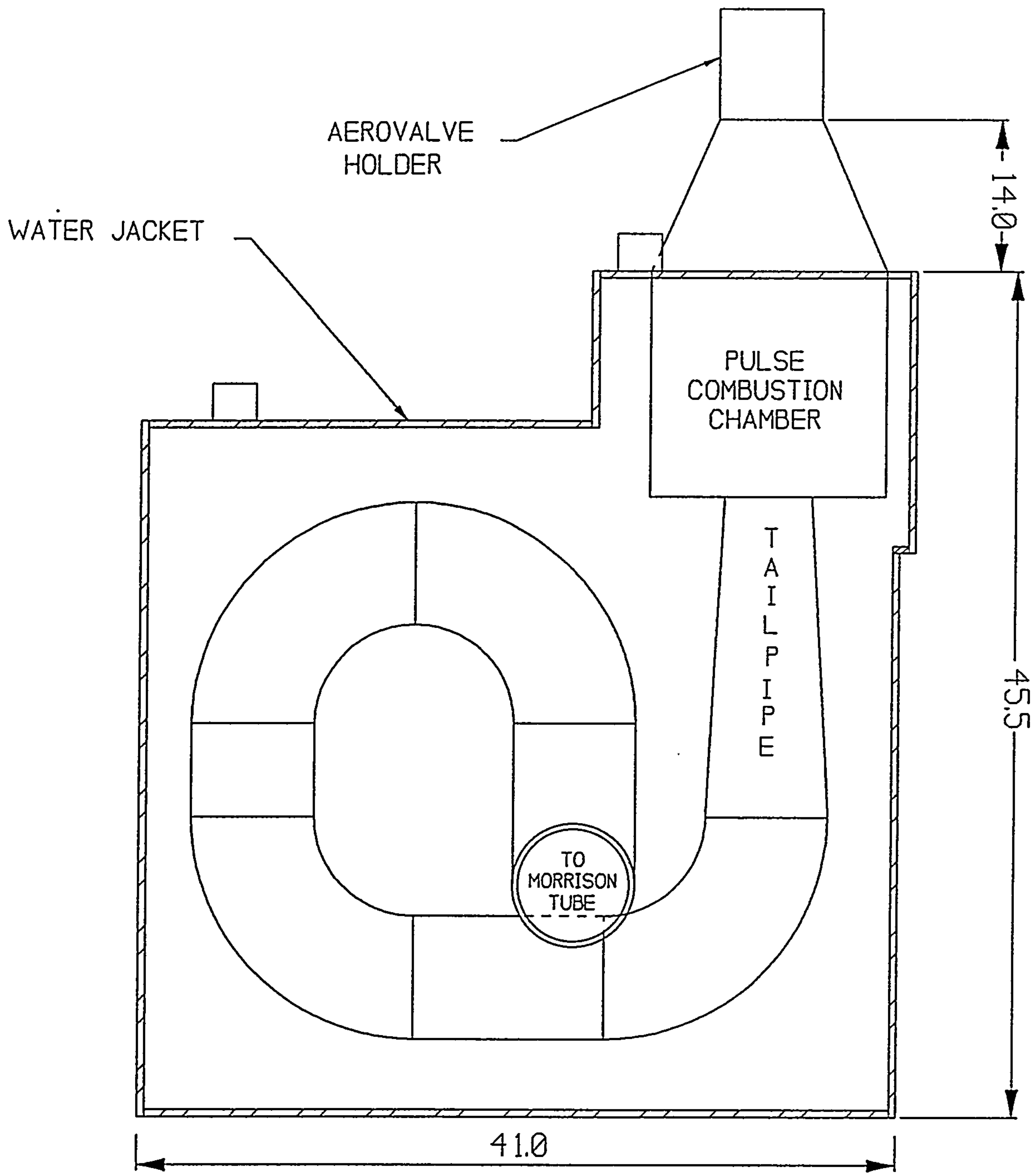


FIGURE 2-7: PULSE COMBUSTOR (DESIGN B)

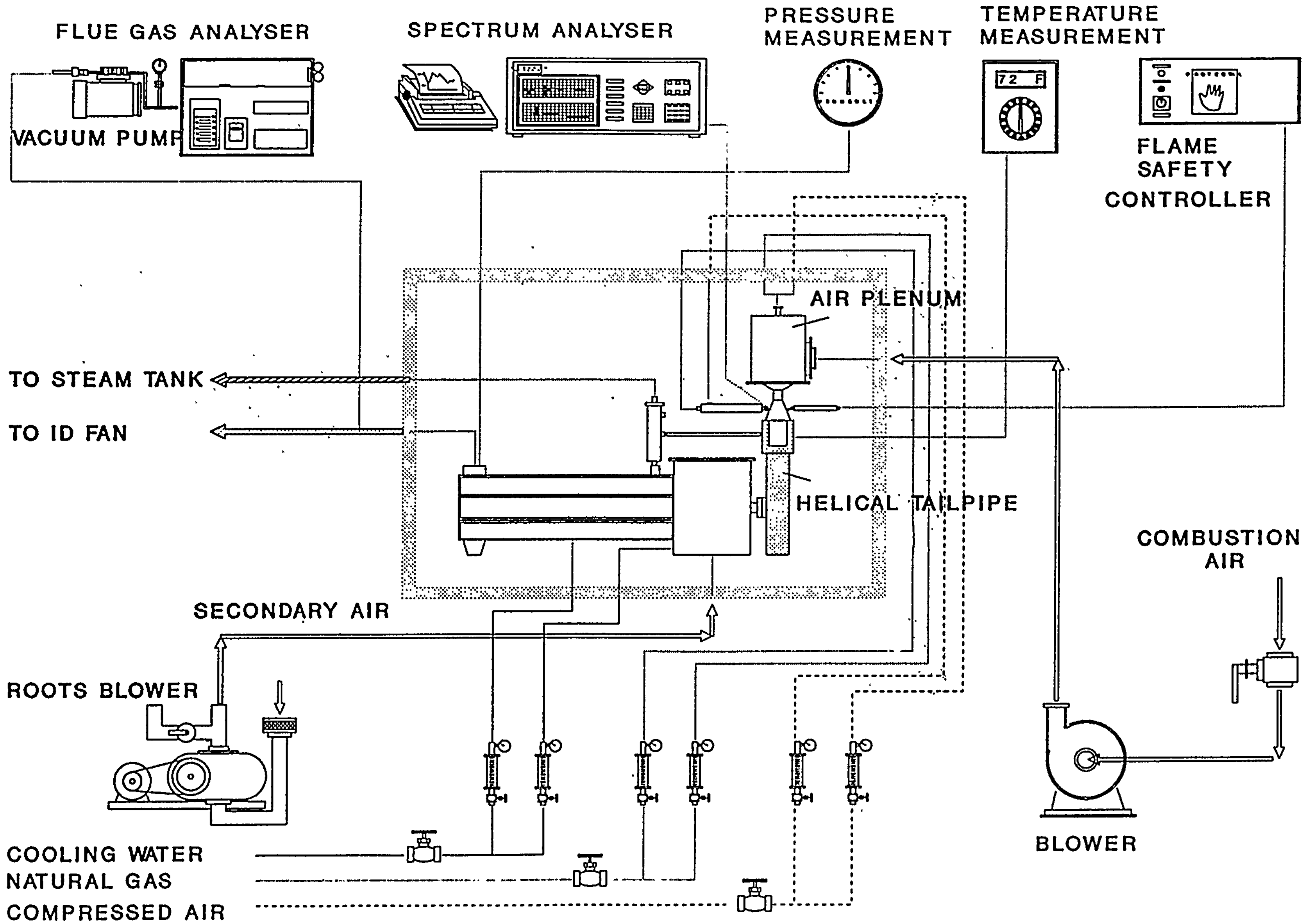


FIGURE 2-8: P&ID OF THE HELICAL TAILPIPE PULSE COMBUSTOR

ERRZ-50F.2A

Preliminary system tests (see Section 2.2) were also conducted in this configuration.

2.1.7.3 Modified Configuration -- C

Based on preliminary system test results (see Section 2.2), a single tailpipe design (termed Design C) was generated to reduce heat loss and improve combustion performance (see Figure 2-9). The tailpipe incorporated a 90° turn to facilitate vertical flow in the combustion zone and achieve uniform coal distribution. This arrangement also helped increase the decoupler volume for char burning. A schematic of the system is shown in Figure 2-10. A pump was incorporated between the boiler and the pulse combustor water jacket to enable forced circulation of water through the high heat flux zone that is characteristic of pulse combustion. The steam-water mixture from the pulse combustor water jacket was admitted into the boiler through boiler side ports.

Preliminary system tests (see Section 2.2) and initial proof-of-concept system tests (see Section 2.3) were conducted in this configuration.

2.1.7.4 Modified Configuration -- D

Based on the preliminary and initial proof-of-concept system test results (see Sections 2.2 and 2.3), the configuration discussed above was further modified to meet target NO_x emissions goals. A coal reburn section and a char burnout section were added as shown in Figure 2-11 to reduce NO_x formation. This arrangement was selected based on the following considerations viz. utilization of the pulse combustor as was, minimization of footprint and vertical space requirement, good mixing of coal, steam, and combustion products in the reburn section, and adequate char residence time in the char burnout section. The revised configuration is shown in Figure 2-12. A photograph of the retrofitted Cleaver Brooks Boiler during integration is shown in Figure 2-13.

Both proof-of-concept system tests (see Section 2.3) and system demonstration tests (see Section 2.5) were performed in this configuration.

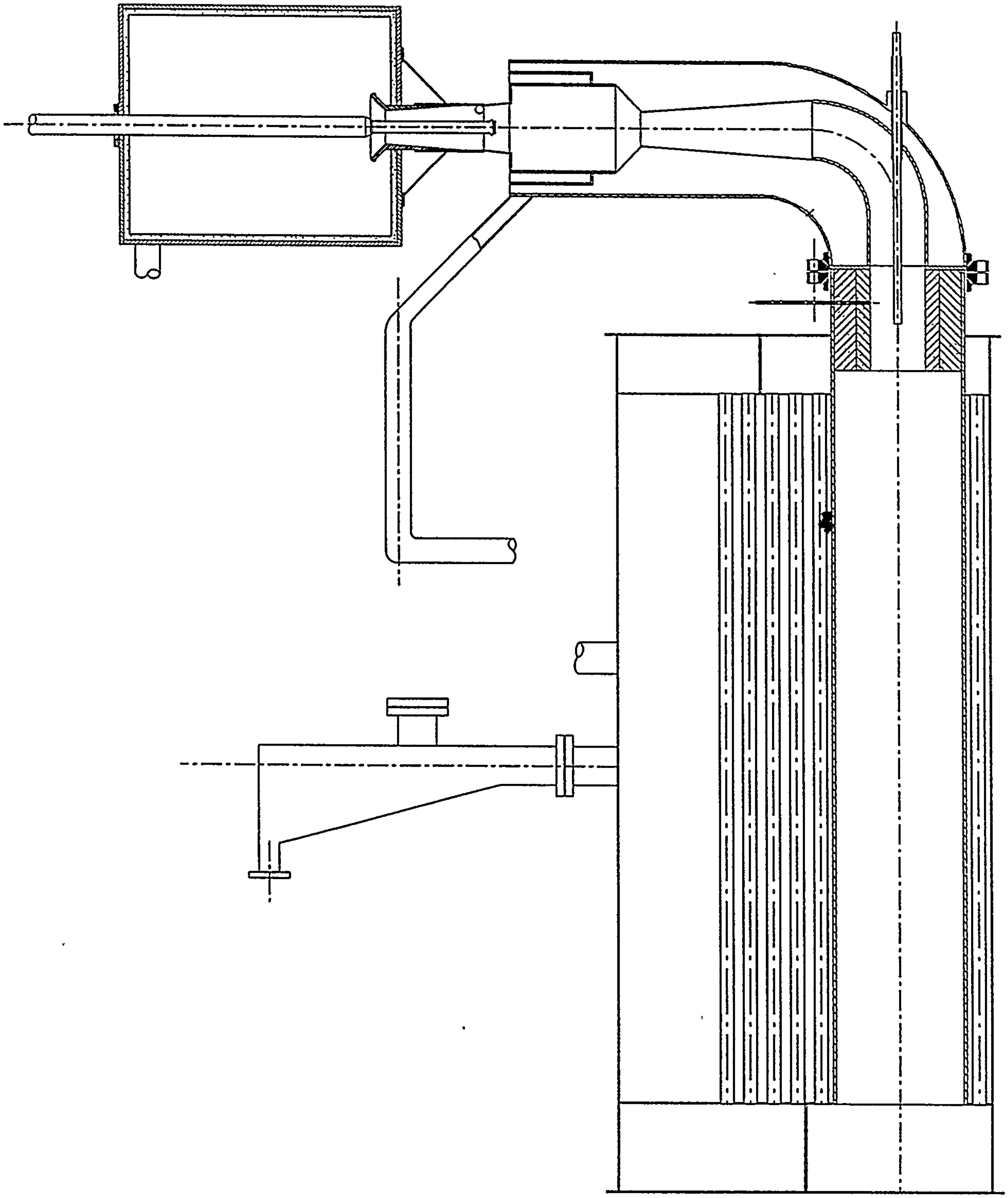


FIGURE 2-9: PULSE COMBUSTOR (DESIGN C)

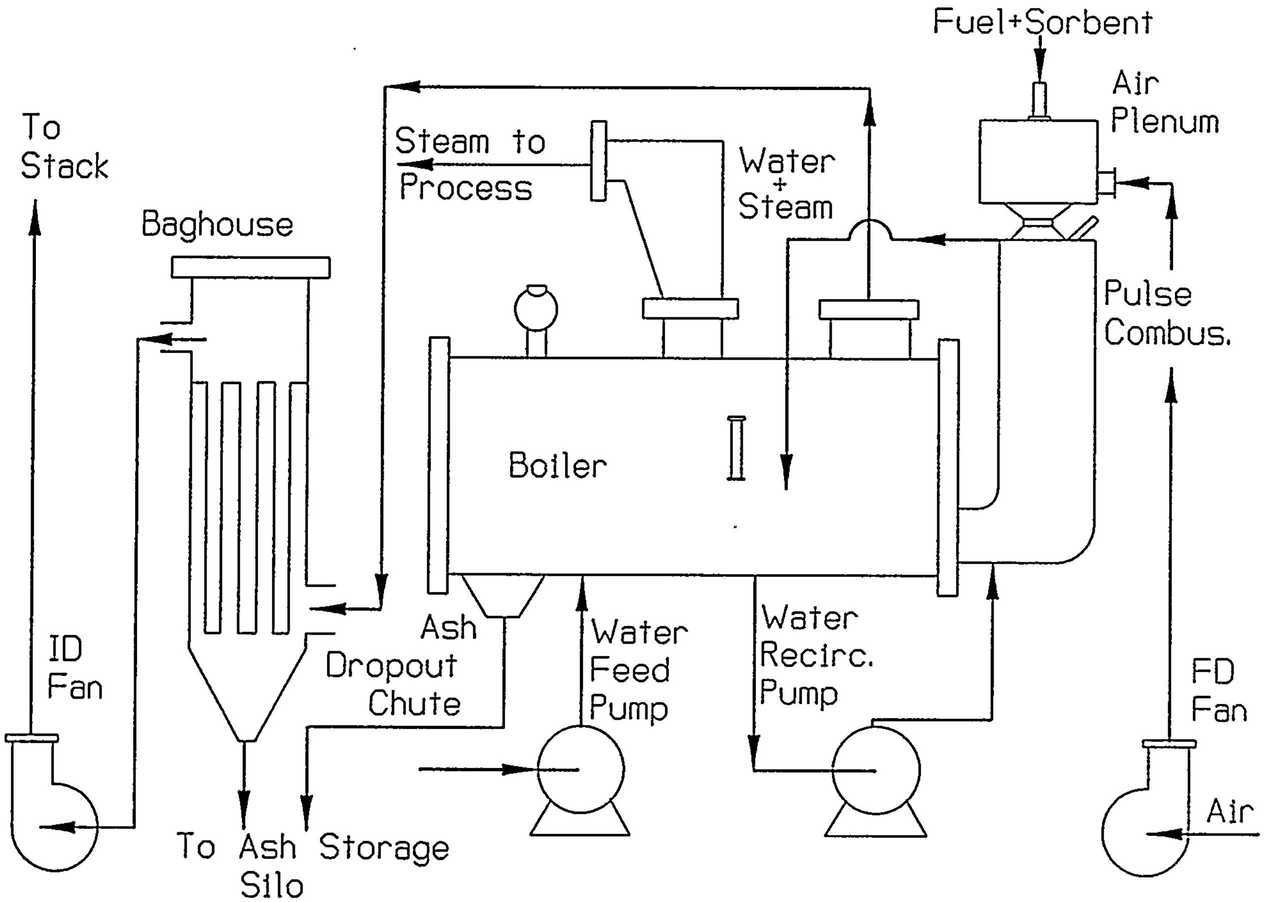


FIGURE 2-10: BOILER RETROFIT PULSE COMBUSTION SYSTEM

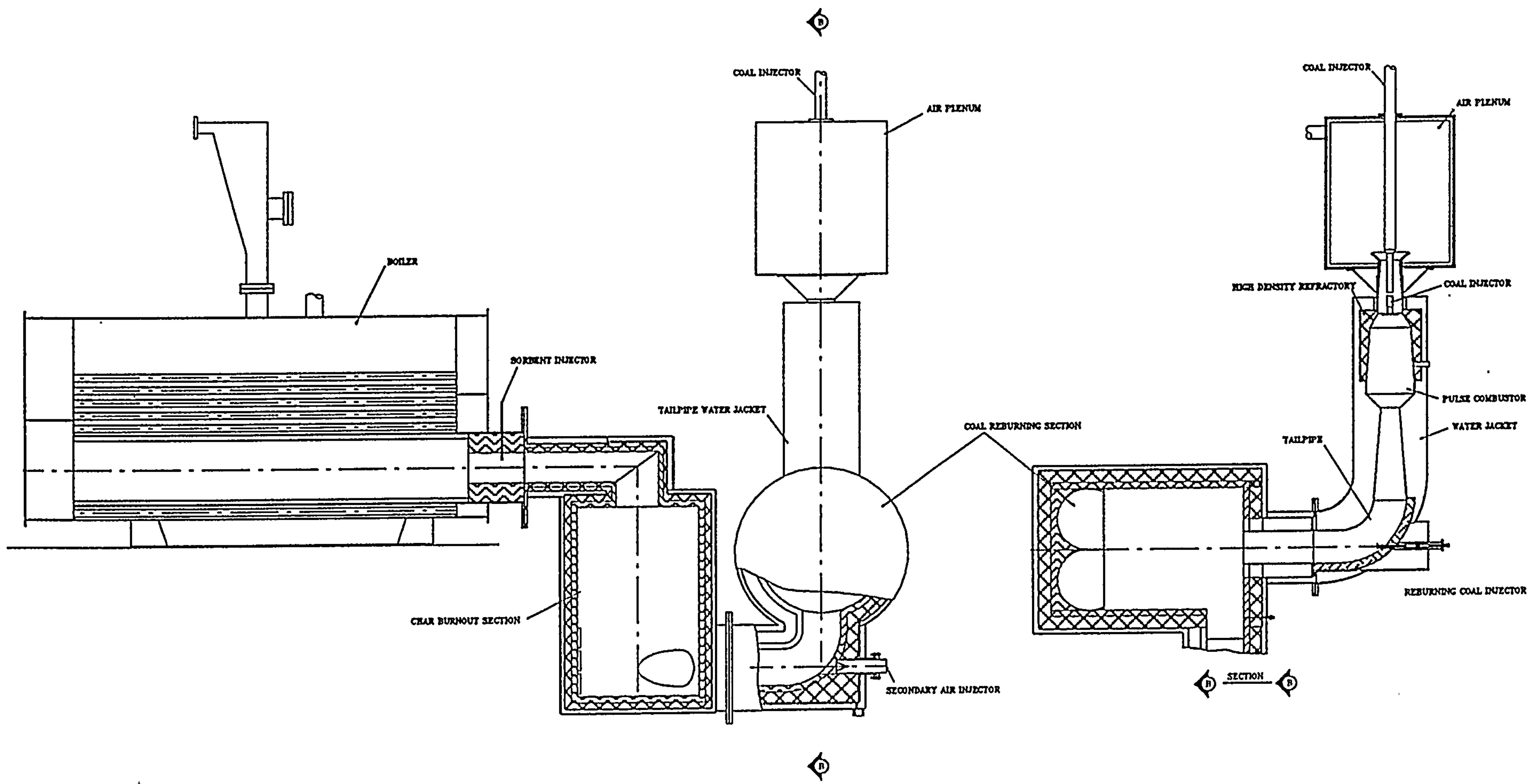


FIGURE 2-11: PULSE COMBUSTOR (DESIGN D)

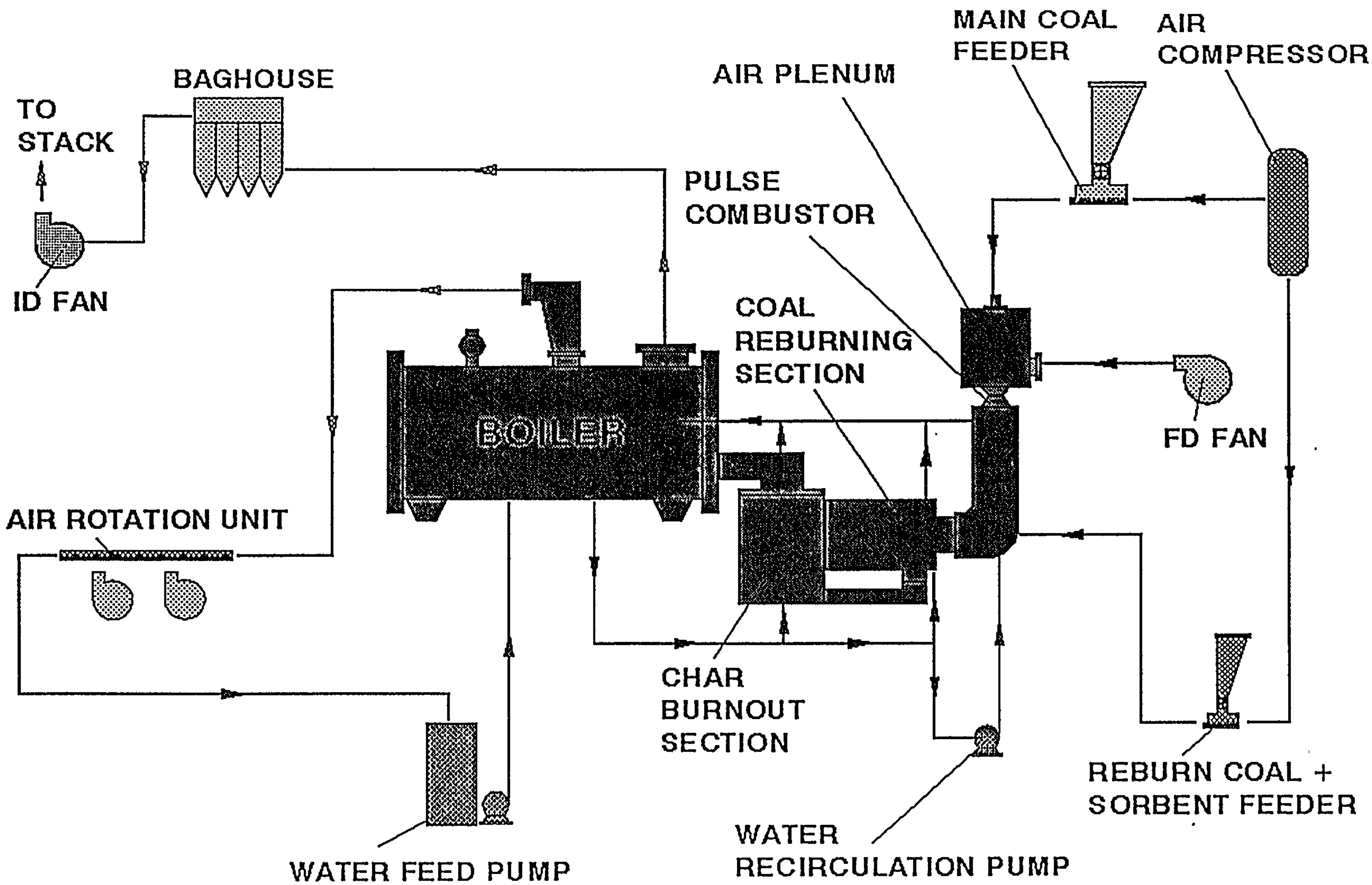


FIGURE 2-12: SCHEMATIC OF THE COMMERCIAL-SCALE COAL-FIRED PULSE COMBUSTION SYSTEM

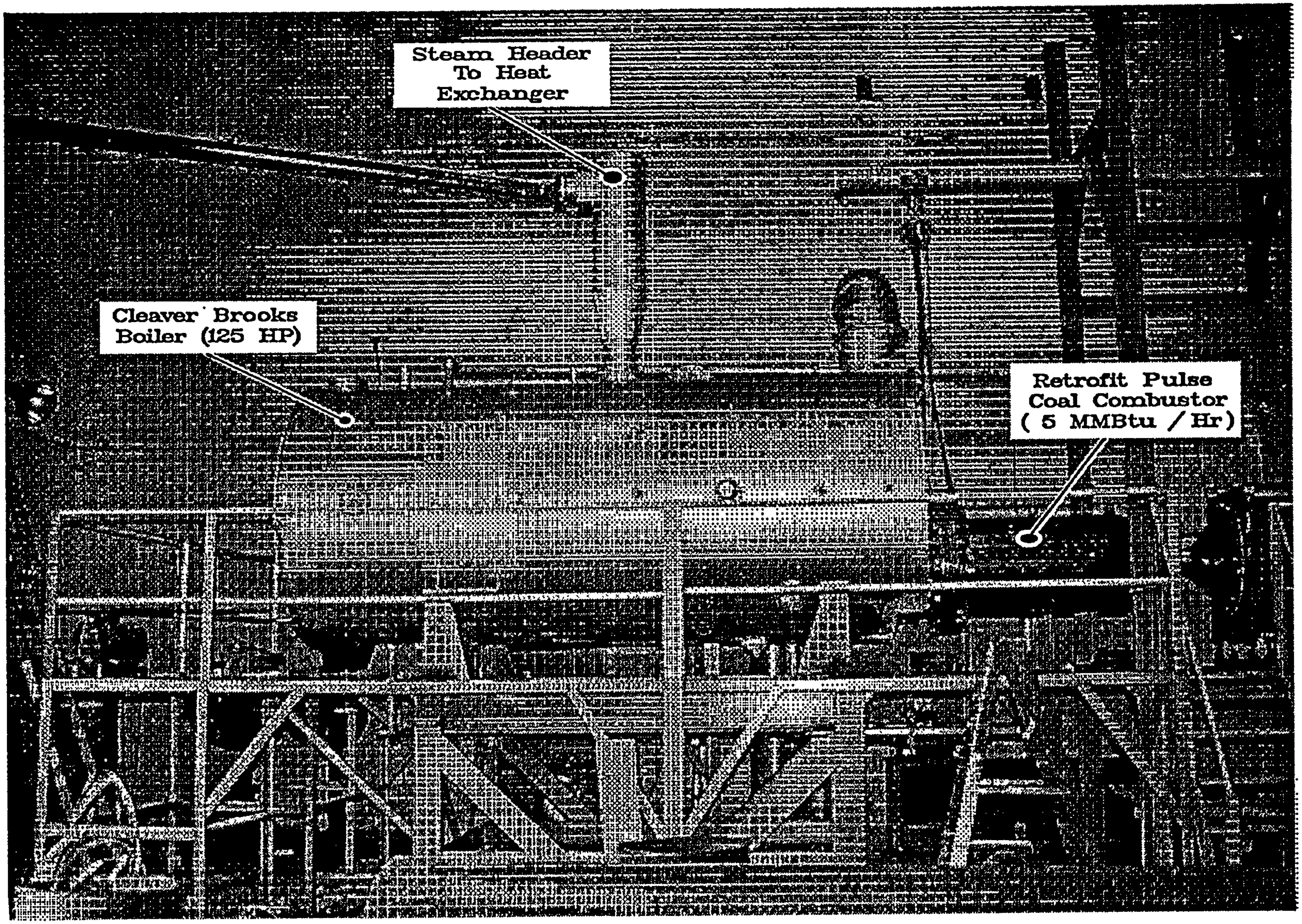


FIGURE 2-13: THE COMMERCIAL-SCALE BOILER RETROFIT COMBUSTION SYSTEM DURING INTEGRATION

2.1.7.5 Air Rotation Units

Two 2.5 MMBtu/hr air rotation units were designed for boiler integration with the warehouse heating system. The steam-to-air heat exchanger design for these units takes the full advantage of the high heat transfer coefficients associated with condensing steam flows. In this case, the overall heat transfer is limited by the external heat transfer area. Fins were used in the design to enhance this surface area and provide a compact heat exchanger with minimal air flow pressure drop. Each air rotation unit (Figures 2-14 and 2-15) used finned steam coils and two propeller fans.

2.1.8 Solids Collection and Disposal

Ash dropout chutes were provided at the front and back ends of the boiler but no solids were collected in those locations (see Section 2.2). A pulse jet baghouse was used for particulate capture. It had 72 No-mix bags. Solids collected in the baghouse hopper were dropped into 55-gallon drums through a rotary valve and disposed of off-site.

2.1.9 Plot Plan

The plot plan of the commercial-scale space-heating system is shown in Figure 2-16. The pulse combustion boiler retrofit system is located in the southwest corner of the building. all the control systems are housed in a room adjoining the unit. The two air rotation units are placed along the south wall. The pulse combustion system, boiler, FD fan, air rotation units and system controls are located inside the building, while the ID fan, coal and limestone feed systems (bins, rotary valves, screw feeders, and eductors) and the baghouse are located outdoors near the southwest wall of the building.

2.1.10 System Controls

The system included both local and panel-mounted instrumentation. Local instrumentation included thermocouples, pressure transmitter, pressure transducers, DP cells, flow meters and flow controllers. Panel-mounted instrumentation included controllers, flow meters, alarms, and push-button switches for automatic

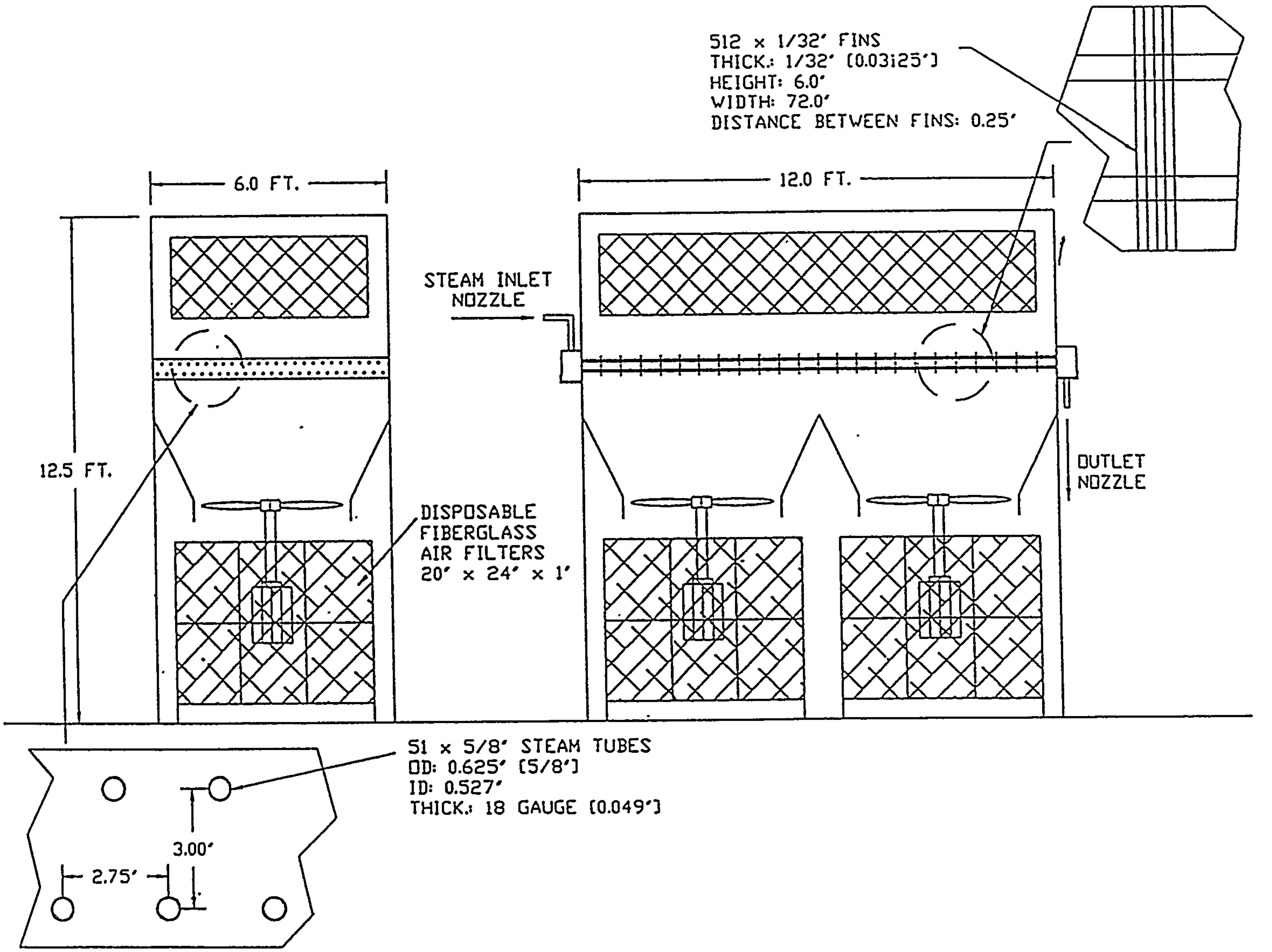


FIGURE 2-14: DESIGN OF AIR ROTATION UNIT

FIGURE 2-15: AIR ROTATION UNIT

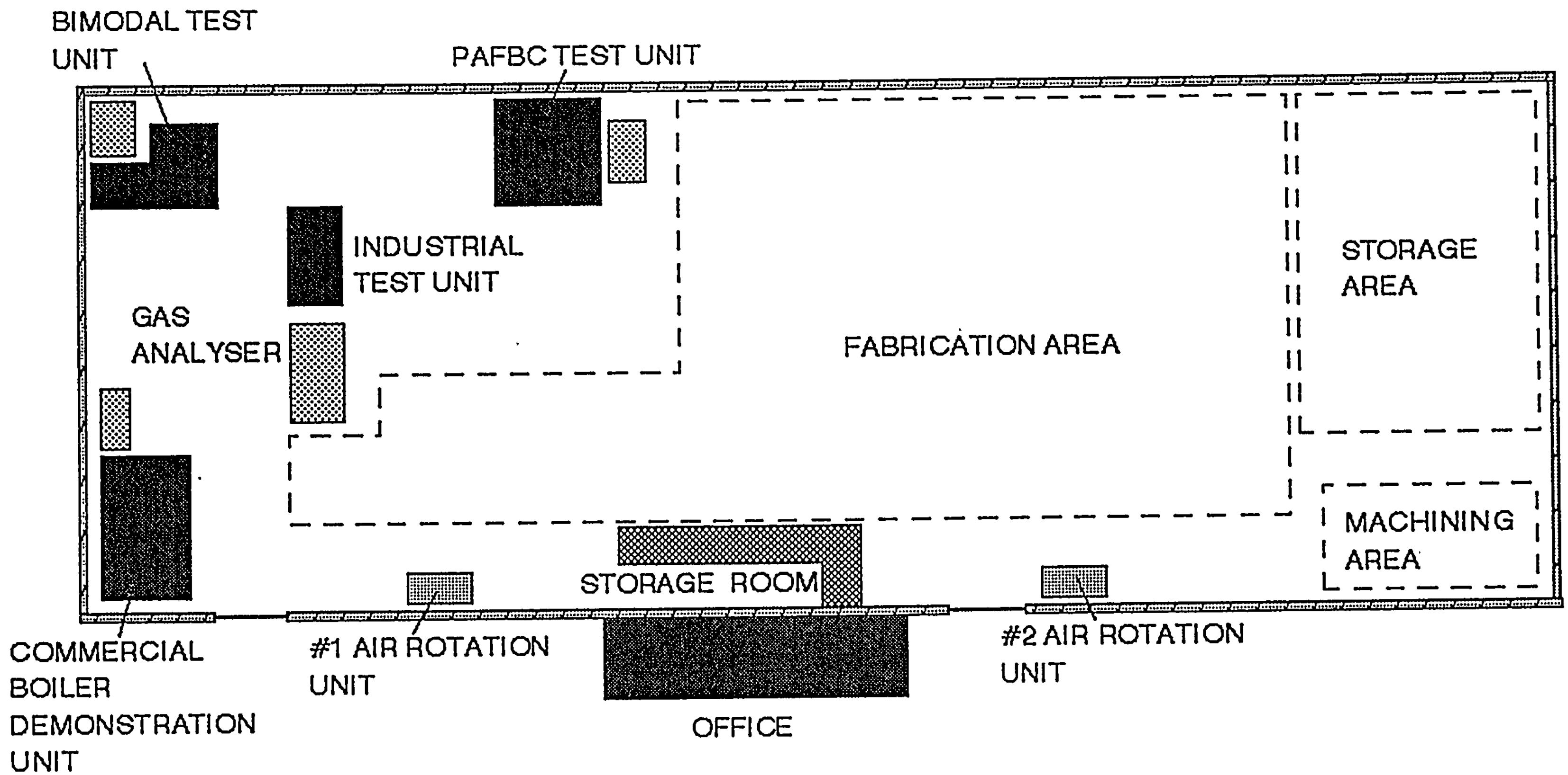


FIGURE 2-16: PLOT PLAN

start-up, shutdown, and normal system control. Initially, the certified control unit from a commercially purchased control system was configured to control system operation. It was a process controller set-up to utilize such unconventional controlling parameters as pulse combustion chamber dynamic pressure. The system was configured to purge the boiler, start the pilot, bring the combustion chamber up to temperature on gas, feed the coal, and modulate the coal feed to maintain steam pressure. This control system was used during the preliminary and proof-of-concept system tests (see Sections 2.2 and 2.3) and during the early part of the system demonstration tests (see Section 2.5).

Due to unsatisfactory performance of the commercial control system (loss of memory, abrupt shutdown of the pulse combustor, etc.), an alternate control system that would work reliably and respond to heat demand was configured by MTCI. Programmable logic controllers (PLC) were used in conjunction with a computer-based data acquisition system. The system was integrated, checked out, and calibrated for use during the system demonstration tests (see Section 2.5). this control system allowed fully automatic start-up with system purge and ignition verification. The system included several safety interlocks to shut down the system in case of unsafe boiler water level, interruption in instrumentation cooling water flow, pilot flame out, and insufficient draft pressure. The computer-based data acquisition system enabled on-line data acquisition and storage for later analysis of data. This control system permitted start-up of the unit with the click of a mouse and achieve steady-state operation on coal.

A Hewlett Packard spectrum analyzer was employed to monitor combustion chamber dynamic pressure. A Horiba/Enertec continuous emissions monitoring system was used to sample and analyze flue gas for O_2, CO_2, CO, NO_x, SO_2, and THC.

2.1.11 Design Summary

The primary nominal facility design parameters are shown in Table 2-5. The specifications of the major components are:

TABLE 2-5:

NOMINAL FACILITY DESIGN PARAMETERS AND SELECTED EQUIPMENT SPECIFICATIONS

DESIGN FIRING RATE:	5 MMBtu/hr
STEAM RATE:	3800 lb/hr @ 15 psig, sat.
COAL TYPE	High Vol., Bit., Pittsburgh No. 8
COAL SIZE DISTRIBUTION:	Standard Grind, Dry Pulverized
SORBENT TYPE:	Lime, Anville
SORBENT SIZE DISTRIBUTION:	Standard Grind, Dry Pulverized
EXCESS AIR:	25%
COMBUSTION MODE:	Non-slagging, Dry Ash Rejection
Ca/S MOLAR RATIO:	2.5
COAL FEED RATE:	400 lb/hr
LIMESTONE FEED RATE:	110 lb/hr
TOTAL ASH COLLECTION RATE:	145 lb/hr
AIR FLOW RATE:	1150 scfm
FLUE GAS FLOW RATE:	1700 acfm @ 300°F
COAL FEEDER RATING:	700 lb/hr
SORBENT FEEDER RATING:	200 lb/hr
F.D. FAN RATING:	1700 scfm @ 10 inch W.C.
I.D. FAN RATING:	2500 scfm @ 15 inch W.C.
BAGHOUSE RATING:	3700 acfm @ 300°F, 1 gr/acf

- Pulse Combustor

Design Firing Rate:	5 MMBtu/hr
Design Excess Air:	25%
Design Combustor Mean Temperature:	2200°F
Load Turndown:	4:1
Fuel:	Coal and/or Gas

- Boiler

Type:	Fire tube
Make:	Cleaver Brooks, 125 hp, 4 pass
Design Steam Rate:	3800 lb/hr
Design Steam Condition:	Sat. @ 15 psig

- Baghouse

Design Gas Inlet Temperature:	300°F
Design Gas Flow Rate:	1700 acfm
Solids Loading:	1 gr/acf
Air-to-Cloth Ratio:	2.5 $ft^3/min/ft^2$
Vendor:	Aeropulse, Inc.
Model Number:	100 BHI-A3-72
Particulate Emission:	< 0.02 lb/MMBtu
Design Pressure Drop:	5 inch w.c.

- Forced Draft Fan

Air Flow Rate:	1700 scfm
Static Pressure:	10 inch w.c.
Design Inlet Temperature:	70°F
Vendor:	Phelps Fan Company
Model Number:	W-170
Motor:	7.5 hp

- Induced Draft Fan

Flue Gas Flow Rate:	2500 scfm
Static Pressure:	15 inch w.c.
Design Inlet Temperature:	300°F
Vendor:	Phelps Fan Company
Model Number:	W-261
Motor:	30 hp

2.1.12 Component Fabrication

Based on the materials and parts list and specifications generated during the design phase, procurement documents were prepared, quotes were obtained, and purchase orders were placed starting with the longest lead items. A schedule for fabrication was prepared and the progress in fabrication was monitored and coordinated.

2.1.13 COMPONENT INTEGRATION

This deals with delineation of system layout, connection of utilities, construction of system support structures and control room, and installation and integration; of all the components of the commercial-scale space-heating system. An erection plan was formulated and implemented in installing the unit on-site. The instrumentation and controls were connected, reviewed, and checked out.

2.2 PRELIMINARY TEST PROGRAM

A series of preliminary tests were performed to provide a preliminary evaluation of performance, to identify key operating variables and their ranges, and to establish operating conditions for the proof-of-concept system tests.

2.2.1 TEST PLAN

A preliminary Test Plan requiring over 100 hours of testing was provided. This Plan defined the following:

- Test program objectives,
- Test schedule,
- Type and range of test parameters and nature of the data that were to be obtained,
- Test matrix and operating conditions, and
- Methods of sampling, instrumentation, data acquisition, chemical analyses and data analyses.

Data analysis was conducted concurrently with all testing to prevent delays in the project and to provide guidance for subsequent tests.

The objective of the Preliminary Test Program was to evaluate the overall performance of the system and its potential for success in the proof-of-concept tests to be performed subsequently. This was accomplished through the performance of:

- Shakedown tests to check out the system components, system integration and system process controls;

- Screening tests to map out the system's operational boundary;

- Emission tests to validate the system's environmental compliance; and

- System operation in automated mode for extended test periods to validate the system for the subsequent proof-of-concept tests.

A plan (Table 2-6) was proposed for the preliminary tests. The system was fueled with natural gas prior to a set of verification and shakedown tests utilizing coal. Coal evaluation was planned during a three-week period toward the end of the test period. Coal testing was expanded prior to the proof-of-concept tests.

Test parameters to be tested relate to pulse combustor operation. Table 2-7 lists the test parameters and their ranges for the Preliminary Test Program.

SAMPLING

Particulate

Emission characterization of the system required isokinetic sampling of the flue gas exiting the system. Equipment conforming to EPA-recommended Sampling Methods 5 or 17 was used to measure the particulate concentration in the flue gas. This equipment was partially purchased and partially fabricated. The size distribution of the sampled particulate was determined by sending samples for outside analyses.

Flue Gas

A particulate-free gas sample was continuously delivered to an extractive Gas Analysis System by drawing the gas through an in-duct sintered metal filter. A Horiba Gas Analyzer was used to continuously monitor the flue gas composition in this way.

TABLE 2-6:

OVERALL TEST PLAN FOR PRELIMINARY TEST PROGRAM

TEST SERIES	TEST OBJECTIVE	TEST DURATION (WEEKS)
1	Instrument calibration.	2
2	System component performance verification.	0.5
3	Interlock verification.	0.5
4	Verification of PID control-loop operation.	0.5
5	Automatic start-up performance verification	1
6	Shakedown tests with natural gas	2
7	Screening tests.	8
8	System automatic control.	2
9	Verification of coal and limestone feed system.	1
10	Shakedown tests with coal (no limestone addition)	1
11	Shakedown tests with coal (with limestone addition)	1
12	Screening tests with coal.	2.5
13	Environmental test with coal.	0.5
14	System validation for proof-of-concept tests.	0.5

TABLE 2-7:

TEST PARAMETERS AND THEIR RANGES

TEST PARAMETERS	TEST RANGES
1. Fuel Type	Natural gas and pulverized coal (Pittsburgh #8)
2. Fuel Feed Rate	1 to 5 MBtu/hr heat input
3. Aerovalve Size	3 sizes
4. Aerovalve Position	Motorized and continuously variable
5. Fuel Injector Position	Motorized and continuously variable
6. Secondary Gas Feed Rate	0 to 1 MBtu/hr heat input
7. Primary Fuel Excess Air	Self-determined by aerovalve and fuel feed rate - 25 to 100% to be tested
8. Secondary Excess Air	0 to 100%
9. Limestone Injection Rate	For coal only; 1 to 3 Ca/S ratio
10. Limestone Recycle Rate	Up to 3 times fresh limestone injection mass flow rate
11. Boiler Steam Pressure	1 to 15 psig

Coal

Coal samples were drawn periodically for chemical analyses. Recommended procedures were adopted for ensuring representative samples.

Natural Gas

Periodic natural gas composition reports issued by Baltimore Gas & Electric Company were monitored and factored into the data analyses of the results from the system.

2.2.2 SYSTEM TESTS

Instrument Calibration

This involved the calibration of the pressure transducers, flow elements and the Gas Analyzer. Since the system was equipped for fully automated operation, the accuracy of the continuously computed mass and heat transfer balances, and consequently the accuracy of the process control, was directly proportional to the accuracy of the calibration.

For each instrument, the calibration procedure resulted in a mathematical relationship connecting the instrument's output signal, usually a voltage or a current, to the process variable which the instrument was dedicated to monitor. The least-squares technique was used to extract accurate mathematical representations of the calibration data.

Table 2-8 lists the instruments that required calibration. The venturi tubes were calibrated against a traversing pitot tube. These venturi tubes were designed for operation in flow regimes giving constant and nearly unity flow coefficients with respect to fluid flow rates. As a result, only a limited number of calibration points were generated for each venturi. Air was the calibrating medium for the venturi tubes. The flow coefficients obtained from the calibration runs were then used with the appropriate fluid densities during system operation.

TABLE 2-8:

LIST OF INSTRUMENTS REQUIRING CALIBRATION

INSTRUMENT PID TAG NO.	DESCRIPTION
FE-1	Venturi to measure flow rate of main combustion air to pulse combustor.
DP-1	FE-1 differential pressure transmitter.
SP-1	FE-1 absolute pressure transmitter.
FE-2	Venturi to measure flow rate of main transport to pulse combustor.
DP-2	FE-2 differential pressure transmitter.
SP-2	FE-2 absolute pressure transmitter.
FE-3	Venturi to measure flow rate of main natural gas to pulse combustor.
DP-3	FE-3 differential pressure transmitter.
SP-3	FE-3 absolute pressure transmitter.
FE-4	Venturi to measure flow rate of flue gas from pulse combustor.
DP-4	FE-4 differential pressure transmitter.
SP-4	FE-4 absolute pressure transmitter.
FE-5	Venturi to measure steam flow rate from pulse combustor water-cooled walls.
DP-5	FE-5 differential pressure transmitter.
SP-5	FE-5 absolute pressure transmitter.
FE-6-1	Venturi to measure total steam flow rate from boiler.
DP-6-1	FE-6-1 differential pressure transmitter.
SP-6-1	FE-6-1 absolute pressure transmitter.
FE-6-2	Venturi to measure steam flow rate to air rotation unit #1.
DP-6-2	FE-6-2 differential pressure transmitter.
SP-6-2	FE-6-2 absolute pressure transmitter.
SP-7	Absolute air plenum pressure transmitter.
SP-8	Combustion chamber absolute pressure transmitter.
SP-9	Decoupling chamber absolute pressure transmitter.
DP-9	Decoupling chamber dynamic pressure transmitter.
SP-11	Baghouse inlet absolute pressure transmitter.
DP-11	Baghouse differential pressure transmitter.
SP-12	Boiler water absolute pressure transmitter.

The pressure transmitters were calibrated using a previously calibrated pressure transducer. A U-tube manometer filled with water was used to calibrate this secondary standard. External pressure was applied to each transmitter in several steps spanning its prescribed range. At each step, the transmitter's average output and that of the transmitter being used as the secondary standard was logged and stored in the Data Acquisition System. The data analyses for the calibration equations were then performed on this stored data.

SYSTEM COMPONENTS VALIDATION

The validation of the design performance of the system components were performed concurrently with the Instruments Calibration task. Of the main system components listed in Table 2-9, only those components that could be operated and checked out without operating the pulse combustor were addressed in this task. These components are indicated with asterisks in Table 2-9.

SYSTEM INTERLOCKS VALIDATION

Validation of the system interlocks listed in Table 2-10 followed the system component validation task. All of these interlocks were verified by observing the response of the commercially purchased control system to signals simulating the occurrence of every permissive condition listed in Table 2-10.

SYSTEM PID CONTROL LOOP VALIDATION

Validation of the System PID control loops (Table 2-11) was performed also by simulation. Simulated set points for each control loop were varied and the resulting control signal response was monitored with the aid of the Data Acquisition System. The response of the control hardware (such as a control damper), characterized by: (i) the time constant for the control hardware to relax to its new position, and (ii) the control hardware position vs. control signal profile were also recorded.

TABLE 2-9:

LIST OF SYSTEM COMPONENTS REQUIRING VALIDATION

1. PULSE COMBUSTOR

    1.1 Air Plenum*
    1.2 Aerovalve*
    1.3 Fuel Injector*
    1.4 Dynamic Pressure Transducer
    1.5 Ignitor
    1.6 Flame Detector

2. FIRE-TUBE BOILER

    2.1 Morrison Tube
    2.2 Water Level Controller*
    2.3 Limestone Re-injector*
    2.4 Staged Air Injector*
    2.5 Decoupler
    2.6 Fire Tubes

3. FD FAN SYSTEM

    3.1 FD Fan*
    3.2 FD Fan Damper*

4. ID FAN SYSTEM

    4.1 ID Fan*
    4.2 ID Fan Damper*
    4.3 ID Flow Switch*
    4.4 Ambient Air Inlet Damper*

5. BAGHOUSE

    5.1 Baghouse Bypass Dampers*
    5.2 Baghouse Pulse-Jet Cleaning System*
    5.3 Baghouse Hopper Evacuation Rotary Valve*

6. AIR ROTATION UNITS

    6.1 Finned-Tube Heat Exchangers
    6.2 Propeller Fans*
    6.3 Air Filters
    6.4 Steam Traps for Condensate Return
    6.5 Condensate Return Tank Water Level Control*

TABLE 2-10:
LIST OF SYSTEM INTERLOCKS REQUIRING VALIDATION

7. COMMERCIALLY PURCHASED CONTROL SYSTEM PROCESS CONTROLLER

    7.1 Interlock Monitor*

        7.1.1 Pulse Combustor Flame Safety*
        7.1.2 Boiler Water Level*
        7.1.3 Condensate Return Tank Level*
        7.1.4 FD Fan Power On*
        7.1.5 FD Damper Limit Switch*
        7.1.6 ID Fan Power On*
        7.1.7 ID Damper Limit Switch*
        7.1.8 ID Flow Switch*
        7.1.9 Main Gas Solenoid Valve*
        7.1.10 Pilot Gas Solenoid Valve*
        7.1.11 Baghouse Inlet Temperature*

TABLE 2-11:
LIST OF SYSTEM PID CONTROL LOOPS REQUIRING VALIDATION

7.2 PID Loop Controller (commercially purchased control system)

7.2.1 FD fan damper control to maintain flue gas oxygen concentration set point

7.2.2 ID fan damper control to maintain decoupler pressure set point

7.2.3 Fuel feed rate control to maintain steam pressure set point in boiler

7.2.4 Limestone feed and transport air flow (for combined coal and limestone feed) to be proportional to fuel feed rate

SYSTEM AUTOMATIC START-UP VALIDATION

System automatic validation comprised the following three sub-validation tasks:

- Data acquisition system hardware validation,
- Data acquisition system software setup validation, and
- Control commercially purchased control system's automatic start-up procedure validation.

These subtasks are explained further below.

The digital Data Acquisition System (DAS) comprised a computer and special hardware. Figure 2-17 shows a sketch of the Data Acquisition System. The DAS comprised time-share (multiplexed) 12-bit A/D converter modules (manufactured by Connecticut MicroComputer, Danbury, Connecticut) connected to an IBM-compatible personal computer (PC) via a twisted pair serial interface (RS-485). The A/D modules, each of which handled 16 differential channels, also communicated with each other via the RS-485 interface. Thermocouple modules were slightly different from the voltage modules. In the former case, a master thermocouple module was used to control the linearization of thermocouple inputs from four, 16-channel A/D converters. No such master module was required for the voltage signal. Thermocouples could have been measured directly as voltages in the voltage modules. In this case, however, the thermocouple linearization could be performed through software resident in the PC. Verification of the DAS was based on the accuracy with which the DAS read standard temperatures and voltages applied to a set of randomly selected channels. Better than 0.1 percent accuracy between the standard voltage and temperature values and those reported by the DAS constituted validation of the DAS.

"Genesis," a commercially available software package, was selected as the DAS operating system for managing the storage and graphical presentation of the real-time system data available to the IBM-PC through the DAS hardware. The package was selected on the basis of a systematic search for a software package conforming to the specifications shown in Table 2-12. Of the four packages that satisfied the specifications, the Genesis package was found to have the lowest

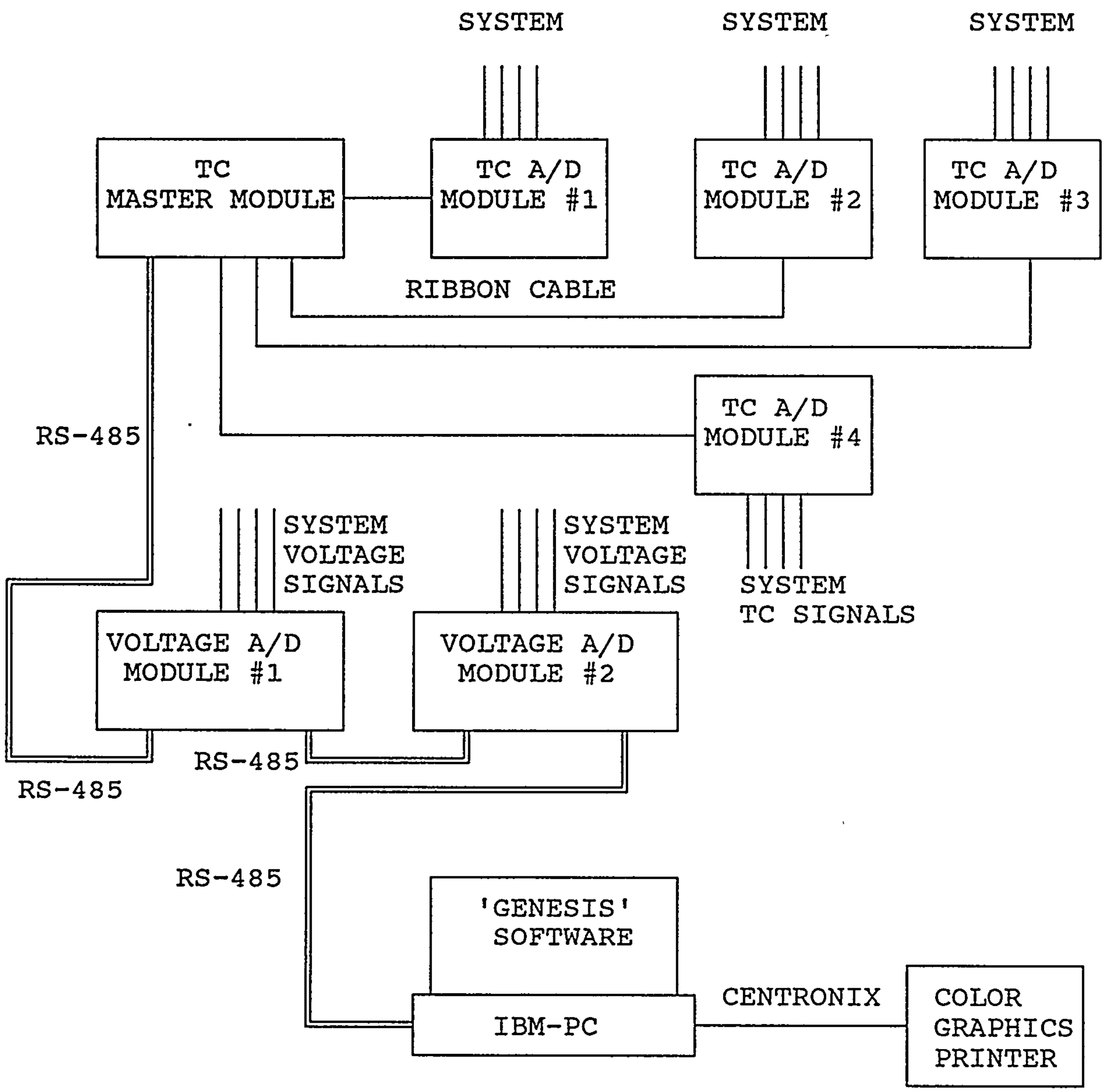


FIGURE 2-17: DATA ACQUISITION SYSTEM SCHEMATIC

TABLE 2-12:

DATA ACQUISITION AND PROCESS CONTROL SOFTWARE SPECIFICATIONS

1. Communications..RS-232

2. Graphics

   (i) User-painted color graphics with animations of process changes; PCX file compatibility preferred.

   (ii) On-screen windowed simulations of analog and digital meters, gauges, and switches.

   (iii) Auto-Cad file import/export capability.

   (iv) Historical graphic trend windowing.

   (v) On-demand display of multiple graphic pages.

   (vi) On-demand color printer outputs of currently displayed graphic page, and/or scheduled printouts of user-selected graphic pages.

3. Reporting

   (i) Scheduled and/or on-demand digital data and alarm printouts.

   (ii) Scheduled and/or on-demand digital data and alarm printouts to floppy disk of hard disk media.

4. Controls (for future reference)

   (i) Support of PID (Proportional-, Integral-, and Derivative-based) process control loops.

   (ii) Support of recipe-driven PID set points.

   (iii) Support of user-developed control strategies.

   (iv) Programming interface for PLC (Programmable Logic Controller).

cost. Although the Genesis package also had the capability for process control functions, it was used in the present application only as a data manager.

The DAS software was evaluated on the basis of the accuracy with which it acquired data from the DAS hardware and displayed it graphically. An example of animated graphics display of time varying data was also used to validate this software. In addition, data printouts and files of historic data generated by the software were examined for accuracy and correspondence with the graphically displayed data.

The Automatic System Start-Up Procedure implemented by the commercially purchased control system process controller is summarized in Table 2-13. The start-up procedure was validated by simulating the signals which inform the process controller of the system status (such as pulse combustor chamber temperature, plenum pressure, flue gas oxygen concentration, etc.). The control options activated by the process controller were monitored while varying the signals in a manner to simulate pulse combustor start-up. The maintenance of steady-state conditions by the process controller were also monitored through the use of the DAS. Process controller actions to variations of each of the following process parameters: (i) flue gas O_2 concentration, (ii) boiler steam pressure, (iii) boiler exit static pressure, (iv) and coal feed rate, were monitored and compared with the desired control actions. The above procedure validated the commercially purchased control system's process controller for natural gas-fired service. The process controller was fully validated for coal service only if it automatically started up the system under natural gas firing.

PHYSICAL AND CHEMICAL ANALYSES

The physical and chemical analyses summarized in Table 2-14 were performed on periodically collected batch samples of material being fed into the system and material being exhausted from the system.

Not all the indicated analyses were performed on all the samples. Rather, a judicious selection of the relevant analyses were performed as dictated by the test conditions and test objectives.

TABLE 2-13:

SYSTEM START-UP PROCEDURE

1. CHECK FOR PRE-IGNITION CONDITION:

   (i) Boiler water level not low

   (ii) Condensate Return Tank water level not low

   (iii) FD damper limit switch not on

   (iv) ID fan limit switch not on

   (v) O_2 Sensor reading not less than 20% (volume)

2. If Pre-ignition condition and condition is met, start ID fan, control ID fan under PID control to maintain set point pressure, and initiate purge Timer, T1, (30 sec. set point).

3. If Pre-ignition and condition is not met during timing of T1, then turn off ID fan, and re-initiate Timer, T1.

4. At end of purge timer, open pilot gas solenoid and initiate start-up timer, T2. Pilot ignition will be initiated at the end of this timer's time-out.

5. When PC chamber temperature > 350°F, start FD fan and control damper under PID control to maintain O_2 level Set Point #1, and wait for s O_2 level.

6. Open main gas solenoid and ramp up main gas flow rate under PID control to maintain PC chamber temperature increment rate (DT/Dt Set Point #1) until a chamber temperature of 1200°F is reached. Now switch O_2 set point to Set Point #2 and wait for s PID control.

7. Ramp up natural gas feed rate at DT/Dt Set Point #2 until a PC gas temperature of 2000°F is reached.

8. Now system is ready for coal feed. Coal feed is PID-controlled to maintain boiler steam pressure set point. The limestone and transport air flow rates are controlled in proportion to the desired coal feed rate.

TABLE 2-14:

PHYSICAL AND CHEMICAL ANALYSES PERFORMED ON SAMPLES

SAMPLE MATERIAL	PHYSICAL OR CHEMICAL ANALYSES
1. Coal	a. Ultimate and proximate coal analyses. b. Particle size distribution by sieve analysis for uncrushed coal, and suitable batch method for pulverized coal.
2. Fly Ash	a. Standard fly ash chemical analysis for Si, Al, Ca, Fe, Na, K, Mg, Ti, SO_3, SO_4, CO_3, LOI, acid insoluble mass fraction and acid insoluble LOI. b. Particle size distribution by suitable batch method.
3. Limestone	a. Standard chemical analysis for Ca, Mg, CO_3, and HCO_3. b. Particle size distribution by suitable batch method.
4. Boiler Dropout Ash	Same as for Fly Ash.

DATA ANALYSES METHODS

Real-time data analyses were performed with the Data Acquisition System to assess: (i) material balance, (ii) thermal balance, and (iii) system performance with respect to combustion, carbon burnout, and emissions control. The results of these on-line calculations were printed periodically on the DAS line printer. Detailed off-line data analyses were performed using Lotus- or Quattro-compatible disk files generated by the DAS.

2.2.2.1 Shakedown Tests in Design Configuration A

A total of seven runs were carried out with the three tailpipe pulse combustor (Design Configuration A -- Section 2.1.71.) on natural gas feed. The major achievements were:

Maximum Firing Rate:	5.58 MMBtu/hr
Minimum Firing Rate:	1.51 MMBtu/hr
Turndown Ratio:	Greater than 3 to 1
Thermal Efficiency:	80 - 86%
Emission data @ 3% O_2:	
- NO_x	37 - 55 ppm
- CO	4 - 400 ppm
- Hydrocarbon	17 - 93 ppm
Sound Pressure Level:	172 - 180 dB
Frequency (in combustion chamber):	45 - 60 Hz

For the design firing rate condition:

Firing Rate:	5.57 MMBtu/hr
Thermal Efficiency:	84.9%
NO_x @ 3% O_2:	53 ppm
CO @ 3% O_2:	4 ppm
Hydrocarbon @ 3% O_2:	17 ppm
Sound Pressure Level:	180 dB
Frequency (in combustion chamber):	60 Hz

Some of the test results are presented in Figures 2-18 through 2-21.

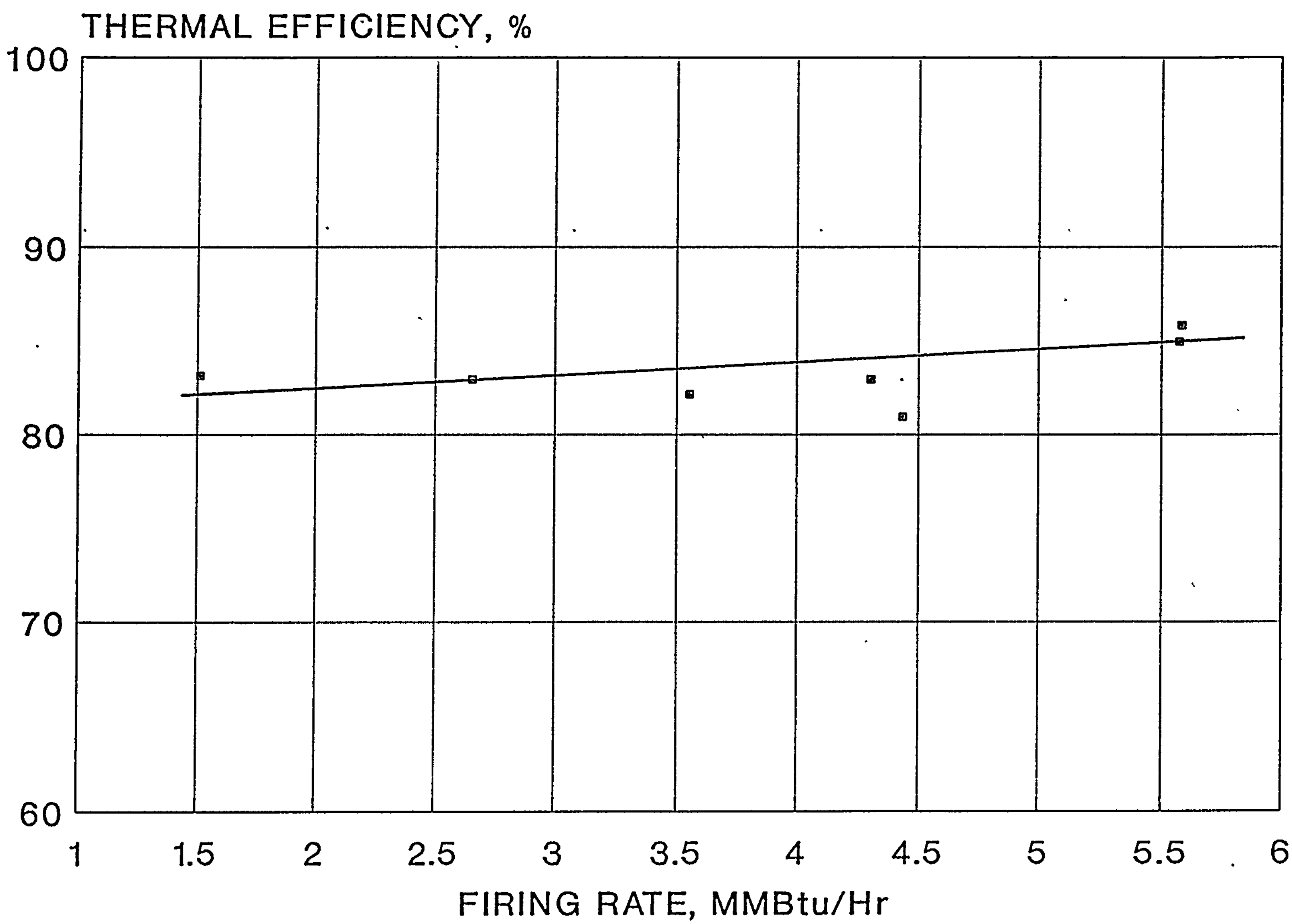


FIGURE 2-18: VARIATION IN THERMAL EFFICIENCY WITH FIRING RATE

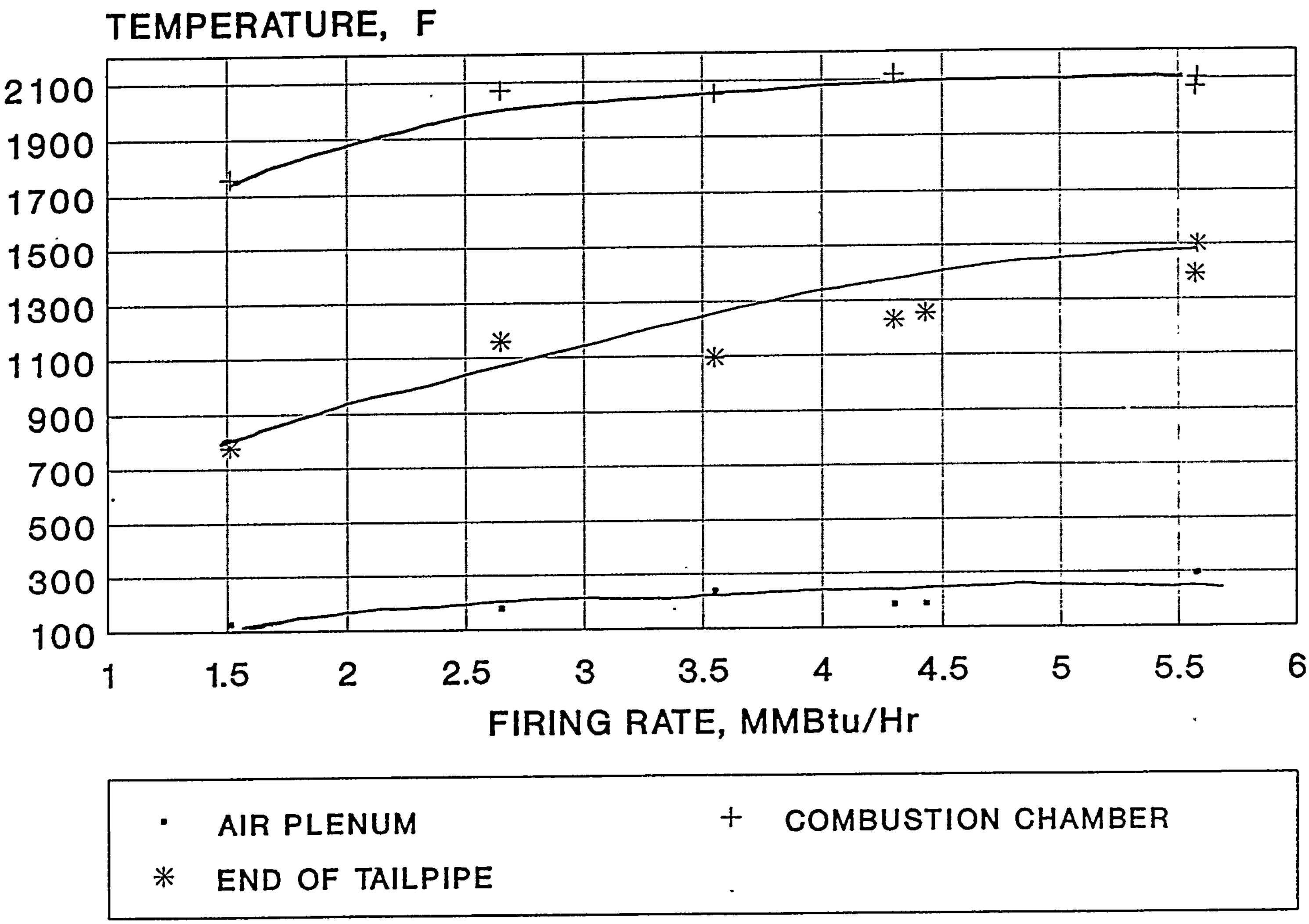
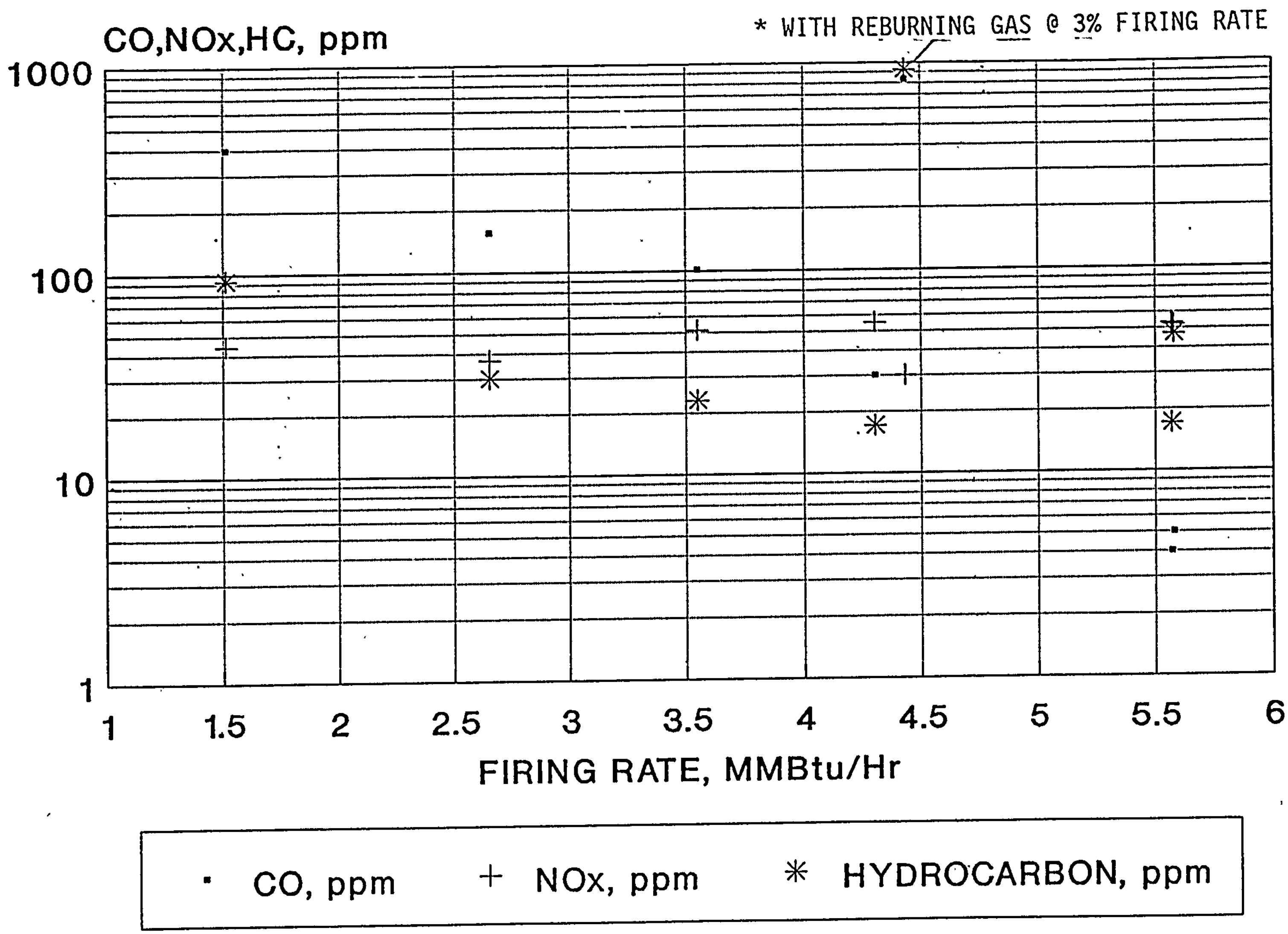


FIGURE 2-19: VARIATION IN SUBSYSTEM TEMPERATURE WITH FIRING RATE



* WITH REBURNING GAS @ 3% FIRING RATE

FIGURE 2-20: EMISSION DATA AS A FUNCTION OF FIRING RATE

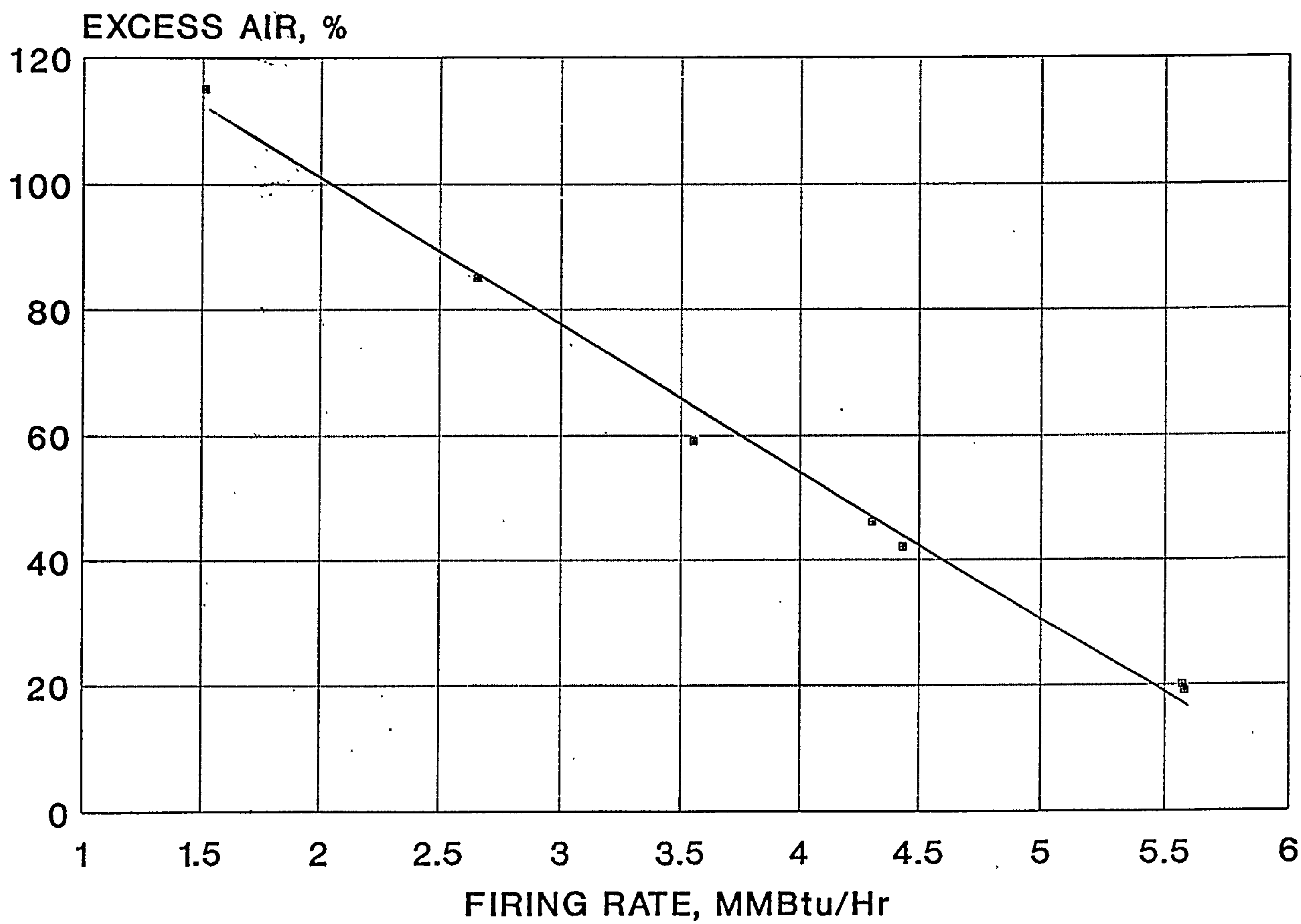


FIGURE 2-21: VARIATION IN EXCESS AIR WITH FIRING RATE

2.2.2.2 SHAKEDOWN TESTS IN DESIGN CONFIGURATION B

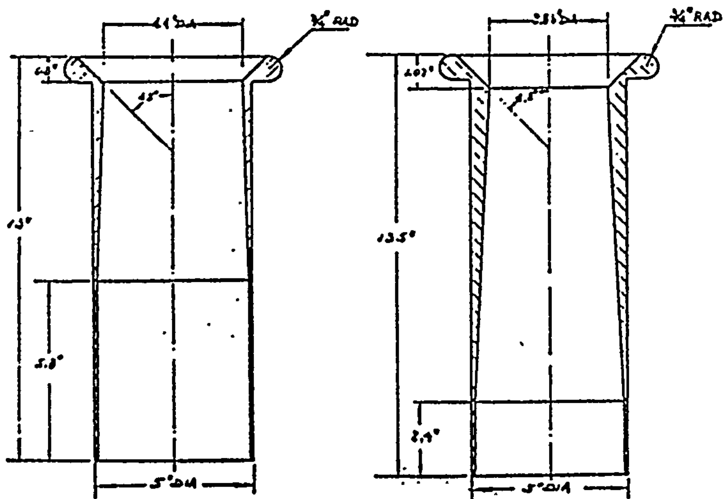
Another series of a total of 55 tests were performed in design configuration B (see Section 2.1.7.2) under natural gas firing. The unit comprised a water-cooled pulsed combustor with a spiral-shaped tailpipe followed by a water-cooled decoupler. A maximum natural gas firing rate of 4 MMBtu/hr was achieved during these tests. The characterization of the helical boiler unit included evaluation of two aerovalves and six gas injectors summarized in Table 2-15 and Figures 2-22 and 2-23. Figure 2-23 summarizes the combustion performances obtained due to variations in the gas injectors for the Type I aerovalve. The Type I aerovalve and Type V gas injector combination appeared to give the optimum combustion performance.

Characterizations of the (i) Back-Flow Ratio (ratio of backward flow rate to forward flow rate through the aerovalve), (ii) Overall Heat Transfer Coefficients in the combustion and decoupler sections, (iii) Pulse combustor Sound Pressure Level, and (iv) NO_x emissions for various gas-firing rates are summarized in Figures 2-24 through 2-26. Figure 2-24 correlates the Back-Flow Ratio with the firing rate, SPL, and combustion chamber static pressure. The backflow ratio - estimated based on air plenum temperature, air supply temperature and combustion chamber temperature - tends to increase with gas firing rate and SPL due to the higher compression ratio, but does not correlate with combustion chamber static pressure. Figure 2-25 shows that the overall flue-gas-to-water heat transfer coefficients are about 40 and 10 Btu/hr/ft^2/°F in the combustion and decoupler sections respectively of the helical boiler. The heat transfer coefficient for the tailpipe section is rather high and is comparable to that in bubbling fluidized beds. Figure 2-26 correlates the NO_x concentrations at the tailpipe and at stack with percent excess air, gas firing rate, combustion chamber temperature, and combustion chamber SPL. The percent excess air and gas firing rate appear as significant parameters influencing the NO_x concentrations. While increasing excess air appears to result in increasing NO_x concentrations, increasing gas firing rate appears to result in decreasing NO_x concentrations. Figure 2-27 shows the effect of secondary gas firing rate on NO_x emissions. Increasing secondary gas firing rate appears to result in decreasing NO_x concentrations. This indicates the beneficial effect of gas reburning on reducing NO_x emissions.

TABLE 2-15:
COMBUSTION PERFORMANCE WITH DIFFERENT TYPES OF AEROVALVES

AEROVALVE TYPE		TYPE I	TYPE II
FIRING RATE, MMBtu/hr		2.76	2.75
PRESSURE, "H_2O	Combustor	8.5	8.5
	Air Plenum	13	7.5
	Decoupler	-1.2	-0.9
TEMPERATURE, °F	Air Plenum (primary)	431	400
	Combustion Chamber	2010	2000
	Tailpipe Exit	1772	1775
	Air Plenum (secondary)	1089	879
	Decoupler	1124	1133
	Stack	471	620
	Steam	214	216
GAS ANALYSIS *	O_2, %, Tailpipe	1.4	0.3
	O_2, %, Stack	9.6	4
	CO, %, Tailpipe	0.03	0.96
	CO, %, Stack	0.02	0.53
	NO_x, ppm, Tailpipe	38	46
	NO_x, ppm, Stack	39	20
	HC, %, Tailpipe	0	0.3
	HC, %, Stack	0	-
FREQUENCY, Hz		64	60
SPL, dB, Combustor Chamber		174	172
GAS INJECTOR POSITION, inch **		1	0.9

* Converted to 3% O_2.
** Gas injector type: Type II.



TYPE (I) TYPE (II)

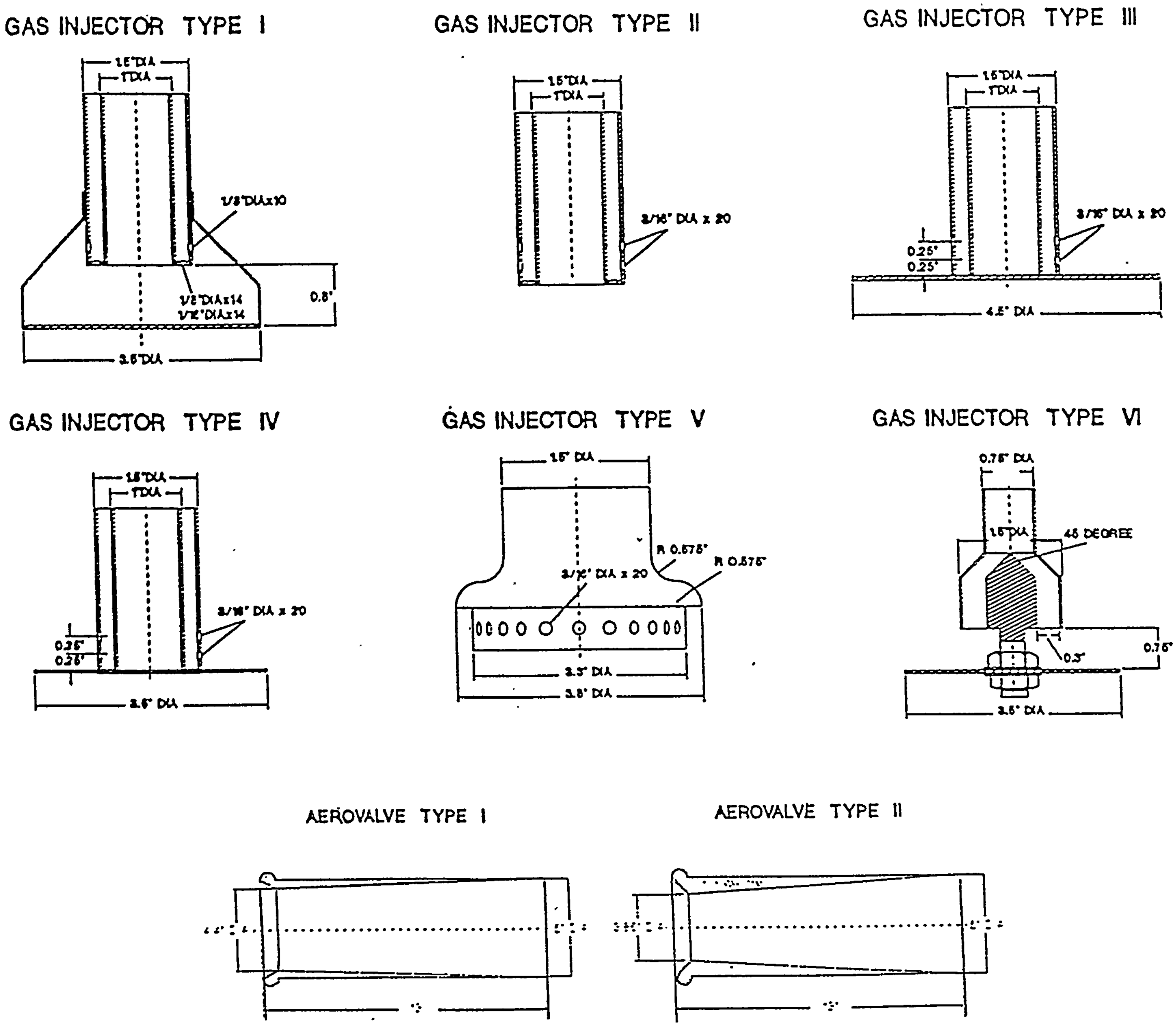


FIGURE 2-22: CONFIGURATION OF SIX TYPES OF GAS INJECTORS AND TWO TYPES OF AEROVALVES

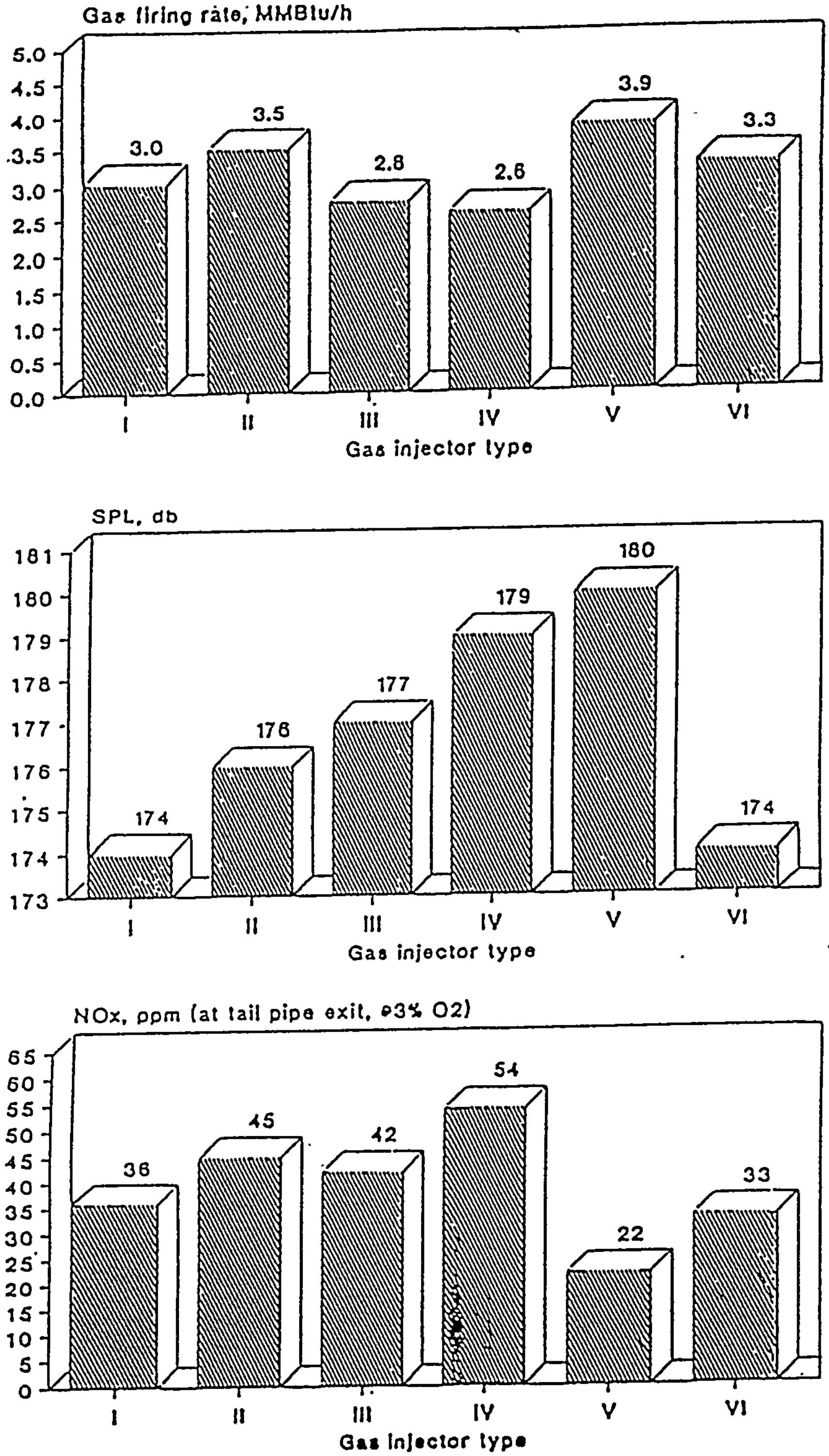


FIGURE 2-23: COMBUSTION PERFORMANCE COMPARISON OF HELICAL UNIT WITH DIFFERENT TYPES OF GAS INJECTORS (TYPE I AEROVALVE)

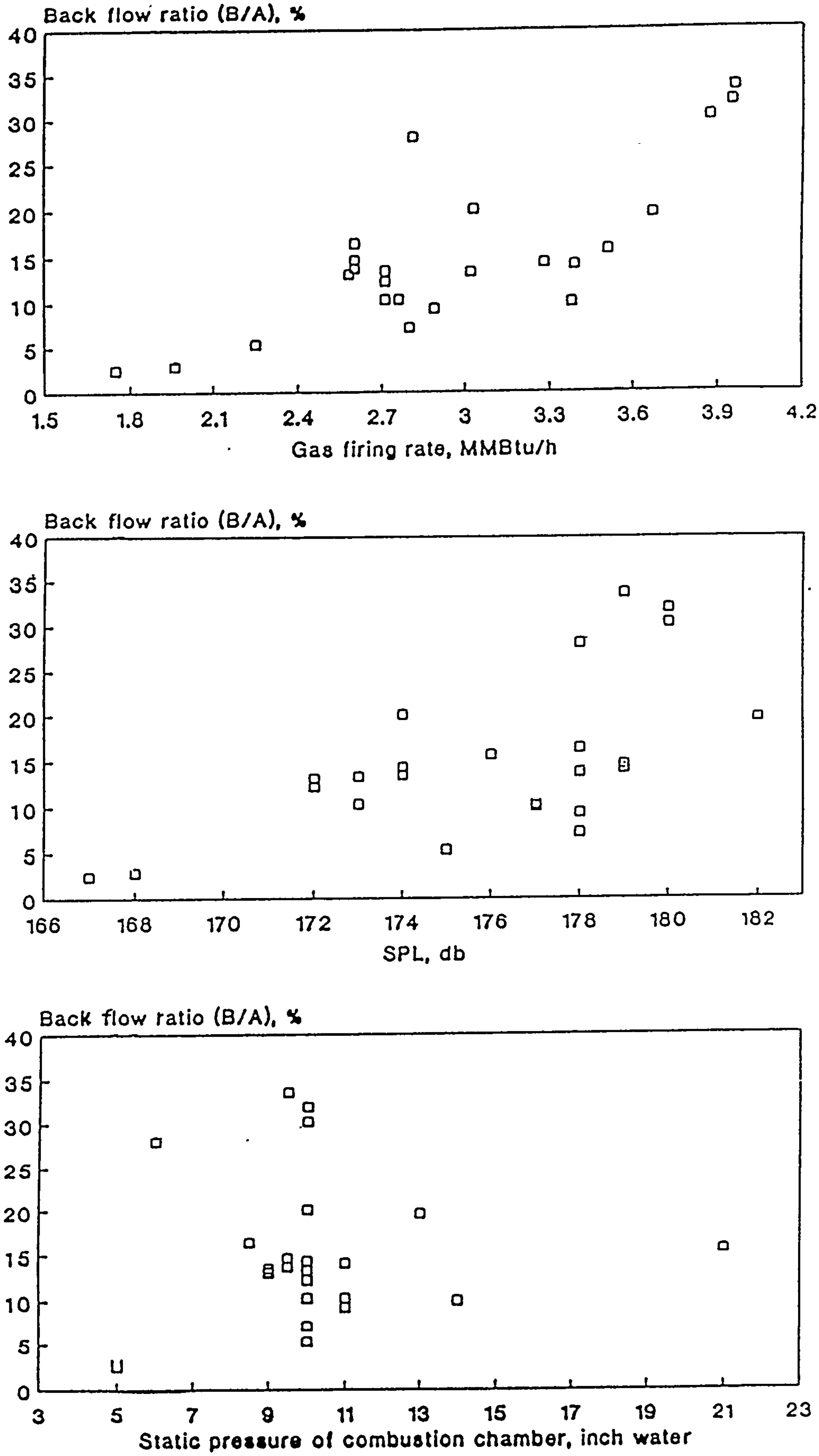


FIGURE 2-24: BACK FLOW RATIO OF HELICAL UNIT FIRING NATURAL GAS

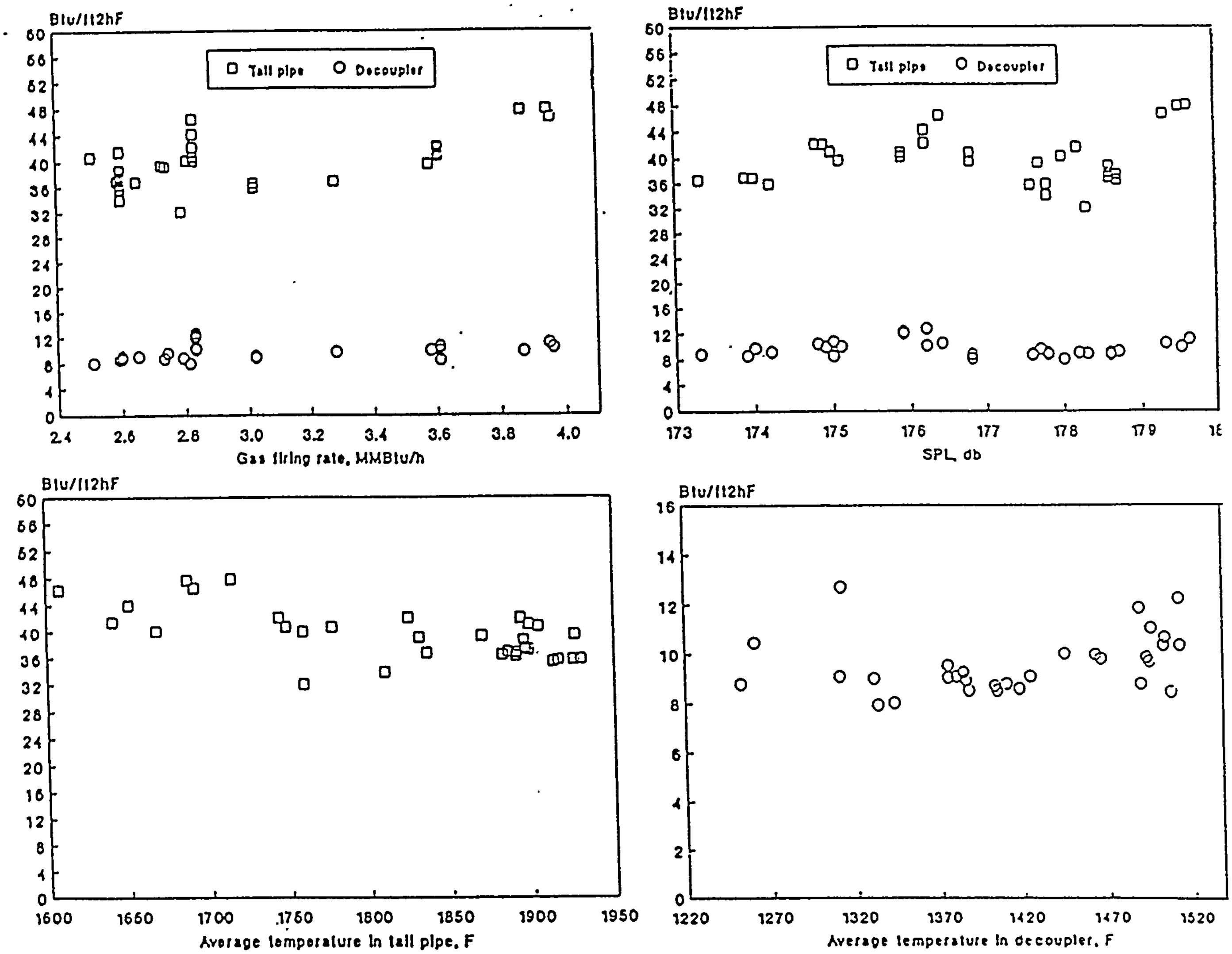


FIGURE 2-25: OVERALL HEAT TRANSFER COEFFICIENT
OF HELICAL UNIT FIRING NATURAL GAS

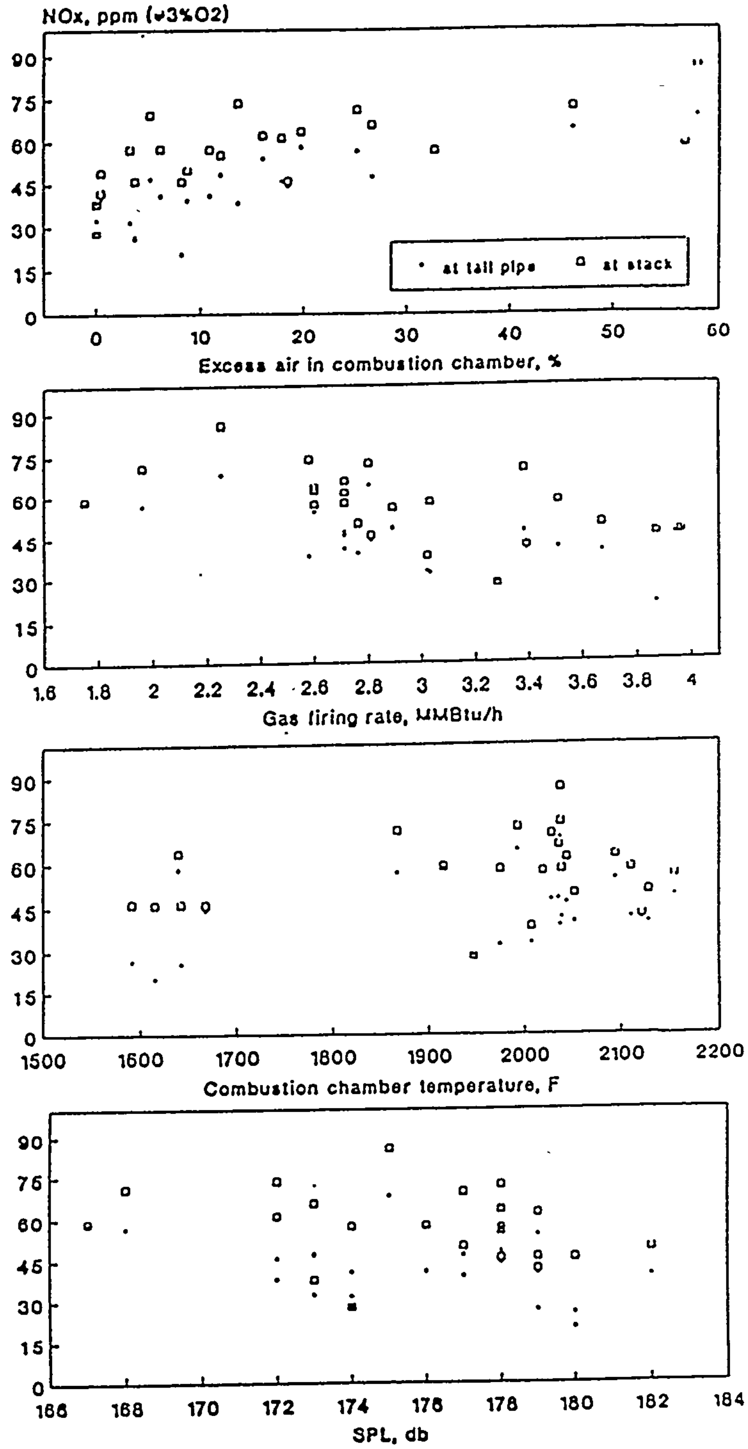
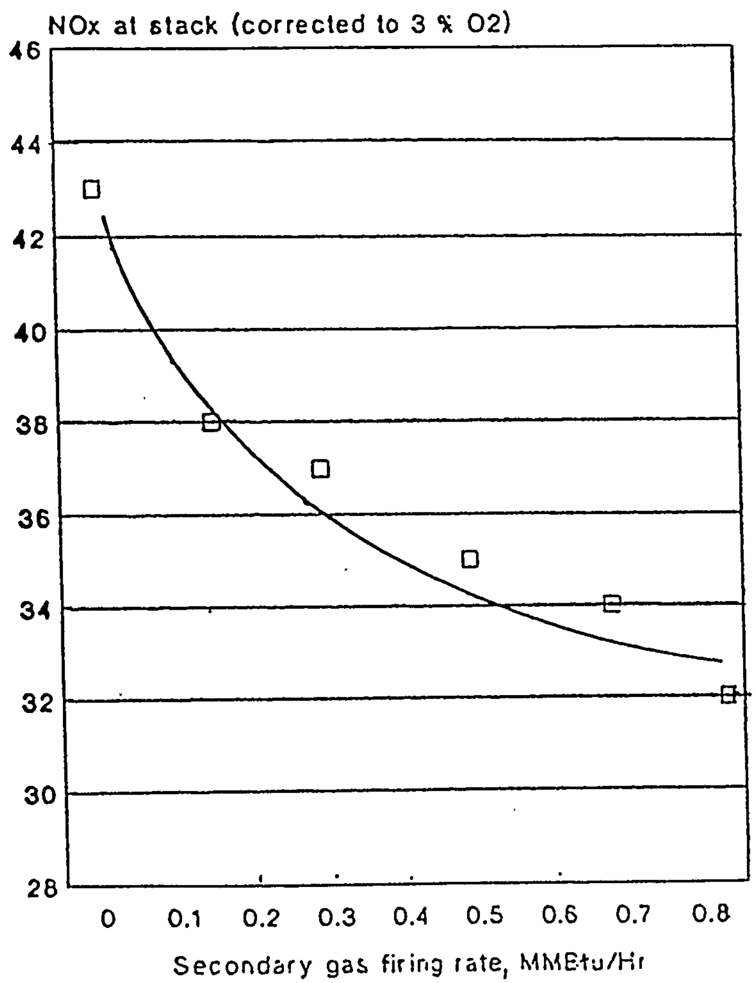
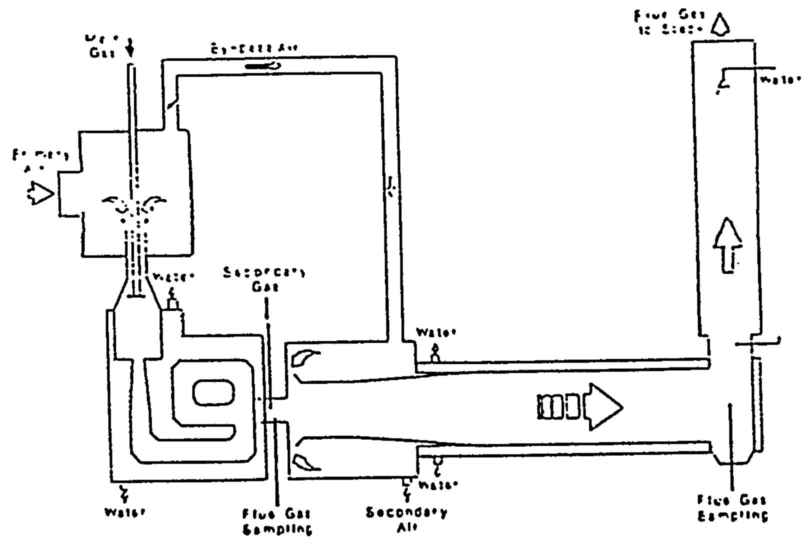


FIGURE 2-26: NO_x EMISSIONS FROM HELICAL UNIT FIRING NATURAL GAS





Gas injector	V	V	V	V	V	V
Aerovalve	1	1	1	1	1	1
Combustor firing rate, MMBtu/Hr	2.83	2.83	2.83	2.83	2.83	2.83
Reburning gas firing rate, MBtu/Hr	0	0.15	0.29	0.49	0.68	0.83
Air plenum pressure, "H2O	10.5	10.5	10.5	10.5	10.5	10.5
Comb. chamber press. "H2O	8.5	8.5	8.0	8.2	8.5	8.3
Air plenum temperature, F	500	522	513	521	525	528
Comb. chamber temperature, F	1809	1845	1958	1939	1902	1927
O2 @ stack, %	4.7	2.8	3.0	2.8	3.1	2.5
CO @ stack, % (@3% O2)	0	0	0	0	0	0
NOx @ stack, % (@3% O2)	43	38	37	35	34	32
[illegible] @ stack, % (@3% O2)	0	0	0	0	0	0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

FIGURE 2-27: NO_x REDUCTION WITH NATURAL GAS REBURNING

2.2.2.3 Shakedown Tests in Design Configuration C

Based on a review of the results from the foregoing natural gas tests and experience in coal combustion in a pulse combustor in another project, the following conclusions were reached:

1) The tailpipe exit temperature in Configuration A was typically less than 1400°F suggesting a heat transfer coefficient higher than the design value. A tailpipe temperature on the order of 2000°F was desired for enhancing coal combustion and this favored a single tailpipe configuration.

2) Because the tailpipe occupied the major portion of the boiler Morrison tube, the decoupler section was not big enough. The distance between the end of the tailpipe and back door was only 72 inches. This seemed to accentuate vibration of the boiler back door. The strength of vibration depended on the firing rate of the pulse combustor and the sound pressure level in the combustor.

Some modifications of the pulse combustor configuration, as shown in Figure 2-28, were carried out. The revised Configuration C (see Section 2.1.7.3) had the following features compared with the one before modification: The tailpipe was changed from multi-pipe (three pipes) to single pipe in order to keep the tailpipe section in high temperature zone by reducing the heat transfer surface. Also, the tailpipe incorporated a 90-degree turn. It directed the flow into the main combustion zone vertically so that the coal particle distribution was uniform. Another advantage of this tailpipe design was that it led to a more compact combustor design that occupied less space. The last section of the tailpipe was made of refractory to protect the uncooled Morrison tube entrance section. The whole refractory liner consisted of two layers of different materials: the inner was made of high-density refractory and the outer was made of low-density refractory. The end of the tailpipe was 140 inches from the back door of the boiler. It increased the volume of the decoupler by 78 percent and was expected to reduce the vibration of the back door and aid in char combustion and sulfur capture.

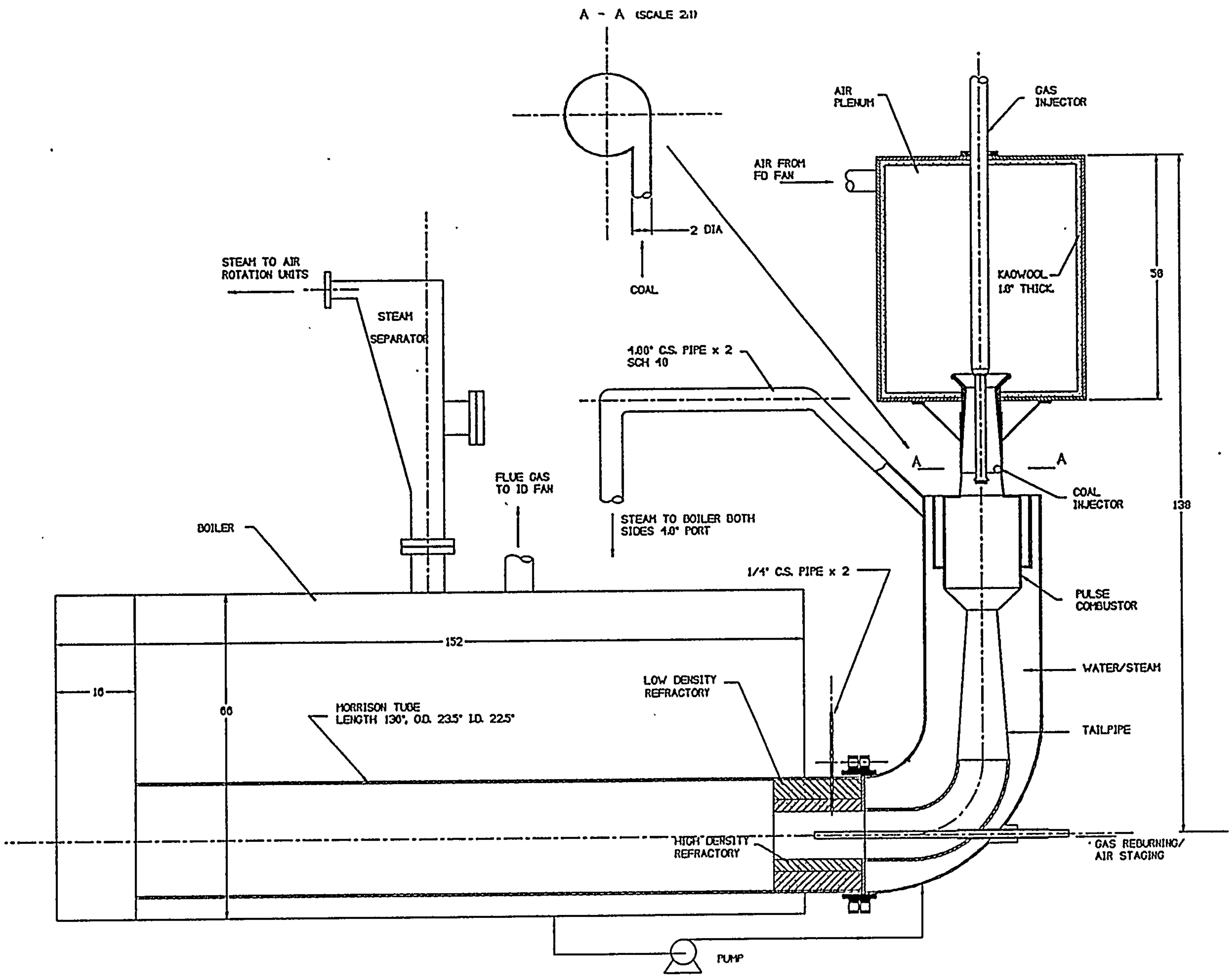


FIGURE 2-28: MODIFICATION OF PULSE COMBUSTOR (CONFIGURATION C)

A conical reducer was added between the combustion chamber and the tapered tailpipe section to prevent coal particle entrapment in recirculation zones. Also, more of the combustion chamber was radiatively cooled and less surface was directly water-cooled to promote coal devolatilization and also to achieve 2000+°F temperature under part-load operation. A pump was incorporated between the boiler and the pulse combustor water jacket to enable forced circulation. The steam-water mixture from the pulse combustor water jacket was admitted on the sides of the boiler and not into the steam separator as done earlier. The air plenum shape was modified from parallel-piped to cylinder in order to make it compact. The air plenum was lined with kaowool to absorb the acoustic energy coming from the combustor.

After modifications were completed, one set of shakedown tests with natural gas was carried out. Table 2-16 shows a summary of test results. The firing rate of the combustion system ranged between 1.36 and 5.32 MMBtu/hr. The thermal efficiency of the boiler was between 80 and 82 percent. The emissions performance of this combustor on natural gas was excellent with NO_x and CO below 30 ppm and negligible TUHC. In this modification, 78 percent of the surface area of the combustion chamber was changed from fully water-cooled mode to radiative cooling. One thermocouple was installed on the surface of the combustion chamber to monitor the metal temperature. The maximum temperature of this surface during the test was 1350°F. This was within the safe operating limit for 304 stainless steel, the material used in the fabrication of the combustion chamber.

The shakedown tests on natural gas went well enough to permit switching to coal-firing. A new coal and gas injector was designed and fabricated. Figure 2-29 shows the new injector. The inner pipe was for coal and limestone feed, and the annular space between the inner and outer pipes was for gas and superheated steam, if necessary. The impactor plate was attached to the end of the injector for distributing coal transversely to the air flow.

TABLE 2-16:

TEST RESULTS SUMMARY FOR MODIFIED PULSE COMBUSTOR

FIRING RATE, MMBtu/hr		1.36	5.32
TEMPERATURE, °F	Air Plenum	98	96
	Combustion Chamber	2032	--
	Exit of Boiler	233	297
PRESSURE, inches of H_2O	Air Plenum	9	11
	Combustion Chamber	0	6.8
	Exit of Boiler	-0.6	0.1
EMISSION DATA	O_2, %	5.2	4.3
	CO, ppm @ 3% O_2	21	17
	NO_x, ppm @ 3% O_2	24	27
	TUHC, ppm @ 3% O_2	0	0
ACOUSTIC DATA COMBUSTION CHAMBER	SPL, dB Frequency, HZ	164 70	174 60
BOILER THERMAL EFFICIENCY, %		80	82.1

Since the initial shakedown tests with coal were planned to be carried out without limestone addition to establish baseline performance, an analysis was performed to estimate the maximum possible SO_2 concentration in the flue gas. This turned out to be about 900 ppmv @ 3% O_2 or 1.8 lb/MMBtu for Coal A. This would have exceeded the New Source Performance Standards (NSPS) for SO_2 emissions. It was therefore decided to limit the SO_2 emissions to 1.2 lb/MMBtu or 600 ppmv @ 3% O_2 by co-firing up to 33% natural gas with coal.

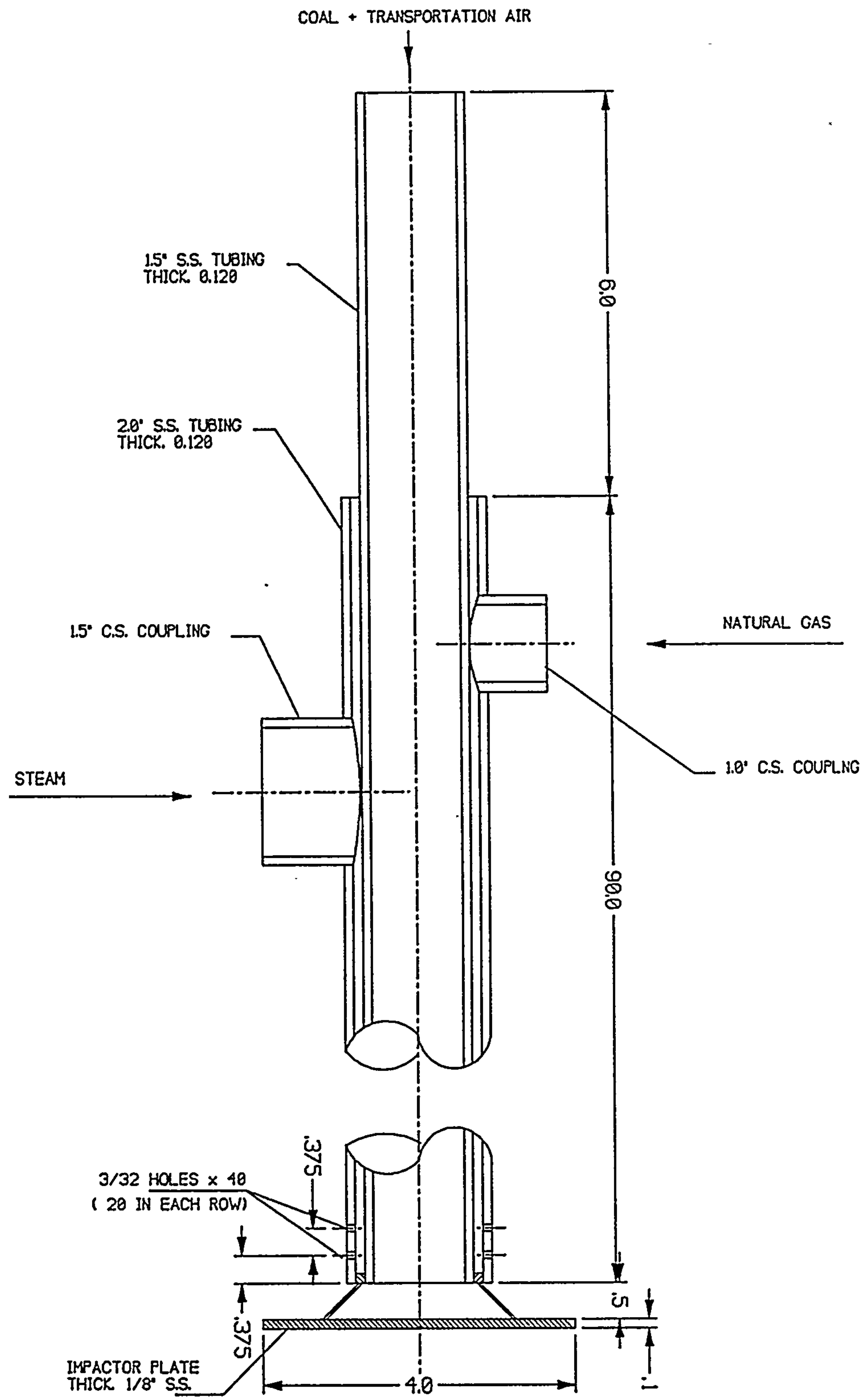


FIGURE 2-29: COAL INJECTOR

A series of shakedown tests were carried out with Coal A. Table 2-17 shows a summary of the test results. The dynamic pressure signal from the combustion chamber is shown in Figure 2-30. The pressure oscillations were relatively robust (4-6 psi peak-to-peak) and near monotonic and sinusoidal. The emissions performance was encouraging. Since a long duration steady-state test was not performed, combustion and thermal efficiencies of the unit were not determined.

Another series of tests was initiated. The main fuel used in these tests was Coal A (analysis is shown in Table 2-1). The total firing rate ranged from 3 MMBtu/hr to 5.4 MMBtu/hr. The natural gas support did not exceed about 15 percent. Test results of this set are shown in Figures 2-31, 2-32, and 2-33. The effect of firing rate on temperatures at various locations was negligible as shown in Figure 2-31. The temperatures in the combustion chamber and at the end of the tailpipe were similar to those with natural gas. But the temperature of radiantly-cooled chamber metal surface reached 1552°F and it was almost 200°F more than the temperature with natural gas. This is attributed to the radiant contribution from the burning coal particles. Figure 2-32 shows the emissions performance at different firing rates. NO_x ranged from 250 to 400 ppm, SO_x ranged from 550 to 670 ppm, CO ranged from 160 to 400 ppm, and the hydrocarbon emissions were below 30 ppm. Figure 2-33 shows the acoustic performance of the pulse combustor firing with pulverized coal. The frequency remained at 56 Hz and the sound pressure level registered 175-176 dB. This indicated very stable coal combustion.

A micronized coal - Coal C - was also tested during this series. The analysis of micronized coal is shown in Table 2-2. Figure 2-34 shows a comparison of test results for these two kinds of coal. Micronized coal showed a better emissions performance than Coal A. But the boiler vibration when firing micronized coal was more serious than with Coal A because the frequency had changed from 56 Hz to 52 Hz and may have coupled with the natural frequency of the system.

TABLE 2-17:

SHAKEDOWN TESTS WITH COAL A

TOTAL FIRING RATE:	3 - 4.5 MMBtu/hr
COAL FIRING RATE:	2 - 3.2 MMBtu/hr
AIR PLENUM TEMPERATURE:	90 - 100°F
COMBUSTION CHAMBER TEMPERATURE:	2000 - 2300°F
TAILPIPE EXIT TEMPERATURE:	1900 - 2200°F
BOILER EXIT:	260 - 280°F
BAGHOUSE INLET:	255 - 275°F
AIR PLENUM STATIC PRESSURE:	4 - 6 inch H_2O
COMBUSTION CHAMBER STATIC PRESSURE:	3 - 4 inch H_2O
COMBUSTION CHAMBER SPL:	174 - 176 dB
FREQUENCY:	56 Hz
SO_2 EMISSIONS:	500 - 600 ppmv @ 3% O_2 (1.0 - 1.2 lb/MMBtu)
NO_x EMISSIONS:	140 - 420 ppmv @ 3% O_2 (0.2 - 0.6 lb/MMBtu)
CO EMISSIONS:	120 - 350 ppmv @ 3% O_2 (0.1 - 0.3 lb/MMBtu)
TUHC EMISSIONS:	5 - 30 ppmv @ 3% O_2

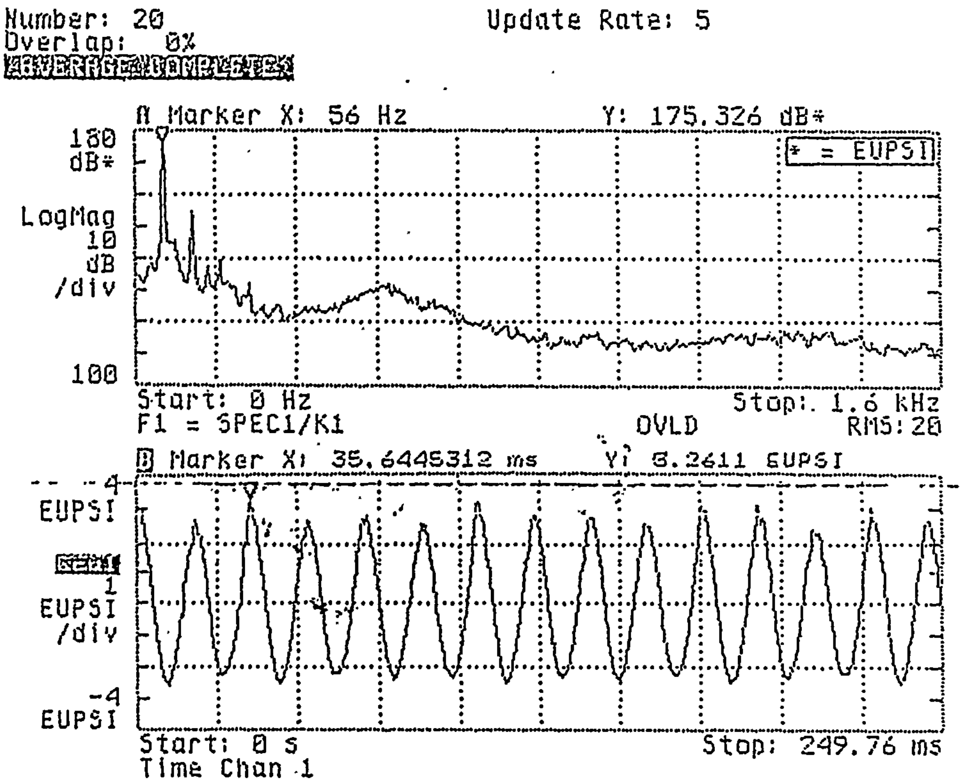


FIGURE 2-30: COMBUSTION CHAMBER POWER SPECTRUM WITH COAL FIRING

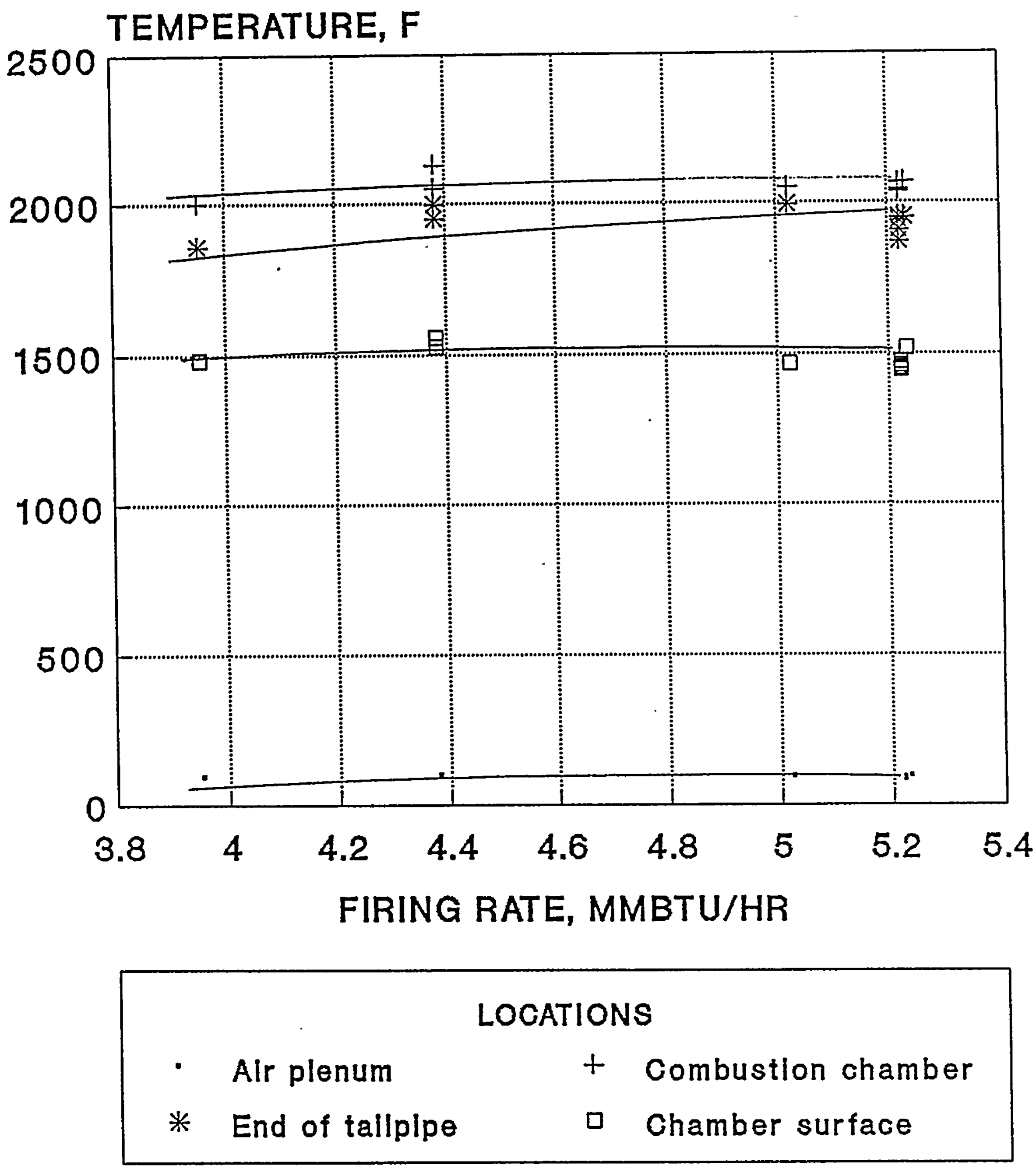


FIGURE 2-31: TEMPERATURE DISTRIBUTION AT DIFFERENT FIRING RATES

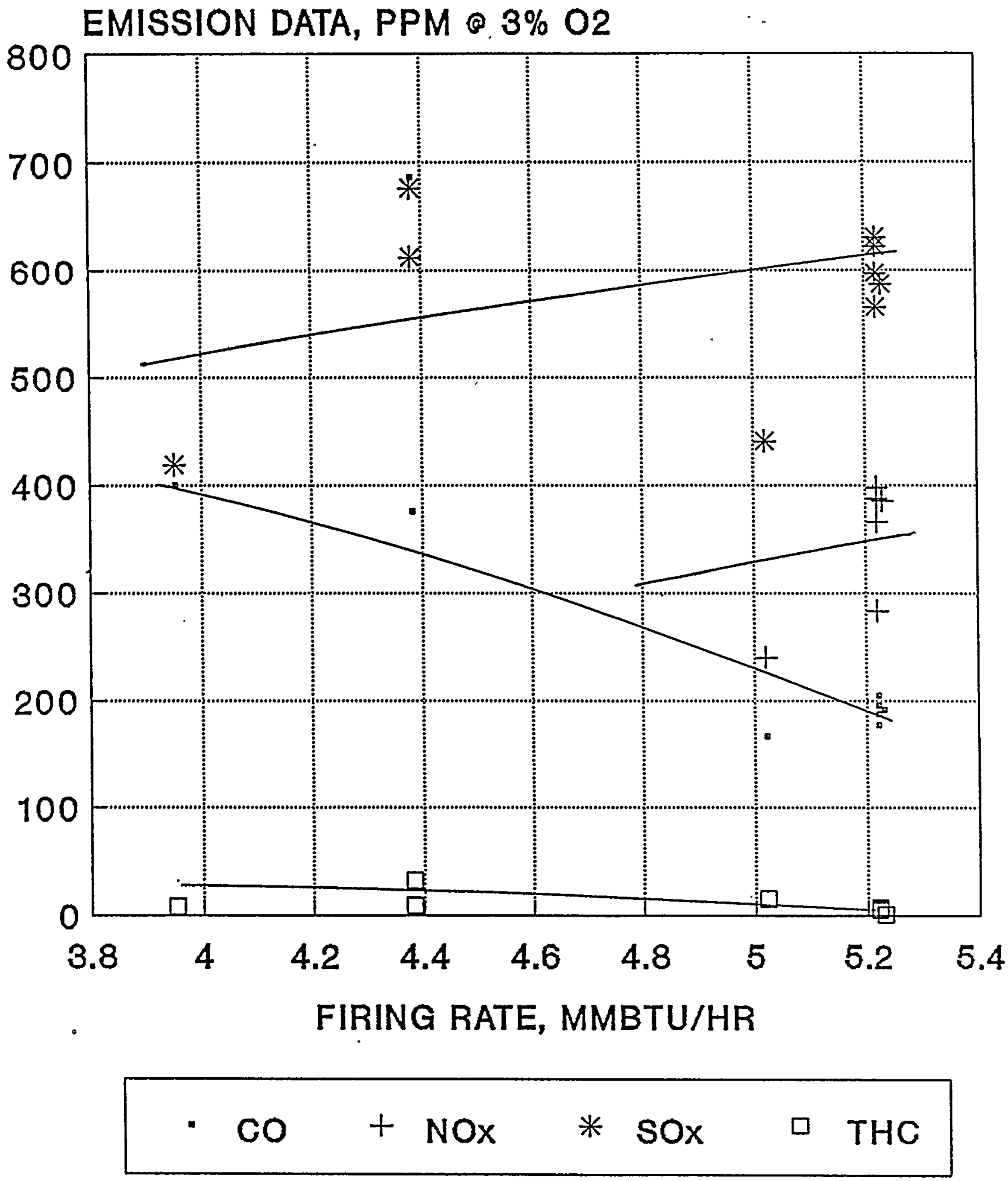


FIGURE 2-32: EMISSIONS PERFORMANCE AT DIFFERENT FIRING RATES

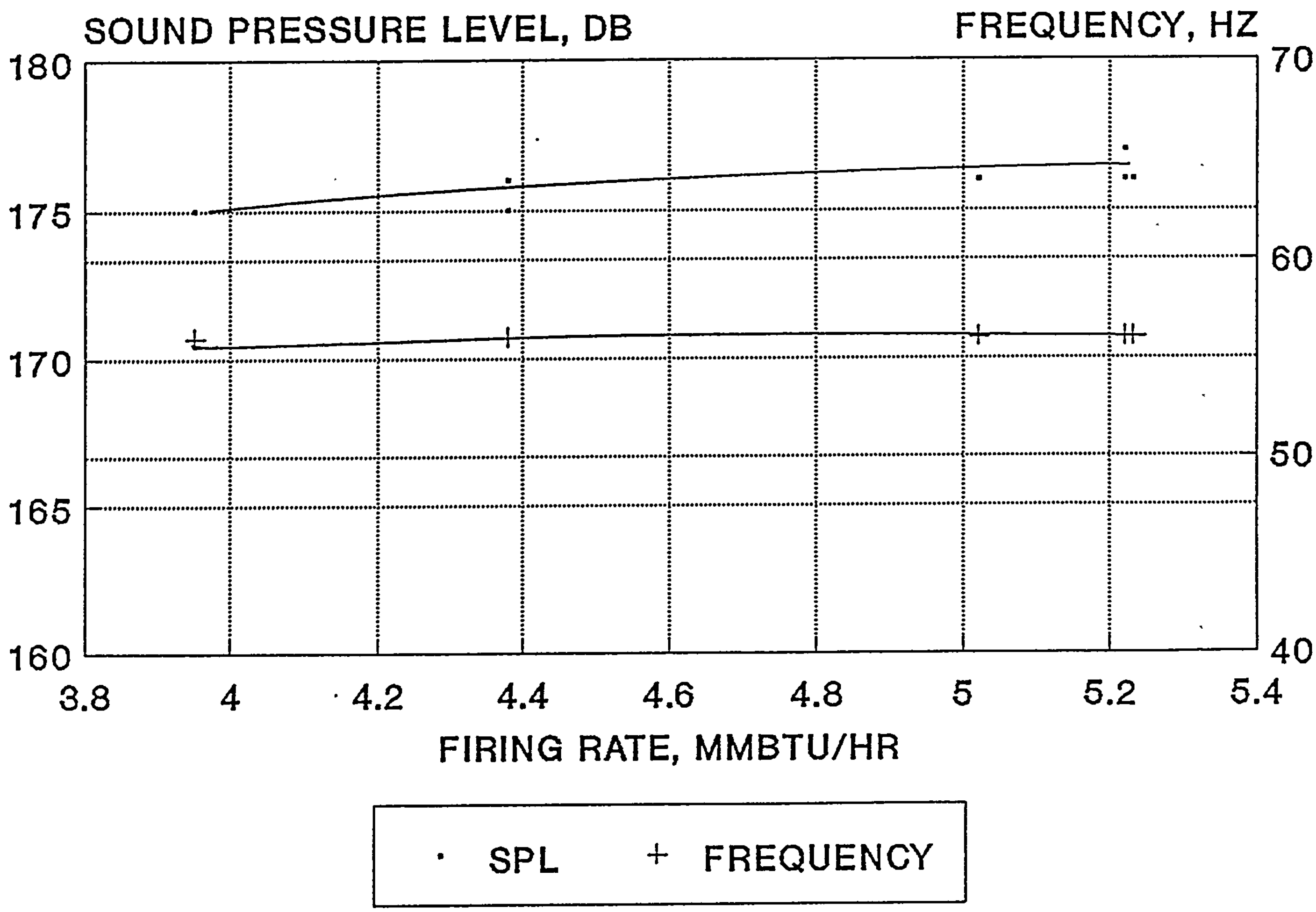
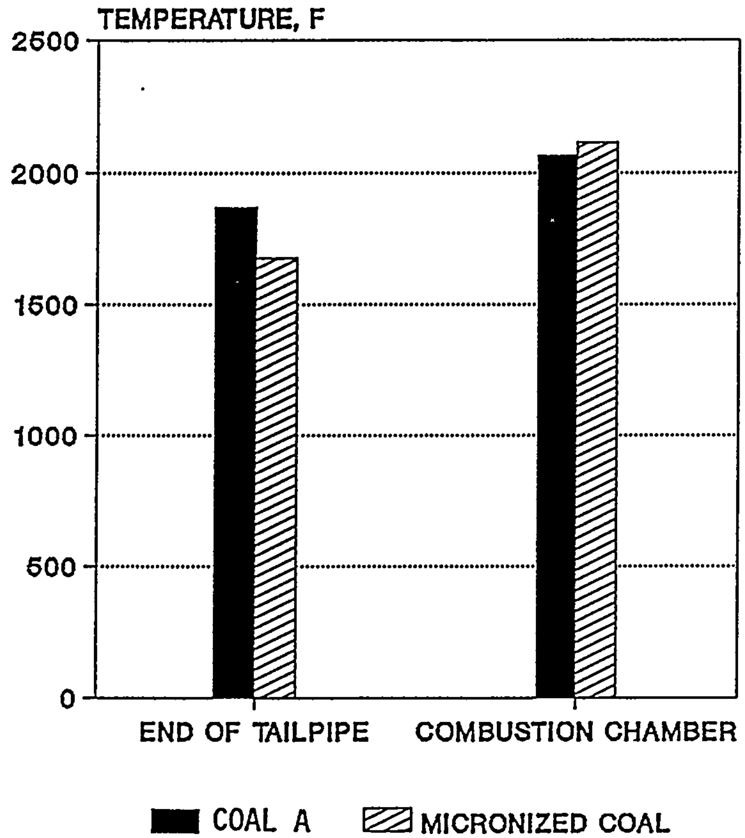


FIGURE 2-33: ACOUSTIC PERFORMANCE AT DIFFERENT FIRING RATES



SAME FIRING RATE 5.3 MMBTU/HR

FIGURE 2-34A: EFFECT OF MICRONIZED COAL ON TEMPERATURE

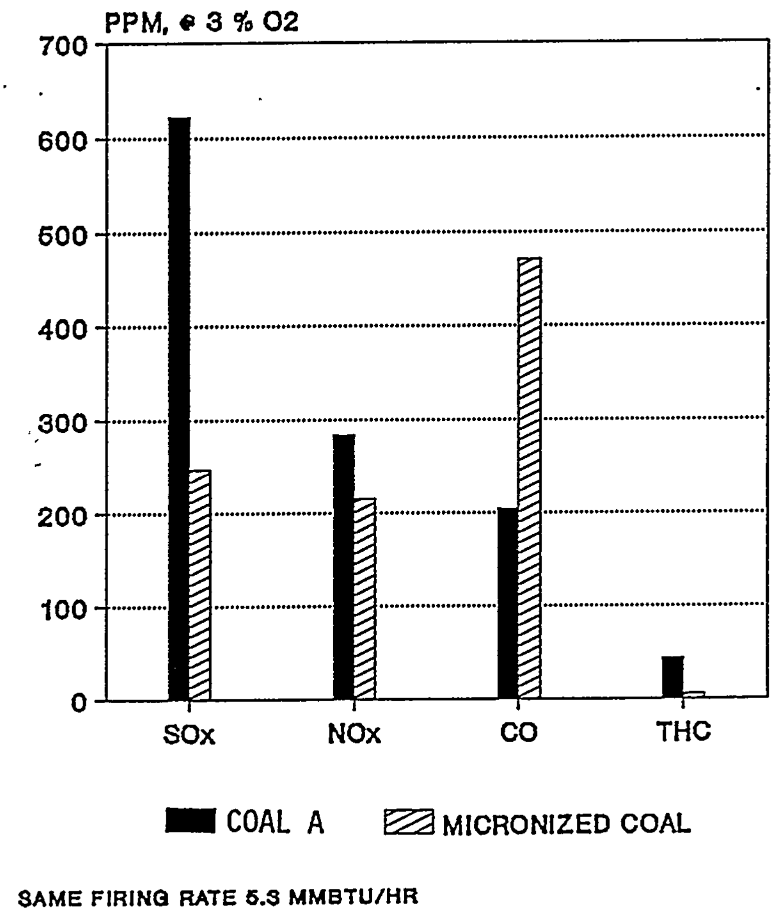


FIGURE 2-34B: EFFECT OF MICRONIZED COAL ON EMISSIONS PERFORMANCE

An additional shakedown test firing Coal A with dolomitic limestone (Table 2-3) was also performed. The test results are shown in Figure 2-35. The mixing of coal with limestone obviously helped drop the SO_x in exhaust gas from 450 ppm to 250 ppm. But it also decreased the temperature of the combustion chamber from 2000°F to 1850°F which produced more CO than in the absence of limestone. The shakedown tests indicated that the coal supply was not uniform because of the very low speed and high intra-sprocket volume of the rotary valve. Therefore, the rotary valve was modified to solve this problem.

The combustion efficiency of the system was low (about 90%). To improve combustion efficiency, it was decided to incorporate a radiation shield inside the Morrison tube to reduce heat loss. A stainless steel tube of 20 inches diameter and 10 feet long was installed in the Morrison tube to act as the radiation shield. In addition, the flow cross-sectional area for coal injection into the combustion chamber was reduced 63 percent by changing the impactor from 1/2 to 3/16 inches. The objective was to increase the injection velocity of the coal and air mixture and improve coal mixing with combustion air. The steam superheating section was also installed so that superheated steam would be injected into the pulse combustion chamber to further reduce the formation of NO_x.

2.2.2.4 Screening Tests in Design Configuration C

More than 100 hours of screening tests were performed to characterize the system. The parameters examined included coal firing rate, excess air level, ash recycle rate, coal type (Coal A and Coal C), dolomitic limestone feed rate, and steam injection rate. The significant accomplishment during this period was the achievement of the following:

- Stable pulse combustor operation was achieved with a variation in coal firing rate from 1.8 to 7.5 MMBtu/hr, indicating a nominal 4:1 turndown capability;

- The pressure oscillations were robust and the sound pressure level (SPL) varied from 161 to 178 dB with an increase in firing rate. The waveform was near sinusoidal as shown in Figure 2-36 with very low harmonics.

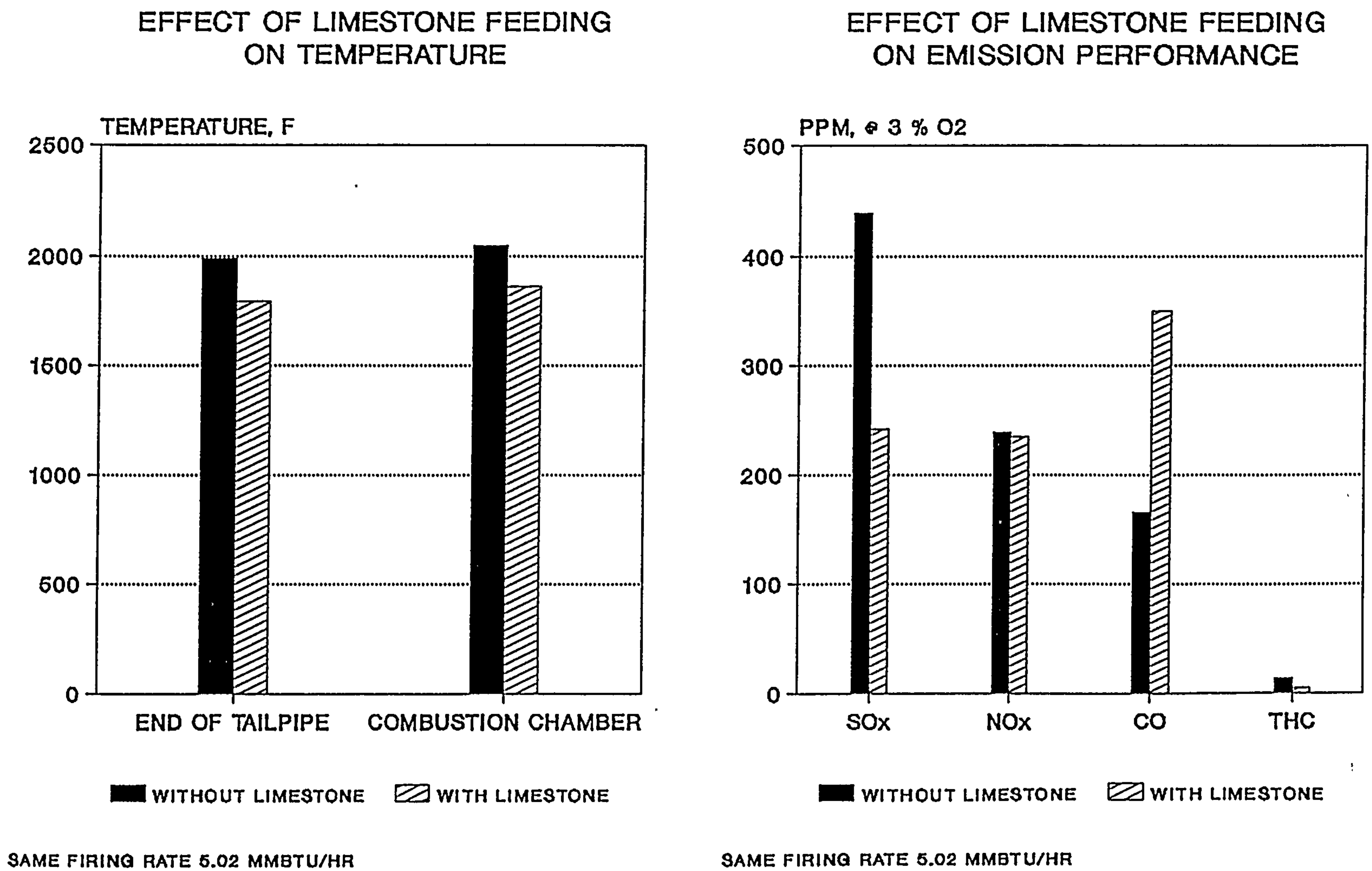


FIGURE 2-35: EFFECT OF LIMESTONE ON TEMPERATURE AND EMISSIONS PERFORMANCE

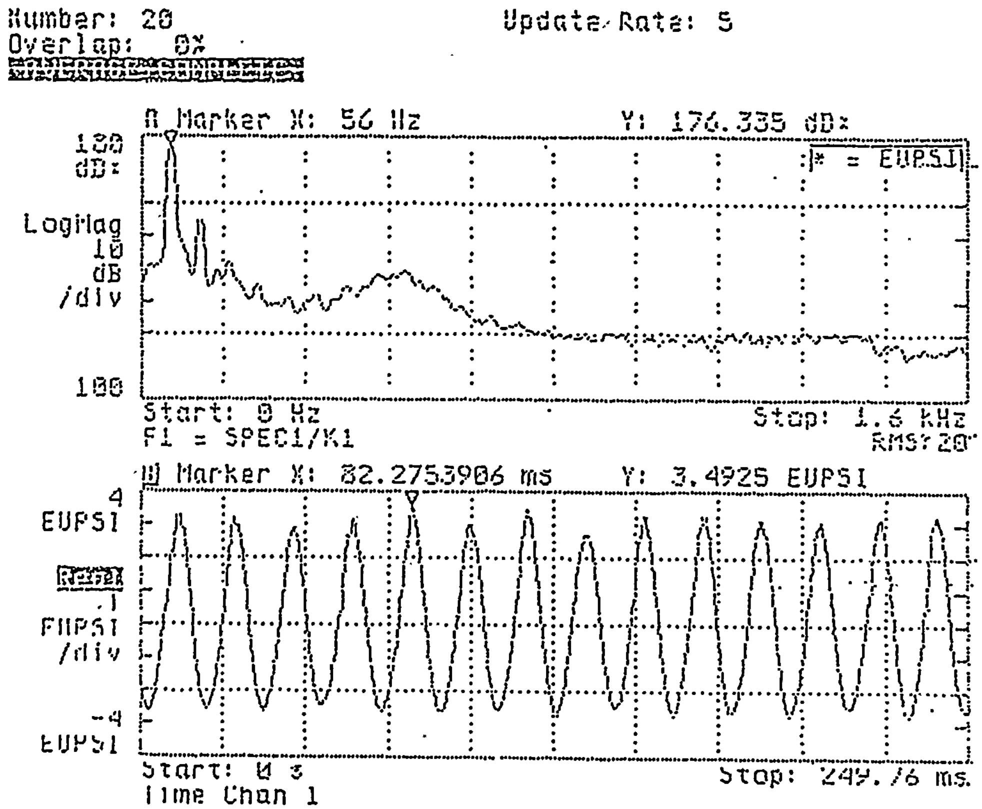


FIGURE 2-36: PULSE COMBUSTION CHAMBER DYNAMIC PRESSURE SIGNAL WITH COAL FIRING

- The combustion efficiency typically ranged from 90 to 95 percent. These are lower than the target value (99+%) due to inadequate char residence time in the hot zone. Ash recycle was attempted to improve combustion performance but the improvement was marginal.

- With micronized coal, the combustion chamber temperature was higher and SO_2, NO_x and TUHC emissions were lower than those in the case of dry pulverized coal. However, the CO emissions were higher.

- With limestone injection, the SO_2 emissions decreased. The CO emissions, however, increased due to lower temperature in the combustion zone. NO_x and TUHC emissions were relatively invariant.

- The pulse combustor demonstrated stable operation at different excess air levels ranging from 10 to 70 percent. The pulse combustor tended to operate with higher excess air levels at lower firing rates.

- The injection of superheated steam into the pulse combustor with coal firing did not reduce NO_x emissions significantly.

- The stack particulate emissions were below 0.01 lb/MMBtu indicating an efficient baghouse operation.

The results of the initial 13 coal system tests performed during this period indicated that some modifications to the system for coal burning were required. Figures 2-37 and 2-38 show the test results. The total firing rate ranged between 4.88 and 5.34 MMBtu/hr with variations in excess air levels. The auxiliary fuel (natural gas) support ranged from 5 to 15 percent including the pilot burner firing rate (1.5% of total). The parameters varied include primary zone stoichiometry and secondary air injection rate and in turn the excess air level, ash recycle rate, and steam injection into the combustion chamber. The temperature in the combustion chamber ranged from 2045 to 2327°F and that at the tailpipe exit ranged from 1923 to 2273°F. The carbon monoxide emissions ranged between 66 and 130 ppm, and NO_x emissions ranged between 550 and 800 ppm, all corrected to 3 percent O_2. The acoustic data showed the sound pressure level in the combustion chamber to average about 176 Db and the frequency to be 58 Hz. The thermal efficiency was low and ranged between 68 and 75 percent.

The unburned carbon loss was significant (13 to 16%) and was much more than anticipated. In order to improve the combustion efficiency of coal, an ash recycle approach was tried. The flow diagram for ash recycle is shown in Figure 2-39. Compressed air passed through an eductor and transported ash collected by

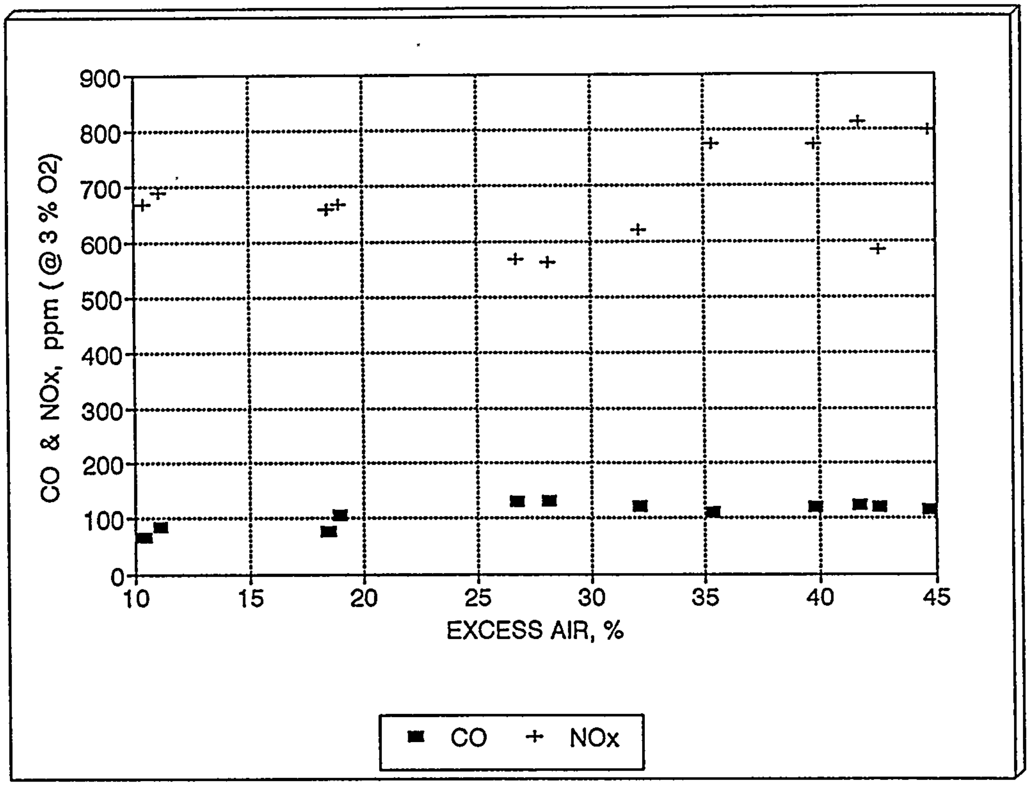


FIGURE 2-37: CO AND NO_x WITH EXCESS AIR

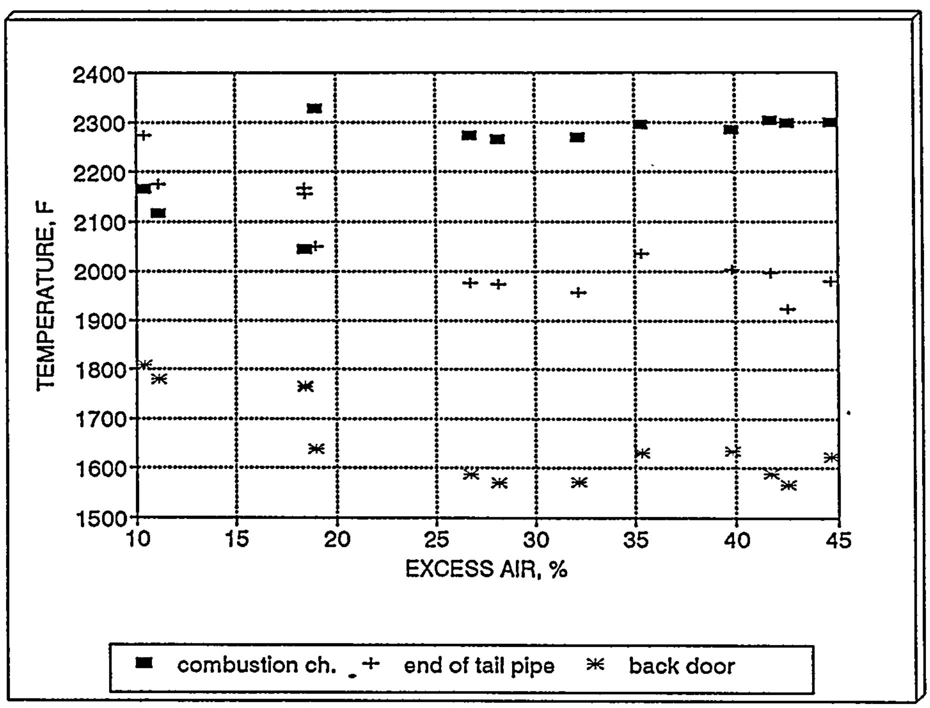


FIGURE 2-38: TEMPERATURE WITH EXCESS AIR

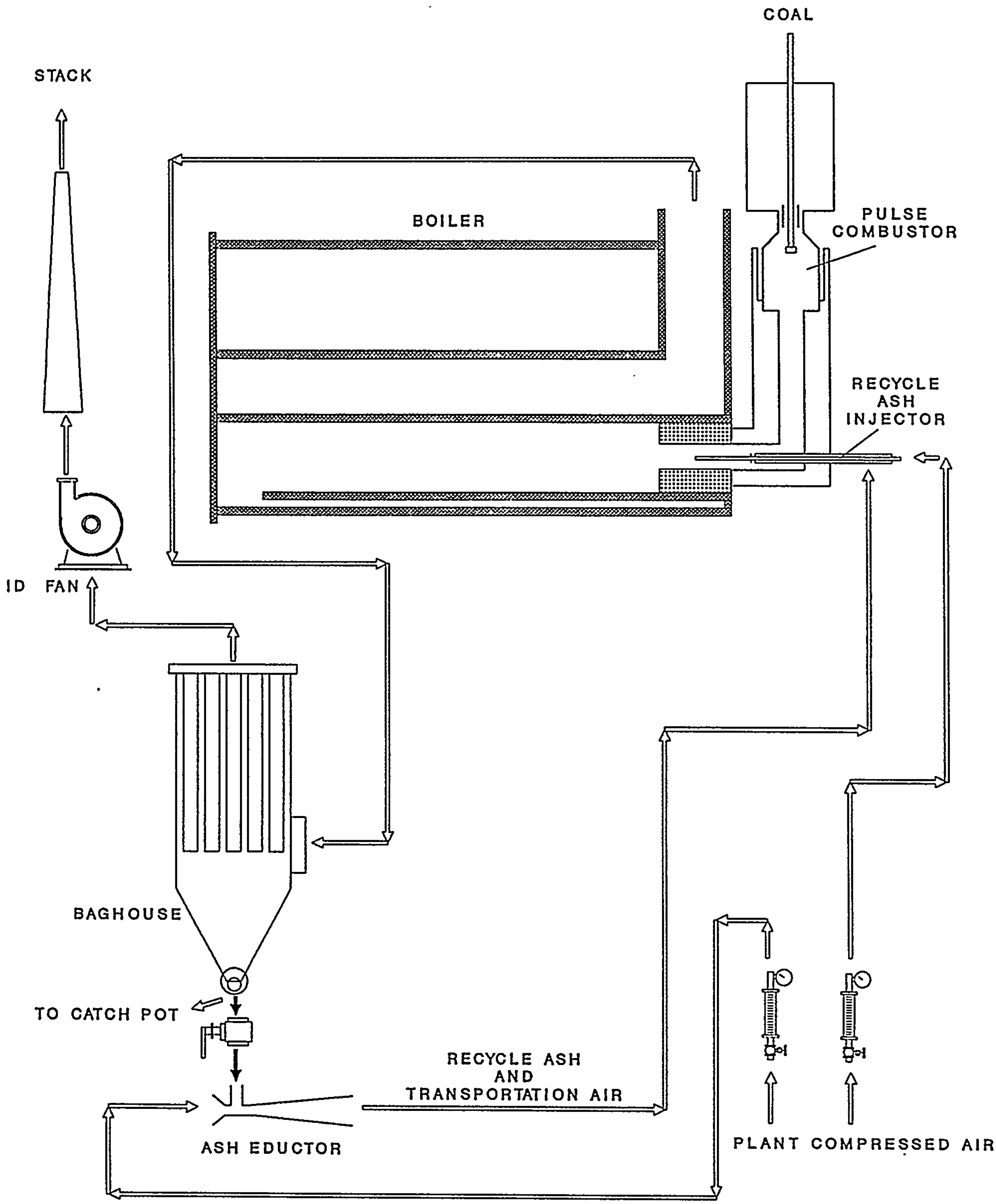


FIGURE 2-39: FLOW DIAGRAM OF ASH RECYCLE STREAM

the baghouse to an injector located near the tailpipe exit. Excess ash which overflowed the stand pipe connecting the baghouse to the eductor was bypassed to the baghouse catch pot. The test results showed marginal improvement in combustion efficiency due to ash recycle. This result was attributed to inadequate 3 T's of combustion viz. time, temperature, and turbulence. The residence time in the Morrison tube was estimated to be on the order of 200 ms and this was considered too short a residence time for char particle heating, ignition and burnout. The average temperature in the Morrison tube was in the 1600 to 2000°F range and was lower than that desired due to the partial char burning. The turbulence or mixing of air and char may have been hampered by the efflux of the gas and solids from the tailpipe in the form of a jet.

The injection of superheated steam into the pulse combustor was also attempted in an effort to reduce the formation of NO_x with coal combustion. Recall that steam injection was successful in bringing the NO_x level down to 20 ppm when firing with natural gas. There was little difference in NO_x level between the two cases viz. with or without the injection of superheated steam.

The following observations were made with reference to the results presented in Figures 2-37 and 2-38:

- Both primary and secondary air flow rates could be varied to regulate the overall excess air level at up to 5 MMBtu/hr firing rate. At higher firing rates, air intake into the combustion chamber became limiting and the excess air level could only be increased through secondary air addition.
- CO and HC increased slightly due to ash recycle while NO_x exhibited a slight decline, as expected.
- The temperature in the combustion chamber tended to increase with excess air while the temperatures at the tailpipe exit and at the turnbox after the first pass decreased. This is attributed to an increase in the fraction of heat released in the chamber with an increase in excess air and a corresponding decrease in the fraction of heat released in the tailpipe. The heat release in the Morrison tube seemed insensitive to excess air.
- The thermal efficiency showed a rising characteristic with excess air due probably to improvement in the boiler tube heat transfer coefficient.

No ash deposition in the horizontal passes of the boiler was found during an inspection pursuant to the above tests. This was very encouraging in that fouling is insignificant even with ash recycle due to pulsating flow.

Three modifications were decided upon. First, a stationary impeller and a partition disk were to be installed in the Morrison tube to swirl the flue from the tailpipe, enhance mixing, and prolong the residence time of char particles.

In the initial tests with coal the unburned carbon loss was significant because of short residence time (~200 ms) in the Morrison tube for char particle burnout. The remedy was to redesign, fabricate, and install a flue gas swirler and a partition disk inside the Morrison tube. The swirler and partition disk would enhance mixing and prolong the residence time of char particles. The swirler consisted of two rings (outer and inner) and 12 tilted blades installed between the rings. The inner ring was covered by 12½-inch disk to prevent bypass through the central part of the swirler. The partition disk was installed 54 inches downstream of the swirler. The char particles deflected by the swirler to the periphery of the Morrison tube would be captured and reflected back by the partition disk. Consequently, the char particles would have enough time to burnout. The latter would increase temperature in the Morrison tube which also would contribute to burnout of the char particles.

Second, a natural gas/NH_3 and air injector would be installed at the exit of the Morrison tube to investigate NO_x reduction. Third, the structure of the back door would be modified from refractory-lining to water-cooling to withstand high temperatures and pulsations at the turnbox and to improve the thermal efficiency.

During the boiler tests, vibrations of the back door area were observed. These vibrations caused cracking of the back door refractory lining. Calculations revealed that the antinode of the dynamic pressure of the pulse combustor was located at the back door. Because of that, it was decided to move the back door further downstream 54 inches. To retain the same configuration of the Morrison tube and turnbox, the length of the Morrison tube was increased by 54 inches. Increasing the length of the Morrison tube would also contribute to increasing the residence time and improve combustion efficiency. The back door would be water-cooled to withstand high temperatures and pulsations.

The modifications were completed (see Figure 2-40) and the combustion system was gradually ramped up in natural gas firing rate to cure the refractory on the boiler extension section. Several tests were run with coal. The pulse combustor operation was stable for a variation in coal firing rate from 1.8 to 7.5 MMBtu/hr, indicating a nominal 4:1 turndown capability. The pressure oscillations were robust and the sound pressure level (SPL) varied from 161 to 178 dB with an increase in firing rate. The wave form was near sinusoidal with very low harmonics. The baghouse catch samples were sent out for analysis.

A summary of the preliminary system tests (screening) completed is provided in Table 2-18. The results of the screening tests indicated the following:

- The firing rate ranged from 1.8 to 7.5 MMBtu/hr;
- The pressure in the air plenum was much higher than those in previous tests due to the pressure drop caused by the swirler;
- Combustion efficiency when firing coal showed improvement but was still below the target value of 99%; and
- Emissions performance was similar to that obtained in previous tests.

Four modifications were initiated:

- The number of blades in the swirler was cut from 12 to 6 to reduce the pressure drop through the swirler;
- A pipe section of 10" diameter, 5" long was added at the entrance to the partition disk to trap the unburned coal particles in the end section and prolong the residence time for burnout;
- An insulation layer was added around the radiation shield to reduce the heat loss from the Morrison tube and increase the temperature in the Morrison tube to promote char burnout.
- The section of the tailpipe beyond the 90° turn was lined with 2.5" thick refractory. The tailpipe was previously surrounded by cooling water. The wall temperature then was estimated to be low (~ 300°F) and this may have cooled and quenched some of the char particles thereby contributing to incomplete combustion.

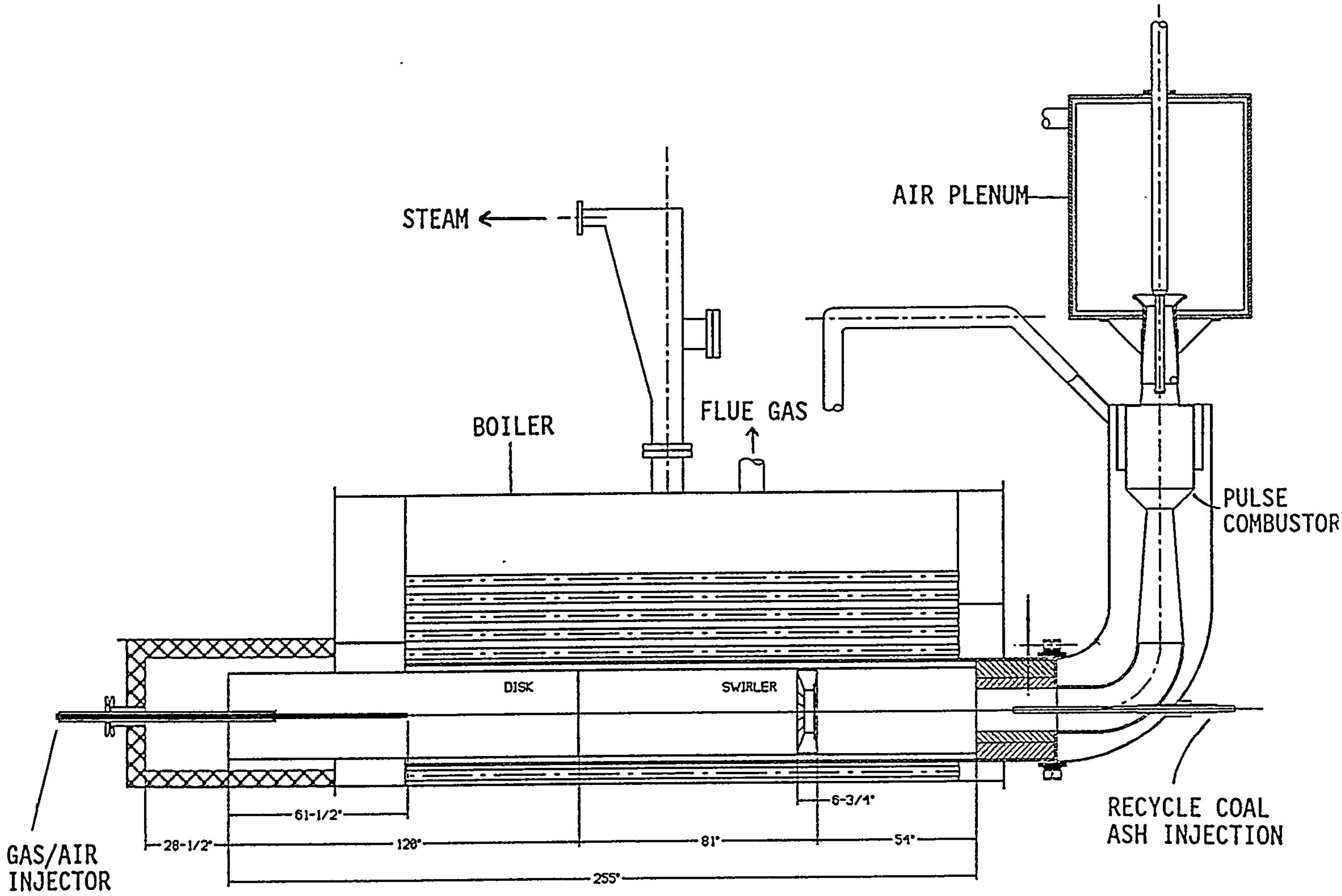


FIGURE 2-40: COMMERCIAL-SCALE PULSE COMBUSTION SYSTEM AFTER MODIFICATION (CONFIGURATION C)

TABLE 2-18:

TEST RESULTS

FIRING RATE, MMBtu/hr		2.65	6.50
TEMPERATURE, °F	Air Plenum	69	82
	Combustion Chamber	2158	2197
	End of Tailpipe	1745	2213
	End of Morrison Tube	1022	1776
	Stack	252	373
EMISSION DATA	O_2, %	7.5	2.9
	CO, ppm @ 3% O_2	431	69
	SO_x, ppm @ 3% O_2	494	659
	NO_x, ppm @ 3% O_2	807	736
	THC, ppm @ 3% O_2	12	19
COMBUSTION EFFICIENCY, %		90.5	94.5

Based on considerations of acoustic decoupling, fabrication difficulty and residence time for reburning, it was decided to move the swirler and partition disk further downstream of the Morrison tube. Also, two injectors were installed: one was a coal/gas injector located in the elbow section of the tailpipe to facilitate coal reburning or gas reburning for the purpose of reducing NO_x emissions. Another injector was located at the swirler inlet to supply secondary combustion air to burnout the rest of char.

Seven test runs were made after the modifications were completed. Table 2-19 describes the main parameters of these test runs.

TABLE 2-19: MAIN PARAMETERS OF TEST RUNS

TEST NO.	070703	070101	070702	070202	070601	070102	070701
FIRING RATE, MMBtu/hr	1.89	4.05	4.68	6.03	6.04	6.11	6.20
FUEL	Coal A	Coal A	Coal A	Coal A	Coal A	Coal A	Coal A
SORBENT	Sorbent A		Sorbent A				Sorbent A
Ca/s MOLAR FEED RATIO	1.8		1.8				1.8

The test results are shown in Figures 2-41 through 2-45. Figure 2-41 shows the temperatures in the combustion chamber, at the end of the tailpipe, and at the end of the Morrison tube at different firing rates. The temperature in the combustion chamber was about 2300°F over the whole range of firing rates which indicates good combustion and heat release within the chamber. The temperatures at the end of the tailpipe and at the end of the Morrison tube show tendency to decrease with a decline in firing rate due to disproportionate heat loss. This reduces the burning rate and decreases the combustion efficiency with a decline in firing rate (Figure 2-42). The temperatures and combustion efficiency at 4 MMBtu/hr are lower because of operation at high excess air level.

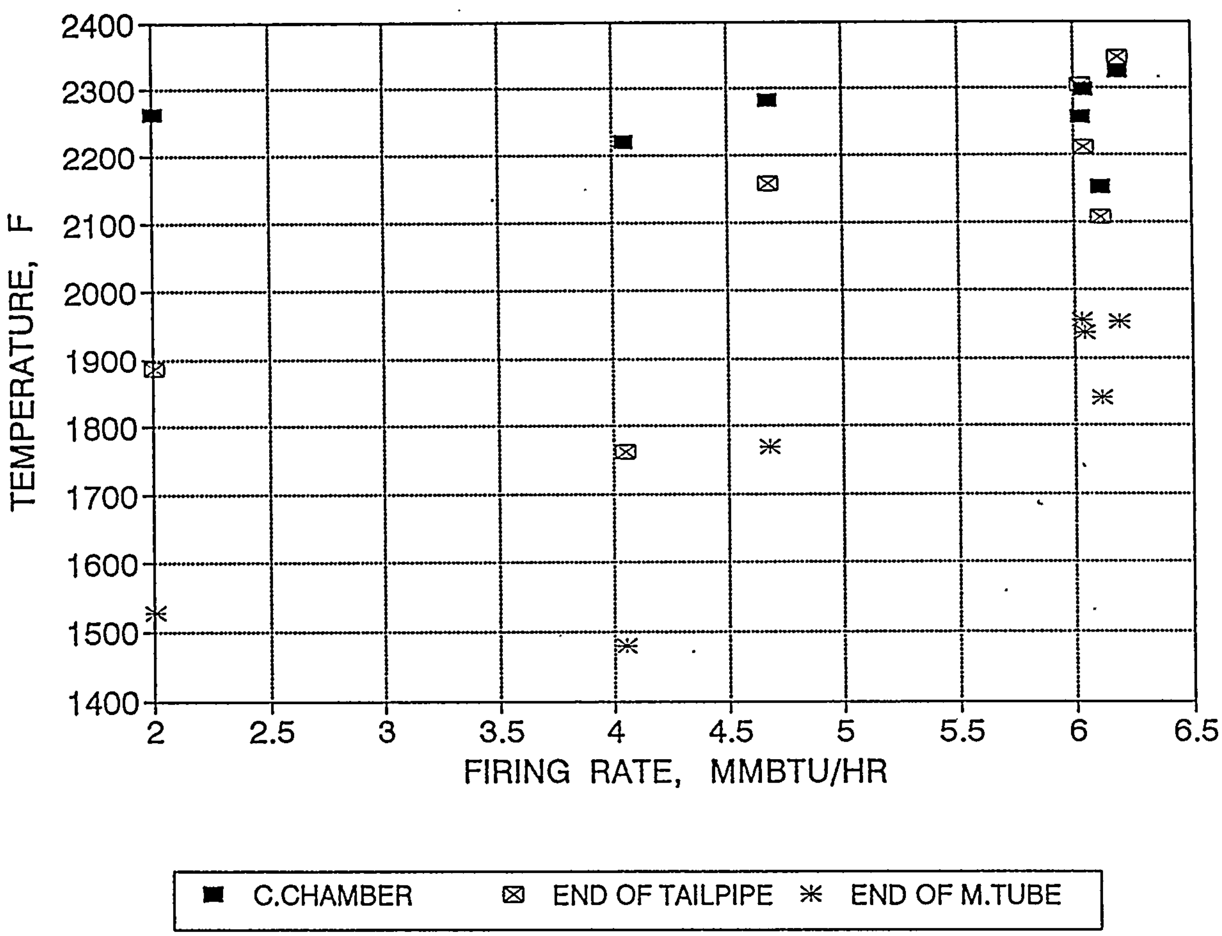


FIGURE 2-41: TEMPERATURE DISTRIBUTIONS - PRELIMINARY SYSTEM TESTS

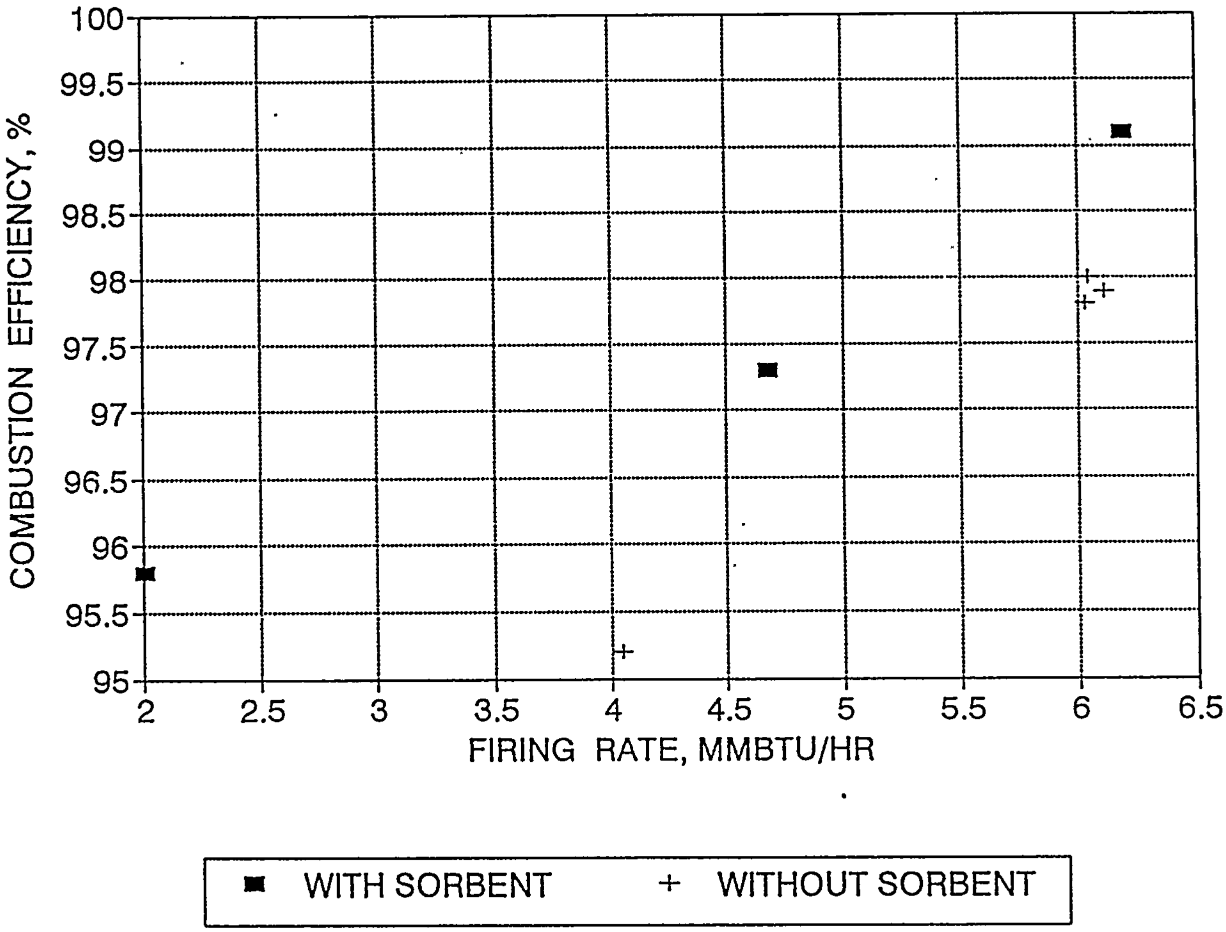


FIGURE 2-42: COMBUSTION EFFICIENCY - PRELIMINARY SYSTEM TESTS

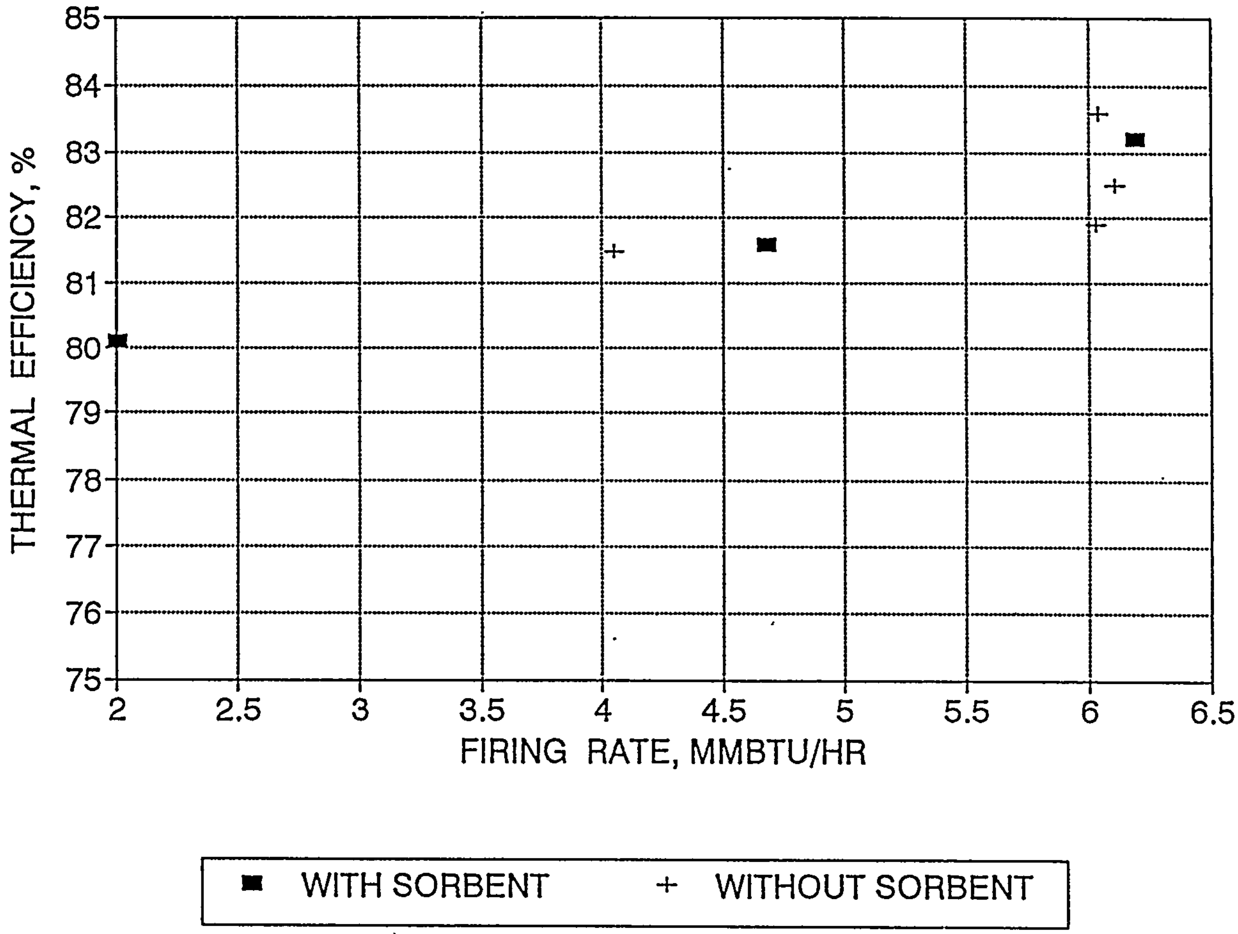


FIGURE 2-43: THERMAL EFFICIENCY - PRELIMINARY SYSTEM TESTS

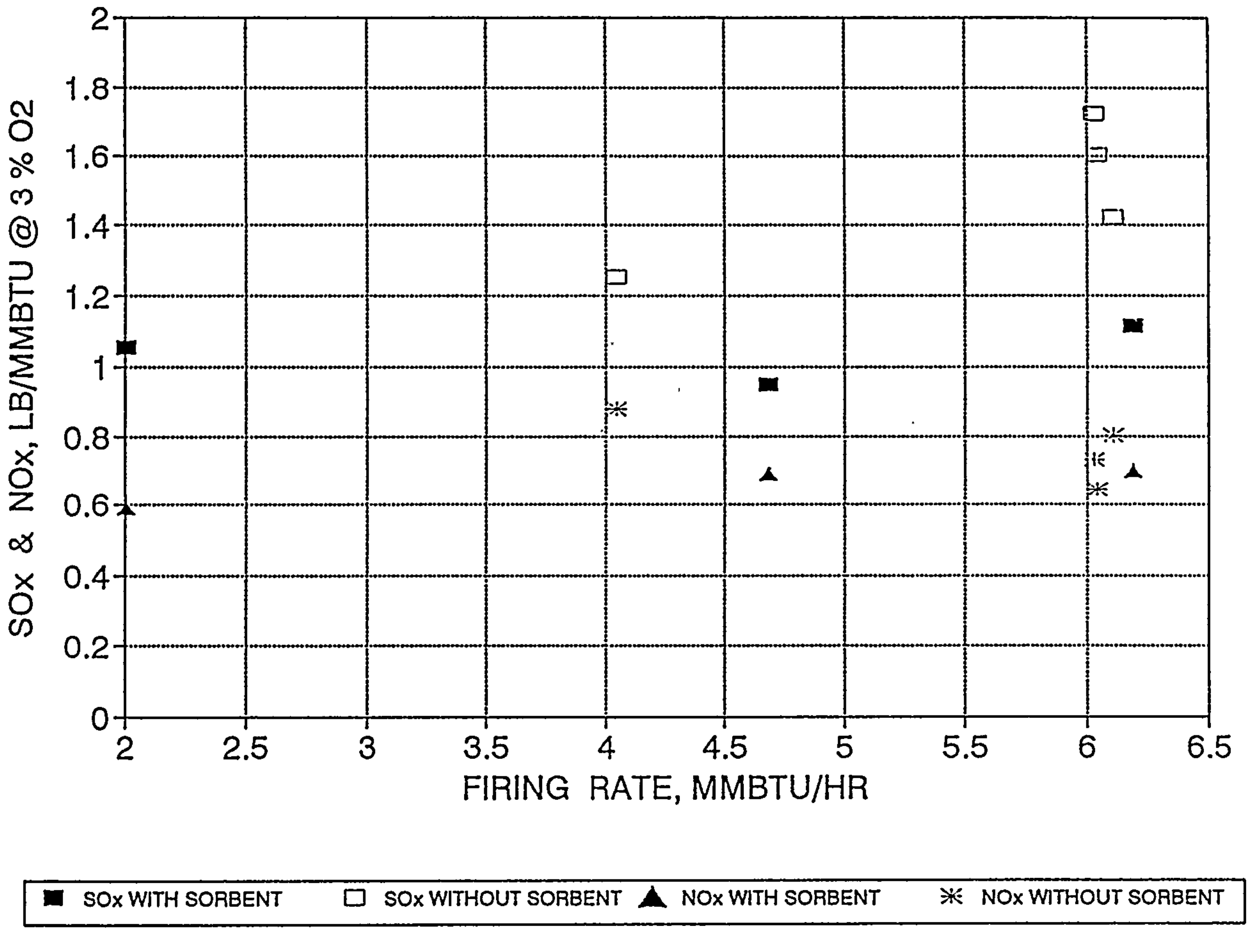


FIGURE 2-44: EMISSIONS RESULTS - PRELIMINARY SYSTEM TESTS

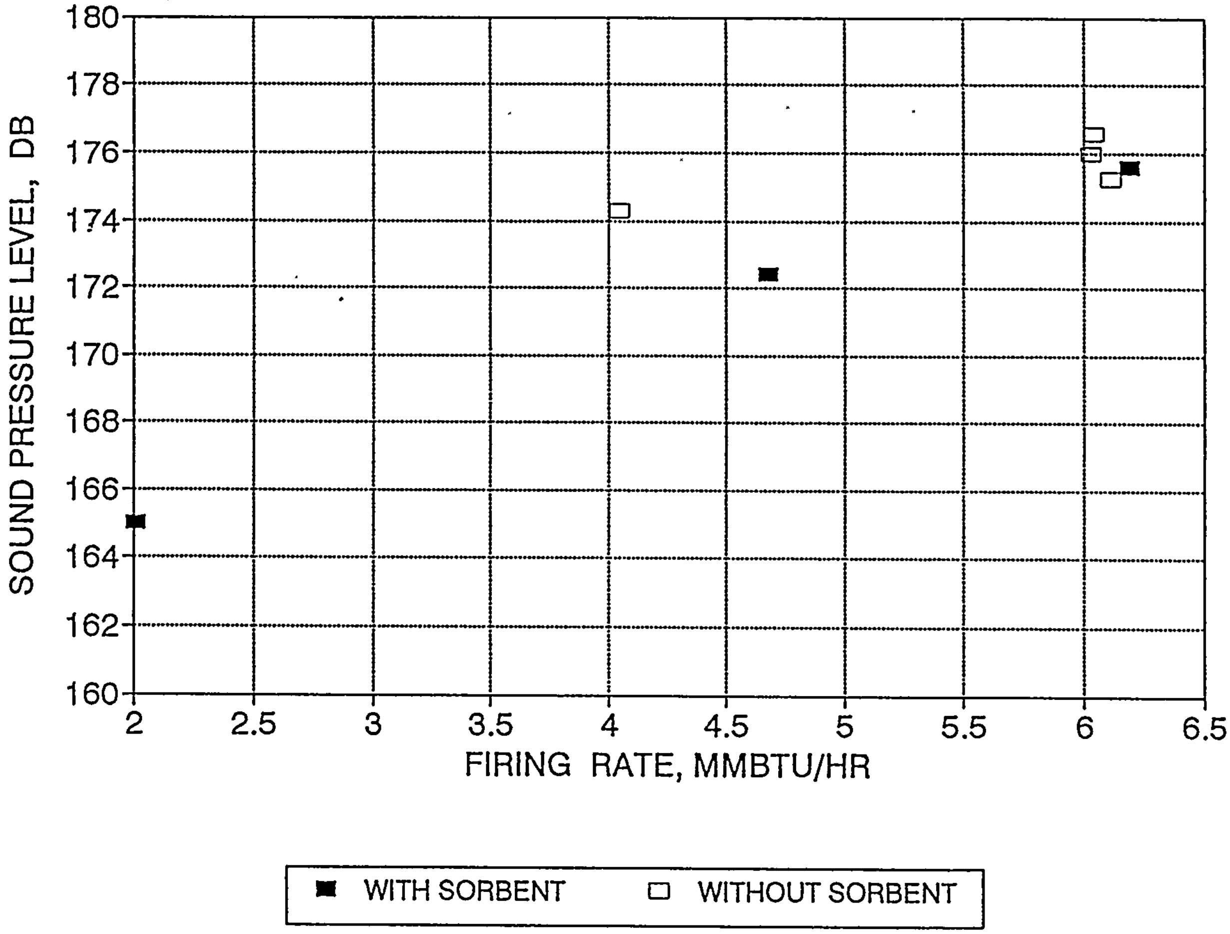


FIGURE 2-45: ACOUSTIC PERFORMANCE - PRELIMINARY SYSTEM TESTS

Figure 2-42 shows the combustion efficiency as a function of firing rate with and without sorbent feed. Lower combustion efficiency is obtained without sorbent feed due to higher excess air/lower temperature operation. The figure shows that at 6.2 MMBtu/hr firing rate, a combustion efficiency of 99 percent is reached which is the target goal for this project.

Figure 2-43 shows the thermal efficiency of the boiler with and without sorbent feeding. The thermal efficiency increases with firing rate due to improved combustion efficiency at higher firing rates. Once again, this quantity exceeds the target goal of 80 percent for this project.

Figure 2-44 shows NO_x and SO_x emissions. When feeding sorbent, the Ca/S molar feed ratio was 1.8. In the tests, 30 percent sulfur capture was obtained and the SO_2 emissions did not exceed the 1.2 lb/MMBtu limit. Considering the short gas residence time in the hot zone (200 to 700 ms), the 30 percent sulfur capture is considered good. NO_x emissions were, however, higher than the target goal of 0.3 lb/MMBtu. The goal was to further reduce NO_x emissions by gas or coal reburning, air staging, and flue gas recirculation.

Figure 2-45 shows acoustic performance of the pulse combustor fired with coal. The sound pressure level exceeded 176 dB at full load and the pressure fluctuations were robust (about 6 psi). The frequency was in the 62 - 64 Hz range.

The test results from the preliminary test program were presented in a project review meeting at PETC. The coal tests demonstrated the capability to meet target goals with respect to combustion efficiency, thermal efficiency, turndown, SO_2 emissions, and particulate emissions. NO_x emissions, however, exceeded the target goal of 0.3 lb/MMBtu and pointed out the need for additional work to reduce NO_x formation. Approval was obtained to proceed to Task 3 and perform proof-of-concept system tests.

2.3 PROOF-OF-CONCEPT SYSTEM TEST PROGRAM

2.3.1 TEST PLAN

A test plan was prepared and a text matrix was formulated (Table 2-20). The test program included steady-state and long duration tests totaling 300 - 500 hours of system operation.

The objectives were to evaluate the following attributes of the system:

- Combustion, thermal and sulfur capture efficiencies;
- Slagging, fouling, erosion and corrosion potential;
- Gaseous (CO, NO_x, SO_2, O_2, THC) and particulate emissions;
- Storage, transportation and handling characteristics of the fuel and sorbent;
- Operability over sustained periods of testing;
- Operating and maintenance (O&M) costs; and
- Cost of consumables (fuel, water, sorbent, electricity and any chemicals).

Steady-state tests were planned to determine combustion efficiency, sulfur capture efficiency, gaseous and particulate emissions, thermal efficiency and turndown ratio of the system as a function of several variables. The parameters to be investigated included: pulse combustor firing rate (1.5 to 5 MMBtu/hr), reburn fuel type (natural gas, coal), and reburn fuel firing rate (0.5 to 1 MMBtu/hr), multiple air staging, Ca/S molar ratio (1.5 to 3), fuel type (natural gas, 3 different coals), and sorbent type (lime and dolomite).

During each test run, the following measurements were to be taken periodically:

- Fuel feed rate and transport air flow rate;
- Primary, secondary and tertiary air flow rates (time average) and temperatures;

TABLE 2-20:
PROOF-OF-CONCEPT SYSTEM TEST MATRIX

TEST NO.	TEST OBJECTIVE	COAL	SORBENT	Ca/S RATIO	PC FIRING MMBtu/hr	REBURN FUEL	REBURN FUEL FIRING RATE MMBtu/hr
1	MEASURE EMISSIONS-SO_2	COAL A	D	2	5	-	-
2	MEASURE EMISSIONS-NO_x	COAL A	D	2	5	GAS	0.5,0.75,1
3	MEASURE EMISSIONS-NO_x	COAL A	D	2	5	COAL A	0.5,0.75,1
4	MEASURE EMISSIONS-SO_2	COAL A	D	1.5,2.5, 3.0	5	COAL A	OPT
5	MEASURE EMISSIONS-SO_2 *	COAL A	L	2	5	COAL A	OPT
6	TURNDOWN	COAL A	D or L	OPT	3	COAL A	OPT
7	TURNDOWN	COAL A	D or L	OPT	1.5	COAL A	OPT
8	LONGER DURATION OPERA-BILITY	COAL A	D or L	OPT	5	COAL A	OPT
9	PERFORM & EMISS.	COAL B	D or L	OPT	5	COAL B	OPT
10	PERFORM & EMISS.	COAL C	D or L	OPT	5	COAL C	OPT

OPT = OPTIMUM
D = DOLOMITE
L = LIME
SORBENT INJECTION LOCATION - TAILPIPE

- Combustion chamber pressure signature using an oscilloscope and an FFT analyzer;
- Flue gas analysis at the exit of the boiler;
- Sorbent feed rate;
- Reburn fuel feed rate;
- Isokinetic sampling at the exit of the baghouse;
- Furnace exit temperature;
- Make-up water flow rate and temperature;
- Steam pressure, temperature, quality and flow rate;
- Pressure and temperature measurements at different parts of the test facility;
- Power input to the feeders, FD and ID fans, pumps, air compressor, and controls;
- Chemical and size analyses of fuel, sorbent, bottom ash and fly ash; and
- Bottom ash and fly ash collection rate.

Heat and material balance calculations were to be performed to verify closure.

The occurrence of slagging was to be detected through a sudden increase in static pressure. The occurrence of fouling in the boiler second, third and fourth passes was to be detected by continuously monitoring the boiler exit temperature.

2.3.2 TEST FACILITY PREPARATION

Available literature on gas/coal reburning was reviewed. The reburn chemistry is known to be sequential with a residence time requirement ranging from 0.5 to 1.5 seconds. The initial thought was to configure two horizontal cyclone-type chambers in series - first for coal reburning and second for char burnout - downstream of the pulse combustor and upstream of the Morrison tube. This would eliminate the need for any boiler modification. Detailed design calculations were made and schematics were prepared. The combustion system appeared bulky with a significant floor area (horizontal space) requirement. This was considered unsatisfactory from a commercialization standpoint due to the limited space usually known to be available in boiler rooms for retrofit installations. Alternative arrangements for coal reburning and char burnout were examined to arrive at a viable, compact and efficient pulse coal combustion system.

Several conceptual arrangements for coal reburn and char burnout were evaluated. The arrangement shown in Figure 2-46 was selected based on the following considerations viz. utilization of the existing pulse combustor as is, minimization of footprint and vertical space requirement, good mixing of coal, steam and combustion products in the reburn section, and adequate char residence time in the char burnout section. The 90° tailpipe configuration of the pulse combustor was retained and the tailpipe integrated with the reburn chamber comprising concave sections such that the tailpipe exit jet impinges on the concave sections and spins around. This was anticipated to aid mixing and enhance coal particle residence time. A bottom exit was provided to minimize particle settling and accumulation. The products from the reburn chamber enter a vertical char burnout chamber tangentially at the bottom. This would aid in minimizing particle settling at the bottom and the cyclonic upflow against gravity will enhance char particle residence time in the chamber and, in turn, the burnout. Both the chambers are refractory-lined (two layers of refractory - high density and low density) and water-cooled. Reburn coal along with steam were proposed for injection into the tailpipe. Steam was considered as a means of enhancing CH_i radical concentration and promoting CH_i/NO reactions such that the coal-steam combination would approximate natural gas reburn chemistry. An initial trial of

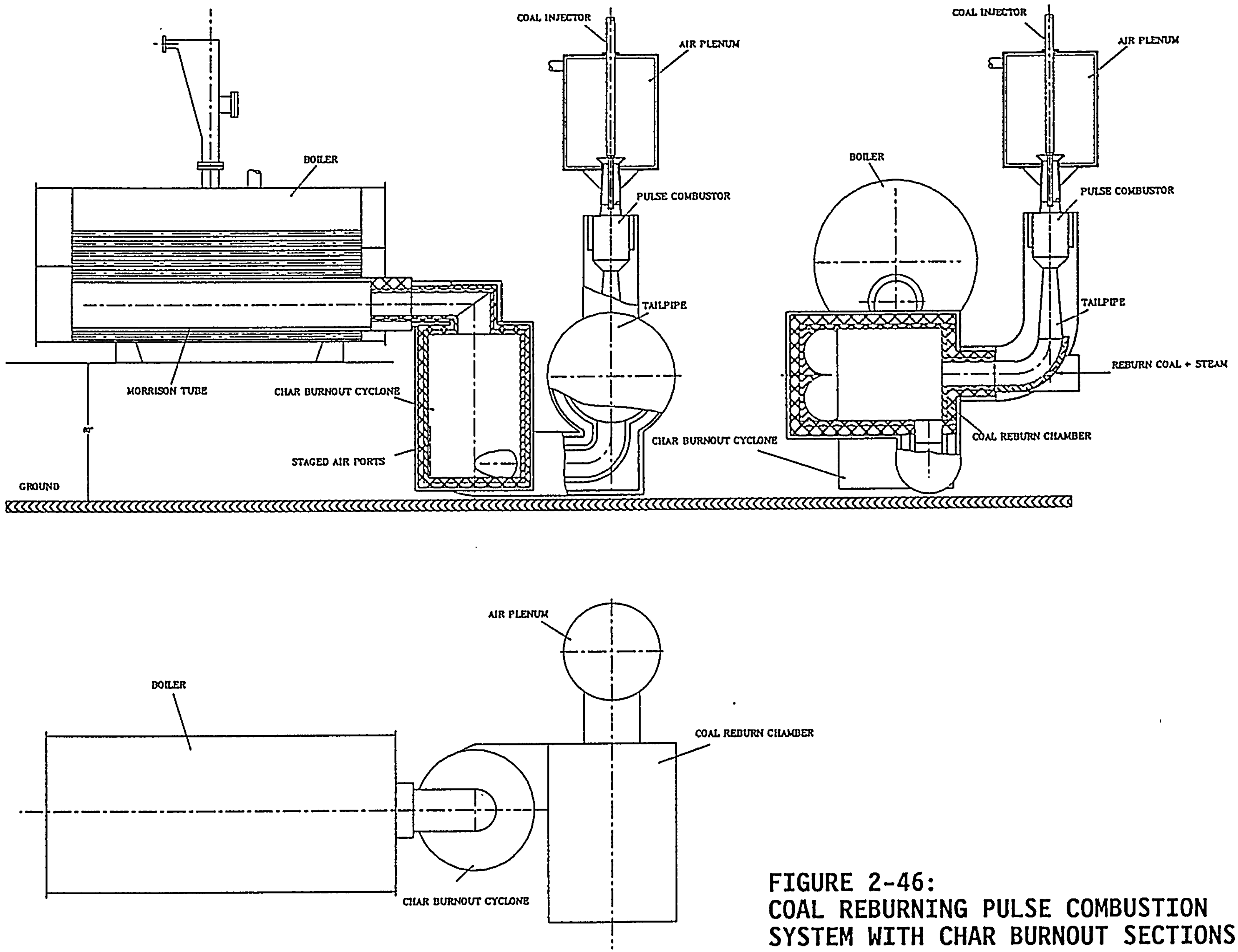


FIGURE 2-46:
COAL REBURNING PULSE COMBUSTION SYSTEM WITH CHAR BURNOUT SECTIONS - CONFIGURATION D

1 lb steam/lb reburn coal was made to establish feasibility. The addition of steam would reduce thermal efficiency by about 1 percent. In the design as suggested here, special care was taken to avoid the use and direct exposure of high-temperature metal surfaces (pipes, cylinders, etc.) to the hot flue gas so as to minimize erosion and corrosion problems. All the components and connecting sections were lined with refractory. The char burnout cyclone incorporated multiple stage ports for air injection. The integration of the char burnout cyclone eliminated the need for the boiler modifications carried out earlier (i.e., radiative shield inside the Morrison tube, swirler, partition disk and the boiler extension). The present arrangement would facilitate ease of boiler retrofit.

Detailed material and energy balance calculations were made in designing the reburn and burnout chambers. Table 2-21 provides a data summary.

A materials list was prepared and procurement initiated. Detailed fabrication drawings of the coal reburn and char burnout chambers were prepared. Support structure modification drawings were also generated. Component fabrication was started. Support structure installation, system integration, piping and instrumentation were completed. Refractory linings in the coal reburning and the coal burnout sections were cured during 40 hours of heat-up and cool down.

2.3.3 Shakedown Tests

Two shakedown tests were performed, one with gas only and another with coal feed into the pulse combustion chamber. The firing rate in the first test was 4 MMBtu/hr, sound pressure level (SPL) in the combustion chamber was 177 dB, and temperatures in the combustion chamber, first and second cyclones, were 2240°F, 2230°F and 2100°F, respectively. In the test with coal feed, the total firing rate was 5 MMBtu/hr and SPL in the combustion chamber was 176 dB. The temperatures in the above cited locations were 2400°F, 2456°F and 2357°, respectively. During the second test, 10 SCFM of natural gas was injected near the end of the tailpipe to examine NO_x reduction. The NO_x in the flue gas decreased from 567 to 283 ppm with gas injection.

TABLE 2-21:

MODIFIED COMBUSTION SYSTEM DESIGN DATA SUMMARY

PULSE COMBUSTOR FIRING RATE	6.25 MMBtu/hr
PRIMARY AIR	4,380 lb/hr
COMBUSTION CHAMBER TEMPERATURE	2300°F
COAL	Seacoal - Coal A
SORBENT	Pfizer Dolomite - Sorbent A
Ca/S MOLAR FEED RATIO	2.5
REBURN COAL	Seacoal - Coal A
REBURN COAL FIRING RATE	1.25 MMBtu/hr
REBURN COAL FEED RATE	89 lb/hr
STEAM INJECTION RATE	1 lb/lb reburn coal
REBURN CHAMBER MEAN TEMPERATURE	2250°F
SECONDARY AIR INJECTION RATE	2210 lb/hr
OVERALL EXCESS AIR	15%
CHAR BURNOUT CHAMBER MEAN TEMPERATURE	2265°F

A reburn coal injector was also designed, fabricated and installed in the tailpipe section to replace the gas reburning injector. A third shakedown test was performed. The test results showed a reduction in NO_x emissions in the flue gas from 600 ppm to between 200 and 250 ppm. The reburning coal was conveyed by a one-inch eductor installed at the bottom of the fluid-bed preconditioner. Interference between the main coal and reburning coal eductors made it difficult to control the coal feed rates independently. In order to separate the coal feed systems, an existing limestone feeder was used for the reburn coal feed. A new fluid-bed preconditioner was designed, fabricated and installed at the outlet of the limestone feeder rotary valve. The outlet of the preconditioner was connected to a one-inch eductor. A test was performed with the new coal reburn feed system. Test data showed good performance of the pulse combustor (176 dB of SPL) and good NO_x reduction - emissions were reduced by as much as 223 ppm - but combustion efficiency was measurably less than the target value of 99+%.

Analysis of the test results indicated incomplete burnout of the reburn char in the secondary cyclone. This was attributed to the relatively high fraction of larger particles (> 74 microns) in the pulverized coal used as reburn fuel and the limited residence time (< 0.5 sec) in the char burnout section. To increase residence time and retention of reburn char particles in the second cyclone and maximize combustion efficiency, a modification of the second cyclone was proposed. Figure 2-47 shows a radiantly cooled center pipe with an attached disk to minimize gas and particle bypassing. It was anticipated that the char particles would be kept by centrifugal forces at the periphery of the cyclone until they burned out and were removed by flue gas flow. Also, a screw feeder was installed under the coal bin rotary valve in order to improve the consistency of the feed rate.

2.3.4 SYSTEM TESTS

Three separate tests were performed at different firing rates (3.63, 4.73 and 5.78 MMBtu/ hr). Ash samples taken from the stack during the tests were analyzed and indicated that the combustion efficiency in the pulse combustor in these tests exceeded 98.8 percent. Air staging in char burnout section was expected to further improve combustion efficiency. At the highest firing rate of

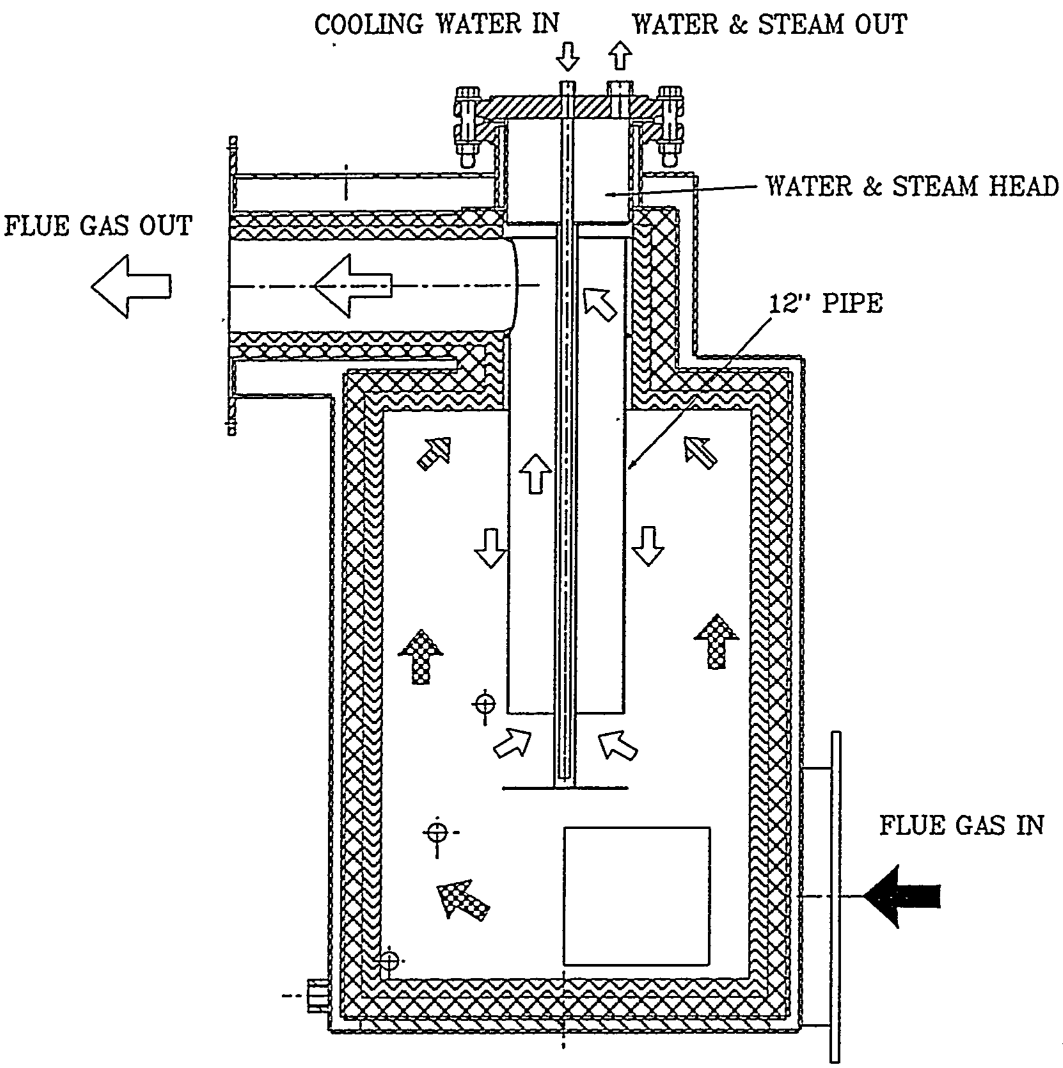


FIGURE 2-47: MODIFICATION OF CHAR BURNOUT CYCLONE

5.78 MMBtu/hr, reburn coal at an 18.2 percent ratio was fed into the system at a location just beyond the combustor tailpipe. The NO_x emissions in the stack decreased from 513 to 145 ppm. To confirm test repeatability and system performance, another test was run at 4.02 MMBtu/hr total firing rate with a reburning coal ratio of 10.4 percent. A NO_x reduction to 167 ppm was achieved.

Three different tests were also performed to determine SO_x emissions reduction in the flue gas. Coal reburning was not used during any of these tests. Instead, the reburning coal feeder and injector were used to feed classified Anville lime (Sorbent B) into the tailpipe. For the three different Ca/S molar ratios (7.6, 11.3 and 15.1) tested, sulfur capture efficiencies were 87, 90.7, and 94.4 percent, respectively. Due to rotary valve feeder limitation, lower Ca/S feed ratios could not be tested.

The commercial unit's performance during the tests conducted is presented in <u>Figures 2-48</u> through <u>2-52</u>. Figure 2-48 provides the SPL and pulsation frequency in the combustion chamber as a function of firing rate. The SPL had a tendency to increase slightly with firing rate and ranged from 175 to 177 dB and frequency was stable in the range of 64 - 68 Hz. Figure 2-49 provides the thermal efficiency of the commercial boiler. The efficiency increased with firing rate from about 80 percent at low firing rate to 85 percent at 5.8 MMBtu/hr. Figure 2-50 shows the flue gas emissions data taken in the test with high sulfur coal (3.18%) and no sorbent feed. The oxygen level was sustained at about 2 percent and total hydrocarbons were in the range of 20 to 30 ppm. The NO_x data (< 200 ppm) reflect the effect of reburning coal on NO_x reduction. CO emissions were on the order of 260 ppm for this test. Air staging was contemplated to reduce the CO and THC even further. Figure 2-51 presents NO_x emissions data with coal reburn. Figure 2-51 shows that reburning coal was optimal at a ratio of between 10 and 18 percent. This was to be verified in future testing. Figure 2-52 indicated that sulfur capture efficiency was high (> 85%).

In previous tests, NO_x and SO_x reduction tests were conducted separately because the same feed system was used for both reburning coal feed and sorbent injection. To perform combined control tests, a separate sorbent feed system (K-Tron screw feeder) was installed. The calibration curve of the screw feeder with

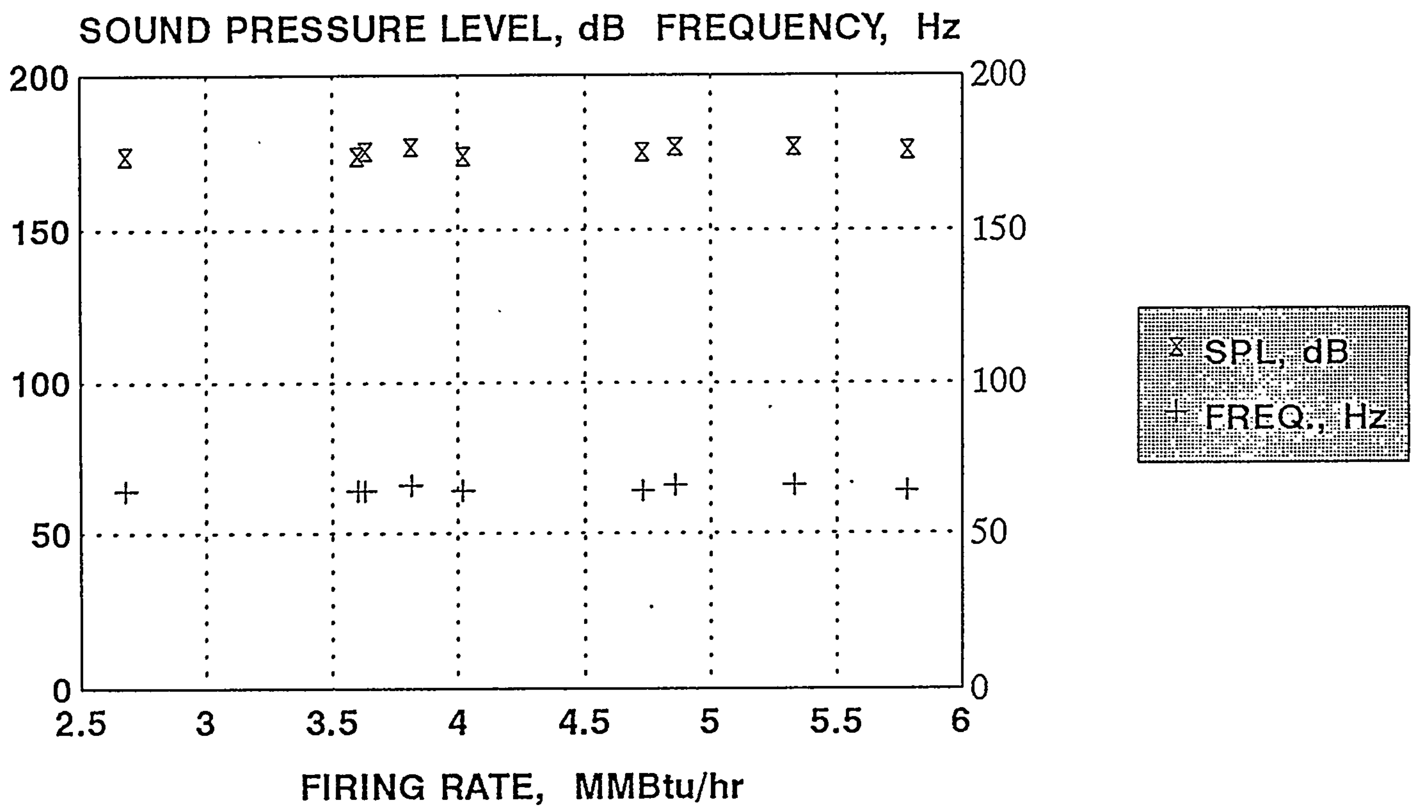


FIGURE 2-48: SPL AND FREQUENCY WITH FIRING RATE

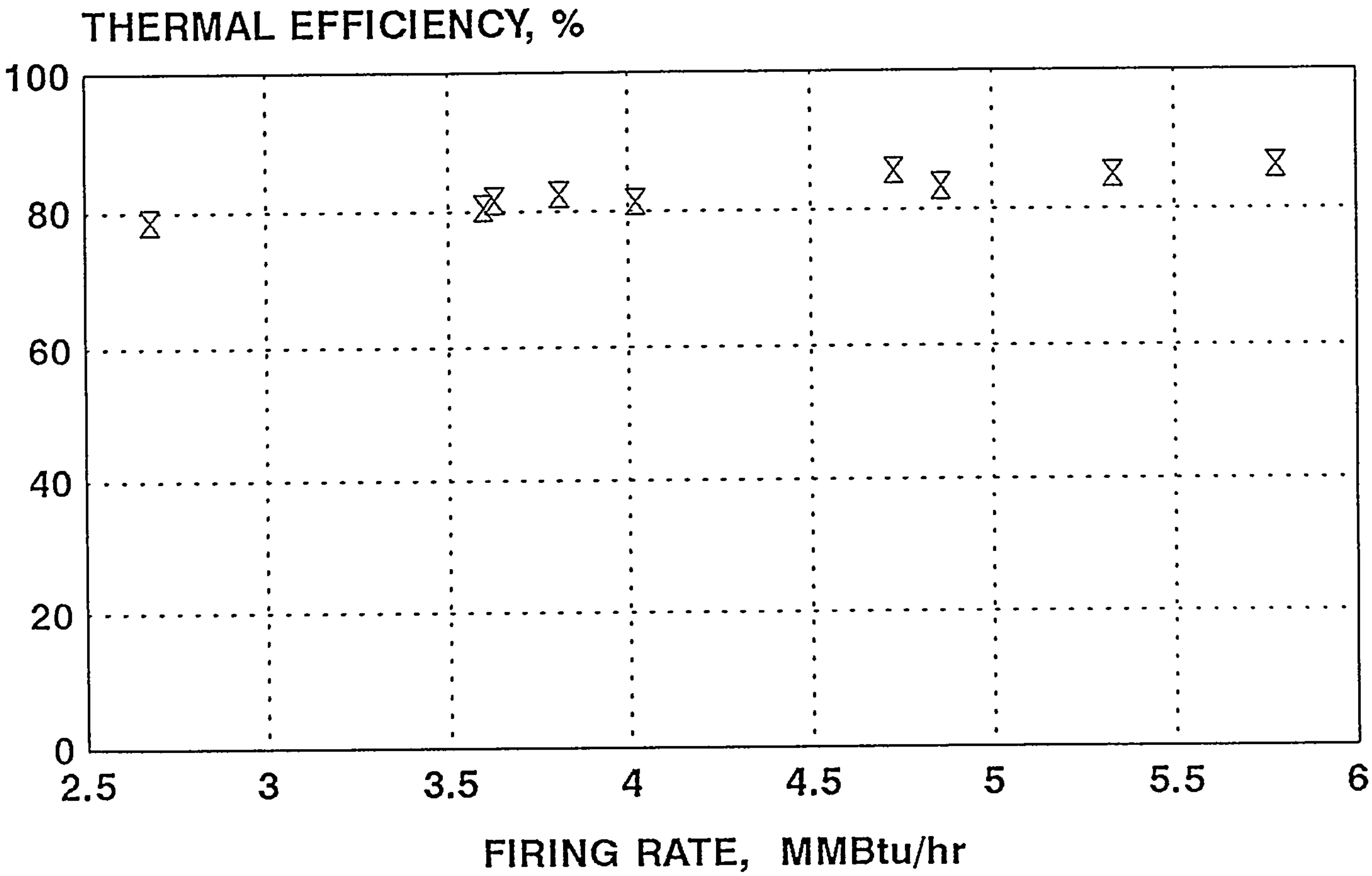


FIGURE 2-49: THERMAL EFFICIENCY WITH FIRING RATE

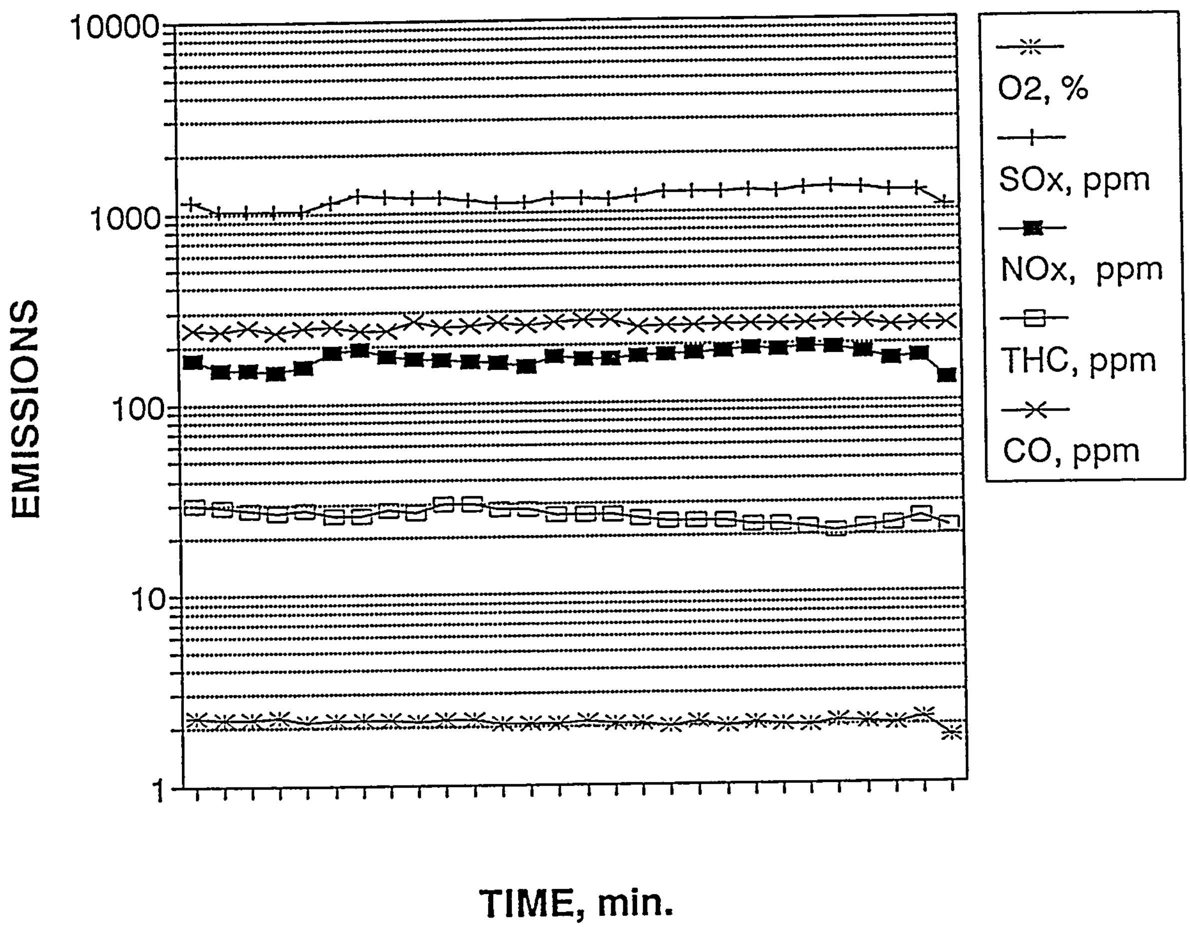


FIGURE 2-50: EMISSIONS RECORD

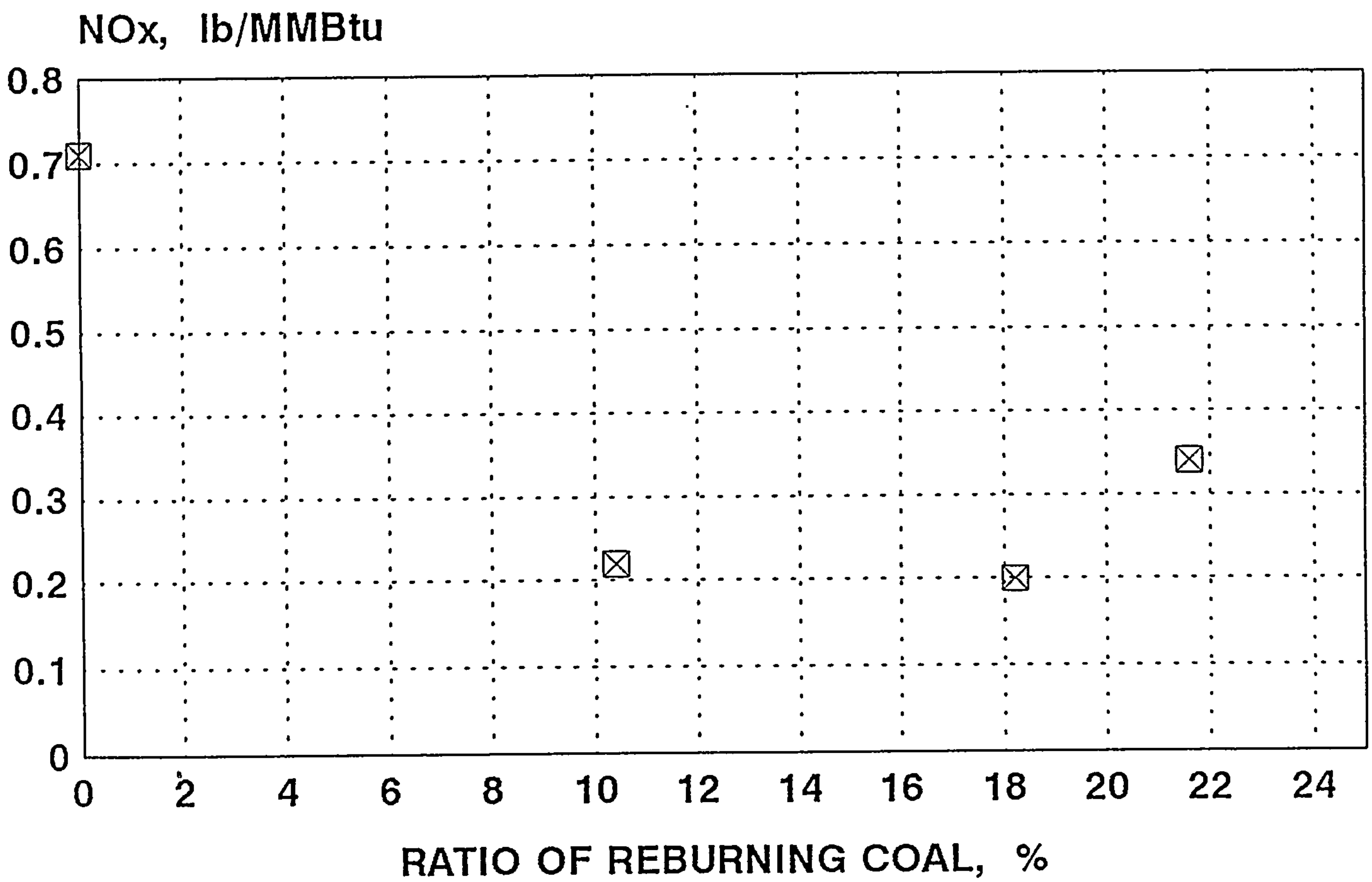


FIGURE 2-51: NO_x EMISSIONS WITH REBURNING COAL

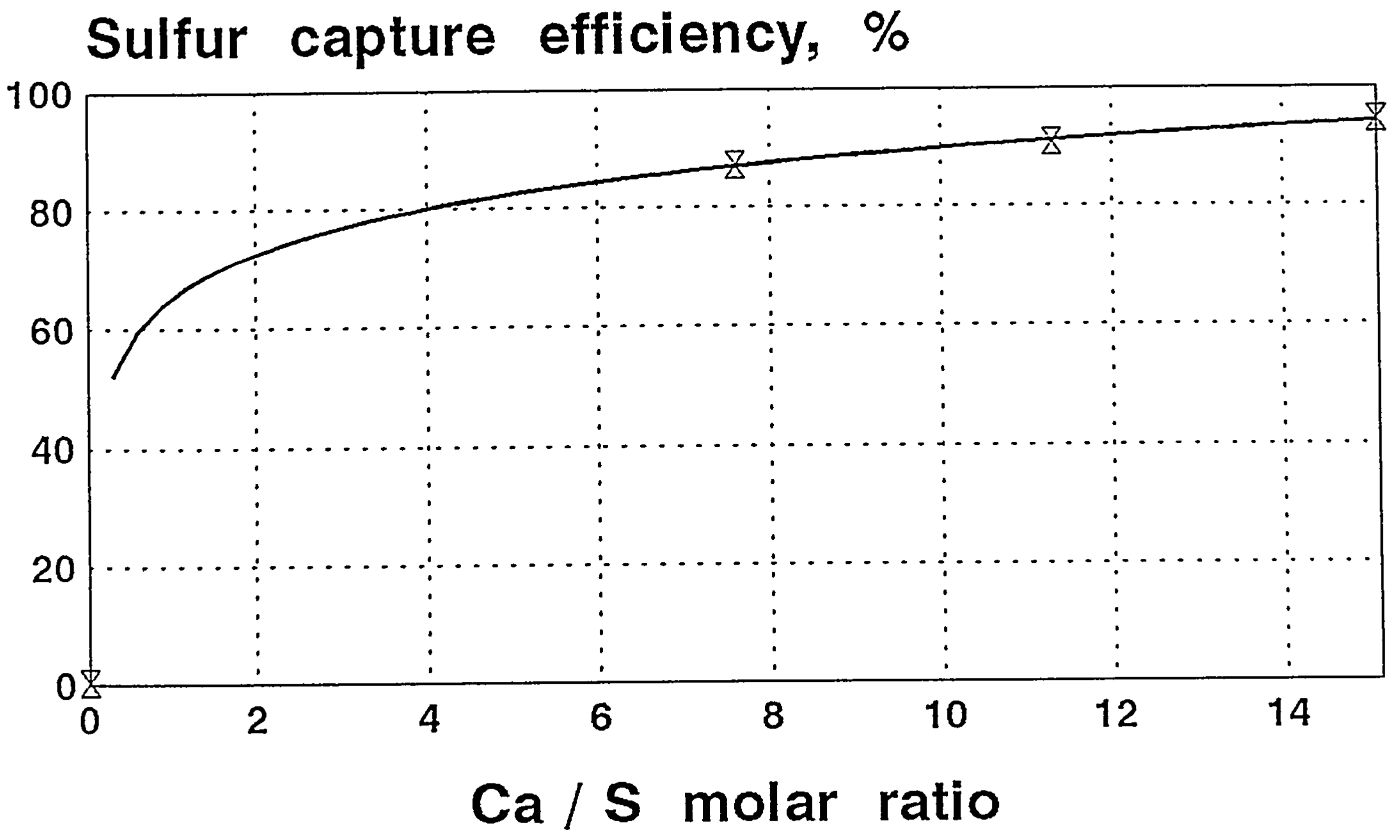


FIGURE 2-52: SULFUR CAPTURE EFFICIENCY WITH CA/S MOLAR RATIO

Anville lime (2 mm maximum size) is shown in Figure 2-53. Table 2-4 presented the Anville lime composition. Sorbent injection was located at the inlet of the Morrison tube. Previous test data indicated that the flue gas temperature was about 2000°F at the inlet and 1650°F at the outlet of the Morrison tube, a good temperature window for sulfur capture. The test results with the new sorbent feed system are shown in Figure 2-54. The figure provides the sulfur capture efficiency as a function of Ca/S molar ratio. For the new sorbent feed system, the Ca/S molar ratio was controlled to about 2 which was much lower than that with the previous system. In the test, sulfur capture efficiency reached 20 percent and SO_2 emissions were 1.19 lb/MMBtu which met NSPS requirements. The low sulfur capture efficiency was attributed to the short residence time (~ 300 ms) in the Morrison tube. Sulfur capture and calcium utilization could be improved by increasing the residence time either by recycling or injection further upstream.

Figure 2-55 shows the flue gas emissions with both reburning coal and sorbent feed. Reburning coal was injected at the end of the tailpipe. The total firing rate of the boiler was about 6 MMBtu/hr. About 14 percent of the total heat was generated by reburning coal. SO_2 emissions dropped from 1.5 to 1.2 lb/MMBtu when the Ca/S molar feed ratio increased from 0 to 2.2. NO_x emissions dropped from 0.7 to 0.2 lb/MMBtu when reburning. Figure 2-56 shows NO_x emissions with reburning coal. It seemed that beyond a reburning coal ratio of 12 percent, the NO_x emissions were relatively flat at about 0.2 lb/MMBtu. Coal reburning increased the CO level from 20 to 100 ppm. Sorbent feed and coal reburning did not have any effect on THC emissions which were below the typical 4 ppm value.

Toward the end of the last test it was found that the combustion chamber had a leak. An inspection of the combustion chamber indicated that the wall had eroded and the leak could not be satisfactorily remedied by welding. It was decided to put high-density refractory around the top section of the combustion chamber including the conical section and part of the aerovalve holder as shown in Figure 2-57. This modification required that the pilot burner, flame detector and instrumentation be relocated from the conical to the cylindrical section of the combustion chamber.

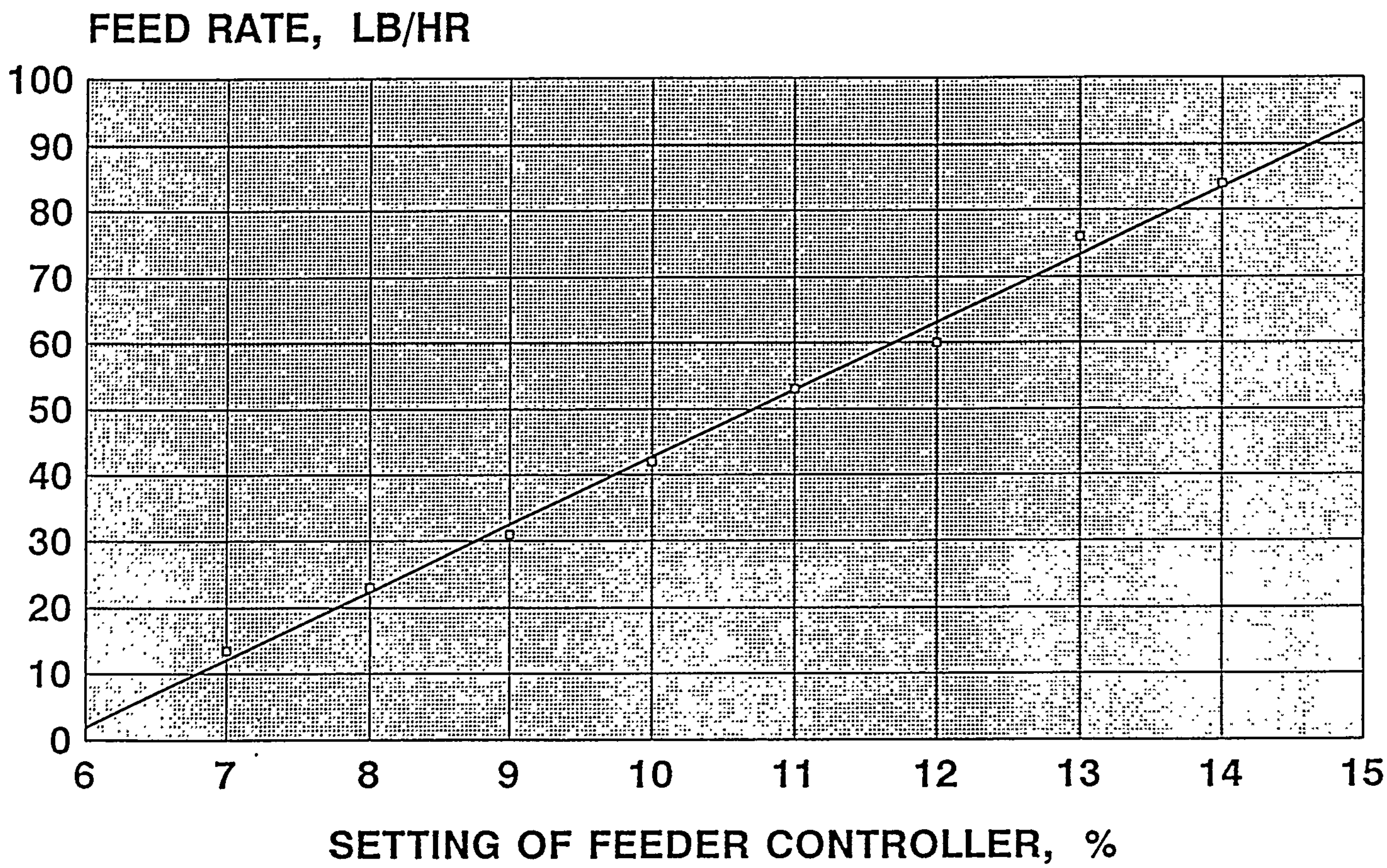


FIGURE 2-53: CALIBRATION CURVE OF SORBENT FEEDER (SCREW FEEDER)

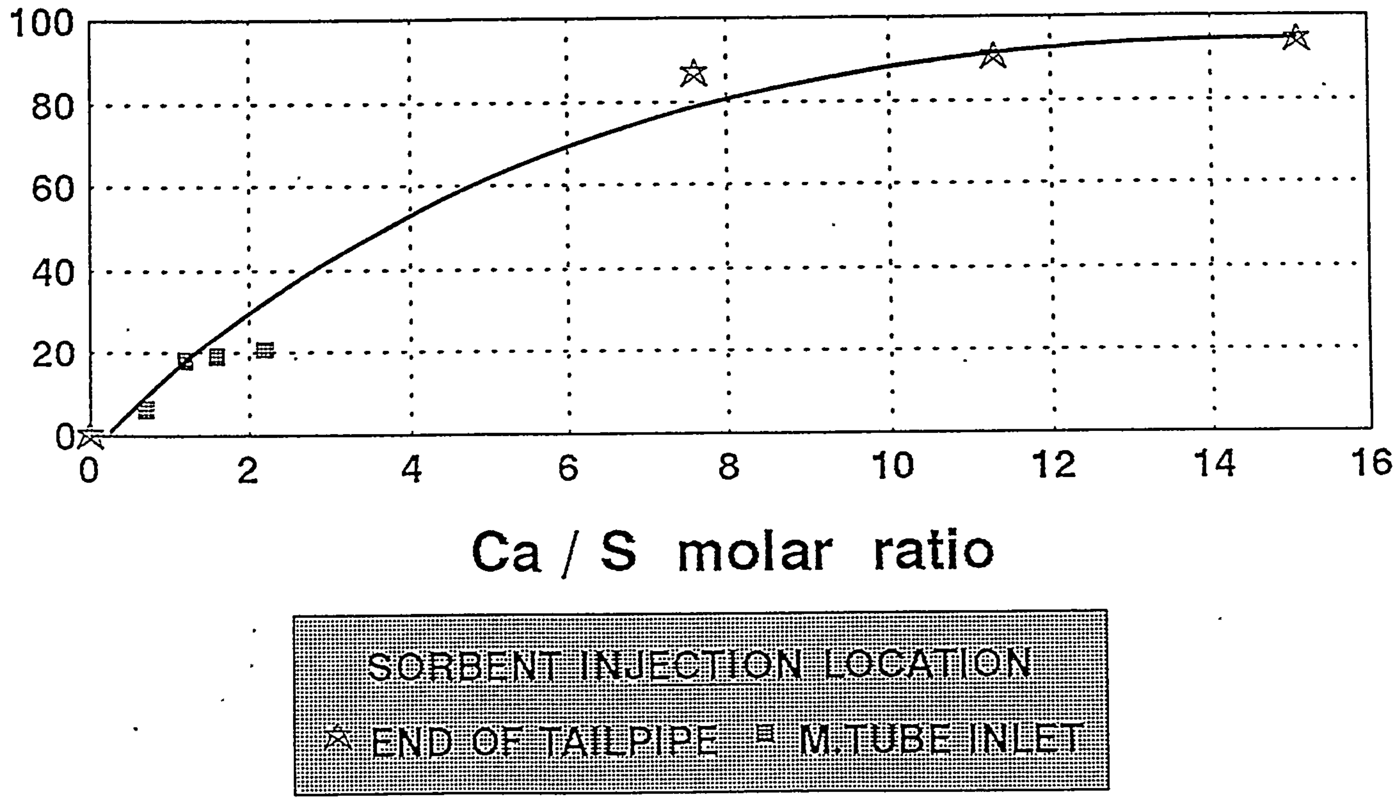


FIGURE 2-54: SULFUR CAPTURE EFFICIENCY WITH CA/S MOLAR RATIO

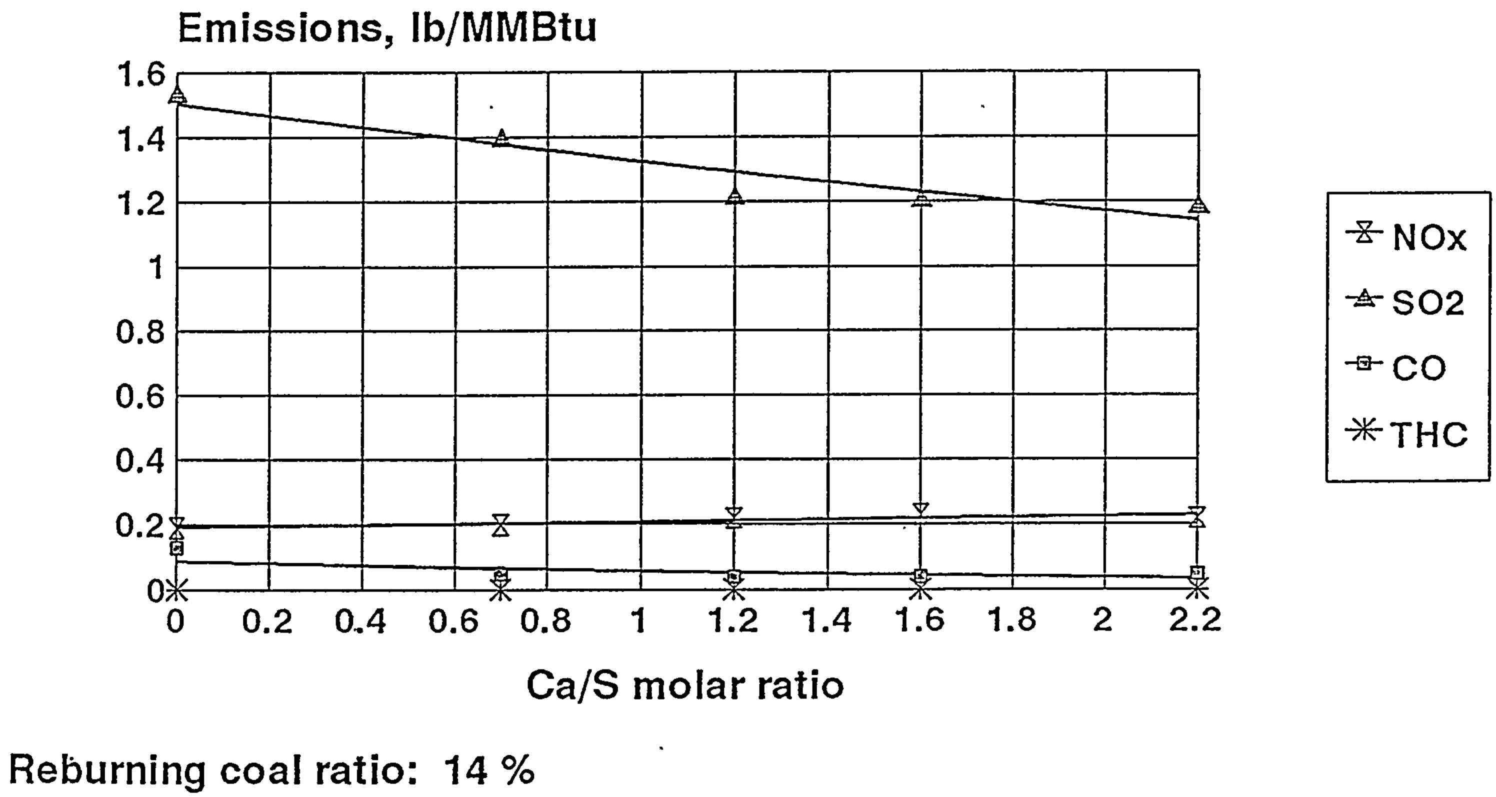


FIGURE 2-55: EMISSIONS WITH SORBENT AND REBURNING COAL FEED

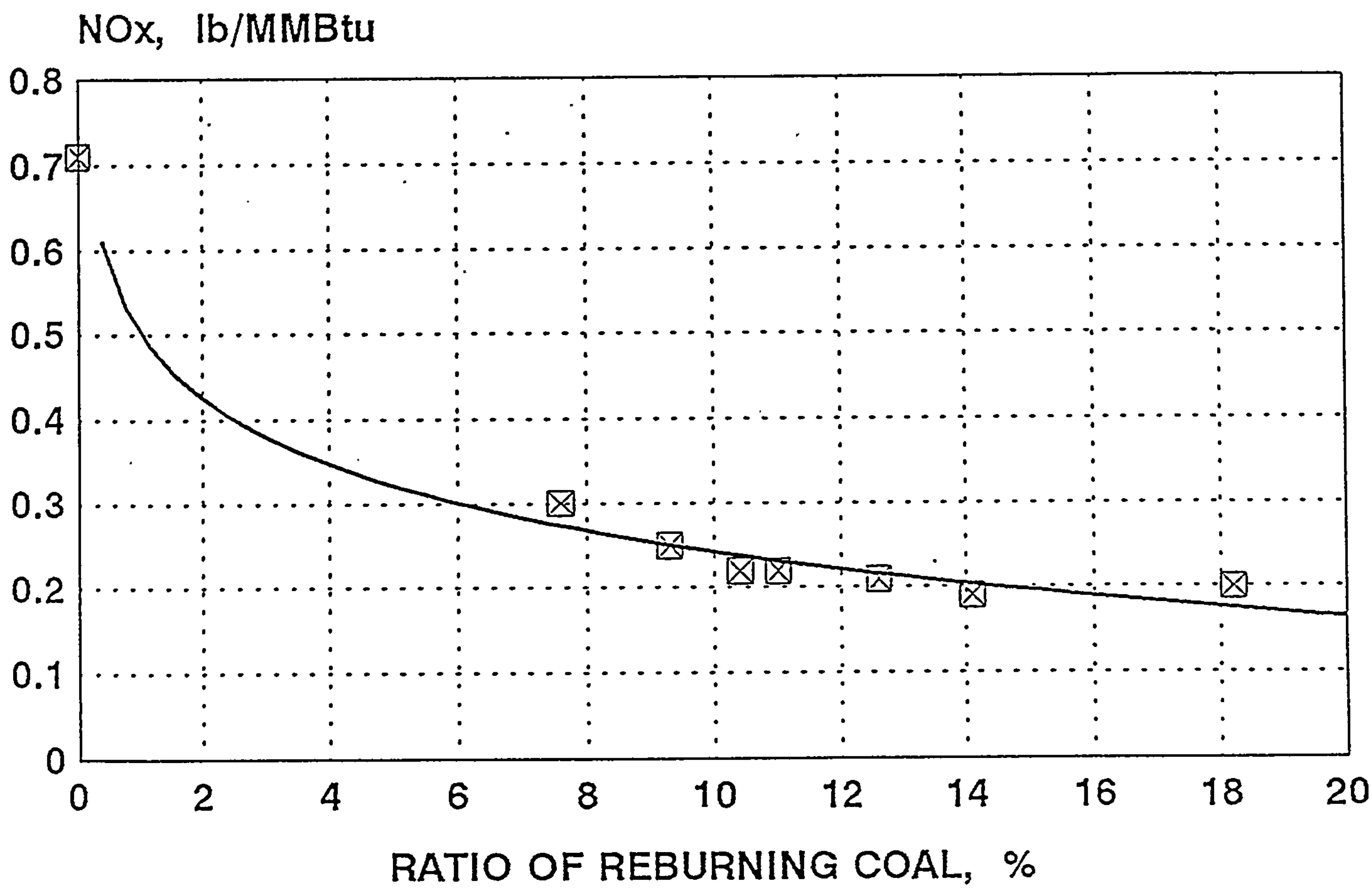


FIGURE 2-56: NO_x EMISSIONS WITH REBURNING COAL

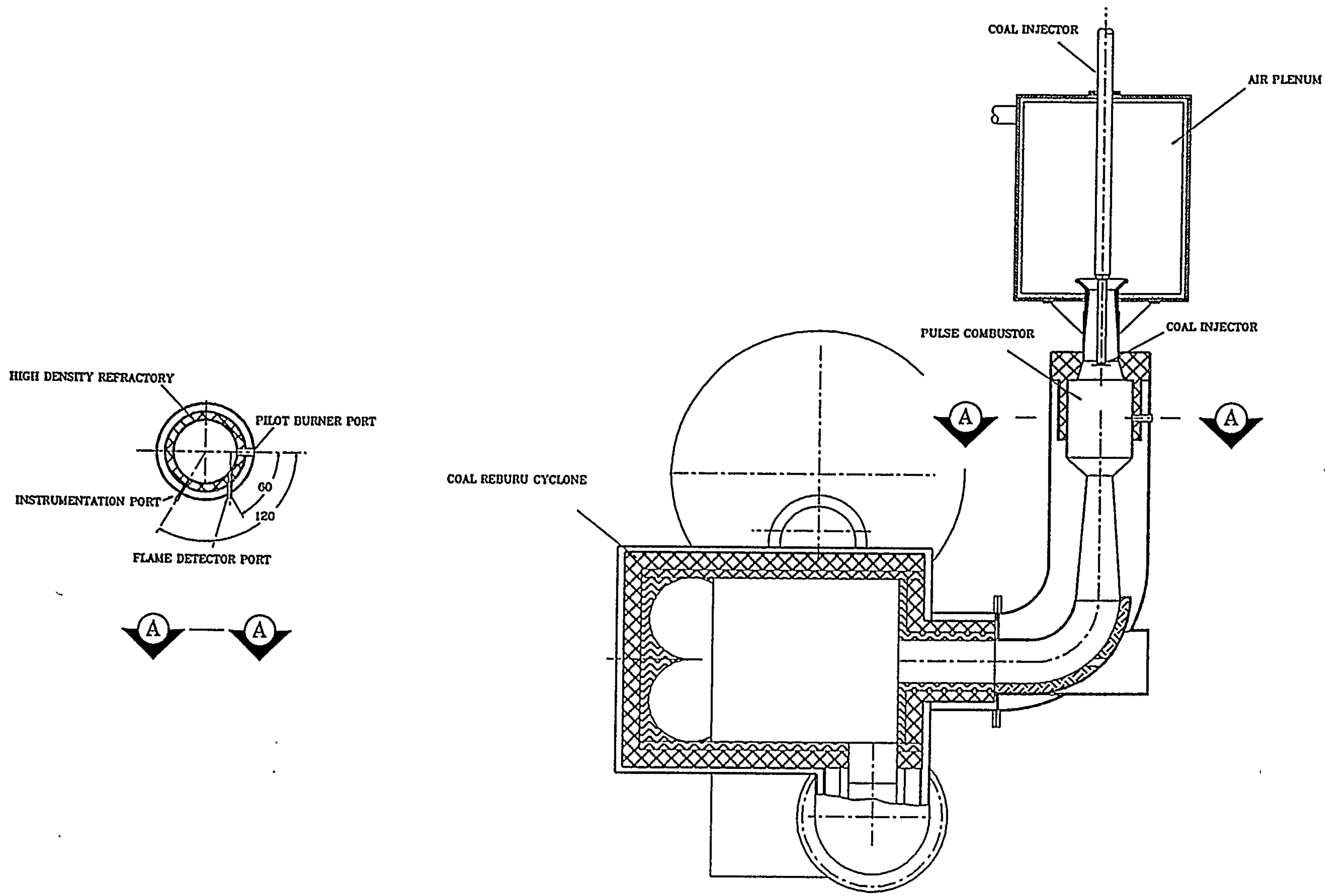


FIGURE 2-57: MODIFICATION OF PULSE COMBUSTION CHAMBER

A review of previous test data indicated that emissions performance under turndown conditions was less than that desired. The pulse combustor required high excess air operation which impeded NO_x reduction. The reason for improper performance of the pulse combustor at low firing rate was hypothesized to be poor fuel and air mixing. Therefore, a new impactor plate was designed, fabricated and integrated with the coal and gas injector as shown in Figure 2-58. The new impactor plate had a bigger diameter to increase main air velocity at the exit of the aerovalve and segmented grooves to increase the velocity of coal and transport air mixture and channel the flow. Both measures were anticipated to improve fuel/air mixing and combustion performance.

To prepare for the 48-hour qualification test, the combustor was partially dismantled and inspected. Some slag was found in the coal reburning section. Review of previous test data showed that the temperature in this section was higher than that per design. Therefore, it was decided to remove refractory from the inlet of coal-reburning section. To sustain the same flow pattern, a 10-inch diameter and 16-inch long S.S. 310 pipe was installed at the inlet. This continuation of the tailpipe was radiantly cooled.

A short test was performed to check the system after modifications. Test data showed that NO_x emissions in the flue gas were surprisingly lower than before and met the target goal even *without coal reburning*. To confirm the test data, the Horiba continuous gas analyzer was thoroughly inspected and calibrated. Tests were performed at full and partial firing rates. At 6.5 MMBtu/hr firing rate, NO_x emissions were below 0.32 lb/MMBtu, and at 4.4 MMBtu/hr, NO_x emissions were at 0.28 lb/MMBtu level. The test data confirmed the new impactor plate installed at the end of the coal injector contributed to better combustion performance of the pulse combustor at substoichiometric conditions.

A 48-hour test was conducted to collect complete performance data of the unit. Emissions data of the test are presented in Figure 2-59. At this point in time, the unit had acquired over 350 hours of operation at firing rates from 2.6 to 6.7 MMBtu/hr with no apparent fouling of the tubes. NO_x emissions ranged

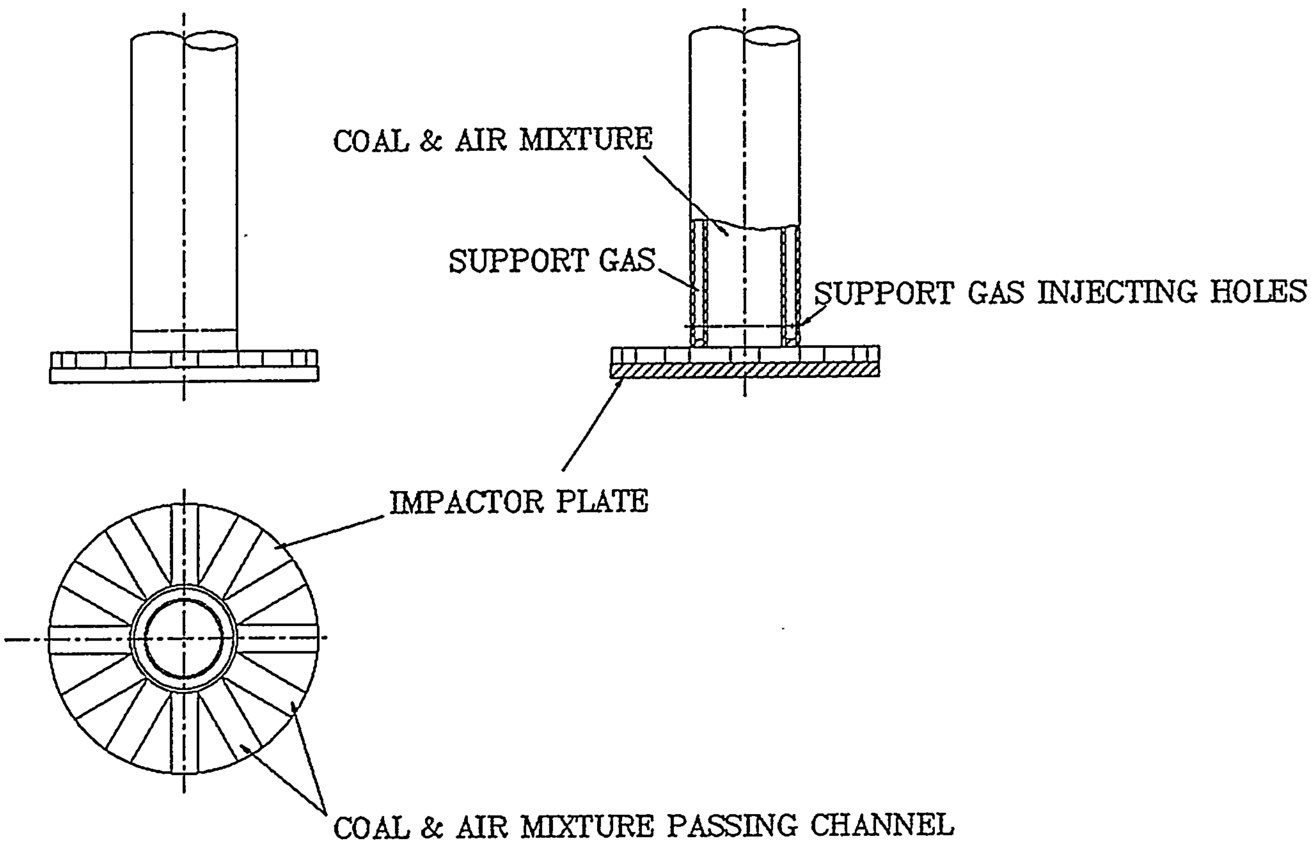


FIGURE 2-58: MODIFICATION OF COAL INJECTOR

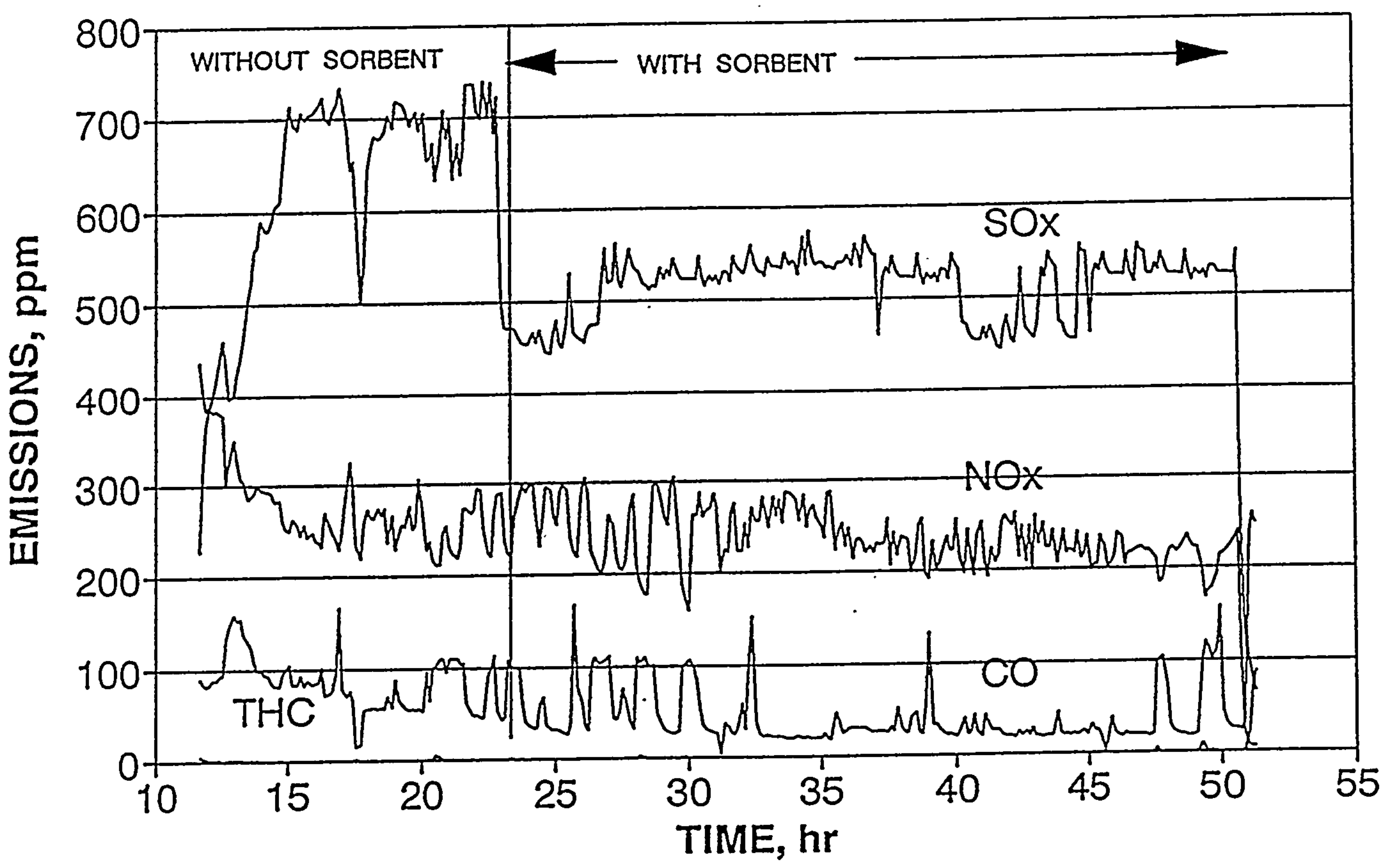


FIGURE 2-59: EMISSIONS IN 48-HOUR TEST - PROOF-OF-CONCEPT TEST

from 0.2 to 0.3 lb/MMBtu, stack particulates were less than .01 lb/MMBtu and a combustion efficiency greater than 99 percent was achieved.

By the end of the proof-of-concept system tests, the basic design of the Commercial Unit was developed and no modifications were expected. Figure 2-60 shows a process and instrumentation diagram (P&ID) of the system prior to the demonstration test series. The system consisted of the following main components:

- FD fan
- Air plenum with coal/gas injector
- Pulse combustor with tailpipe
- Coal reburning section
- Char burnout section
- Fire-tube boiler with Morrison tube
- Baghouse
- ID fan
- Stack
- Main coal hopper
- Reburn coal hopper
- Sorbent screw feeder
- Two air rotation units (Figure 2-60 shows only one)
- Water make-up tank with pumps
- Air compressor (not shown in Figure 2-60)
- Control system and instrumentation.

Air, natural gas, coal, flue gas, water and steam streams are all shown in Figure 2-60.

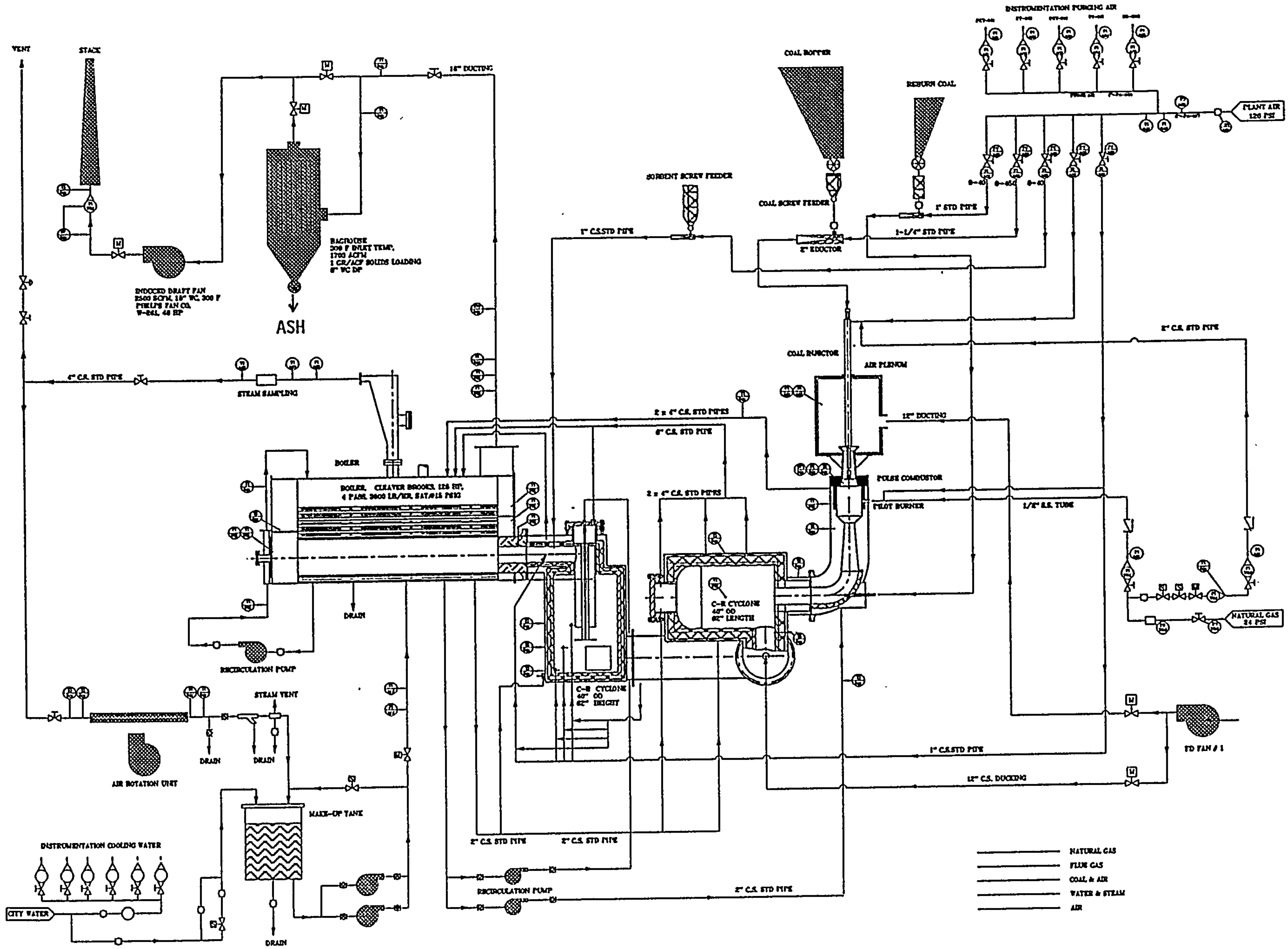


FIGURE 2-60: P&ID OF THE SYSTEM - CONFIGURATION D AT THE END OF PROOF-OF-CONCEPT TEST SERIES

2.4 ECONOMIC EVALUATION AND COMMERCIALIZATION PLAN

This section provides an assessment of the system tested in the project (Sections 2.3 and 2.5). In Section 2.6, a revised final system design together with a revised economic evaluation and market projection are presented. A steam-generation cost model was developed to compare the economics of steam production in the commercial-scale, coal-fired pulse combustion system with that in a natural gas-or oil-fired system. It is to be noted that the application considered here is a boiler retrofit installation. The purpose of this model was to define the competitive capital cost range for the MTCI system under a specified set of technical and economic conditions.

The model had a number of flexible input variables covering technical, environmental and financial assumptions. In order to simplify this multi-dimensional model, a baseline parameter set was defined. For these baseline parameters, specific fixed values were employed. Selection of these values were based on technological assessment, vendor cost data and current prices.[3,11]

Parameters such as capacity factor and differential fuel cost (i.e., natural gas or oil price minus coal price per MMBtu) were allowed to vary in order to estimate steam production cost and target capital cost for a coal-fired pulse combustion system. Table 2-22 summarizes the input parameters for the steam cost model. With coal reburn, the commercial-scale pulse combustion system was expected to fire 6.0 MMBtu/hr at full load. Therefore, gas/oil burner vendors were approached to obtain quotes for a 6.0 MMBtu/hr burner with single-fuel (natural gas) or dual-fuel (natural gas or oil) capability. Current prices for a natural gas burner with blower and controls turned out to be about $14,000 and for a dual-fuel burner system, $32,000. Tables 2-23 and 2-24 show a capital cost estimate of the Commercial System and economic analysis projections.

The results generated from the steam cost model are shown in Figures 2-61 and 2-62. Figure 2-61 indicates the variation in allowable capital cost for the pulse coal combustion system with differential fuel cost for a unit operating at different capacity factors. (Allowable cost is that capital cost that is competitive with gas/oil burner systems.) Figure 2-61 presents the results for the replacement of a dual-fuel (natural gas and oil combination burner) system.

TABLE 2-22:
STEAM COST MODEL INPUT DATA

	COAL-FIRED PULSE COMBUST. SYSTEM	SINGLE-FUEL (NAT. GAS) BURNER SYSTEM	DUAL-FUEL (N.GAS/OIL) BURNER SYSTEM
FUEL	COAL/NAT. GAS	NATURAL GAS	N. GAS/OIL
FUEL COMPOSITION BY FIRING RATE, %	85/15		
SORBENT	LIMESTONE or DOLOMITE	-	-
FIRING RATE, MMBtu/hr	6.0	6.0	6.0
BOILER CAPACITY, PPH @ 15 psig, sat.	4,436	4,436	4,436
COMBUSTION EFFICIENCY, %	99	99.999	99.999
THERMAL EFFICIENCY, %	84	83	83
CAPACITY FACTOR	Variable	Variable	Variable
ELECTRICITY CONSUMPTION, kWh/1000 lb steam	17.4	3.8	5.7
FUEL HHV, Btu/lb	12,500	23,400	23,400
FUEL SULFUR, Wt.%	3	-	-
FUEL ASH, Wt.%	8	-	-
SORBENT Ca/S FEED RATIO	2.5	-	
SORBENT PURITY, Wt.%	90	-	-
SULFUR RETENTION, %	43	-	-
FUEL COST, $/MMBtu	2.0/Variable	Variable	Variable
SORBENT COST, $/ton	15	-	-
WASTE DISPOSAL COST, $/ton	15	-	-
ELECTRICITY COST, $/kWh	0.075	0.075	0.075
NO. OF OPERATORS PER SHIFT	0.125	-	-
NO. OF SHIFTS PER DAY	1	-	-
OPERATOR COST, $/hr	16	-	-
LABOR OVERHEAD, % Direct	80	-	-
MAINTENANCE, % Installed	5	2.5	2.5
TAX & INSURANCE, % Installed	2.5	2.5	2.5
CAPITAL COST, $	Variable	14,000	32,000
ENGINEERING, INSTALLATION AND START-UP COST, % Capital	37.5	6.25	6.25
CONTINGENCY, %	10	-	-
PAYBACK PERIOD, yr	5	5	5
ANNUAL INTEREST RATE, %	9	9	9

TABLE 2-23:
CAPITAL COST ESTIMATE - BOILER RETROFIT

PURCHASE PRICE	
BAGHOUSE	$ 12,036
ID, FD & STAGING AIR FANS	$ 12,505
ELECTRIC AIR COMPRESSOR	$ 14,500
WATER PUMPS	$ 1,800
SCREW CONVEYORS	$ 9,300
CONTROL SYSTEMS & INSTRUMENTATION	$ 40,000
TOTAL	$ 90,141
FABRICATION COST (Materials & Labor)	
AIR PLENUM	$ 1,600
PULSE COMBUSTOR	$ 16,980
REBURN & BURNOUT SECTIONS	$ 27,250
COAL & LIMESTONE SILOS	$ 8,900
TOTAL	$ 54,730
COST PLUS 10% PROFIT PER UNIT	$159,358
COST FOR 10 OR MORE UNITS	$127,486

TABLE 2-24:
ECONOMIC ANALYSIS PROJECTIONS

DIRECT INVESTMENT EXPENDITURES	$127,486 - 159,358
SHIPMENT	$ 3,000 - 10,000
SITE MODIFICATION COSTS	$ 15,000 - 40,000
INSTALLATION CHARGES	$ 31,872 - 39,840
ENGINEERING, DESIGN & START-UP COSTS	$ 15,936 - 19,920
MAINTENANCE	$ 8,765 - 10,956
CONSUMABLES	
WATER	550 gal/hr
NATURAL GAS	18 scfm
COAL	350 lb/hr
LIMESTONE	50 lb/hr
ELECTRICITY	78 kW

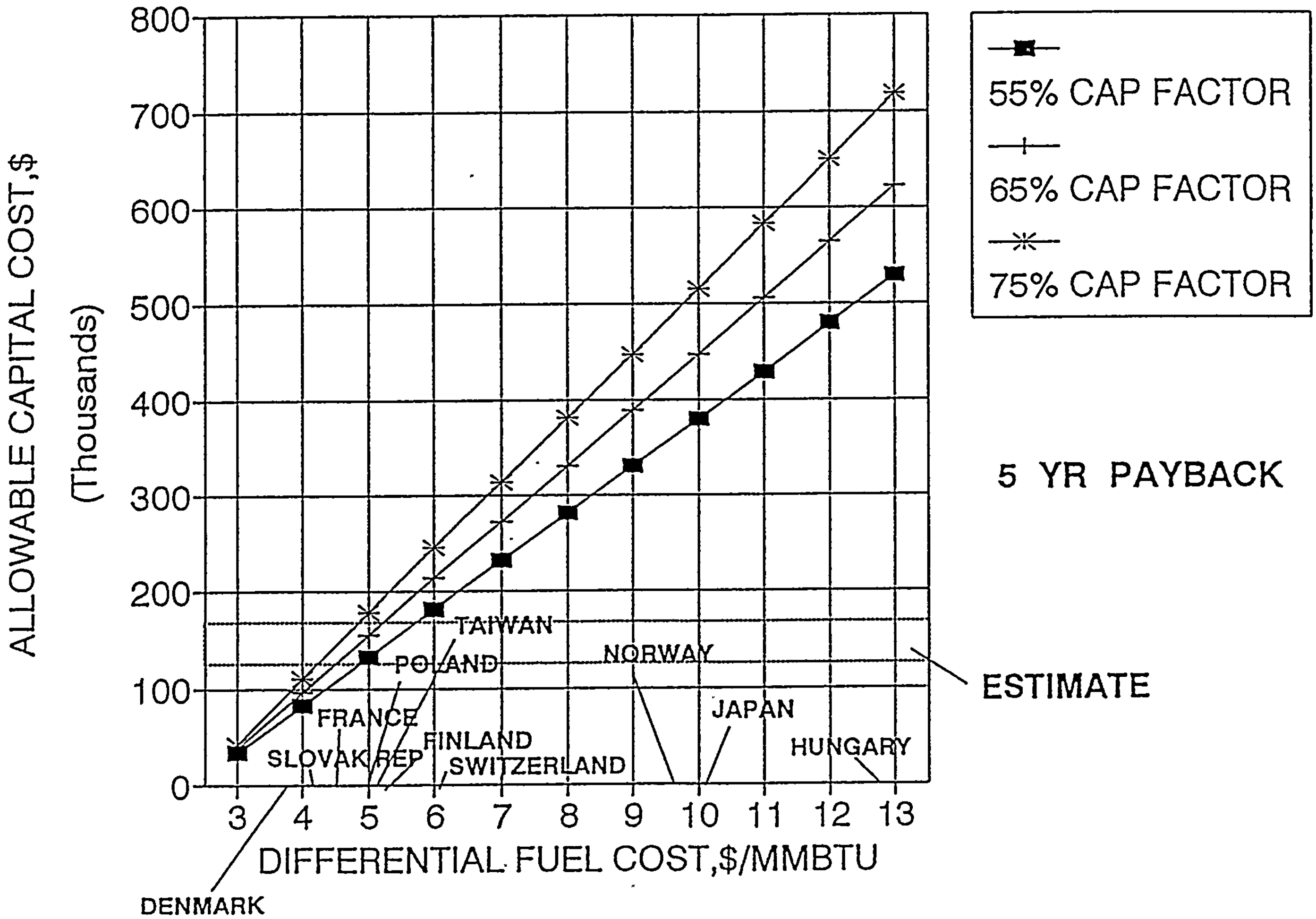


FIGURE 2-61: PULSE COAL COMBUSTION SYSTEM FOR BOILER RETROFIT - NATURAL GAS/OIL COMBINATION BURNER REPLACEMENT (FIVE-YEAR PAYBACK)

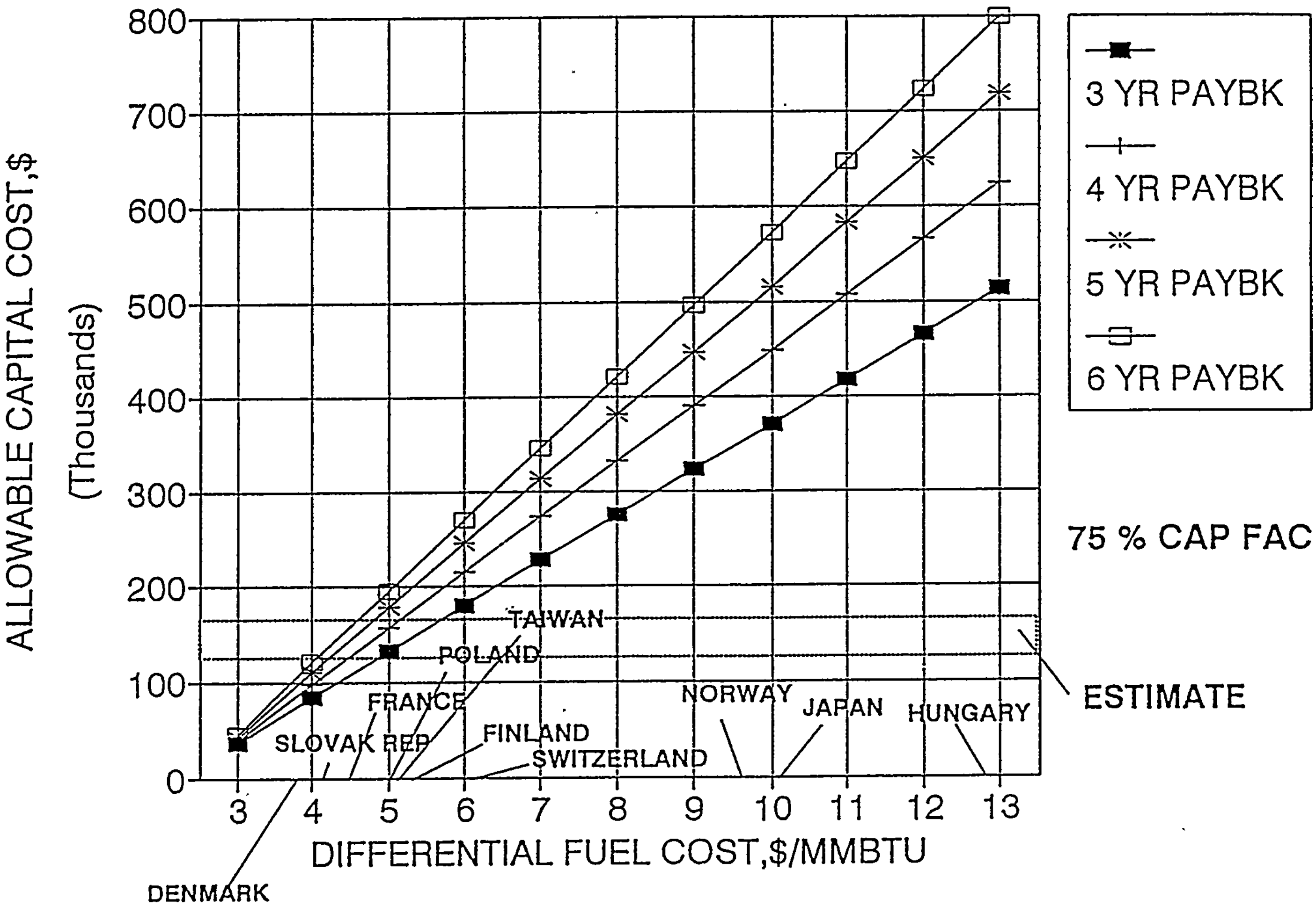


FIGURE 2-62: PULSE COAL COMBUSTION SYSTEM FOR BOILER RETROFIT - NATURAL GAS/OIL COMBINATION BURNER REPLACEMENT (75% CAPACITY FACTOR)

These capital costs were generated by matching the steam costs ($/1000 lb) for the dual-fuel burner system with the pulse coal combustion system. Note that the design, engineering, installation and start-up cost was factored into the model as a percent of the allowable capital cost. This percent value was made many times higher for the coal system in comparison to that for the gas/oil system (see Table 2-22) consistent with the complexity of the coal combustion system in relation to the gas/oil system. The analysis does not take into account the variation in labor and material/parts costs from country to country. The allowable capital cost of the pulse coal combustion system varies with the differential fuel cost and capacity factor as shown in Figure 2-61. Commercial boilers are typically said to operate at the 75% capacity factor level. At this load and at the current U.S. commercial sector natural gas price of $5 per MMBtu,[3] the differential fuel cost is $3/MMBtu, making the allowable capital cost of the pulse coal combustion system to fall in the range between $35,000 and $50,000. European differential fuel costs are more favorable and therefore the allowable capital cost for the pulse coal combustion system was expected to exceed the estimated capital cost indicated above (see Tables 2-23 and 2-24). At 75 percent capacity factor level and at differential fuel cost of $4.5/MMBtu and higher (e.g., in France, Poland, Taiwan, etc.), allowable capital cost of the pulse coal combustion system became $150,000 and higher for a five-year payback period.

An estimate of the MTCI pulse coal combustion system capital cost (see Table 2-23), turned out to be approximately $128,000 which exceeded the target range of the U.S. commercial boiler market sector but remained below the costs in the European and Far East market sectors. Note that the MTCI system is multi-fuel (gas, coal and oil) capable and is designed to meet stringent emissions standards. The capital cost projections are based on an after-tax payback period of five years which typically could correspond to a pre-tax payback period of three to three and one-half years.

Figure 2-62 shows the allowable capital cost for the pulse coal combustion system as a function of differential fuel cost for four payback periods (3, 4, 5, and 6 years) at 75 percent capacity factor. As can be seen from Figure 2-62, the marketability of the MTCI system in selected European countries, Taiwan and Japan, is much more favorable as the payback period increases to 6 years. A 6-

year payback period corresponds to a 15 percent discounted-cash-flow rate of return (DCFRR) in about 16 years as opposed to a 15 percent DCFRR in 10 years for a five-year payback period (Figure 2-63).

2.5 SITE DEMONSTRATION

2.5.1 DEMONSTRATION PLAN

The demonstration test was conducted at the same site that was formerly the Striegel warehouse but now under new ownership. Before the demonstration test was started, a demonstration test plan requiring over 1,000 hours of testing was developed. The plan defined the following:

- Test site location and general description;
- Test matrix and time schedule to perform the demonstration;
- Overall demonstration test plan;
- Site characteristics, accessibility to installation, availability of labor, materials, utilities and any other items needed for installation and operation;
- System modification and/or refurbishment needed to perform the demonstration;
- Projected requirements for labor and consumable items; and
- Updated cost estimate.

The demonstration test of the commercial unit was planned to heat the building and evaluate the heating capability of the unit. Steam from the commercial boiler passed through 5-inch piping to two air rotation units located near the south wall of the laboratory at 170′ apart. Each air rotation unit consists of a steam condenser, two fans and a filter. The baghouse, ID fan, coal bin, coal feeder and stack are located outside the building near the west wall.

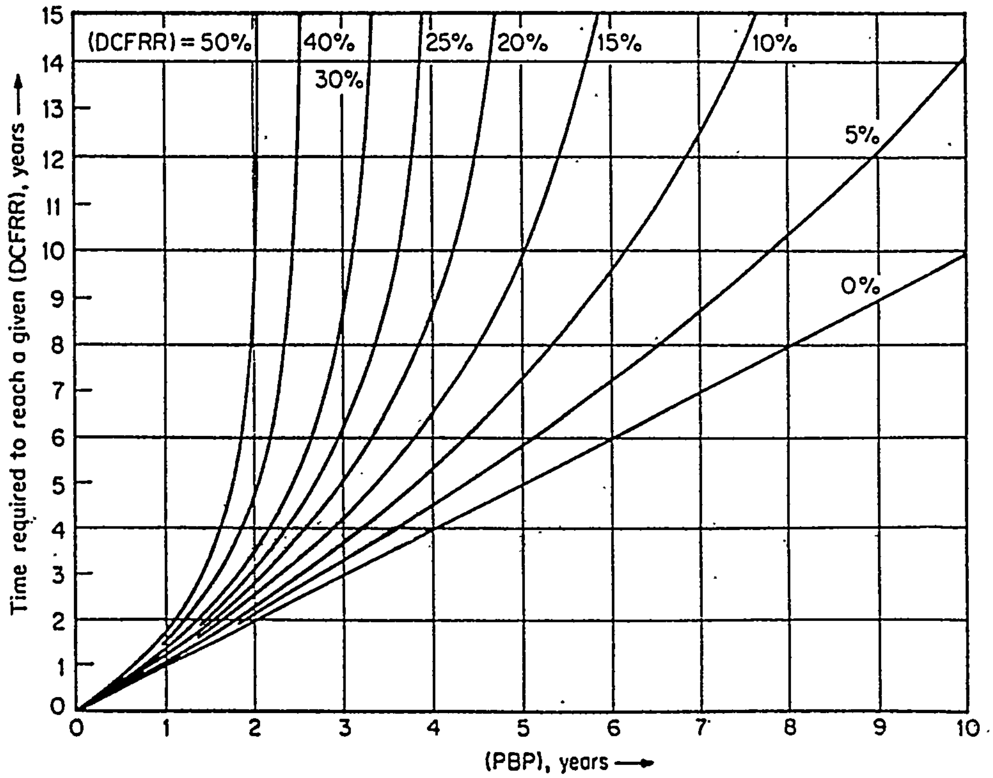


FIGURE 2-63: RELATIONSHIP BETWEEN PAYBACK PERIOD AND DISCOUNTED-CASH-FLOW RATE OF RETURN[12]

TEST MATRIX AND TIME SCHEDULE TO PERFORM THE DEMONSTRATION

One thousand hours of demonstration were considered reasonable to qualify the system for commercial application. Such variables as type of coal and steam load were changed during the demonstration test. A site demonstration test matrix is shown in Table 2-25.

TABLE 2-25: SITE DEMONSTRATION TEST MATRIX

Test No.	Test Objective	Coal	Sorbent	PC Firing Rate, MMBtu/hr	Ca/S Ratio	Control System	Test Duration, hr
1	Full load/ partial load combination	A	B	2 - 6	3	Existing + Manual	200
2	Full load/ partial load combination	B	B	2 - 6	3	Existing + Manual	100
3	Full load/ partial load combination	A	B	2 - 6	3	New Control System	700

Oxygen Level:	2 - 4%
Coal Feed Size:	Dry, Pulverized
Sorbent Feed Size:	Dry, Pulverized
Coal Injection Location:	Pulse Combustor
Sorbent Injection Location:	Morrison Tube Inlet
Air Injection:	Multiple Staging

OVERALL DEMONSTRATION TEST PLAN

The main objective of the test was to evaluate the suitability of the system to heat a commercial sector space. It was proposed to configure the test so as to simulate operation of the system in normal commercial application. Full-load tests were to be performed to demonstrate the maximum capability of the system for space-heating purposes. A temperature sensor/thermostat was installed to control the firing rate of the pulse combustor and maintain the temperature at a certain level. The test was to show that the system could operate at different loads and even shut-off if necessary to maintain the set point. The test was to demonstrate that the system can be easily re-started.

During the test, the overall performance of the system was to be monitored and controlled. The temperature profile along the whole system was to be continuously measured and maintained by adjusting the firing rate of the pulse combustor and air flow rate. It was planned to periodically take steam samples to measure steam quality and calculate the boiler thermal efficiency.

Coal, limestone and ash samples were to be taken in the tests and sent out for chemical and size analyses. The carbon content in the ash was to be used for combustion efficiency calculations and further for heat balance calculation. The mass balance was to be checked for each test.

The MTCI continuous stack gas analysis system was to be used for flue gas sampling. The gas data were to be continuously recorded by a data acquisition system. In the test, the oxygen level was to be maintained at about 3 percent level. The SO_2 level was to be maintained below 1.2 lb/MMBtu by sorbent injection. The new coal injector eliminated the need for coal reburn in the system. The screening tests showed that the NO_x level in the flue gas could be maintained at 0.3 lb/ MMBtu. The staging air was to be used to maintain CO level below 100 ppm.

The basic measurement parameters for the demonstration test are shown in Table 2-26.

TABLE 2-26:
MEASUREMENT PARAMETERS FOR THE DEMONSTRATION TEST

FLOW MEASUREMENT ITEMS	UNIT
Main Gas	cfm
Main Air	cfm
Pilot Gas	cfm
Pilot Air	cfm
Coal Transportation Air	cfm
Main Air	cfm
Staging Air (1)	cfm
Staging Air (2)	cfm
Staging Air (3)	cfm
Staging Air (4)	cfm
Cooling Air for Reburning Coal Port	cfm
Limestone Transportation Air	cfm
Flue Gas to Stack	cfm
Boiler Make-Up Water	gpm
PRESSURE MEASUREMENT ITEMS	
Steam at Boiler Exit	psig
Air Plenum	Inches of Water
Pulse Combustion Chamber	Inches of Water
Exit of Boiler	Inches of Water
Pressure Differential of Coal-Reburning Section	Inches of Water
Pressure Differential of Char-Burnout Section	Inches of Water
COAL AND LIMESTONE MEASUREMENT ITEMS	
Coal Feeder Setting	Hz
Limestone Feeder Setting	Hz
ACOUSTIC MEASUREMENT ITEMS	
Sound Pressure Level	dB
Frequency	Hz
EMISSION MEASUREMENT ITEMS	
O_2 Oxygen	%
CO_2 Carbon Dioxide	%
CO Carbon Monoxide	ppm
SO_2 Sulfur Dioxide	ppm
NO_x Nitrogen Oxide	ppm
THC Total Hydrocarbons	ppm
TEMPERATURE MEASUREMENT ITEMS	
Air Or Flue Gas	

TABLE 2-26: MEASUREMENT PARAMETERS FOR THE DEMONSTRATION TEST (CONT'D)

Main Gas	°F
Air at FD Fan Exit	°F
Air Plenum	°F
Exit of Tailpipe	°F
Middle of Coal-Reburning Section	°F
Exit of Coal-Reburning Section	°F
Middle of Char-Burnout Section	°F
Top of Char-Burnout Section	°F
Inlet to Morrison Tube	°F
Back Door of Boiler	°F
End of Pass 2	°F
End of Pass 3	°F
End of Pass 4	°F
Baghouse Inlet (1)	°F
Baghouse Inlet (2)	°F
Flue Gas Venturi Exit	°F
Water or Steam	
Inlet of Water Jacket of 2 Sections	°F
Inlet of Char Burnout Section Water Jacket	°F
Exit of Char Burnout Section Water Jacket	°F
Boiler Inlet	°F
Inlet of Pulse Combustion Chamber Water Jacket	°F
Middle of Pulse Combustion Chamber Water Jacket	°F
Exit of Pulse Combustion Chamber Water Jacket	°F
Inlet of Back Door Water Jacket	°F
Exit of Back Door Water Jacket	°F
Inlet of Steam Sampling Unit	°F
Exit of Steam Sampling Unit	°F
Inlet of #1 Air Rotation Unit	°F
Exit of #1 Air Rotation Unit	°F
Inlet of #2 Air Rotation Unit	°F
Exit of #2 Air Rotation Unit	°F
SAMPLING ITEMS	
Coal	
Limestone	
Ash	
Steam	

The screening tests showed that the critical control system worked unsatisfactorily; it lost memory, shut off the combustor abruptly, etc. An alternate control system that could work reliably and respond to heat demand was mandatory for commercialization of the system. It was therefore decided to integrate a programmable logic controller (PLC) to control the operation of the system. The control logic flow diagram of the system operation is shown in Figure 2-64. In view of the lead time involved in procuring parts and integrating this new control system, the first part of the test (about 300 hours) was manually controlled by MTCI engineers according to the control logic flow diagram. The second part of the tests was automatically controlled by the PLC.

SITE CHARACTERISTICS: ACCESSIBILITY TO INSTALLATION, AVAILABILITY OF LABOR, MATERIALS, UTILITIES AND ANY OTHER ITEMS NEEDED FOR INSTALLATION AND OPERATION

The system was fabricated and installed at MTCI's Baltimore laboratory using MTCI's fabrication and installation equipment such as welding machines, machine tools, overhead and mobile cranes. MTCI's Baltimore laboratory had the materials, utilities, and manpower available for maintenance, modification and operation of the system.

SYSTEM MODIFICATION AND/OR REFURBISHMENT NEEDED TO PERFORM THE DEMONSTRATION

The baghouse of the system was inspected and cleaned for the demonstration test. If there were torn bags, they were replaced by new ones.

The commercial boiler coal-feeding system consisted of the coal bin, rotary valve attached to the bottom of the coal bin, screw feeder arranged below the rotary valve, and a 2-inch eductor connected to the exit of the screw feeder. The discharge side of the eductor was connected to the coal injector. The screw feeder box had two level sensors and coal was maintained between the two levels. The screening tests showed that the coal feed was not steady which affected the performance of the pulse combustor and the flue gas emissions level. To improve the uniformity of the coal feed, the rotary valve capacity needed to be increased. Also, a vibrator was to be installed at the coal bin wall.

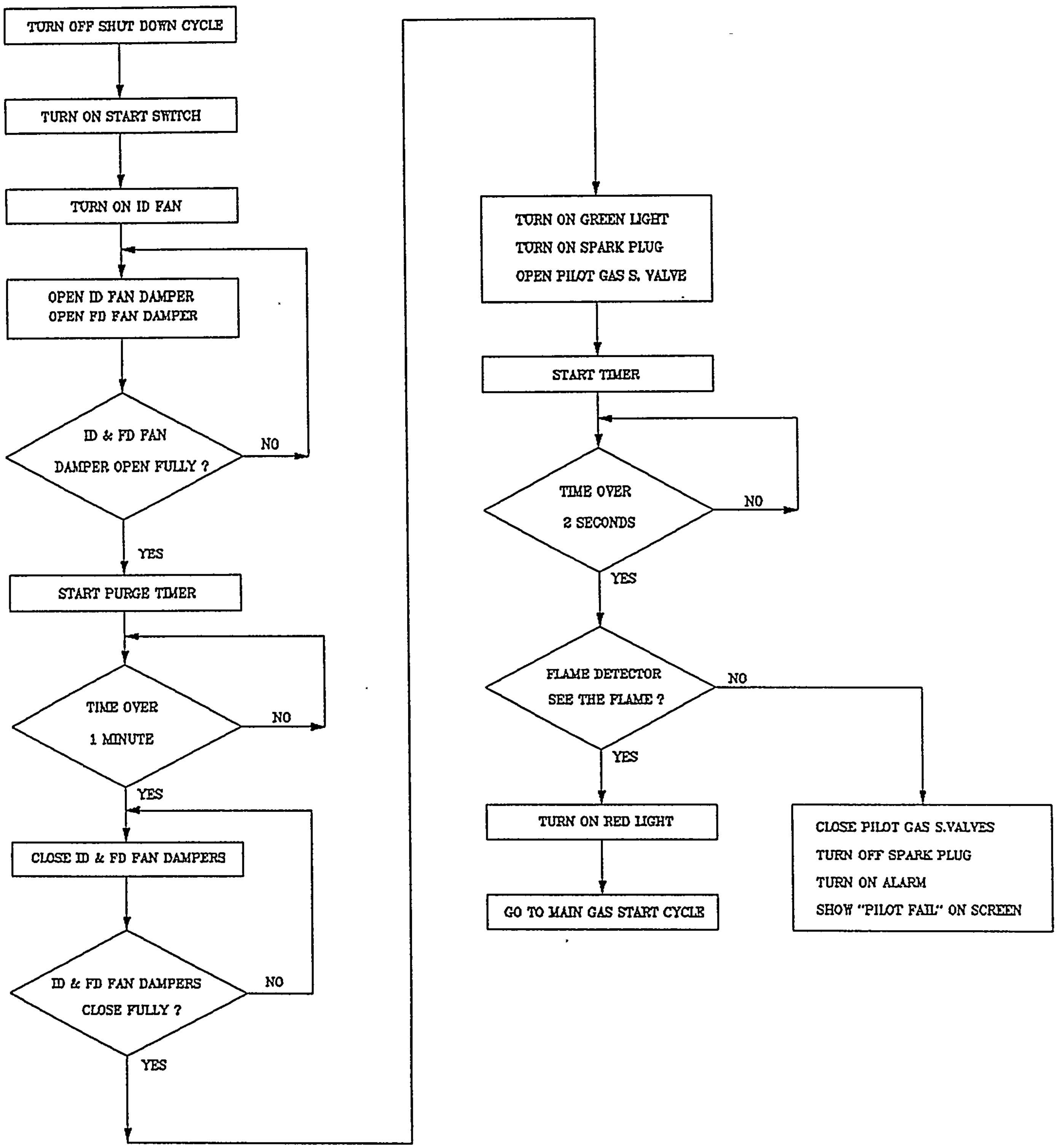


FIGURE 2-64A: CONTROL LOGIC FLOW DIAGRAM FOR THE SYSTEM OPERATION (PURGE CYCLE)

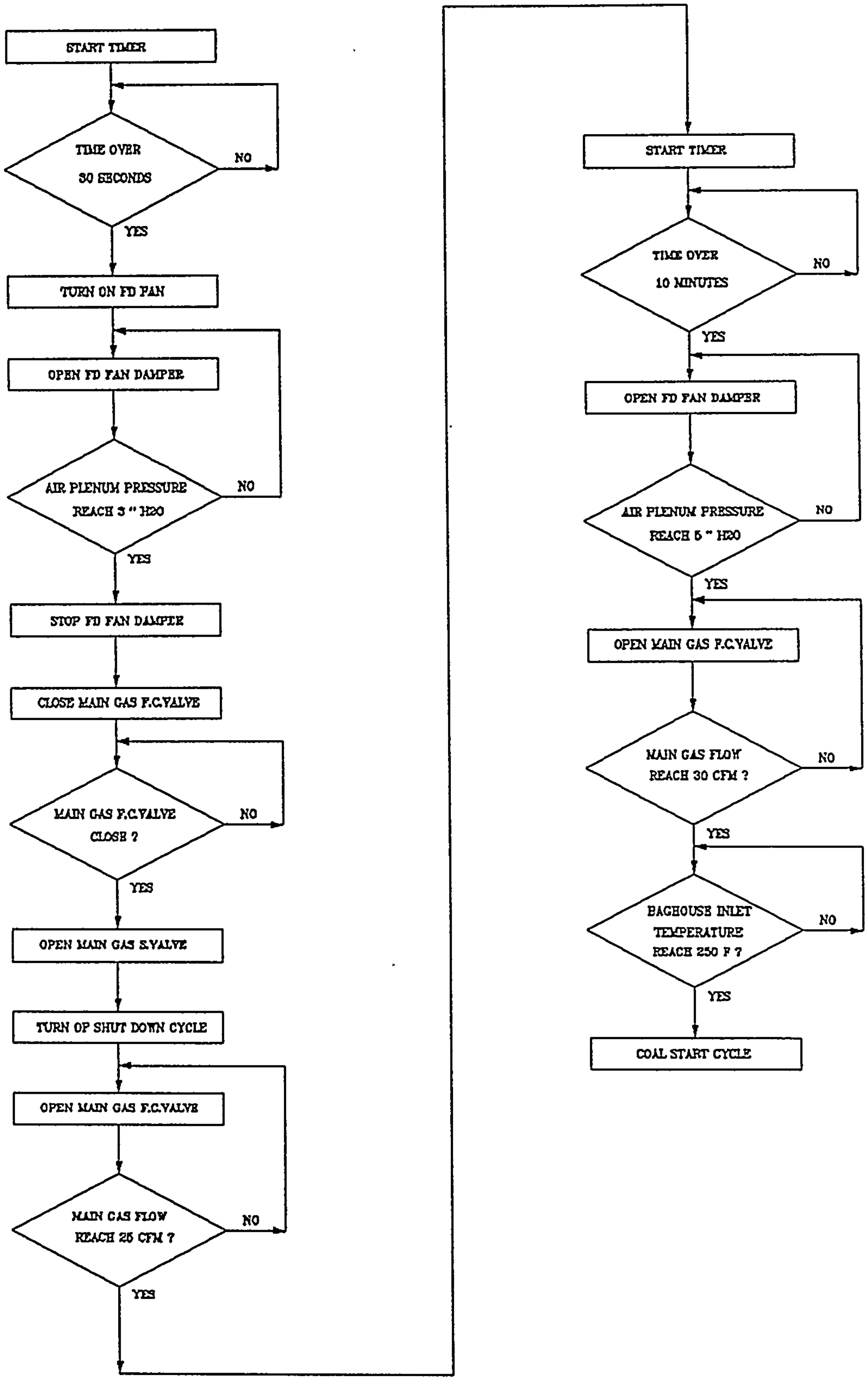


FIGURE 2-64B: CONTROL LOGIC FLOW DIAGRAM FOR THE SYSTEM OPERATION
(MAIN GAS START-UP CYCLE)

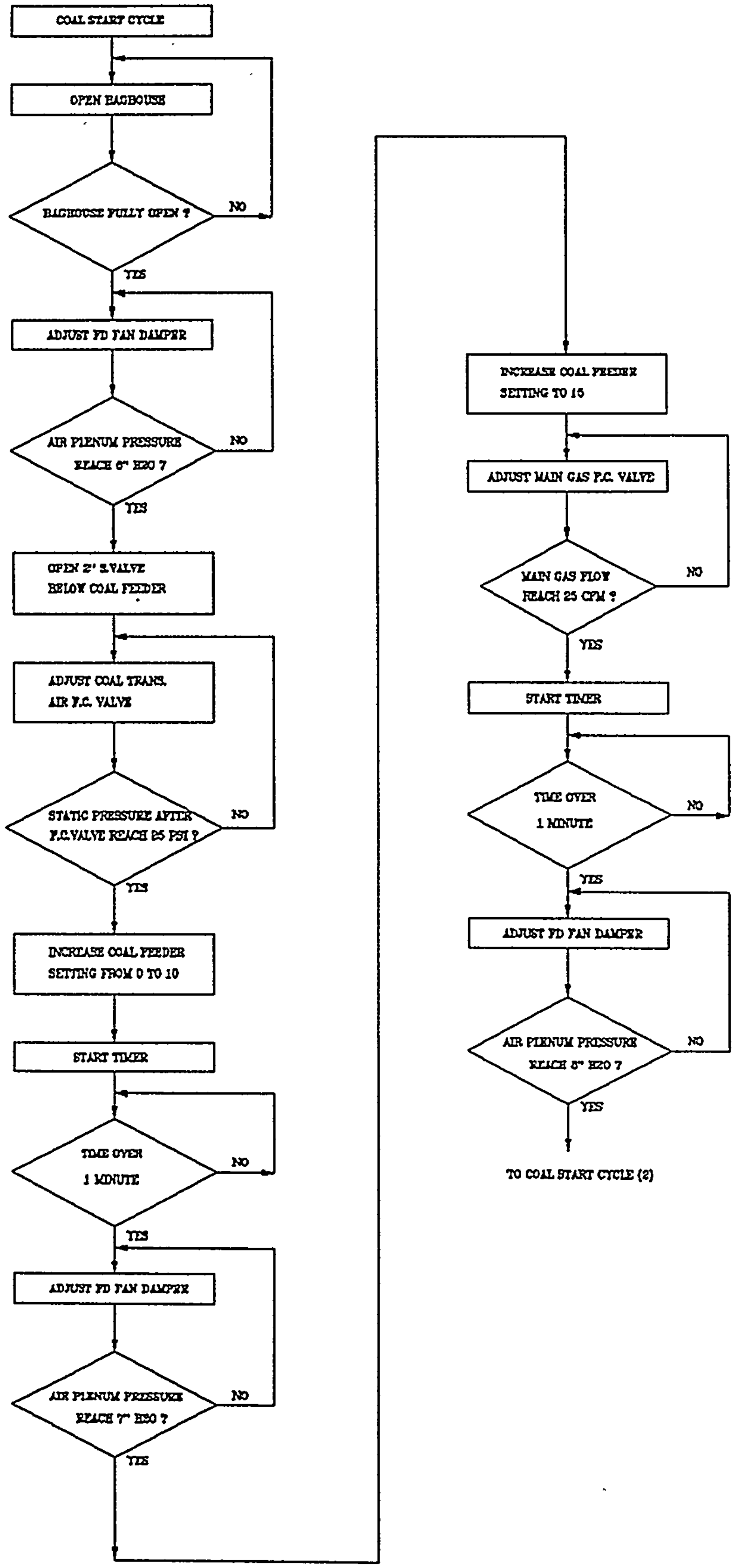


FIGURE 2-64c: CONTROL LOGIC FLOW DIAGRAM FOR THE SYSTEM OPERATION (COAL START-UP CYCLE-1)

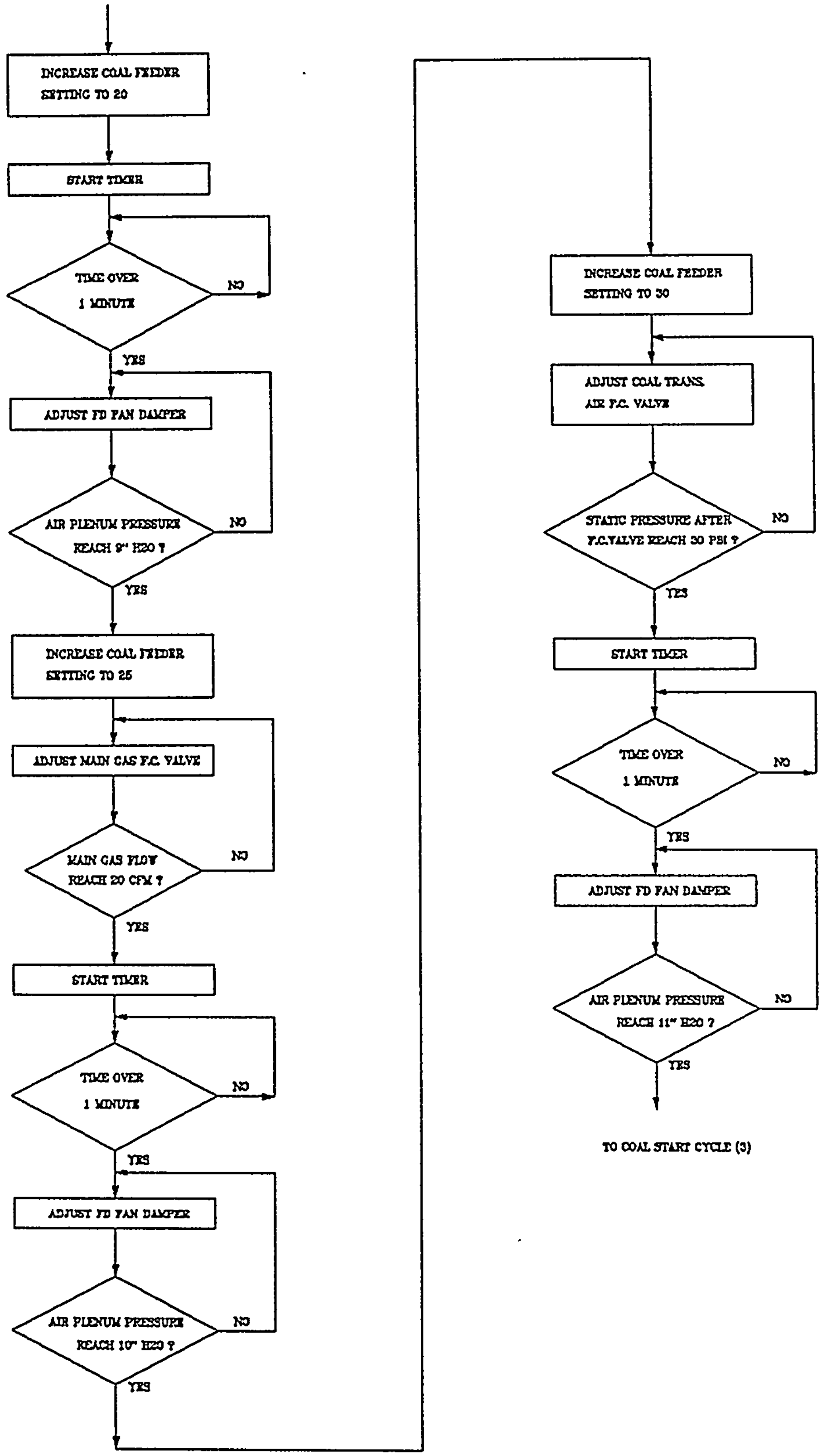


FIGURE 2-64D: CONTROL LOGIC FLOW DIAGRAM FOR THE SYSTEM OPERATION (COAL START-UP CYCLE-2)

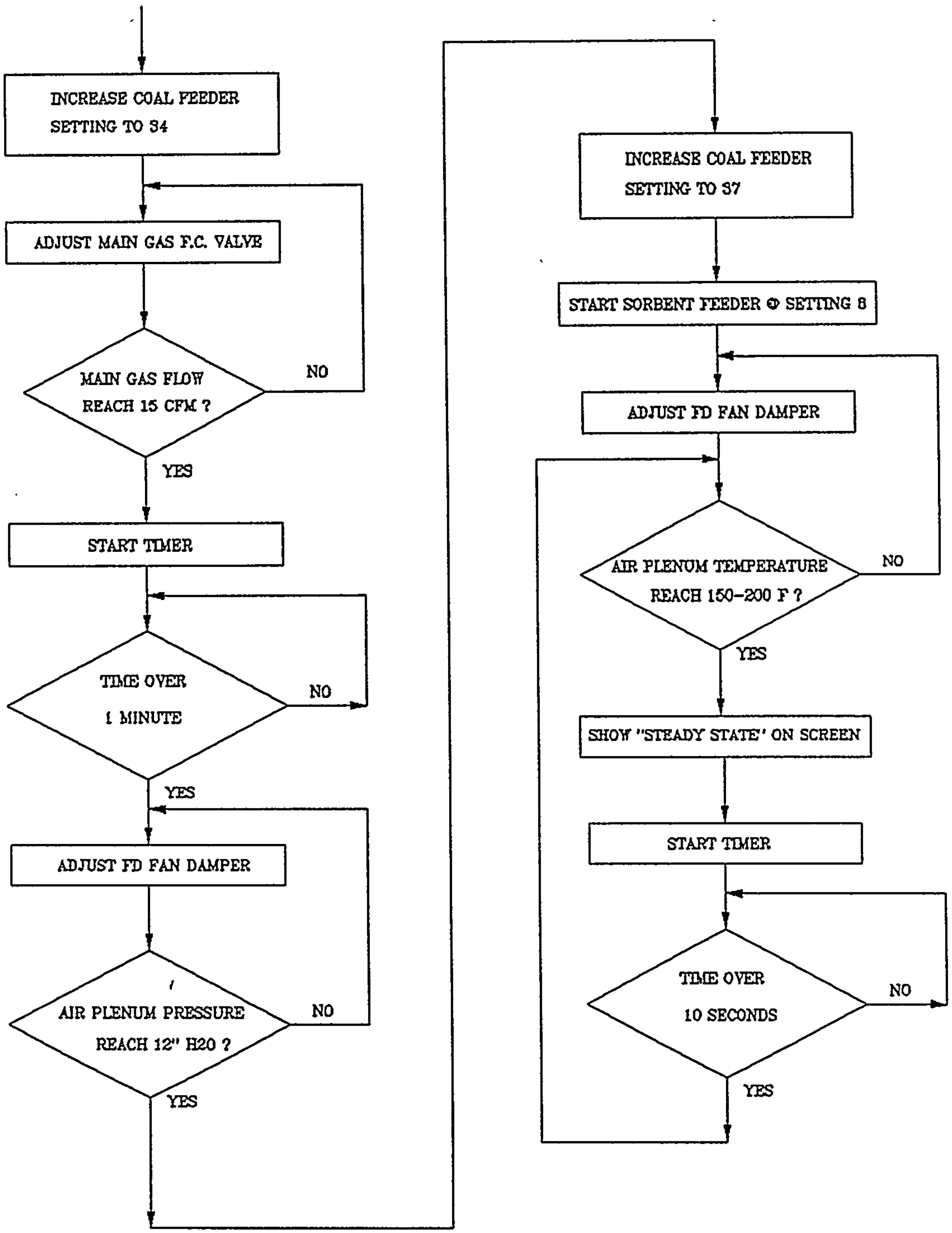


FIGURE 64E: CONTROL LOGIC FLOW DIAGRAM FOR THE SYSTEM OPERATION (COAL START-UP CYCLE-3)

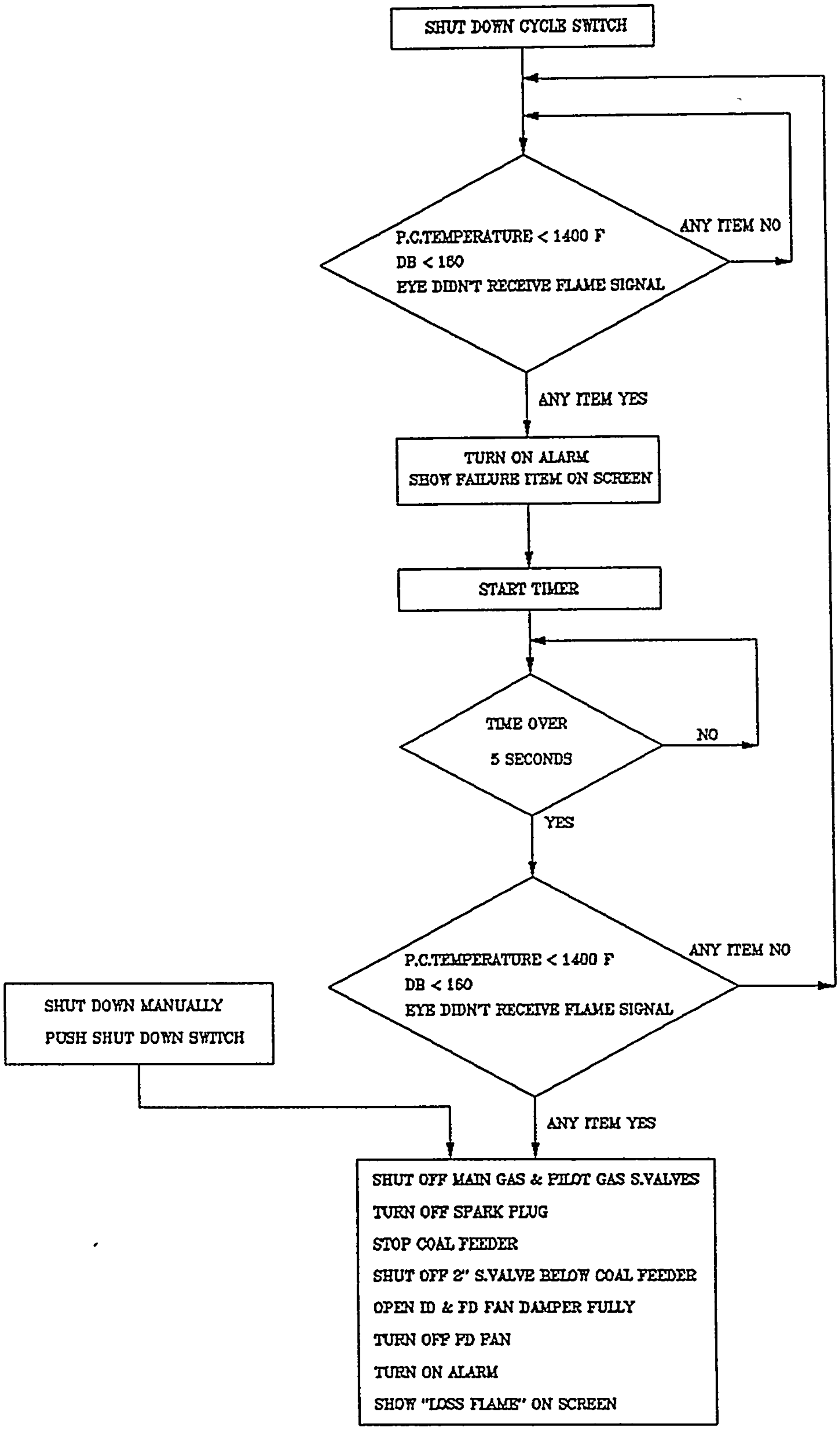


FIGURE 64F: CONTROL LOGIC FLOW DIAGRAM FOR THE SYSTEM OPERATION (SHUTDOWN CYCLE)

To supply adequate staging air for char burnout and to reduce CO emissions in the flue gas, it was decided to install a T-connection with a 6-inch pipe and butterfly valve at the exit of the FD fan and connect the 6-inch pipe to the passage between coal reburn and char burnout sections.

The lower half of the back side of the boiler had a semi-cylinder section attached to it to reduce the vibrations of the back door and to increase the residence time of the coal particles in the hot zone of the system. Because of the incorporation of coal reburn and char burnout sections, there were no vibrations at the back door area and there was sufficient residence time for coal particles to burn out in the system. It was therefore decided to remove the semi-cylinder section.

As was mentioned earlier, the current control system was not satisfactory for long duration tests; therefore, it was to be replaced with a programmable logic controller (PLC) which would be installed and integrated by MTCI engineers.

PROJECTED REQUIREMENTS FOR LABOR AND CONSUMABLE ITEMS

Such consumables as natural gas, water, compressed air and electricity were available in the laboratory. Two hundred tons of pulverized coal and 60 tons of sorbent were to be procured to complete the demonstration test. Initially, one engineer and one helper were to operate the system. Later, the system was to be monitored by automatic controller in the intermittent presence of one technician.

2.5.2 Site Demonstration Tests

All of the system modifications that were outlined in the Plan were completed. Several tests were performed with the original commercially purchased control system's PLC before the long duration site demonstration tests were started. This test series was performed to evaluate the readiness of the system for long duration operation and therefore is termed Series 0. Table 2-27 summarizes the test results. The five tests were run for a total duration of 48 hours. In all these tests, the pulse combustor (primary zone) was operated in the fuel-rich or substoichiometric mode. Ash was only analyzed for the sample collected in Test No. 011195.

TABLE 2-27:
DEMONSTRATION TEST DATA SUMMARY - SERIES 0
(COAL A)

TEST NO.		01	02	03	04	05
SPECIFICATION		*	*	*	*	**
Firing Rate, MMBtu/hr	Total firing rate	5.95	6.09	6.04	6.04	6.30
	Coal	5.04	5.18	5.04	5.04	5.30
	Natural gas	0.91	0.91	1.00	1.00	1.00
	Reburning coal	0.0	0.0	0.0	0.0	0.3
Temperature, °F	Air plenum	163	122	190	186	191
	Combustion chamber	2200	2348	2350	2350	2350
	1st cyclone (avg.)	1671	1677	1574	1629	1614
	2nd cyclone (avg.)	2091	2200	2148	2309	2446
	Stack	275	272	278	311	344
	Steam	216	216	214	223	222
Pressure, H_2O	Air plenum	5.5	6	5.3	6	9.7
	Combustion chamber	9.5	9	9.5	11.5	15.2
	1st cyclone	0.4	0.3	0.2	0.2	0.3
	2nd cyclone	4	4.5	4.2	5.2	9
	Stack	-0.8	-0.3	-0.8	-1	-0.2
Excess Air, %		12.7	14.5	12.5	10.3	17.1
Emissions at Stack (corrected to 3% O_2)	O2, %	2.5	2.8	2.4	2.0	3.1
	CO2, %	15.46	15	15.7	16.1	15.3
	CO, ppm	60	69	68	95	56
	SOx, ppm	693	681	750	750	784
	NOx, ppm	185	197	205	225	411
	HC, ppm	8	10	7	7	6
	CO, lb/MMBtu	0.06	0.07	0.06	0.09	0.05
	SOx, lb/MMBtu	1.56	1.54	1.67	1.66	1.72
	NOx, lb/MMBtu	0.24	0.25	0.26	0.28	0.51
	HC, lb/MMBtu	0.00	0.01	0.00	0.00	0.00
Acoustic Data of Combustor Chamber	SPL, dB	173.6	172.8	173.1	172.6	172.3
	Frequency, Hz	62	60	62	62	62
Thermal Efficiency		84.8	81.8	83.0	84.0	83.3

* No reburning coal
** With reburning coal

The results continued to verify the good combustion and emissions performance of the system. The temperature in the combustion chamber was about 2300°F, the same as in the previous tests. In fact, all the data were similar to those reported earlier, indicating good repeatability.

Table 2-27 also shows low NO_x emissions (below 0.3 lb/MMBtu) in the tests without reburning coal. In the test with reburning coal (last column, Table 27), NO_x emission was higher. It is attributed to additional volatile and char burning in the char burnout section, generating additional NO_x. Therefore, reburn coal injection may not be a good option in the case of substoichiometric conditions in the primary (pulse combustion) zone.

In the period of time from January to June 1995, a total of 1,020 hours of the demonstration test were conducted on the system at different conditions according to the demonstration plan. Except for some minor modifications, no changes were made in the system during this period. Main coal and gas were injected into the pulse combustion chamber. Reburning coal, when used was injected after the tailpipe. Secondary air was supplied into the pass between the coal reburn and char burnout sections. Sorbent (Anville lime) was injected before the Morrison tube of the boiler. A total of six test series were performed and these data are summarized in what follows.

A 48-hour, full load, low sulfur coal test with no reburning coal was performed on the system on January 11 and 12, 1995. Table 2-28 shows the performance data for the test. Flue gas emissions history during steady state is shown in Figures 2-65 and 2-66. High SO_2 level corresponds to data taken with no sorbent feed. The NO_x level was below 0.3 lb/MMBtu during the test. Note that no reburning coal was used in the test. The test demonstrated good combustion (higher than 99%) and thermal efficiencies (higher than 82%) of the commercial system. At Ca/S molar ratio of 1.67, SO_x emissions level was below 1.2 lb/MMBtu.

TABLE 2-28:
DEMONSTRATION TEST DATA SUMMARY - SERIES 1
(FULL LOAD, COAL A, SORBENT B, 48 HOURS)

TEST NO.		011095	011095	011195	011195	011195
Firing Rate, MMBtu/hr	Total firing rate	6.26	6.26	5.96	5.96	5.96
	Coal	5.18	5.18	5.04	5.04	5.04
	Natural gas	1.08	1.08	0.92	0.92	0.92
	Reburning coal	0	0	0	0	0
Ca/S Molar Ratio		0	1.26	0	1.67	1.67
Temperature, °F	Air plenum	109	108	106	99	91
	Combustion chamber	2212	2158	2313	2289	2339
	1st cyclone (avg.)	1728	1735	1636	1669	1681
	2nd cyclone (avg.)	2225	2250	2190	2245	2259
	Stack	308	314	299	313	325
	Steam	223	224	223	224	224
Pressure, inches of H_2O	Air plenum	6	6.3	7.5	9.1	9.3
	Combustion chamber	16.5	19	10.8	15.6	13.3
	1st cyclone	0.5	0.4	0.5	0.5	0.8
	2nd cyclone	1.3	1.7	1.6	1.7	1.6
	Stack	-0.8	-0.5	-0.7	-0.6	-1
Excess Air, %		16.1	19.4	14.8	14.8	18.0
Emissions at Stack (corrected to 3% O_2)	O2, %	2.9	3.4	2.7	2.7	3.2
	CO2, %	15.7	15.2	15.9	15.7	15.3
	CO, ppm	67	23	75	38	40
	SOx, ppm	750	635	774	570	580
	NOx, ppm	233	225	226	240	217
	HC, ppm	8	6	8	8	9
	CO, lb/MMBtu	0.06	0.02	0.06	0.03	0.03
	SOx, lb/MMBtu	1.56	1.28	1.56	1.16	1.18
	NOx, lb/MMBtu	0.28	0.26	0.26	0.28	0.25
	HC, lb/MMBtu	0	0	0	0	0
Acoustic Data of Combustor Chamber	SPL, dB	169.1	168.2	170.0	168.8	169.3
	Frequency, Hz	62	62	60	58	58
Combustion Efficiency, %		-	-	-	-	99.1
Thermal Efficiency, %		83.2	82.6	82.4	82.6	83.4
Sulfur Capture Efficiency, %		0	11.5	0	21.5	20.2

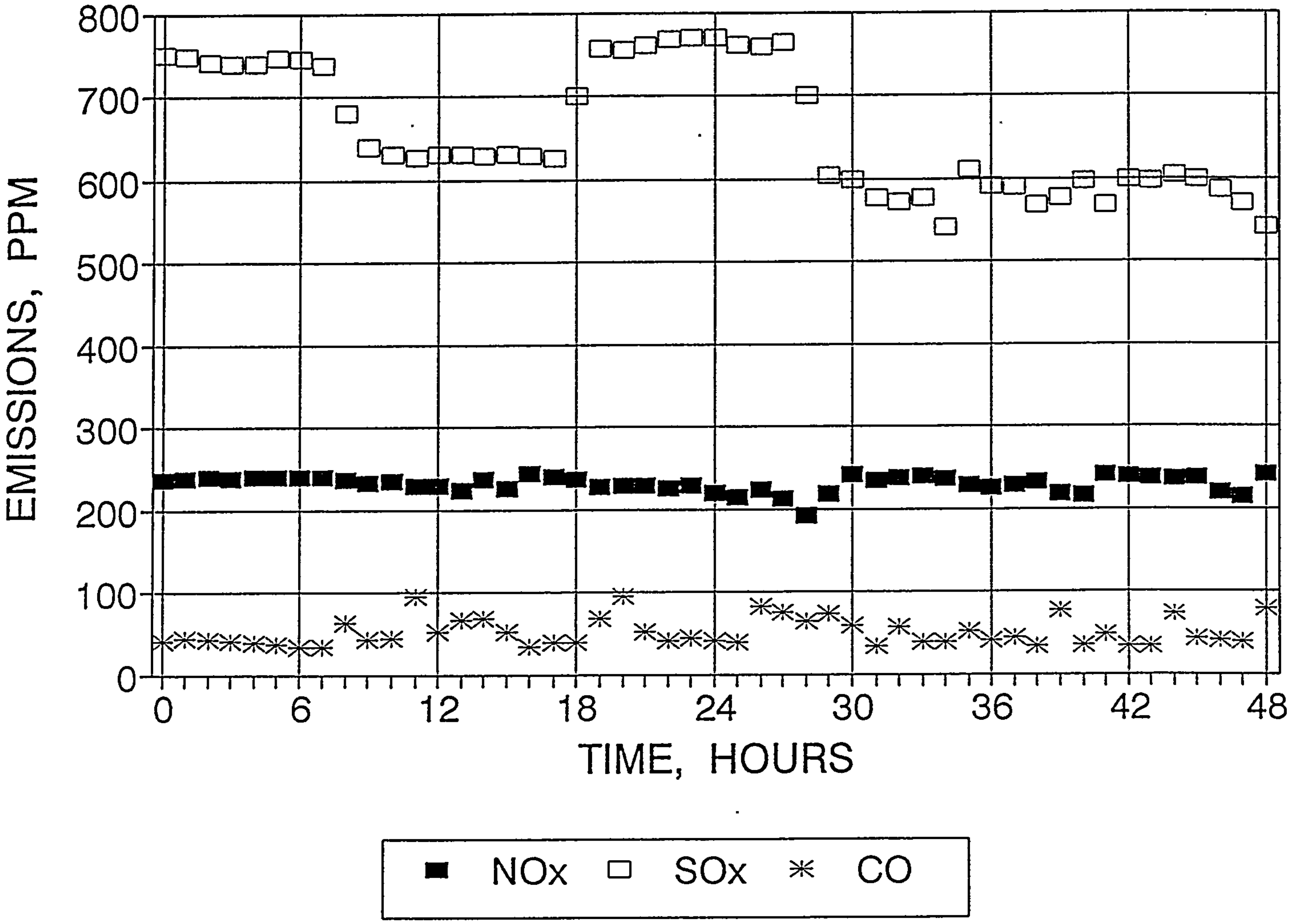


FIGURE 2-65: EMISSIONS HISTORY OF NO_x, SO_x, AND CO - DEMONSTRATION TEST SERIES 1

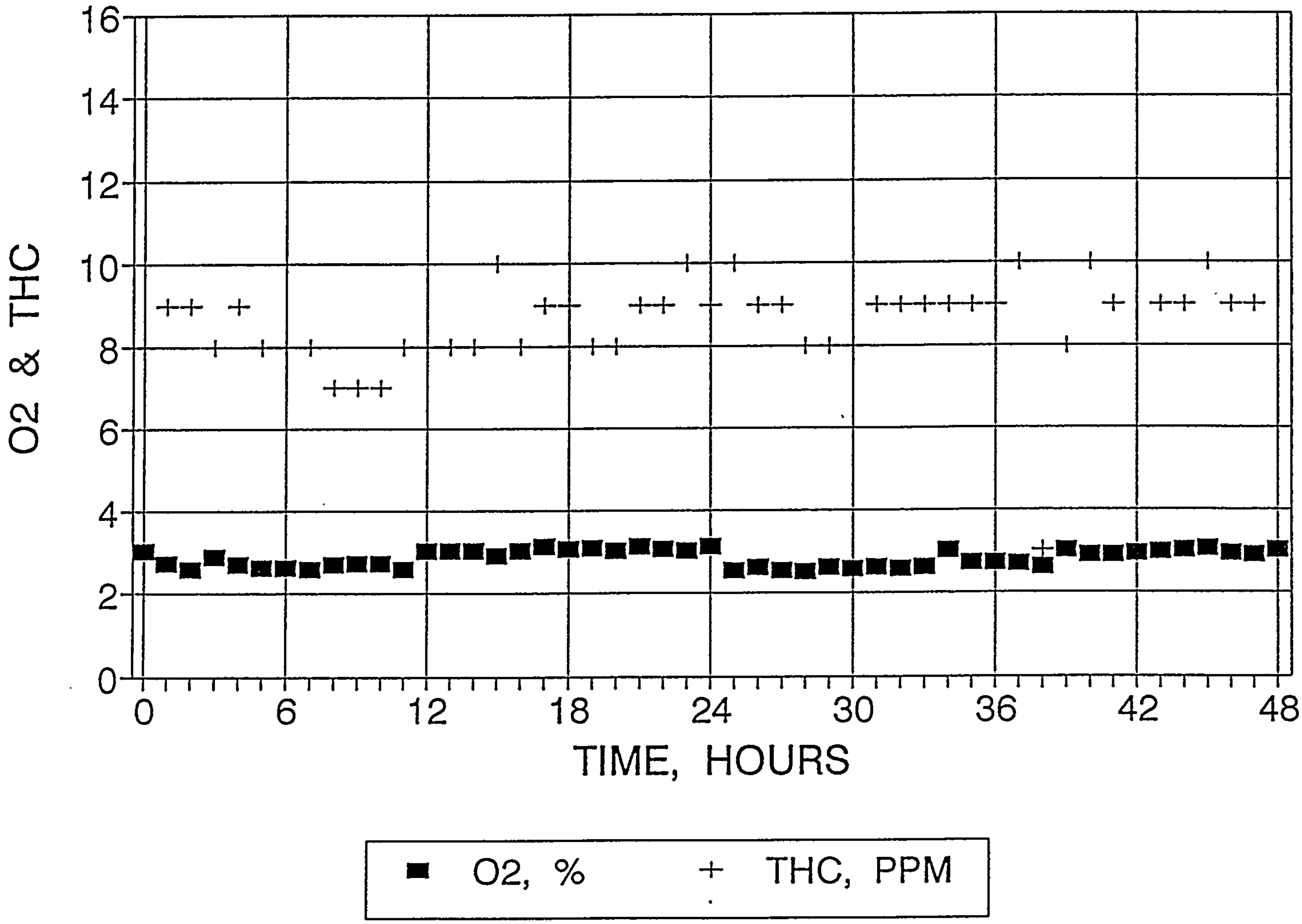


FIGURE 2-66: EMISSIONS HISTORY OF THC AND SO_2 - DEMONSTRATION TEST SERIES 1

After the test, the boiler was inspected and no fouling was found in the boiler tubes. A trace of slag was found at the bottom of the char burnout section. It was decided to install a conical water-jacket section connected to the four-inch cooling pipe (Figure 2-67) to reduce the temperature in this section and prevent slagging.

After the modification was completed, an eight-day continuous test was performed utilizing the old controller (Control Tektronix Mastermind). The test showed good repeatability of the combustion and emissions performance of the commercial unit. Table 2-29 shows a summary of the steady-state test data obtained. Each column represents an average of the data collected for an entire day. Figure 2-68 shows the history of oxygen and total hydrocarbons emissions in the flue gas at the exit of the boiler, and Figure 2-69 shows emissions of NO_x, SO_x, and CO. No reburning coal was used in the test. For sulfur capture, lime was injected at the inlet to the Morrison tube with a Ca/S molar feed ratio of about 1.6. As in previous tests, NO_x emissions were below 0.3 lb/MMBtu and SO_x emissions were below 1.2 lb/MMBtu. Combustion efficiency of the system was about 99 percent, and thermal efficiency was about 82 percent.

It was found during the test that the flue gas duct downstream of the baghouse was leaking. The 15-foot long damaged section of the duct was replaced by a new pipe. The unit seemed to be in good condition otherwise to continue testing.

Integration of the new programmable logic controller (PLC) was completed. A test of the commercial unit was performed to debug the PLC hardware and software. The test was continued until the PLC debugging was completed. The test demonstrated the ease of operation of the new MTCI programmable logic controller at all stages including start-up, operation, and shutdown of the unit. The real-time monitoring by the PLC provided an opportunity for the visual observation and acquisition of the data from the system within the control room.

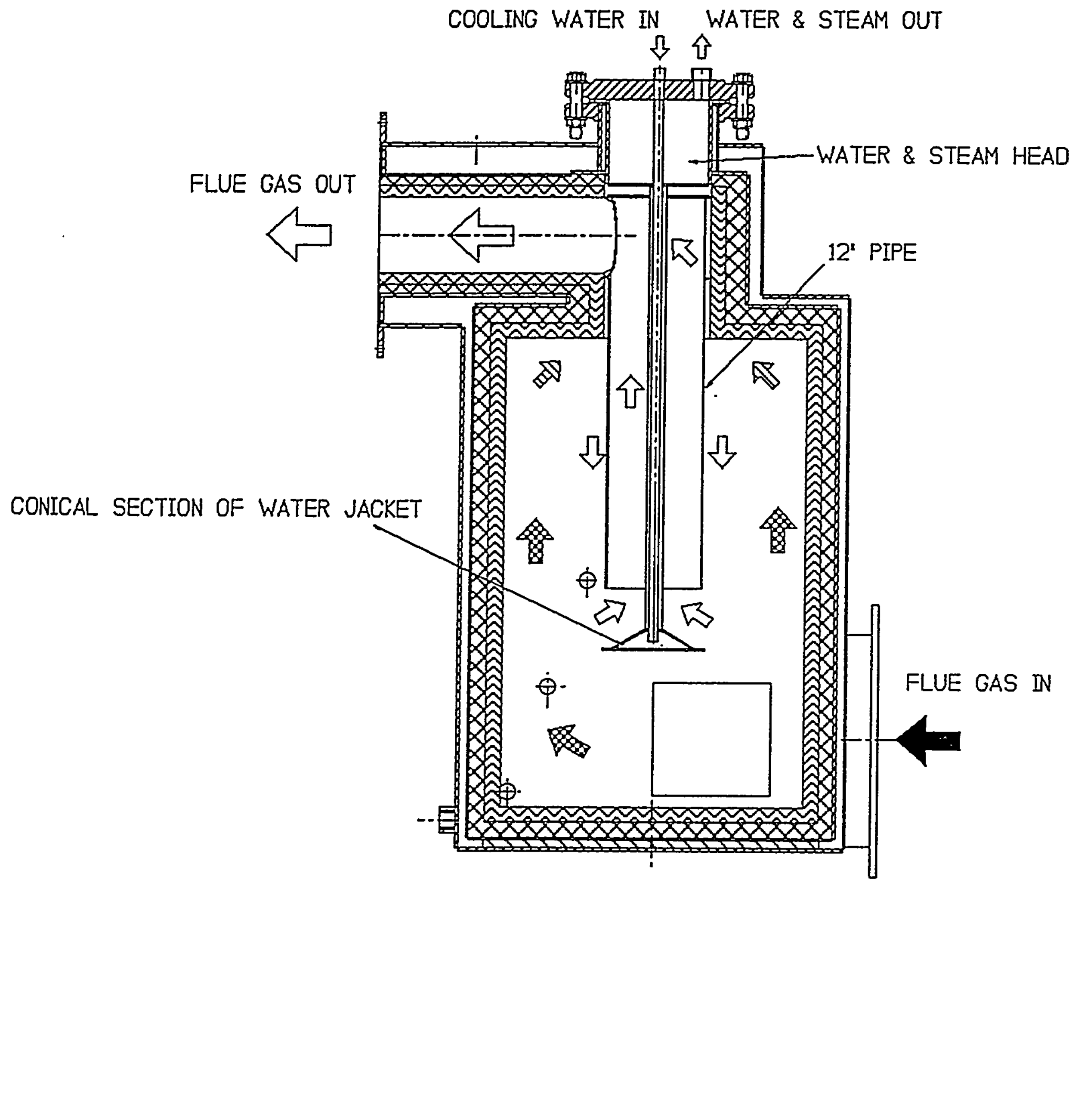


FIGURE 2-67: MODIFICATION OF INNER WATER JACKET OF CHAR BURNOUT SECTION

TABLE 2-29:
DEMONSTRATION TEST DATA SUMMARY - SERIES 2
(FULL LOAD, COAL A, SORBENT B, 192 HOURS)

TEST NUMBER		0123951	0124951	0125951	0126951	0127951	0128951	0129951	0130951
Firing Rate, MMBtu/hr	Total firing rate	6.18	6.26	6.10	6.04	6.10	6.13	6.04	6.10
	Coal	5.18	5.18	5.18	5.04	5.18	5.04	5.04	5.18
	Natural gas	1.00	1.08	0.92	1.00	0.92	1.09	1.00	0.92
Ratio of Reburning Coal/ Total Firing Rate, %		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ca/S Molar Ratio		1.62	1.62	1.62	1.62	1.62	1.62	1.62	1.62
Temperature, °F	Air plenum	120	132	125	124	128	124	126	125
	Combustion chamber	2212	2250	2313	2258	2339	2320	2310	2289
	1st cyclone (avg.)	1730	1736	1692	1689	1686	1716	1727	1741
	2nd cyclone (avg.)	2224	2251	2194	2241	2261	2259	2241	2251
	Stack	310	315	318	322	325	332	335	340
	Steam	225	226	224	229	231	228	227	231
Pressure, inches of H_2O	Air plenum	8.0	8.3	7.9	9.1	8.0	7.5	7.0	6.0
	Combustion chamber	15.0	15.0	14.8	15.6	13.3	13.3	12.8	12.9
	1st cyclone	0.5	0.4	0.5	0.5	0.8	0.8	1.0	0.9
	2nd cyclone	1.3	1.7	1.6	1.7	1.6	1.6	1.6	1.6
	Stack	-0.8	-0.5	0.7	-0.6	-1.0	-1.0	01.0	-1.0
Excess Air, %		16.1	15.4	16.1	14.8	12.9	13.6	14.2	16.1
Emissions at Stack (corrected to 3% O_2)	O2, %	2.9	2.8	2.9	2.7	2.4	2.5	2.6	2.9
	CO2, %	15.7	15.2	15.9	15.7	15.3	15.6	15.8	15.2
	CO, ppm	67	56	41	43	66	72	64	56
	SOx, ppm	568	577	532	573	549	575	555	577
	NOx, ppm	233	224	231	213	219	213	220	214
	HC, ppm	8	6	8	8	9	8	7	9
	CO, lb/MMBtu	0.06	0.05	0.03	0.04	0.06	0.06	0.06	0.05
	SOx, lb/MMBtu	1.19	1.20	1.06	1.17	1.16	1.19	1.13	1.19
	NOx, lb/MMBtu	0.28	0.26	0.26	0.25	0.26	0.25	0.25	0.25
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic Data of Combustion Chamber	SPL, dB	171.2	170.5	170.6	170.8	170.4	170.6	170.2	170.1
	Frequency, Hz	62	62	60	58	60	60	62	60
Combustion Efficiency, %		-	98.9	-	-	-	-	-	99.1
Thermal Efficiency, %		84.3	82.6	80.5	81.5	81.5	81.2	82.3	81.5
Sulfur Capture Efficiency, %		18.8	17.0	28.6	19.8	21.9	17.2	22.5	19.8

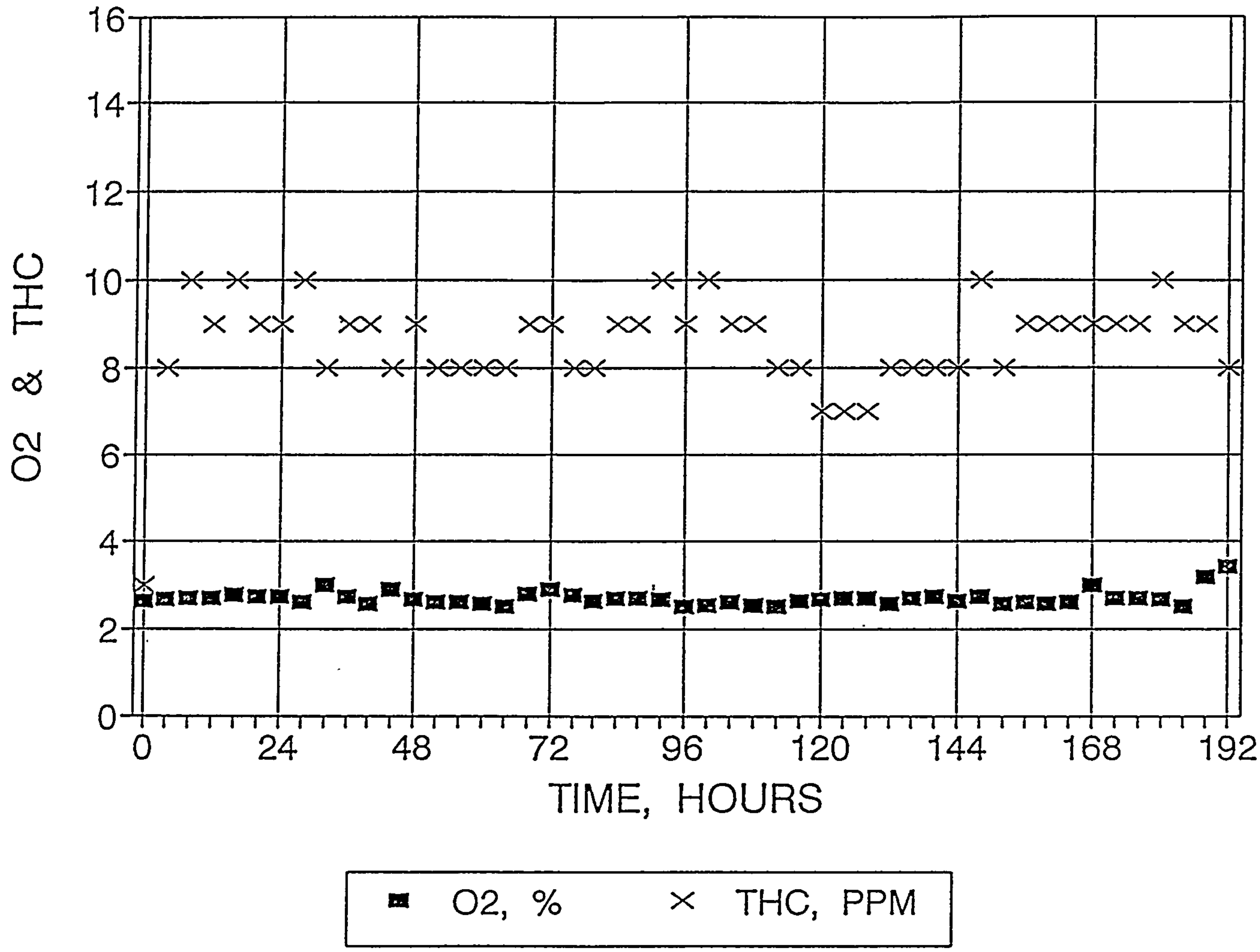


FIGURE 2-68: HISTORY OF O_2 AND THC - DEMONSTRATION TEST SERIES 2

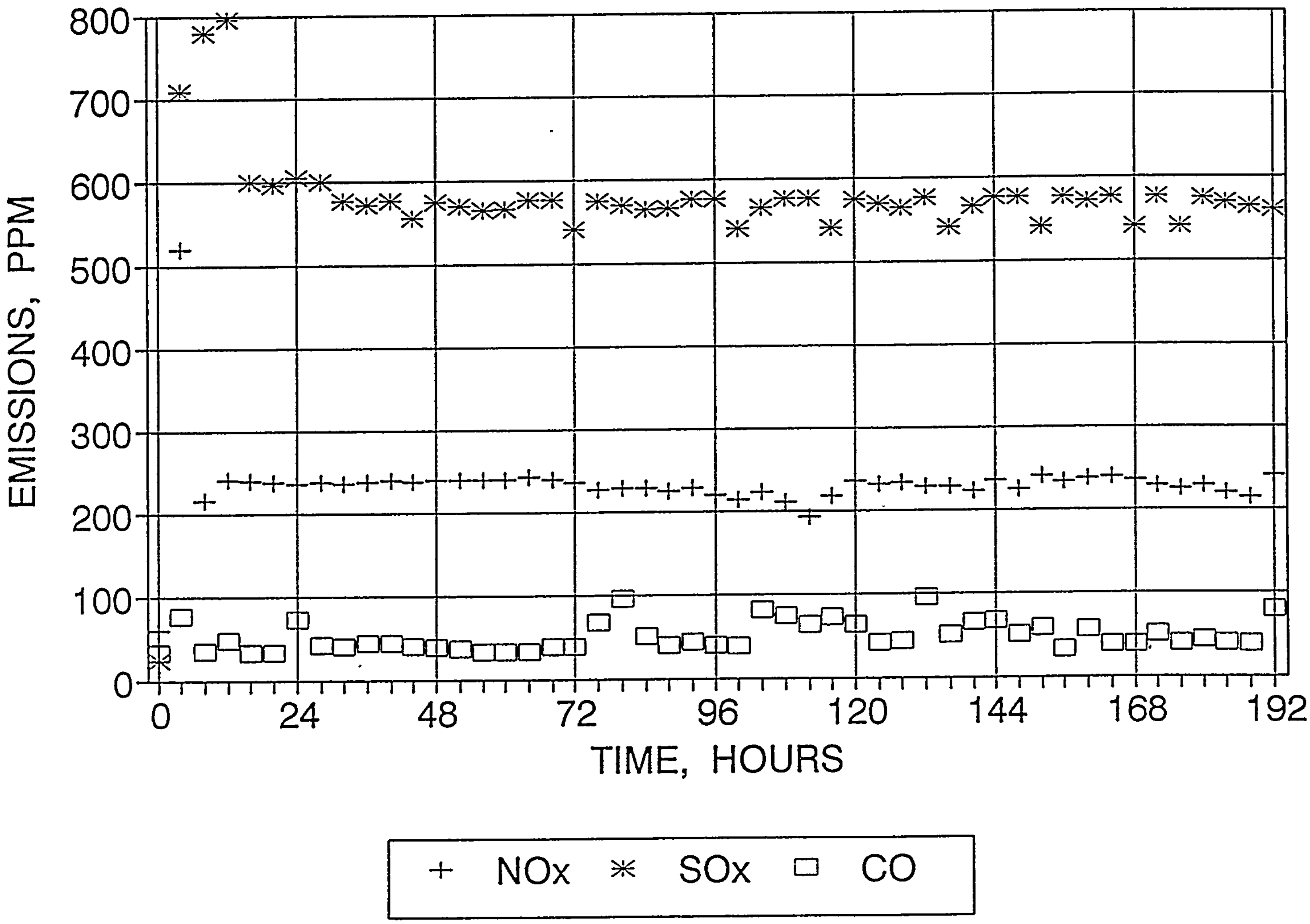


FIGURE 2-69: EMISSIONS HISTORY OF NO_x, SO_x AND CO - DEMONSTRATION TEST SERIES 2

A 48-hour, full load, low sulfur coal demonstration test was performed on the commercial unit with the new PLC. As before, the test demonstrated good combustion and emissions performance of the unit. Table 2-30 shows a summary of the steady-state test data obtained twice a day. Figure 2-70 represents the history of oxygen and total hydrocarbon emissions in the flue gas at the exit of the boiler, and Figure 2-71 shows emissions of NO_x, SO_x and CO. For sulfur capture, lime was injected at the inlet to the Morrison tube of the boiler with a Ca/S molar feed ratio of about 1.6. No reburning coal was used in the test.

Once again, the test demonstrated good combustion (99%) and thermal efficiencies (higher than 83%). NO_x emissions were at a level no higher than 0.3 lb/MMBtu and SO_x emissions with sorbent feed were about 1.2 lb/MMBtu.

An 84-hour partial (75%) load test was performed on the commercial unit. Coal A was injected into the coal reburning section for NO_x reduction at about 16 percent of total firing rate. Anville lime was injected at the inlet to the Morrison tube for SO_x reduction. The test demonstrated good combustion and emission performance of the system. Table 2-31 shows a summary of the steady-state test data obtained twice a day. Reburning coal and reduction of air supply into the pulse combustion chamber reduced NO_x emission to the 0.19 lb/MMBtu level. Figures 2-72 and 2-73 represent the history of oxygen, THC, NO_x, SO_x, and CO concentrations in the flue gas. Figure 2-74 shows the history of the baghouse inlet temperature during the test. The temperature seems to be stable which indicates that pulsations kept the boiler tubes clean and there was no fouling problem. The test demonstrated good combustion efficiency of the commercial unit: 99.2 percent. Thermal efficiency was higher than 80 percent. At Ca/S molar ratio, SO_x emissions were reduced to about 0.8 lb/MMBtu.

A total of an additional 360 successive hours of testing were performed on the commercial system. The test was configured to simulate operation under normal commercial application and consisted of alternating 12-hour periods of full and partial load subtests. The test demonstrated repeatability of data obtained in previous full and partial load tests performed on the system. No reburning coal was fed during the full load test. In the partial load test,

TABLE 2-30:
DEMONSTRATION TEST DATA SUMMARY - SERIES 3
(FULL LOAD, COAL A, SORBENT B, 48 HOURS)

TEST NUMBER		032995	033095	033095	033195	033195
Firing Rate, MMBtu/hr	Total firing rate	6.29	6.17	6.25	6.09	6.03
	Coal	5.39	5.25	5.32	5.18	5.11
	Natural gas	0.90	0.92	0.93	0.91	0.92
Ratio of Reburning Coal/ Total Firing Rate, %		0.0	0.0	0.0	0.0	0.0
Ca/S Molar Ratio		0.8	1.60	1.58	1.62	1.64
Temperature, °F	Air plenum	-	120	111	121	119
	Combustion chamber	2331	2304	2340	2325	2304
	1st cyclone (avg.)	1819	1831	1828	1831	1825
	2nd cyclone (avg.)	2119	2190	2201	2215	2230
	Stack	367	305	309	323	321
	Steam	224	220	221	225	227
Pressure, inches of H_2O	Air plenum	8.0	8.3	7.9	9.1	8.0
	Combustion chamber	15.0	15.0	14.8	15.6	13.3
	1st cyclone	0.5	0.4	0.5	0.5	0.8
	2nd cyclone	1.3	1.7	1.6	1.7	1.6
	Stack	-0.8	-0.5	0.7	-0.6	-1.0
Excess Air, %		25.8	17.4	19.4	16.1	17.4
Emissions at Stack (corrected to 3% O_2)	O2, %	4.3	3.1	3.4	2.9	3.1
	CO2, %	14.7	14.9	15.1	15.3	14.8
	CO, ppm	87	68	74	81	61
	SOx, ppm	697	580	592	578	566
	NOx, ppm	259	251	228	219	222
	HC, ppm	8	6	5	8	7
	CO, lb/MMBtu	0.07	0.06	0.06	0.07	0.05
	SOx, lb/MMBtu	1.36	1.21	1.20	1.19	1.18
	NOx, lb/MMBtu	0.29	0.30	0.26	0.26	0.26
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00
Acoustic Data of Combustion Chamber	SPL, dB	171.1	172.0	171.6	171.9	171.5
	Frequency, Hz	60	60	60	60	60
Combustion Efficiency, %		-	-	-	-	99.1
Thermal Efficiency, %		84.4	83.0	83.4	84.8	83.5
Sulfur Capture Efficiency, %		9.2	18.6	19.4	20.0	20.3

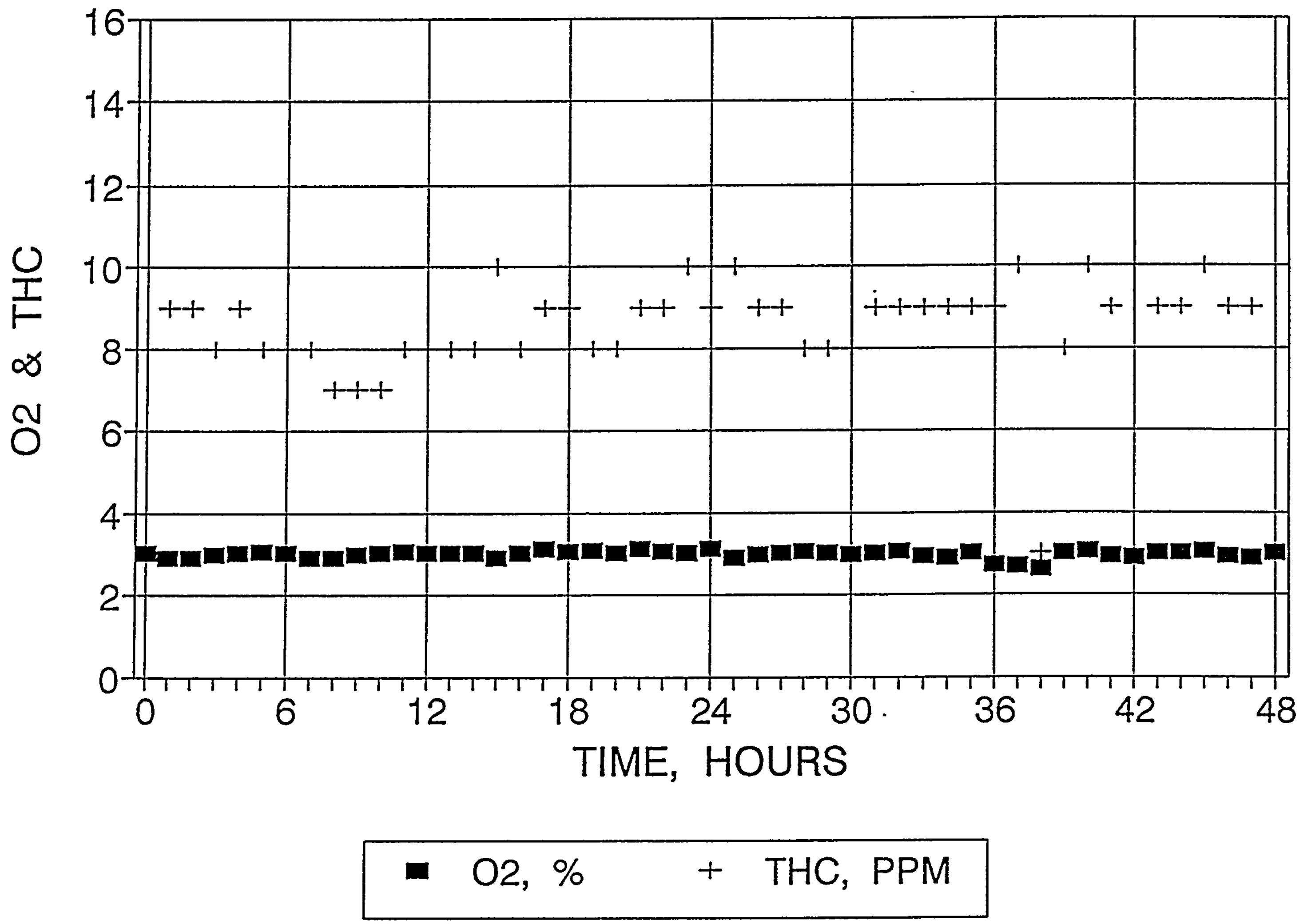


FIGURE 2-70: HISTORY OF O_2 AND THC - DEMONSTRATION TEST SERIES 3

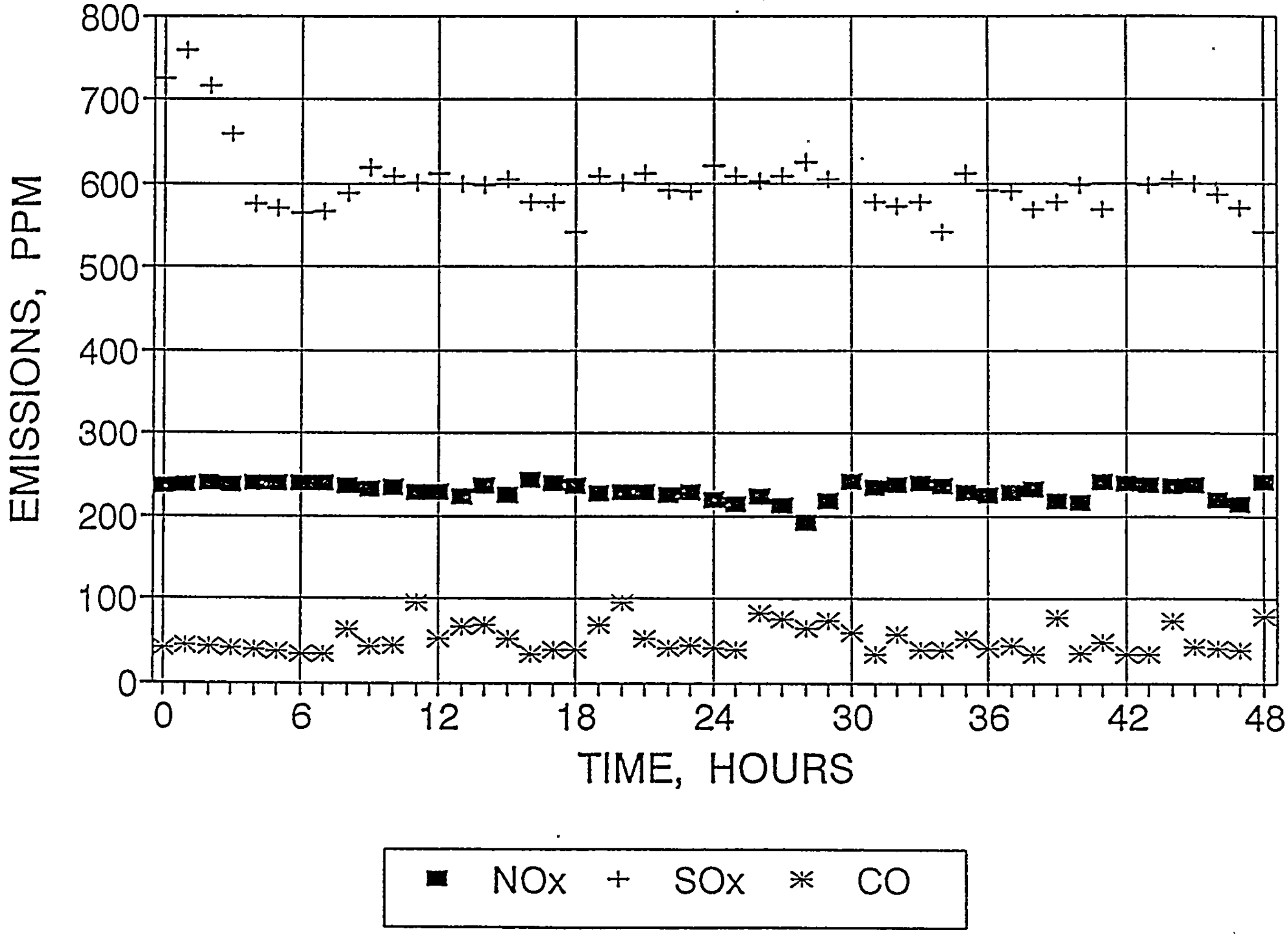


FIGURE 2-71: HISTORY OF NO_x, SO_x AND CO - DEMONSTRATION TEST SERIES 3

TABLE 2-31:
DEMONSTRATION TEST DATA SUMMARY - Series 4
(75 Percent Load, Coal A, Sorbent B, 84 Hours)

Test Number		051395	051395	051495	051495	051595	051595
Firing Rate, MMBtu/hr	Total firing rate	4.47	4.62	4.67	4.72	4.72	4.72
	Coal	2.98	3.13	3.18	3.23	3.23	3.23
	Natural gas	1.49	1.49	1.49	1.49	1.49	1.49
Ratio of Reburning Coal/ Total Firing Rate, %		11.5	14.4	15.4	16.3	16.3	16.3
Ca/S Molar Ratio		0	0	0	0	1.8	1.8
Temperature, °F	Air plenum	---	99	99	99	101	103
	Combustion chamber	2280	2312	2225	2330	2332	2331
	1st cyclone (avg.)	2071	2111	2116	2109	2107	2110
	2nd cyclone (avg.)	1878	1924	1925	1912	1860	1874
	Baghouse inlet	303	304	305	305	306	306
	Steam	212	213	212	212	212	213
Pressure, H_2O	Air plenum	6.0	5.8	5.5	4.5	4.5	4.5
	Combustion chamber	7.0	6.7	6.5	6.0	6.0	6.0
	1st cyclone	1.3	1.3	1.1	1.3	1.4	1.4
	2nd cyclone	0	0.1	0	0.2	0.3	0.3
	Stack	-1.2	-1.2	-1.3	-0.8	-0.7	-0.7
Excess Air, %		25.1	23.6	23.6	20.1	24.3	22.9
Emissions at Stack (corrected to 3% O_2)	O2, %	4.2	4.0	4.0	3.5	4.1	3.9
	CO2, %	13.2	13.3	13.3	13.4	13	13
	CO, ppm	65	69	64	93	110	134
	SOx, ppm	564	557	533	545	382	364
	NOx, ppm	372	198	177	155	158	138
	HC, ppm	3	3	2	5	4	4
	CO, lb/MMBtu	0.05	0.06	0.06	0.09	0.10	0.12
	SOx, lb/MMBtu	1.11	1.19	1.14	1.18	0.83	0.79
	NOx, lb/MMBtu	0.41	0.24	0.21	0.19	0.19	0.17
	HC, lb/MMBtu	0	0	0	0	0	0
Acoustic Data of Combustion Chamber	SPL, dB	172.4	172.4	172.4	171.6	171.6	171.4
	Frequency, Hz	64	64	64	62	62	62
Combustion Efficiency, %		-	99.2	-	-	-	99.2
Thermal Efficiency, %		81.0	82.3	82.2	81.9	82.2	83.5
Sulfur Capture Efficiency, %		0	0	0	0	30.6	34.0

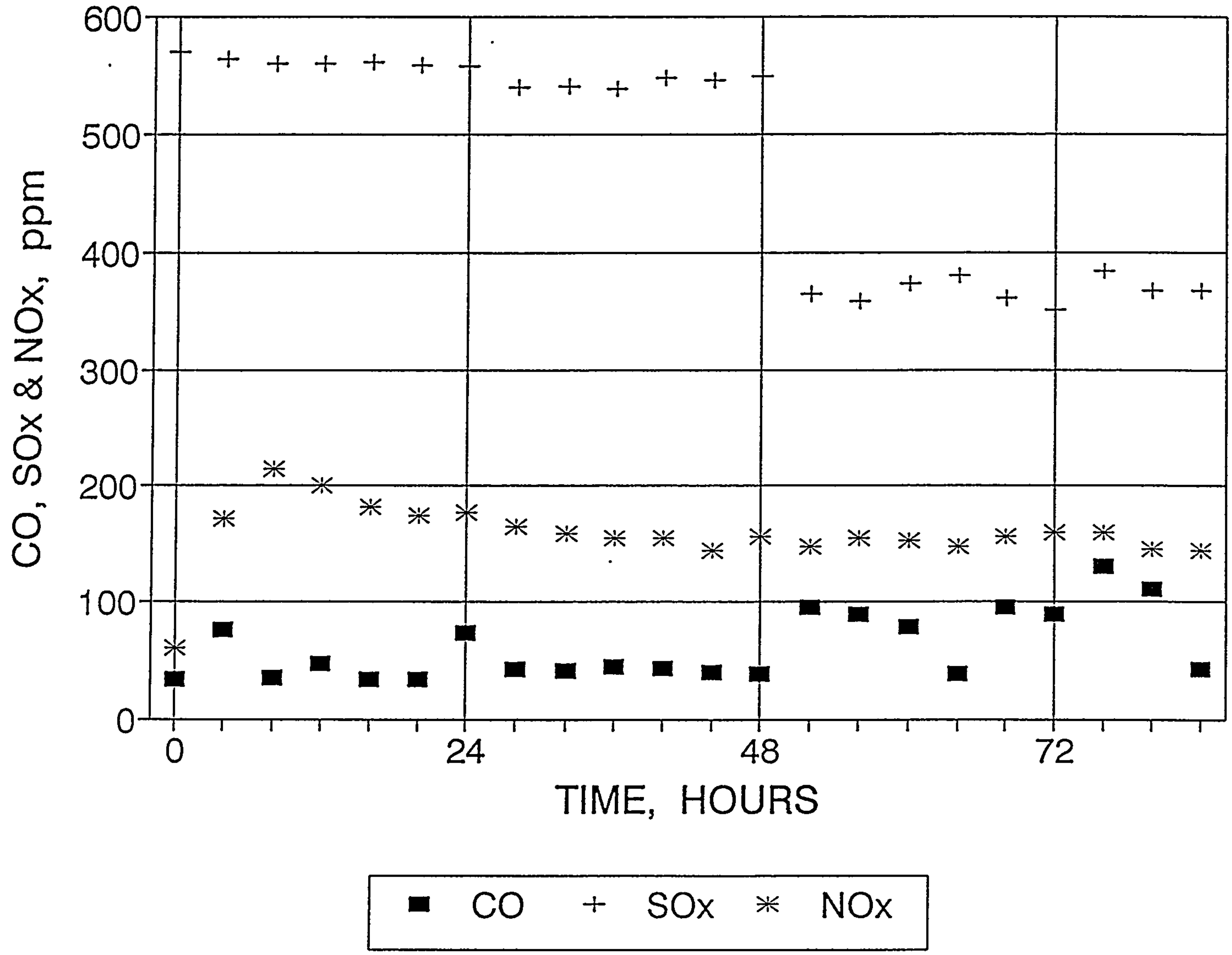


FIGURE 2-72: HISTORY OF CO, SO_x AND NO_x - DEMONSTRATION TEST SERIES 4

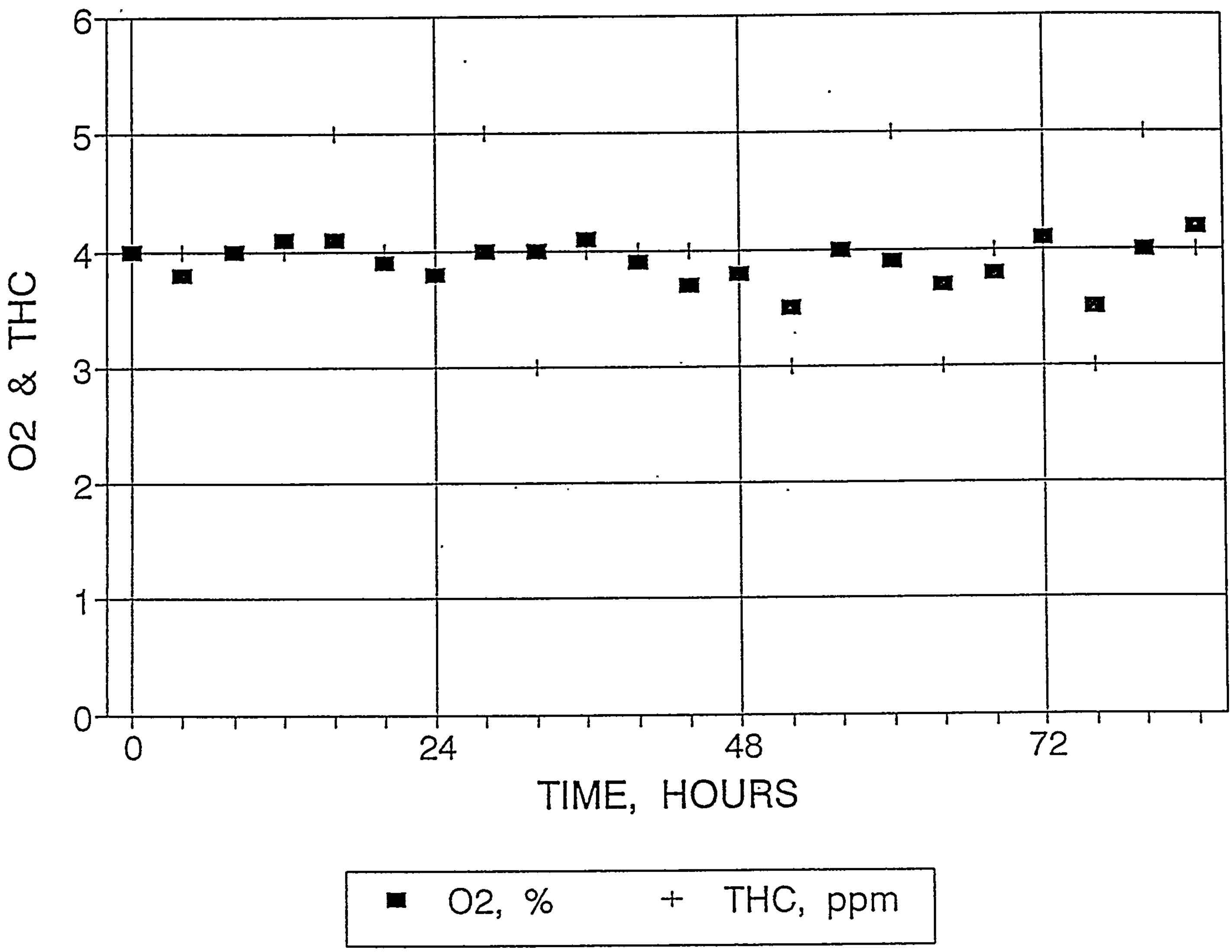


FIGURE 2-73: HISTORY OF O_2 AND THC - DEMONSTRATION TEST SERIES 4

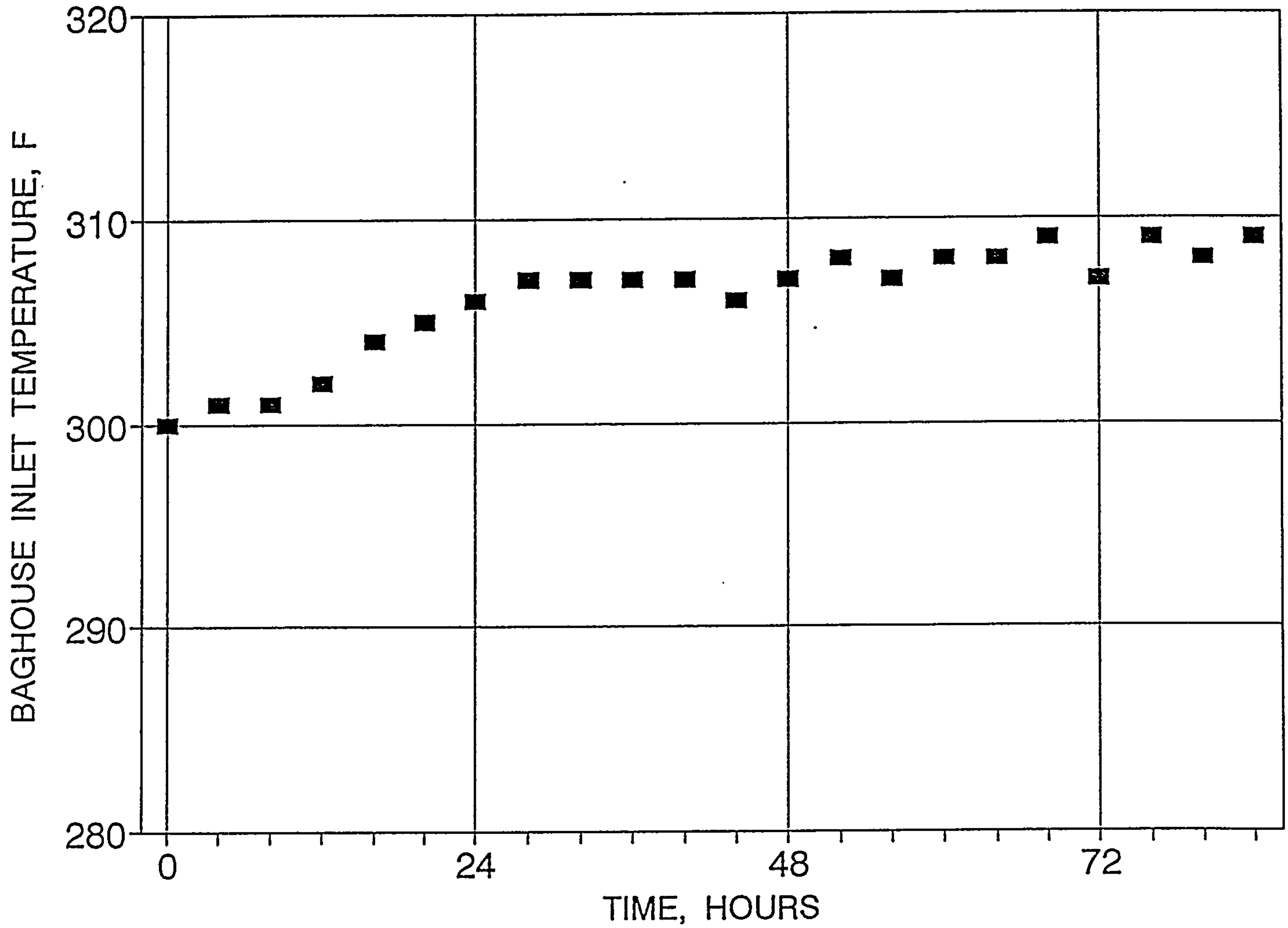


FIGURE 2-74: HISTORY OF BAGHOUSE INLET TEMPERATURE - DEMONSTRATION TEST SERIES 4

reburning coal was fed into the coal reburning section at about 16 percent of total firing rate. This measure allowed improvement of the emission performance of the system. Table 2-32 shows a summary of the steady-state test data collected. Figure 2-75 shows emissions of NO_x, SO_x and CO in the flue gas at the exit of the boiler and Figure 2-76 represents the history of oxygen and total hydrocarbon (THC) emissions and Figure 2-77 shows the baghouse inlet flue gas temperature history during the test. These tests were also conducted with the Pittsburgh #8 coal containing 1.23 percent sulfur (Coal A). Combustion efficiency in the test was, again, no lower than 99 percent, and thermal efficiency was higher than 82 percent. At the same Ca/S molar ratio of about 1.6, sulfur capture efficiency in the partial load test was higher (about 31%) which can be attributed to longer residence times.

The site demonstration test series was completed by an additional 288 successive hour test. The test was performed with a Pittsburgh #8 coal containing higher sulfur content (3.18%), and the test consisted of alternating 12 hour periods of full and partial load subtests. As in the previous tests, the emissions performance of the system during full load periods was good without reburning coal. However, during the partial load periods, coal (16% of the total firing rate) was fed into the reburning section to reduce NO_x emissions. The high sulfur coal required rather high lime feed rate (Ca/S molar ratio of between 5 and 6) for SO_x reduction to the 1.2 lb/MMBtu level.

Table 2-33 presents a summary of the steady-state test data collected during the test, one set for each 12-hour period. Figure 2-78 shows the history of CO, NO_x and SO_x. Combustion was stable for substoichiometric conditions in the combustion chamber at full firing rate. This helped reduce NO_x emissions to about 0.3 lb/ MMBtu without involving reburning coal feed. However, at low firing rate, it was difficult to run the unit at low stoichiometry in the primary zone and, therefore, reburning coal at a firing rate of about 16 percent of the total rate was used to reduce NO_x emissions to below 0.27 lb/MMBtu. The high sulfur coal used in the test required higher Ca/S ratio for controlling SO_2 emissions as compared to that in low sulfur coal tests. At low firing rate, gas support fraction was higher and SO_x emissions were lower at a lower Ca/S molar feed ratio

TABLE 2-32:
DEMONSTRATION TEST DATA SUMMARY - TEST SERIES 5

(ALTERNATING SYSTEM OPERATION AT 12 HOURS FULL AND 12 HOURS PARTIAL LOAD, COAL A, SORBENT B, 360 HOURS)

Test No.		051795	051795	051895	051895	051995	051995
Firing rate, MMBtu/Hr	Total firing rate	6.25	4.65	6.28	4.66	6.24	4.64
	Coal	5.32	3.16	5.35	3.17	5.31	3.15
	Natural gas	0.92	1.48	0.92	1.48	0.92	1.48
Ratio of reburning coal/total firing rate, %		0	16.1	0	16.1	0	16.1
Ca/S molar ratio		1.61	1.60	1.61	1.58	1.62	1.58
Temperature, F	Air plenum	120	99	121	100	120	99
	Combustion chamber	2324	2225	2321	2226	2319	2221
	1st cyclone (average)	1830	2116	1830	2120	1826	2112
	2nd cyclone (average)	2221	1925	2209	1929	2217	1921
	Baghouse inlet	321	305	315	306	320	304
	Steam	222	212	223	213	225	213
Pressure, H2O	Air plenum	8.3	5.5	8.2	5.7	8.4	5.6
	Combustion chamber	14.3	6.7	14.4	6.9	14.2	6.8
	1st cyclone	0.5	1.0	0.5	1.0	0.6	1.2
	2nd cyclone	1.6	0.1	1.7	0.1	1.7	0.2
	Stack	-0.7	-1.3	-0.7	-1.3	-0.7	-1.3
Excess air, %		20.1	25.1	19.4	25.1	18.7	24.3
Emissions at stack (corrected to 3 % O2)	O2. %	3.5	4.2	3.4	4.2	3.3	4.1
	CO2, %	15.1	13.3	15.2	13.3	15.3	13.4
	CO, ppm	72	64	88	52	75	45
	SOx, ppm	590	382	593	383	589	381
	NOx, ppm	230	180	213	158	230	174
	HC, ppm	6	4	6	4	6	4.00
	CO, lb/MMBtu	0.07	0.06	0.08	0.05	0.07	0.04
	SOx, lb/MMBtu	1.23	0.82	1.22	0.82	1.21	0.81
	NOx, lb/MMBtu	0.34	0.28	0.31	0.24	0.34	0.27
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic data of combustion chamber	SPL, db	171.5	171.6	172.4	172.0	171.2	171.3
	Frequency, Hz	60	62	60	62	60	62
Combustion efficiency, %		-	-	99.0	-	-	-
Thermal efficiency, %		83.5	82.2	83.9	82.4	83.3	82.0
Sulfur capture efficiency, %		17.6	31.2	18.1	31.2	18.5	31.6

TABLE 2-32:
DEMONSTRATION TEST DATA SUMMARY - TEST SERIES 5

(ALTERNATING SYSTEM OPERATION AT 12 HOURS FULL AND 12 HOURS PARTIAL LOAD, COAL A, SORBENT B, 360 HOURS) (CONT'D)

Test No.		052095	052095	052195	052195	052295	052295
Firing rate, MMBtu/Hr	Total firing rate	6.26	4.66	6.24	4.67	6.25	4.65
	Coal	5.34	3.16	5.32	3.17	5.33	3.15
	Natural gas	0.92	1.50	0.92	1.50	0.92	1.50
Ratio of reburning coal/total firing rate, %		0	16.1	0	16.1	0	16.1
Ca/S molar ratio		1.61	1.40	1.61	1.40	1.61	1.40
Temperature, F	Air plenum	125	95	130	100	125	95
	Combustion chamber	2301	2230	2294	2218	2296	2226
	1st cyclone (average)	1881	2116	1875	2120	1877	2112
	2nd cyclone (average)	2195	1925	2201	1929	2191	1921
	Baghouse inlet	332	310	326	311	331	309
	Steam	224	213	223	214	224	213
Pressure, H2O	Air plenum	8.5	5.5	9.0	5.7	8.8	6.0
	Combustion chamber	14.0	7.0	13.5	7.2	14.0	7.5
	1st cyclone	0.9	0.5	0.8	0.6	1.0	0.7
	2nd cyclone	2.0	1.5	2.0	1.6	2.0	1.4
	Stack	-1.0	-1.3	-0.8	-1.2	-1.0	-1.1
Excess air, %		20.1	23.6	18.7	23.6	20.1	22.9
Emissions at stack (corrected to 3 % O2)	O2. %	3.5	4.0	3.3	4.0	3.5	3.9
	CO2, %	15.1	13.3	15.2	13.3	15.1	13.5
	CO, ppm	72	64	88	69	54	75
	SOx, ppm	570	401	588	402	569	412
	NOx, ppm	225	160	239	170	220	165
	HC, ppm	6	4	6	4	6	4
	CO, lb/MMBtu	0.07	0.06	0.08	0.06	0.05	0.07
	SOx, lb/MMBtu	1.18	0.85	1.21	0.85	1.18	0.87
	NOx, lb/MMBtu	0.34	0.24	0.35	0.26	0.33	0.25
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic data of combustion chamber	SPL, db	172.0	171.6	171.5	172.0	171.2	171.3
	Frequency, Hz	62	62	62	62	60	62
Combustion efficiency; %		--	-	-	-	-	99.4
Thermal efficiency, %		83.0	82.2	82.8	82.4	83.3	82.0
Sulfur capture efficiency, %		20.7	28.6	18.8	28.7	20.7	26.9

TABLE 2-32:
DEMONSTRATION TEST DATA SUMMARY - TEST SERIES 5

(ALTERNATING SYSTEM OPERATION AT 12 HOURS FULL AND 12 HOURS PARTIAL LOAD, COAL A, SORBENT B, 360 HOURS) (CONT'D)

Test No.		052395	052395	052495	052495	052595	052595
Firing rate, MMBtu/Hr	Total firing rate	6.28	4.65	6.25	4.66	6.27	4.64
	Coal	5.34	3.16	5.37	3.17	5.33	3.15
	Natural gas	0.92	1.48	0.92	1.48	0.92	1.48
Ratio of reburning coal/total firing rate, %		0	16.1	0	16.1	0	16.1
Ca/S molar ratio		1.61	1.60	1.60	1.60	1.61	1.60
Temperature, F	Air plenum	120	99	121	105	109	103
	Combustion chamber	2333	2225	2315	2226	2298	2221
	1st cyclone (average)	1837	2116	1840	2120	1856	2112
	2nd cyclone (average)	2201	1925	2190	1929	1929	1921
	Baghouse inlet	322	305	315	306	320	304
	Steam	223	213	224	213	223	212
Pressure, H2O	Air plenum	8.3	5.5	8.4	6.0	8.0	5.7
	Combustion chamber	14.4	6.5	14.6	7.3	14.0	6.5
	1st cyclone	0.5	1.1	0.6	1.3	0.6	1.2
	2nd cyclone	1.6	0.2	1.8	0.1	1.6	0.2
	Stack	-0.7	-1.2	-0.8	-1.1	-0.8	-1.1
Excess air, %		20.1	24.3	20.1	23.6	18.7	25.1
Emissions at stack (corrected to 3 % O2)	O2. %	3.5	4.1	3.5	4.0	3.3	4.2
	CO2, %	15.2	13.3	15.2	13.3	15.1	13.1
	CO, ppm	72	64	98	71	84	88
	SOx, ppm	592	382	580	401	591	381
	NOx, ppm	231	158	227	170	231	165
	HC, ppm	6	4	6	4	6	4
	CO, lb/MMBtu	0.07	0.06	0.09	0.07	0.08	0.08
	SOx, lb/MMBtu	1.22	0.81	1.21	0.85	1.21	0.82
	NOx, lb/MMBtu	0.34	0.24	0.34	0.26	0.34	0.25
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic data of combustion chamber	SPL, db	172.2	171.6	173.1	172.0	171.2	171.3
	Frequency, Hz	60	62	60	62	60	62
Combustion efficiency, %		-	-	99.2	-	-	-
Thermal efficiency, %		83.5	82.2	84.3	82.4	83.3	82.0
Sulfur capture efficiency, %		17.6	31.6	19.8	28.9	18.6	31.2

TABLE 2-32:
DEMONSTRATION TEST DATA SUMMARY - TEST SERIES 5

(ALTERNATING SYSTEM OPERATION AT 12 HOURS FULL AND 12 HOURS PARTIAL LOAD, COAL A, SORBENT B, 360 HOURS) (CONT'D)

Test No.		052695	052695	052795	052795	052895	052895
Firing rate, MMBtu/Hr	Total firing rate	6.25	4.65	6.28	4.66	6.24	4.64
	Coal	5.32	3.16	5.35	3.17	5.31	3.15
	Natural gas	0.92	1.48	0.92	1.48	0.92	1.48
Ratio of reburning coal/total firing rate, %		0	16.1	0	16.1	0	16.1
Ca/S molar ratio		1.61	1.60	1.60	1.60	1.61	1.60
Temperature, F	Air plenum	109	115	125	107	109	106
	Combustion chamber	2300	2225	2321	2226	2295	2221
	1st cyclone (average)	1830	2116	1830	2120	1826	2112
	2nd cyclone (average)	2221	1925	2209	1929	2217	1921
	Baghouse inlet	321	305	315	306	320	304
	Steam	222	212	223	212	224	213
Pressure, H2O	Air plenum	8.3	5.8	8.4	5.8	8.3	5.7
	Combustion chamber	14.7	6.8	14.8	6.7	14.3	6.6
	1st cyclone	0.6	1.2	0.6	1.1	0.7	1.2
	2nd cyclone	1.5	0.3	1.5	1.5	1.6	0.2
	Stack	-0.7	-1.1	-0.8	-1.0	-0.8	-1.0
Excess air, %		17.4	23.6	19.4	22.9	19.4	23.6
Emissions at stack (corrected to 3 % O2)	O2. %	3.1	4.0	3.4	3.9	3.4	4.0
	CO2, %	15.2	13.3	15.2	13.3	15.1	13.3
	CO, ppm	72	55	60	64	84	57
	SOx, ppm	590	382	593	593	580	381
	NOx, ppm	230	158	219	170	230	180
	HC, ppm	6	4	6	4	6	4
	CO, lb/MMBtu	0.06	0.05	0.05	0.06	0.08	0.05
	SOx, lb/MMBtu	1.20	0.81	1.22	1.24	1.20	0.81
	NOx, lb/MMBtu	0.34	0.24	0.32	0.26	0.34	0.27
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic data of combustion chamber	SPL, db	171.5	171.6	172.4	172.0	171.2	171.3
	Frequency, Hz	60	62	60	62	60	62
Combustion efficiency, %		-	-	-	99.0	-	-
Thermal efficiency, %		83.5	82.2	83.9	82.4	83.3	82.0
Sulfur capture efficiency, %		19.5	32.0	18.1	-4.6	19.3	32.0

TABLE 2-32:
DEMONSTRATION TEST DATA SUMMARY - TEST SERIES 5

(ALTERNATING SYSTEM OPERATION AT 12 HOURS FULL AND 12 HOURS PARTIAL LOAD, COAL A, SORBENT B, 360 HOURS) (CONT'D)

Test No.		052995	052995	053095	053095	053195	053195
Firing rate, MMBtu/Hr	Total firing rate	6.23	4.66	6.26	4.67	6.22	4.65
	Coal	5.30	3.17	5.33	3.17	5.29	3.16
	Natural gas	0.92	1.48	0.92	1.48	0.92	1.48
Ratio of reburning coal/total firing rate, %		0	16.1	0	16.1	0	16.1
Ca/S molar ratio		1.61	1.60	1.61	1.58	1.62	1.58
Temperature, F	Air plenum	120	103	132	117	119	98
	Combustion chambe	2315	2170	2330	2232	2298	2166
	1st cyclone (average)	1850	2101	1870	2115	1846	2097
	2nd cyclone (average	2190	1929	2209	1933	2170	1936
	Baghouse inlet	325	309	330	310	323	313
	Steam	221	212	222	212	220	213
Pressure, H2O	Air plenum	9.0	5.5	9.1	6.0	8.8	5.7
	Combustion chamber	13.9	6.7	14.0	6.7	13.9	7.8
	1st cyclone	0.8	1.0	0.9	1.2	0.7	1.0
	2nd cyclone	1.9	0.2	2.1	0.3	1.7	0.1
	Stack	-0.6	-1.2	-0.6	-1.0	-0.5	-1.1
Excess air, %		20.1	25.1	20.7	24.3	20.1	19.4
Emissions at stack (corrected to 3 % O2)	O2. %	3.5	4.2	3.6	4.1	3.5	3.4
	CO2, %	15.0	13.3	14.9	13.3	15.0	15.1
	CO, ppm	36	64	65	58	48	72
	SOx, ppm	576	390	579	404	563	402
	NOx, ppm	229	180	230	181	227	160
	HC, ppm	6	4	6	4	6	4
	CO, lb/MMBtu	0.03	0.06	0.06	0.05	0.04	0.06
	SOx, lb/MMBtu	1.20	0.83	1.21	0.86	1.18	0.82
	NOx, lb/MMBtu	0.34	0.28	0.34	0.28	0.34	0.23
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic data of combustion chamber	SPL, db	170.8	171.9	171.7	172.0	171.2	171.6
	Frequency, Hz	60	62	60	62	60	62
Combustion efficiency, %		-	-	99.2	-	-	-
Thermal efficiency, %		83.2	82.4	83.6	82.5	83.3	82.2
Sulfur capture efficiency, %		19.3	30.0	18.8	27.9	20.9	30.9

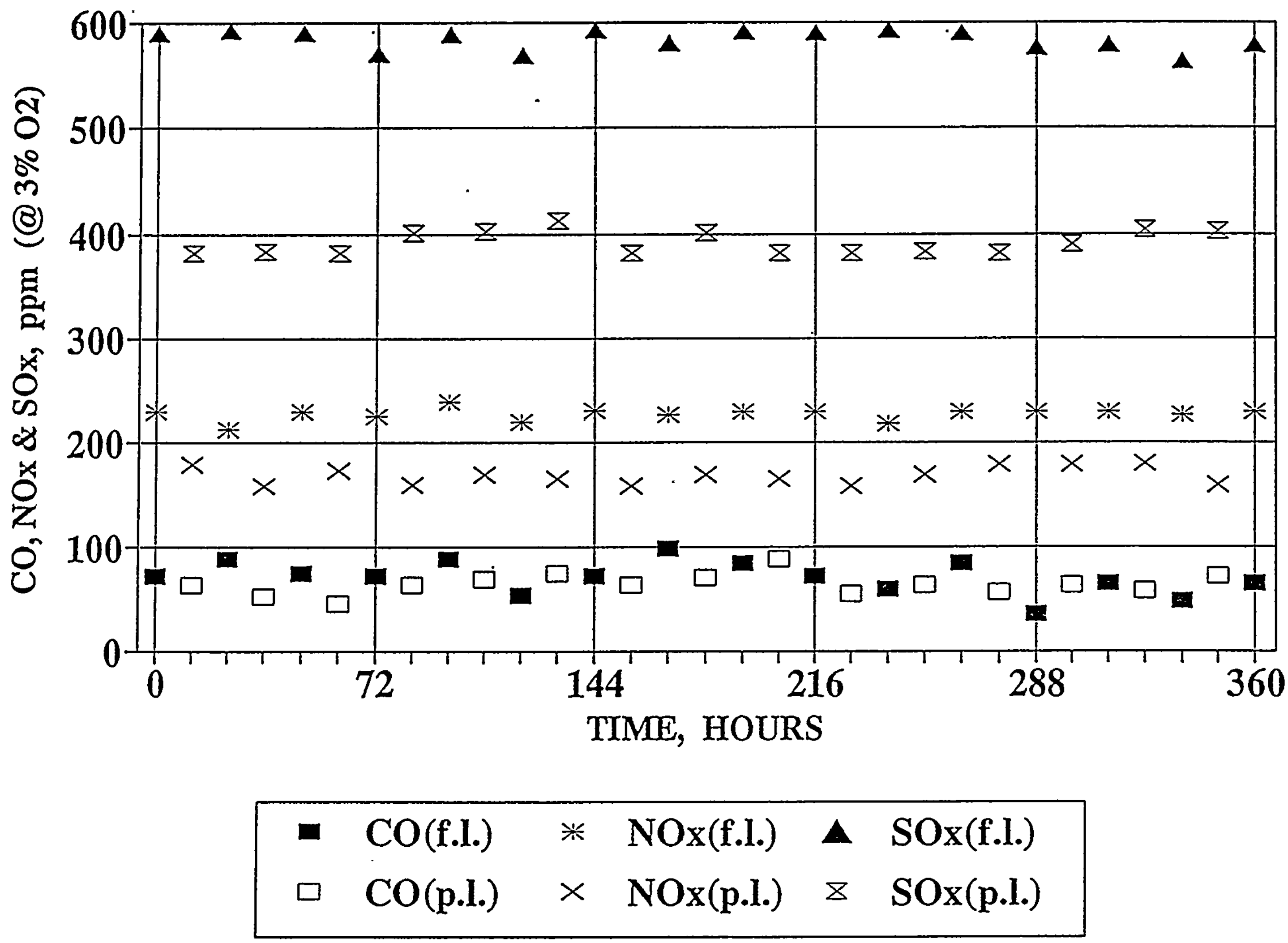


FIGURE 2-75: HISTORY OF CO, SO_x AND NO_x - DEMONSTRATION TEST SERIES 5

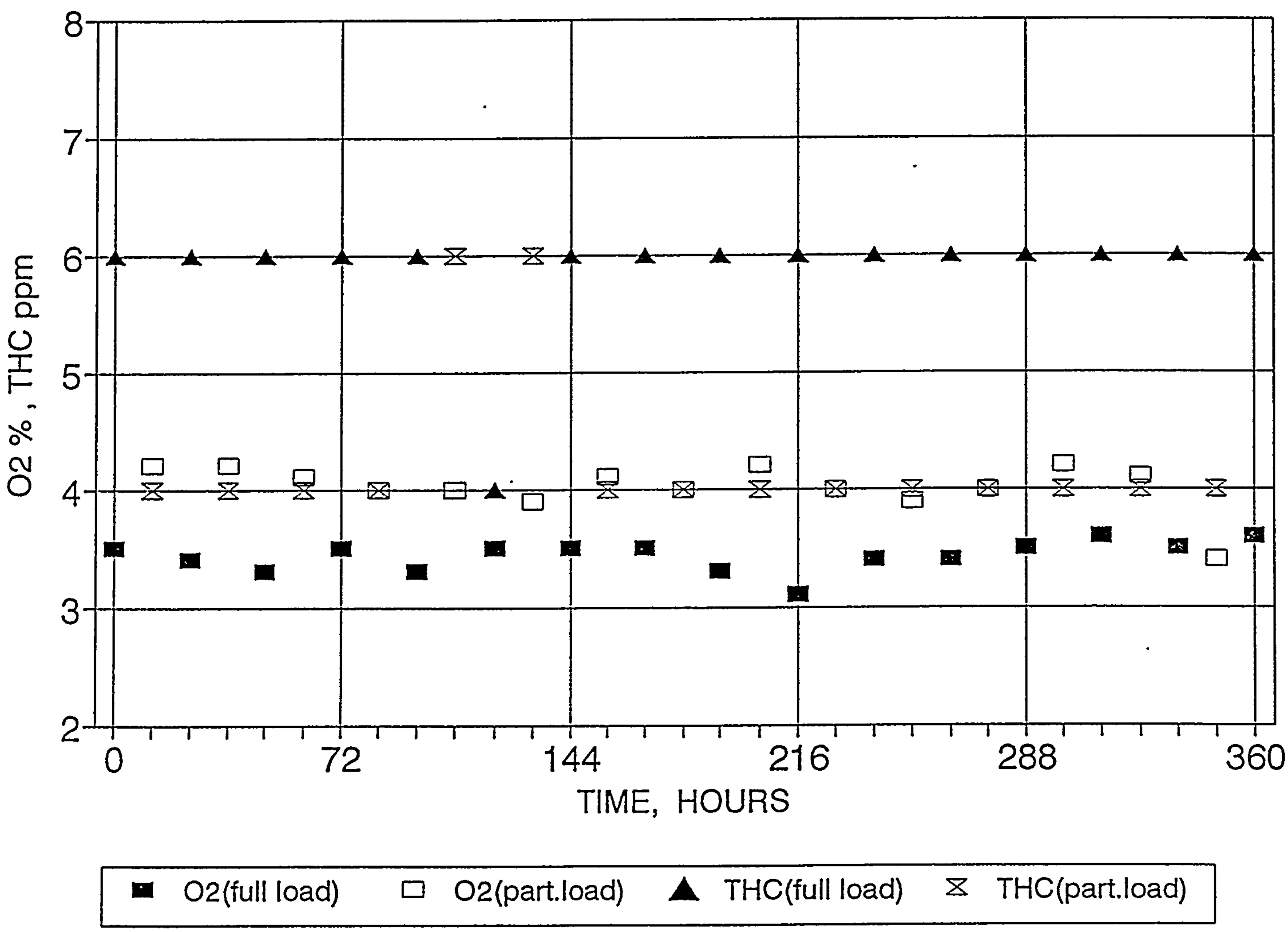


FIGURE 2-76: HISTORY OF O_2 AND THC - DEMONSTRATION TEST SERIES 5

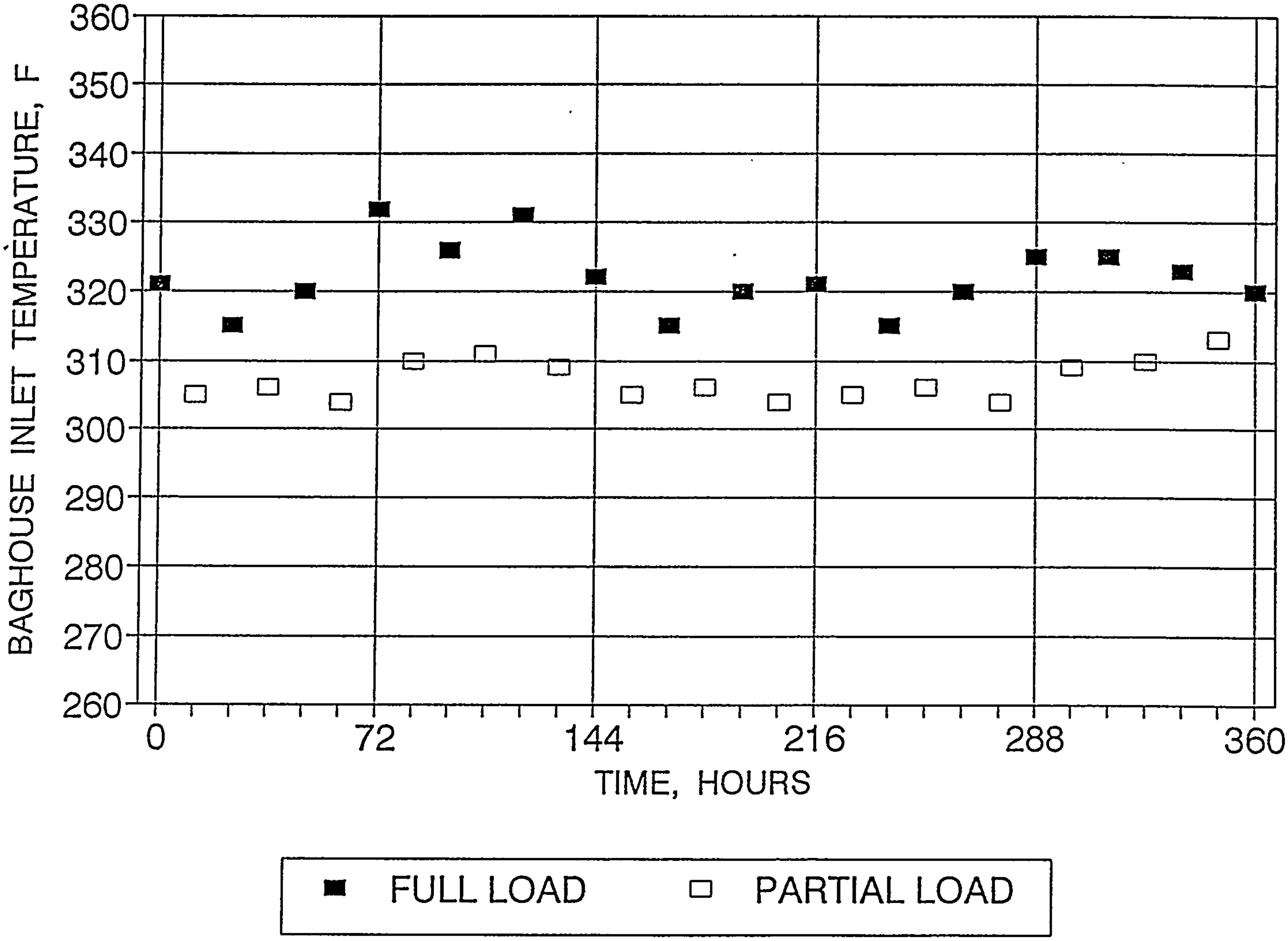


FIGURE 2-77: HISTORY OF BAGHOUSE INLET TEMPERATURE - DEMONSTRATION TEST SERIES 5

TABLE 2-33:
DEMONSTRATION TEST DATA SUMMARY - SERIES 6

(ALTERNATING SYSTEM OPERATION AT 12 HOURS FULL AND 12 HOURS PARTIAL LOAD, COAL B, SORBENT B, 288 HOURS)

Test No.		061295	061295	061395	061395	061495	061495
Firing rate, MMBtu/Hr	Total firing rate	6.26	4.58	6.26	4.58	6.26	4.58
	Coal	5.29	3.12	5.29	3.12	5.29	3.12
	Natural gas	0.97	1.46	0.97	1.46	0.97	1.46
Ratio of reburning coal/total firing rate, %		0	16.1	0	16.1	0	16.1
Ca/S molar ratio		5.64	5.28	5.64	5.28	5.64	5.28
Temperature, F	Air plenum	122	98	111	100	120	91
	Combustion chamber	2310	2216	2319	2214	2301	2219
	1st cyclone (average)	1834	2111	1841	2125	1829	2121
	2nd cyclone (average)	2217	1926	2208	1930	2217	1921
	Baghouse inlet	321	309	321	310	323	308
	Steam	223	212	223	213	225	214
Pressure, H2O	Air plenum	8.2	5.6	8.2	5.7	8.3	5.6
	Combustion chamber	14.3	6.7	14.2	6.8	14.1	6.9
	1st cyclone	0.6	1.1	0.5	1.0	0.6	1.2
	2nd cyclone	1.6	0.1	1.6	0.1	1.7	0.2
	Stack	-0.7	-1.1	-0.7	-1.2	-0.8	-1.1
Excess air, %		16.1	25.1	16.7	25.1	16.7	24.3
Emissions at stack (corrected to 3 % O2)	O2. %	2.9	4.2	3.0	4.2	3.0	4.1
	CO2, %	15.1	14.3	15.2	14.4	15.3	14.5
	CO, ppm	72	64	88	52	75	45
	SOx, ppm	601	503	590	511	596	498
	NOx, ppm	219	180	211	175	207	171
	HC, ppm	6	4	6	4	6	4
	CO, lb/MMBtu	0.06	0.06	0.08	0.05	0.07	0.04
	SOx, lb/MMBtu	1.18	1.06	1.17	1.08	1.18	1.04
	NOx, lb/MMBtu	0.31	0.27	0.30	0.27	0.29	0.26
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic data of combustion chamber	SPL, db	171.5	171.6	172.4	172.0	171.2	171.3
	Frequency, Hz	60	62	60	62	60	62
Combustion efficiency, %		-	-	99.0	-	-	-
Thermal efficiency, %		83.5	82.2	83.9	82.4	83.3	82.0
Sulfur capture efficiency, %		72.5	69.5	72.9	69.0	72.6	69.9

TABLE 2-33:
DEMONSTRATION TEST DATA SUMMARY - SERIES 6

(ALTERNATING SYSTEM OPERATION AT 12 HOURS FULL AND 12 HOURS PARTIAL LOAD, COAL B, SORBENT B, 288 HOURS) (CONT'D)

Test No.		061595	061595	061695	061695	061795	061795
Firing rate, MMBtu/Hr	Total firing rate	6.26	4.58	6.26	4.58	6.26	4.58
	Coal	5.29	3.12	5.29	3.12	5.29	3.12
	Natural gas	0.97	1.46	0.97	1.46	0.97	1.46
Ratio of reburning coal/total firing rate, %		0	16.1	0	16.1	0	16.1
Ca/S molar ratio		6.21	5.28	6.21	5.28	6.21	5.28
Temperature, F	Air plenum	126	99	131	86	122	95
	Combustion chamber	2302	2231	2284	2210	2298	2219
	1st cyclone (average)	1891	2116	1875	2120	1877	2112
	2nd cyclone (average)	2199	1915	2201	1929	2191	1921
	Baghouse inlet	321	310	323	311	319	309
	Steam	224	213	223	214	224	213
Pressure, H2O	Air plenum	8.5	5.5	9.0	5.7	8.8	6.0
	Combustion chamber	13.9	7.0	13.5	7.2	14.0	7.5
	1st cyclone	0.9	0.5	0.8	0.6	1.0	0.7
	2nd cyclone	2.0	1.5	2.0	1.6	2.0	1.4
	Stack	-1.0	-1.3	-0.8	-1.2	-1.4	-1.1
Excess air, %		15.4	23.6	16.1	23.6	16.1	22.9
Emissions at stack (corrected to 3 % O2)	O2. %	2.8	4.0	2.9	4.0	2.9	3.9
	CO2, %	15.1	13.3	15.2	13.3	15.1	13.5
	CO, ppm	72	64	88	69	54	75
	SOx, ppm	570	512	565	499	569	505
	NOx, ppm	225	181	209	170	220	175
	HC, ppm	6	4	6	4	6	4
	CO, lb/MMBtu	0.06	0.06	0.08	0.06	0.05	0.07
	SOx, lb/MMBtu	1.12	1.07	1.11	1.04	1.12	1.05
	NOx, lb/MMBtu	0.32	0.27	0.30	0.25	0.31	0.26
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic data of combustion chamber	SPL, db	172.0	171.6	171.7	172.0	171.2	171.4
	Frequency, Hz	62	62	62	62	60	62
Combustion efficiency, %		-	-	98.9	-	-	-
Thermal efficiency, %		83.0	82.2	82.8	82.4	83.3	82.4
Sulfur capture efficiency, %		74.1	69.3	74.2	70.1	74.0	69.9

TABLE 2-33:
DEMONSTRATION TEST DATA SUMMARY - SERIES 6

(ALTERNATING SYSTEM OPERATION AT 12 HOURS FULL AND 12 HOURS PARTIAL LOAD, COAL B, SORBENT B, 288 HOURS)
(CONT'D)

Test No.		061895	061895	061995	061995	062095	062095
Firing rate, MMBtu/Hr	Total firing rate	6.26	4.58	6.26	4.58	6.26	4.58
	Coal	5.29	3.12	5.29	3.12	5.29	3.12
	Natural gas	0.97	1.46	0.97	1.46	0.97	1.46
Ratio of reburning coal/total firing rate, %		0	16.1	0	16.1	0	16.1
Ca/S molar ratio		6.21	5.28	6.21	5.28	6.21	5.28
Temperature, F	Air plenum	120	99	121	105	109	103
	Combustion chamber	2333	2225	2315	2226	2298	2221
	1st cyclone (average)	1837	2116	1840	2120	1856	2112
	2nd cyclone (average)	2201	1925	2190	1920	2179	1921
	Baghouse inlet	321	306	319	308	320	307
	Steam	223	213	224	213	223	212
Pressure, H2O	Air plenum	8.3	5.5	8.4	6.0	8.0	5.7
	Combustion chamber	14.4	6.5	14.6	7.3	14.0	6.5
	1st cyclone	0.5	1.1	0.6	1.3	0.6	1.2
	2nd cyclone	1.6	0.2	1.8	0.1	1.6	0.2
	Stack	-0.7	-1.2	-0.8	-1.1	-0.8	-1.1
Excess air, %		17.4	24.3	16.1	24.3	16.1	25.1
Emissions at stack (corrected to 3 % O2)	O2, %	3.1	4.1	2.9	4.1	2.9	4.2
	CO2, %	15.2	13.3	15.3	13.3	15.2	13.1
	CO, ppm	72	64	98	71	84	88
	SOx, ppm	566	501	559	488	581	494
	NOx, ppm	201	178	205	170	211	165
	HC, ppm	6	4	6	4	6	4
	CO,lb/MMBtu	0.06	0.06	0.08	0.07	0.07	0.08
	SOx, lb/MMBtu	1.13	1.05	1.10	1.02	1.15	1.04
	NOx, lb/MMBtu	0.29	0.27	0.29	0.26	0.30	0.25
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic data of combustion chamber	SPL, db	172.2	171.6	173.1	172.0	171.2	171.6
	Frequency, Hz	60	62	60	62	60	62
Combustion efficiency, %		-	-	99.1	-	-	-
Thermal efficiency, %		83.8	82.2	84.2	82.4	83.3	82.0
Sulfur capture efficiency, %		73.8	69.8	74.4	70.5	73.4	70.0

TABLE 2-33:
DEMONSTRATION TEST DATA SUMMARY - SERIES 6

(ALTERNATING SYSTEM OPERATION AT 12 HOURS FULL AND 12 HOURS PARTIAL LOAD, COAL B, SORBENT B, 288 HOURS) (CONT'D)

Test No.		062195	062195	062295	062295	062395	062395
Firing rate, MMBtu/Hr	Total firing rate	6.26	4.58	6.26	4.58	6.26	4.58
	Coal	5.29	3.12	5.29	3.12	5.29	3.12
	Natural gas	0.97	1.46	0.97	1.46	0.97	1.46
Ratio of reburning coal/total firing rate, %		0	16.1	0	16.1	0	16.1
Ca/S molar ratio		6.21	5.28	6.21	5.28	6.21	5.28
Temperature, F	Air plenum	115	97	125	107	109	97
	Combustion chamber	2301	2222	2319	2218	2294	2209
	1st cyclone (average)	1835	2120	1834	2123	1827	2110
	2nd cyclone (average)	2218	1927	2208	1928	2215	1920
	Baghouse inlet	324	310	324	308	323	309
	Steam	223	213	224	214	225	213
Pressure, H2O	Air plenum	8.3	5.7	8.3	5.7	8.2	5.6
	Combustion chamber	14.2	6.8	14.0	6.7	14.1	6.6
	1st cyclone	0.6	1.2	0.6	1.1	0.7	1.2
	2nd cyclone	1.5	0.3	1.5	0.1	1.6	0.2
	Stack	-0.7	-1.1	-0.8	-1.0	-0.8	-1.0
Excess air, %		17.4	23.6	16.7	22.9	16.1	23.6
Emissions at stack (corrected to 3 % O2)	O2. %	3.1	4.0	3.0	3.9	2.9	4.0
	CO2, %	15.2	13.3	15.3	13.3	15.7	13.3
	CO, ppm	72	55	60	64	84	57
	SOx, ppm	546	501	559	491	541	495
	NOx, ppm	201	175	217	170	213	180
	HC, ppm	6	4	6	4	6	4
	CO,lb/MMBtu	0.06	0.05	0.05	0.06	0.07	0.05
	SOx, lb/MMBtu	1.09	1.04	1.11	1.02	1.07	1.03
	NOx, lb/MMBtu	0.29	0.26	0.31	0.25	0.30	0.27
	HC, lb/MMBtu	0.00	0.00	0.00	0.00	0.00	0.00
Acoustic data of combustion chamber	SPL, db	171.5	171.6	172.4	172.0	171.2	171.3
	Frequency, Hz	60	62	60	62	60	62
Combustion efficiency, %		-	-	99.2	-	-	-
Thermal efficiency, %		83.5	82.2	83.9	82.4	83.3	82.0
Sulfur capture efficiency, %		74.7	69.9	74.3	70.7	75.3	70.3

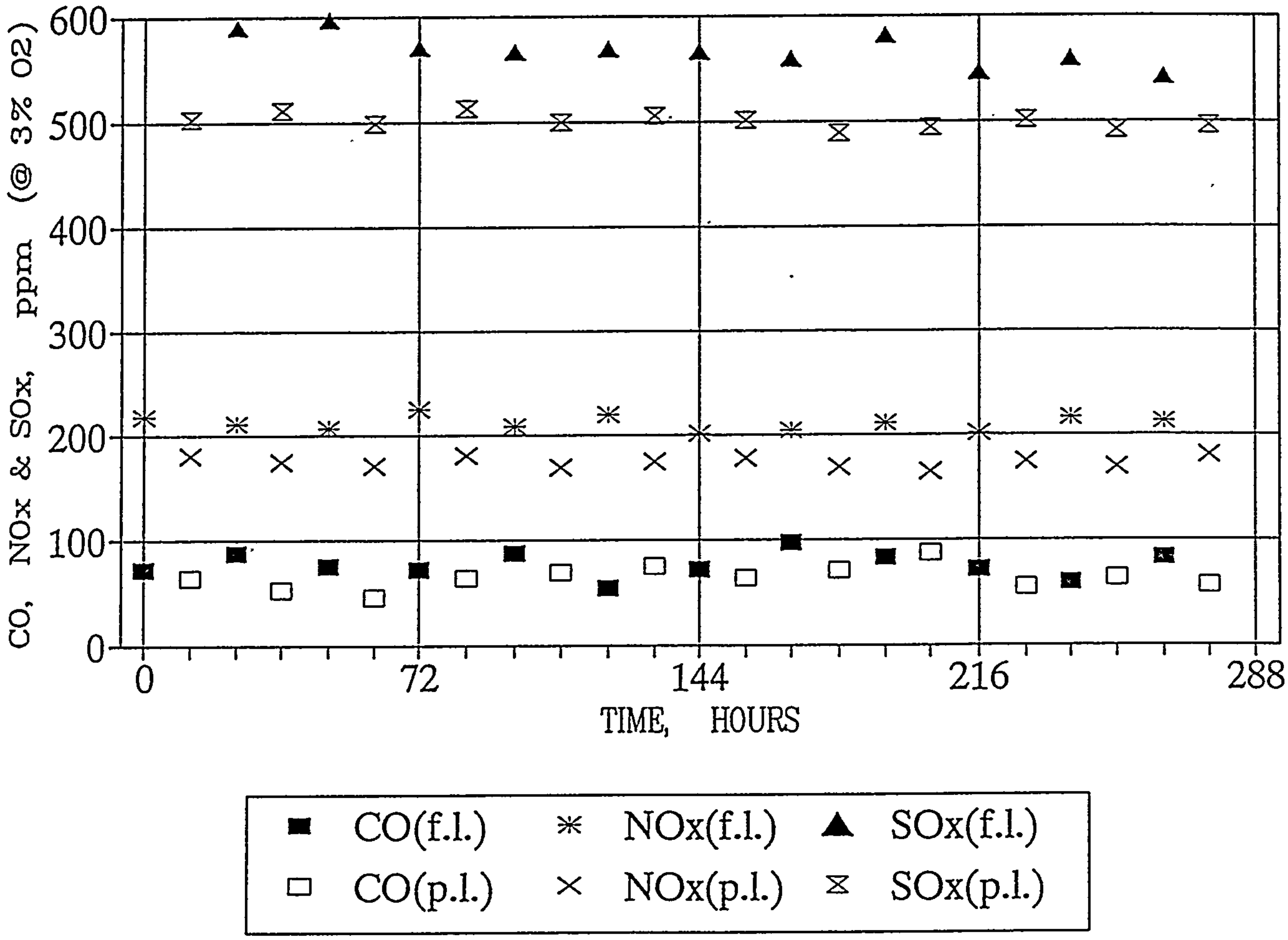


FIGURE 2-78: HISTORY OF CO, SO_x AND NO_x - DEMONSTRATION TEST SERIES 6

(5.28). However, sulfur capture efficiency at low firing rate was lower compared with that of a high firing rate test. The sulfur capture efficiency is affected by residence time and concentration of SO_x in the flue gas. It seems that lower concentrations of SO_x at low firing rate had more of an effect than the longer residence time and resulted in lower sulfur capture efficiency. Figure 2-79 shows O_2 and total hydrocarbons in the flue gas. As mentioned earlier, the higher primary zone stoichiometry in the pulse combustor at low firing rate gives rise to a higher O_2 level in the flue gas. THC emissions were, as always, very low. Combustion efficiency of the system with high sulfur coal was about 99 percent. Thermal efficiency, again, was higher than 82 percent. Figure 2-80 indicates the baghouse inlet temperature history during the test. The temperature was stable which suggests that there was no fouling of the boiler tubes.

This completed the demonstration test series.

The data from the six test series are consolidated and presented in Figures 2-81 through 2-85. The figures indicate the following:

- The full load firing rate was generally in the 6.0 to 6.3 MMBtu/hr range, while the partial load firing rate typically spanned the 4.5 to 4.7 MMBtu/hr range. The unit was not run at lower loads because NO_x emissions goal of 0.3 lb/MMBtu could not be met at firing rates less than 3 MMBtu/hr. Consequently, turndown was limited to between 2/3 and 3/4 of full load.

- The combustion efficiency generally is on the order of 99 percent and meets the project target goal.

- Sulfur capture efficiency increases with Ca/S molar feed ratio. Calcium utilization is, however, low due to the relatively large particle size (about 67 percent above 150 μm diameter) and short residence time (about 260 ms) in the 1500 to 2000°F temperature window for sulfur capture.

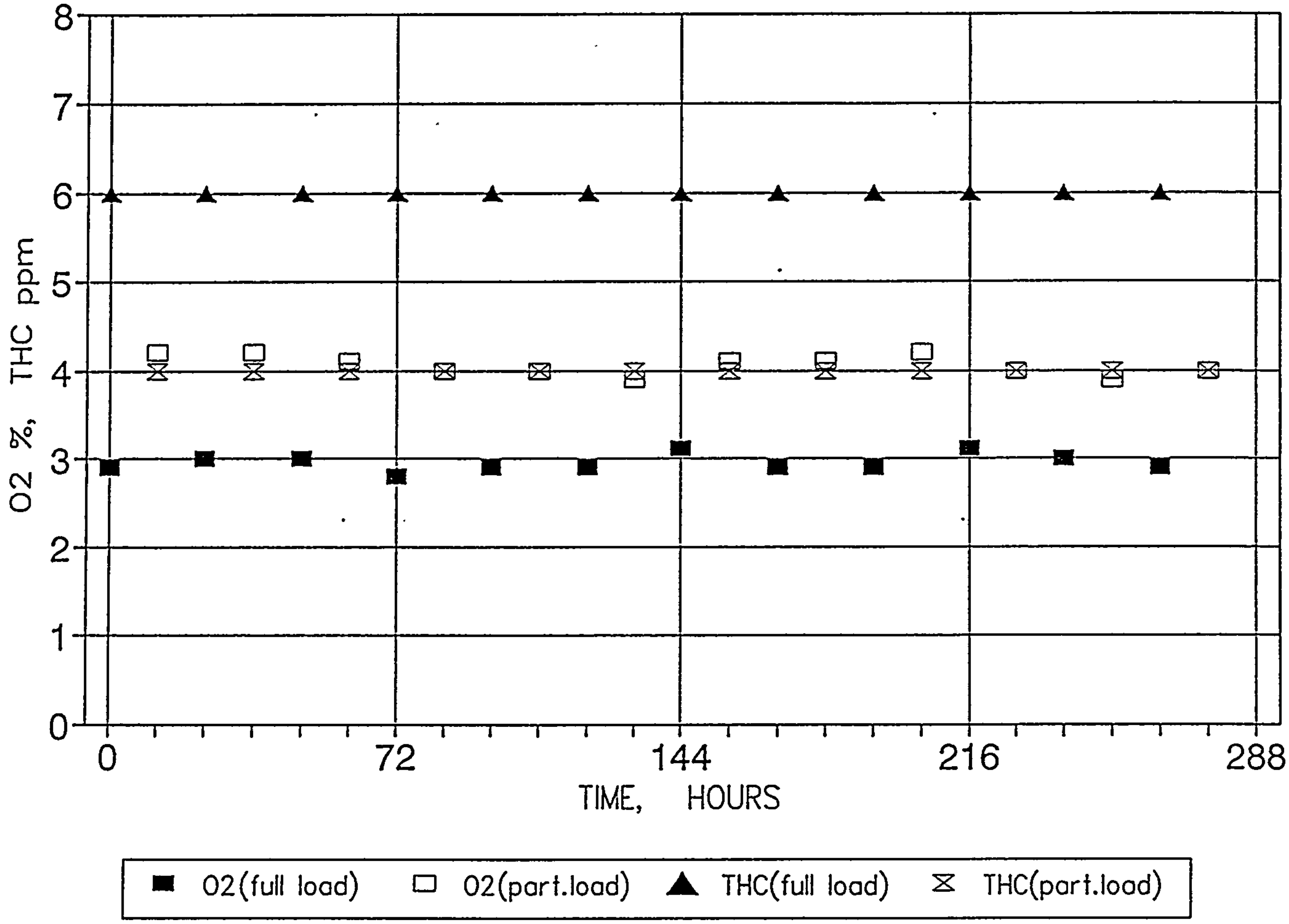


FIGURE 2-79: HISTORY OF O_2 AND THC - DEMONSTRATION TEST SERIES 6

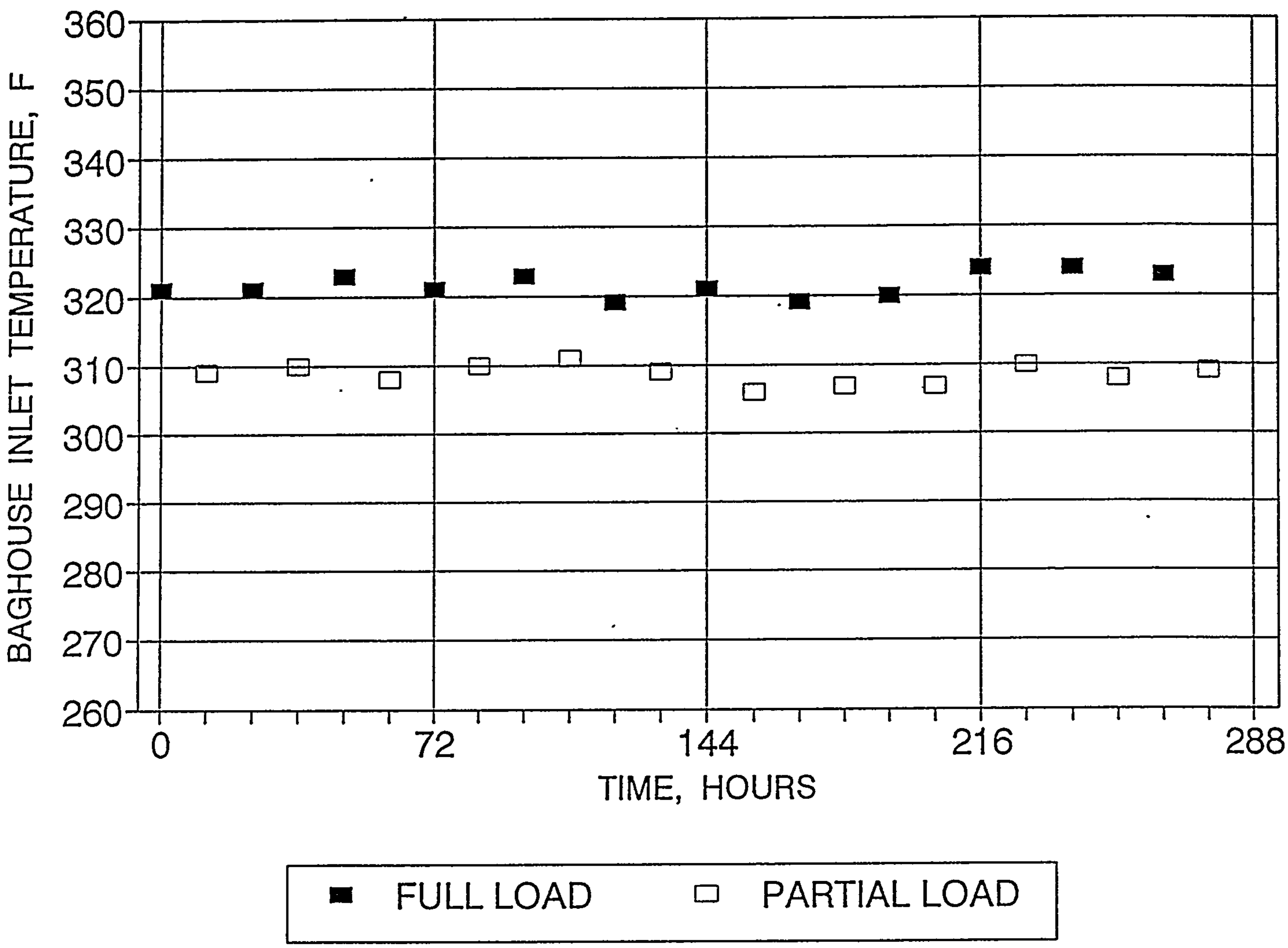


FIGURE 2-80: HISTORY OF BAGHOUSE INLET TEMPERATURE - DEMONSTRATION TEST SERIES 6

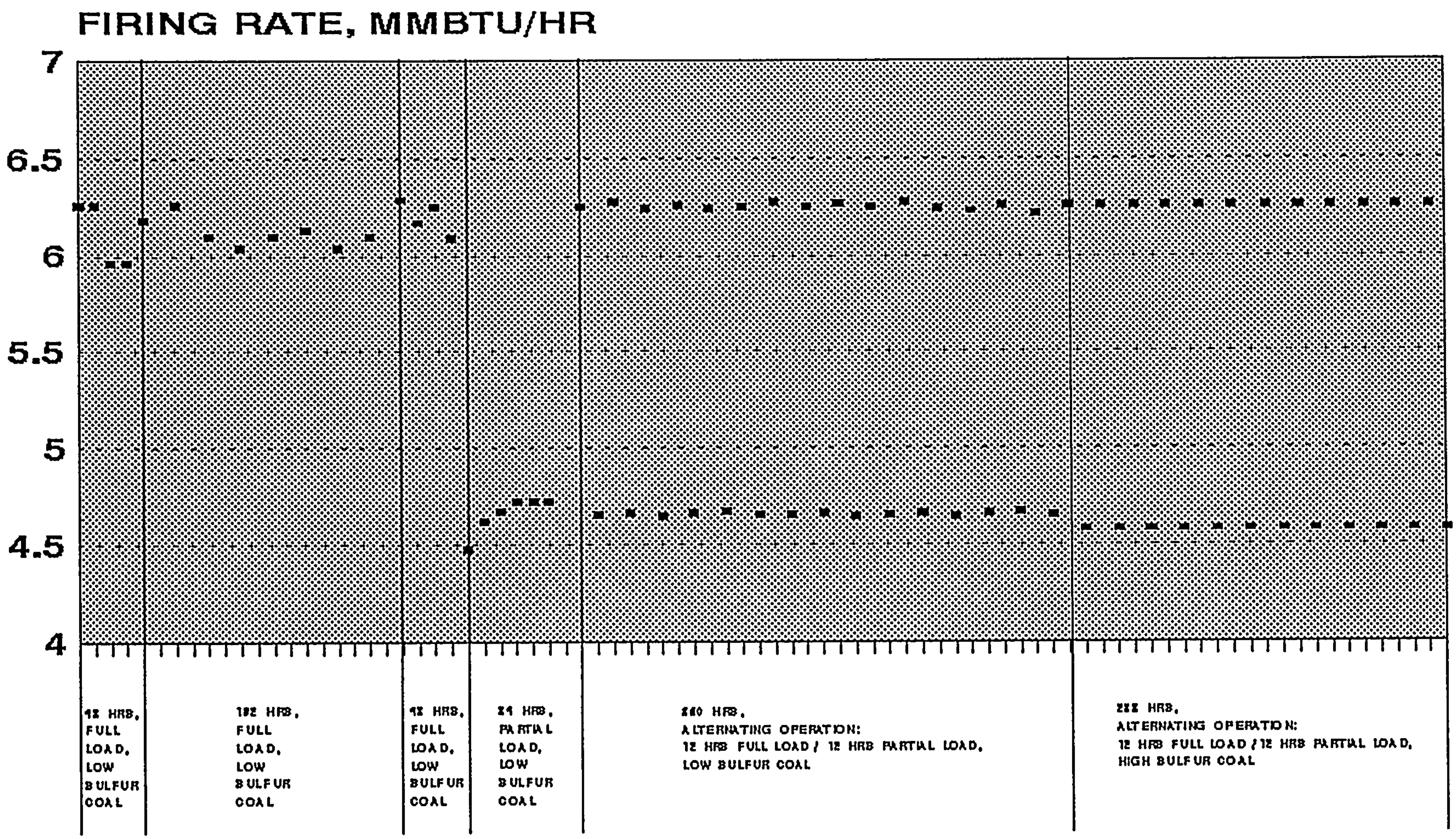


FIGURE 2-81: DEMONSTRATION TEST OVERALL DATA (FIRING RATE)

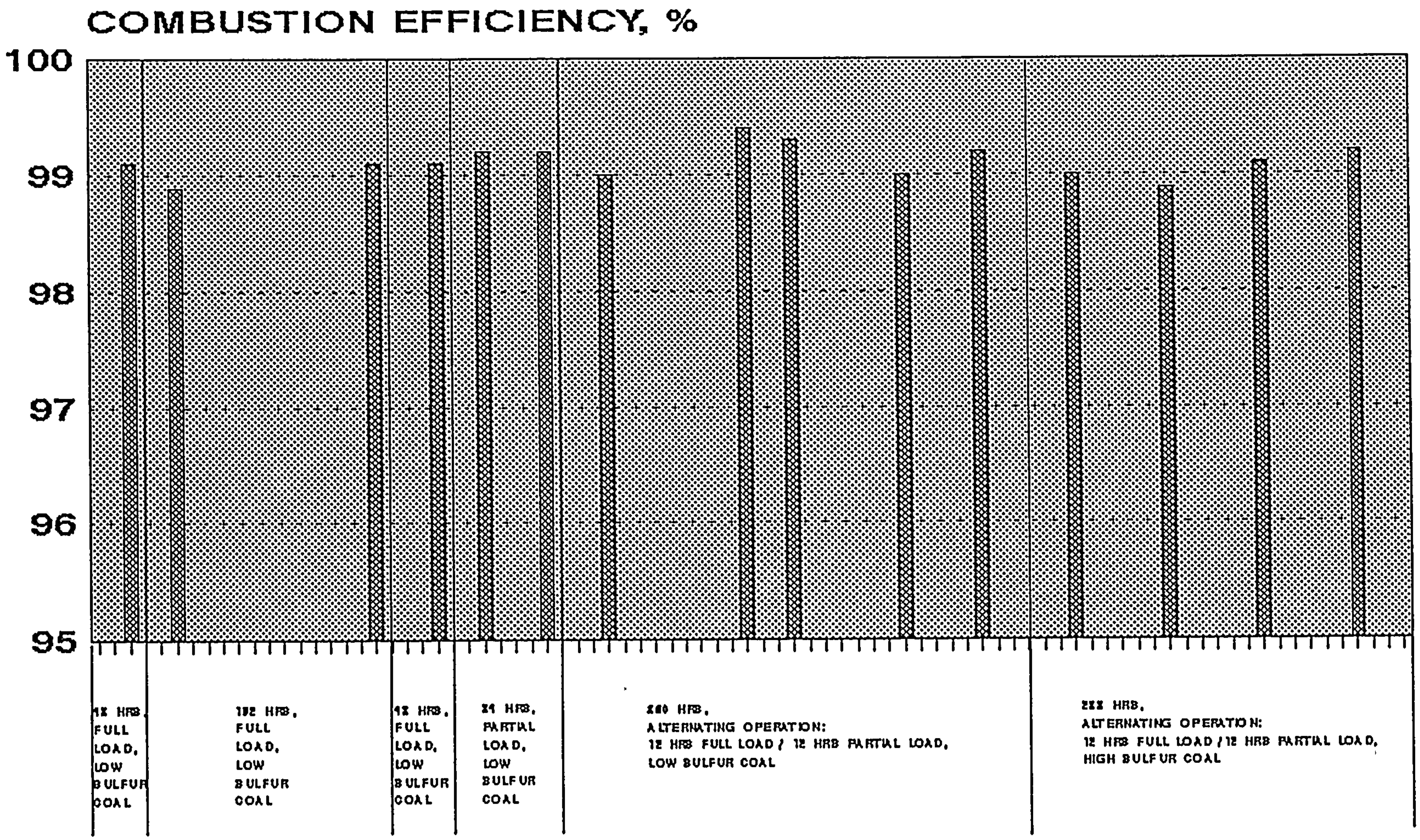


FIGURE 2-82: DEMONSTRATION TEST OVERALL DATA
(COMBUSTION EFFICIENCY)

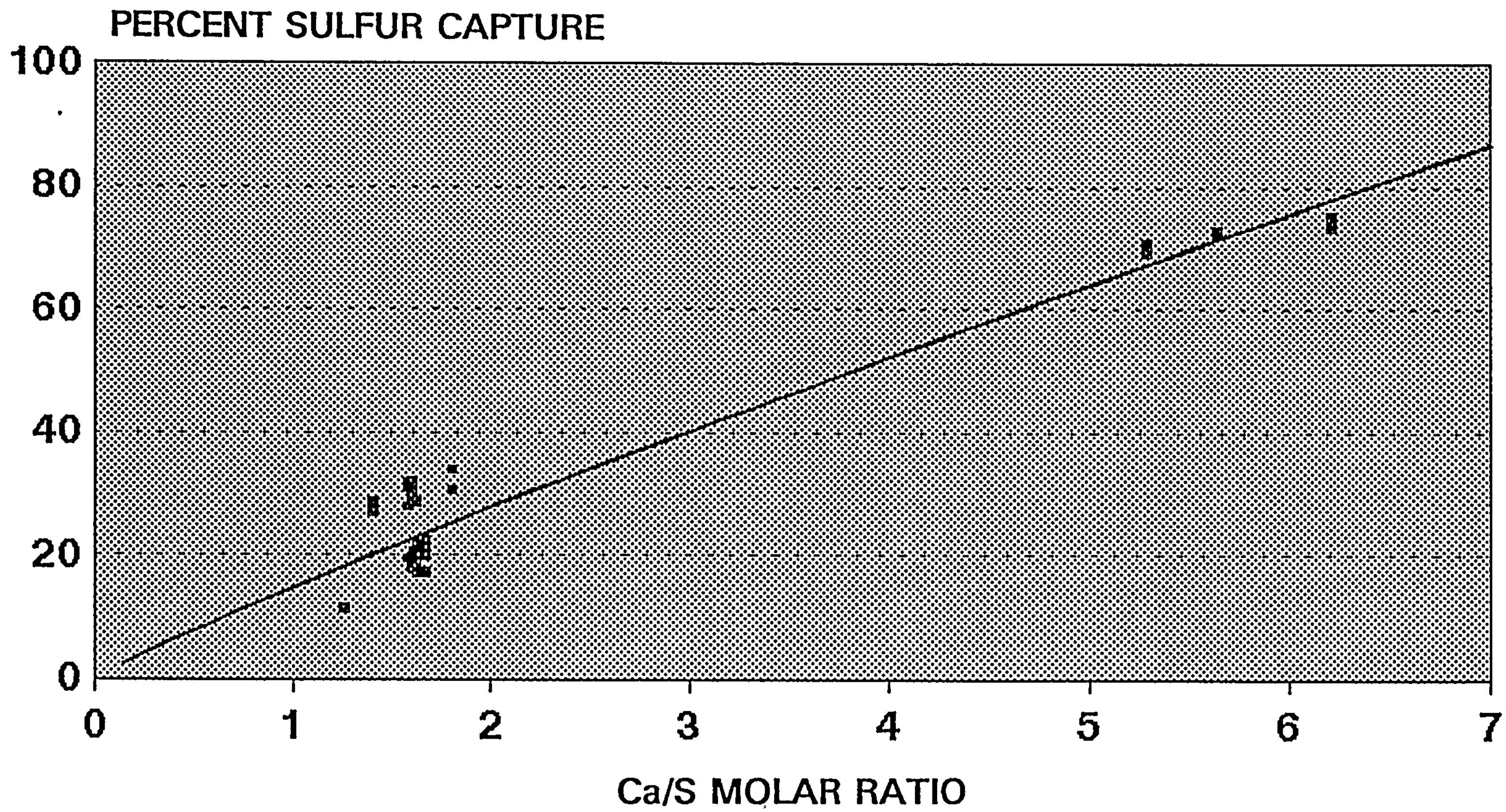


FIGURE 2-83: DEMONSTRATION TEST OVERALL DATA
(PERCENT SULFUR CAPTURE EFFICIENCY VS. CA/S MOLAR RATIO)

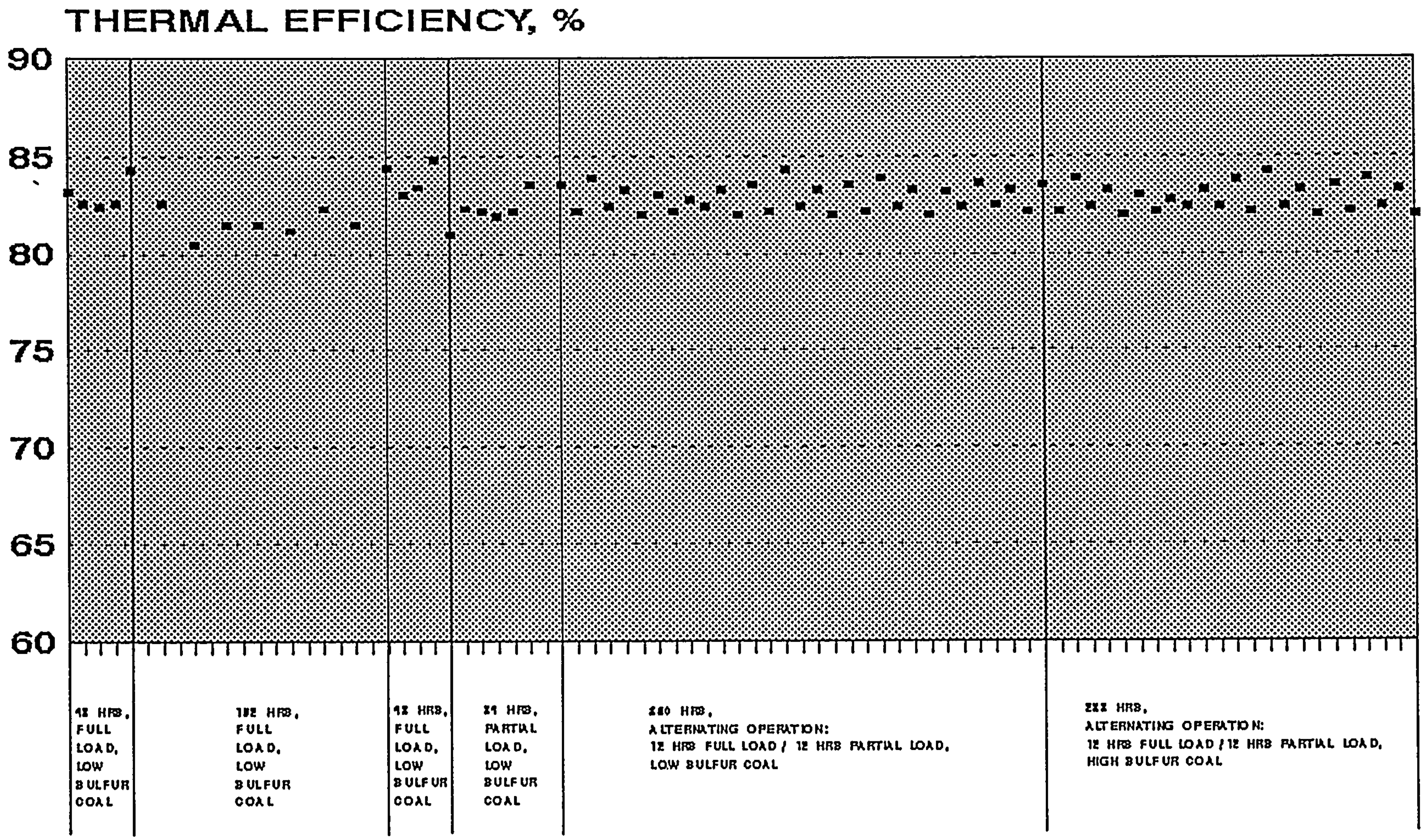


FIGURE 2-84: DEMONSTRATION TEST OVERALL DATA (THERMAL EFFICIENCY)

ERRZ-50F.2C

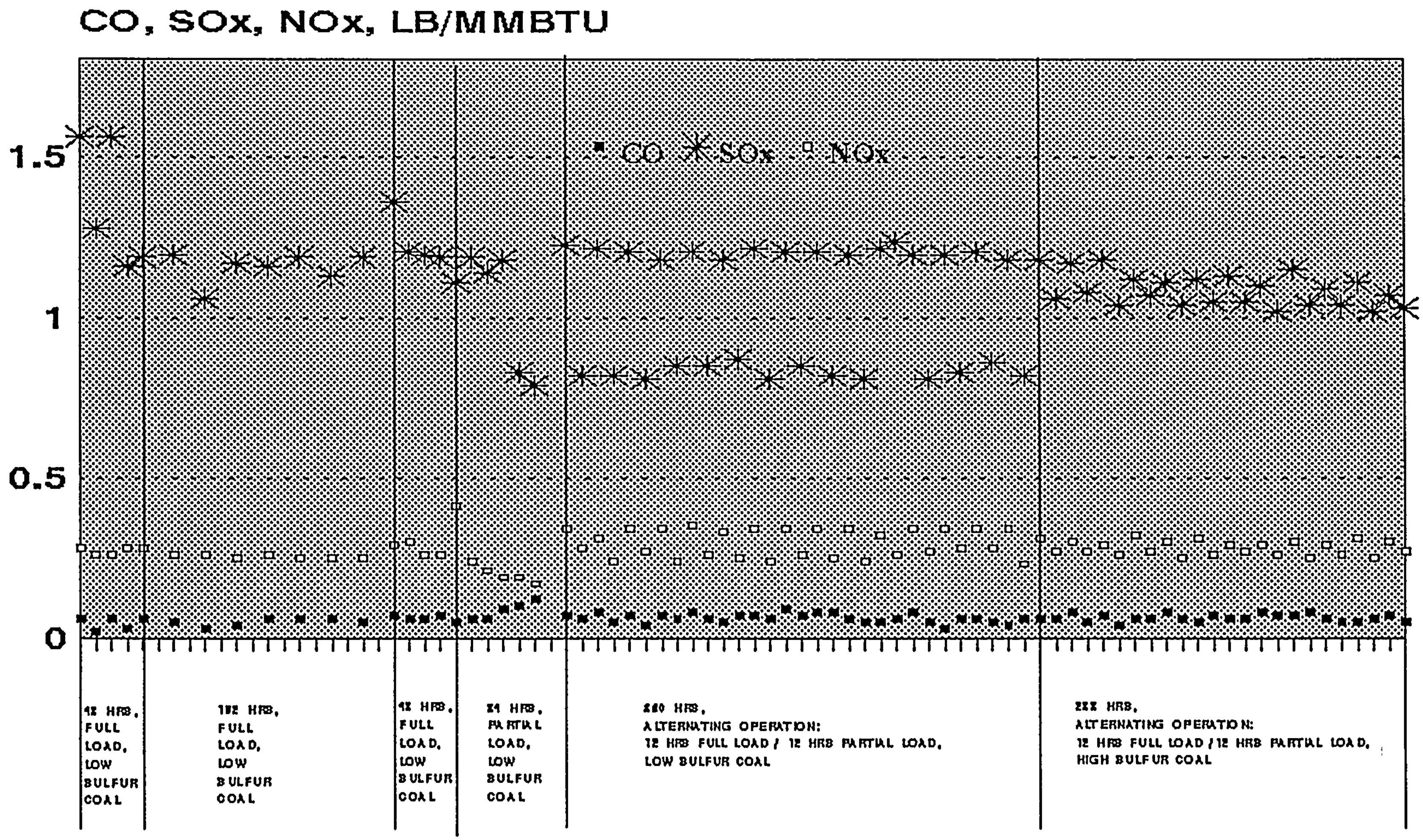


FIGURE 2-85: DEMONSTRATION TEST OVERALL DATA (CO, SO_x, NO_x)

- Thermal efficiency is in the 80 to 85 percent range and exceeds the project target goal.

- Generally, CO emissions are less than 0.1 lb/MMBtu, NO_x emissions are on the order of 0.3 lb/MMBtu, and SO_2 emissions are on the order of 1.2 lb/MMBtu. The NO_x and SO_2 emissions meet the project target goals, while the CO emissions are low and do not have a specified target goal.

The results from Tables 2-28 through 2-33 also indicate:

- Support gas on the order of 15 percent of the total firing is required for stable pulse combustion.

- Reburning coal injection is not required at full load but is required at part load to limit NO_x emissions to 0.3 lb/MMBtu.

- The air plenum pressure is generally low and is on the order of 8 inches of water at full load and about 6 inches of water at part load.

- The pulse combustor boost pressure is significant and varies from 5 to 10 inches of water at full load.

- The pulse combustor sound pressure level (SPL) typically spans the 170 to 172 dB range (3 to 4 psi peak-to-peak pressure) and the pulsation frequency lies between 60 and 64 Hz.

- Total hydrocarbon emissions were low and always below 10 ppm @ 3% O_2.

- The baghouse inlet temperature remained fairly steady during each test series (within a 10°F window) suggesting lack of fouling of fire-tubes.

- The system could be started with a single button computer control and brought on-line automatically to full-load. The control system was repeatedly able to automatically purge the boiler, start the pilot, bring the combustion chamber up to its preset temperature on natural gas, feed the coal, modulate the coal feed to maintain steam pressure, and regulate the reburn coal (if necessary) and sorbent feeds to meet emissions goals.

2.5.3 System Inspection

With the completion of the site demonstration testing, a visual inspection of the commercial unit was performed. The air plenum, coal reburning section, char burnout section, and back door of the boiler were opened and/or disassembled for inspection. No significant change was observed in the inspected areas. Several small cracks in the refractory were found in the coal reburning and char burnout sections. These are considered normal and relatively innocuous. No fouling was found in the boiler tubes except in two tubes at the very bottom of the boiler; a small amount of ash was deposited at the bottom of these tubes restricting about 20 percent of the tube opening. The coal/gas injector was disconnected and removed from the pulse combustion chamber. The injector was substantially in its original condition except for a slight warping of the impactor plate. A thicker plate with gusset reinforcement is stipulated for future applications.

2.6 ENGINEERING EVALUATION

The system demonstration tests indicated that the pulse coal combustion system could meet all the project target goals save for the turndown. The system was unable to meet the NO_x emissions goal of 0.3 lb/MMBtu at low loads or high turndown ratios. This shortcoming is attributed to a mismatch between the original pulse combustor design specifications and the actual operating conditions during the demonstration tests. Recall that the pulse combustor was originally designed to operate in the fuel lean or superstoichiometric (~ 25% excess air) mode. Consequently, the tailpipe inlet was sized to accommodate the flow of combustion products at firing rates up to 6.5 MMBtu/hr. This full load firing rate exceeded the boiler design requirement of 5 MMBtu/hr due to pulse combustor being water-jacketed (this provided additional heat transfer surface) and the need for maintaining the flue gas exit/stack temperature above the acid dewpoint. Proof-of-concept system tests, however, pointed out that NO_x emissions in the superstoichiometric mode of operation far exceeded the target goal. This entailed the inclusion of a reburn stage or control of primary zone stoichiometry to operate in the fuel-rich mode for controlling NO_x emissions. The reburn route was initially followed with success in achieving the target emissions goals. During this development phase, a modified coal injector was fabricated and tested as well. This demonstrated the potential for operating the pulse combustor in the substoichiometric or fuel-rich mode and in turn control the NO_x emissions.

The test results were satisfactory for operation at modest partial load (about two-thirds of full load) to full load but not at low levels (down to one-third of full load). This deficiency stems from the tailpipe inlet being much larger than that required for substoichiometric operation. The tailpipe is "too open" so-to-speak - especially at low loads - thereby generating a lower peak-to-peak pressure and higher backflow rate of combustion products from the tailpipe into the combustion chamber than those for the correct size tailpipe. This excessive backflow or low diodicity impacts combustion stability through mixture flammability, therefore, combustor stability is impaired at substoichiometric conditions and superstoichiometric mode of operations is required at low loads to ensure combustion stability. Superstoichiometry, however, favors NO_x formation and in turn renders it difficult to meet the target goals at low loads.

A cost estimate was made prior to the system demonstration tests to evaluate the feasibility of replacing the pulse combustor with another one sized appropriately for substoichiometric operation. The funds remaining were barely sufficient to conduct the tests and complete the program; no funds were available to make additional changes to the pulse combustor.

MTCI pulse combustors typically operate at a turndown of between 4 to 1 and 5 to 1. Based on the test results and operating experience, it is considered easy and straightforward to configure a pulse combustor to fire coal and achieve a turndown of greater than 3 to 1 while operating in the substoichiometric mode. Since the system demonstration tests have shown that NO_x emissions can be controlled to meet the target goal by fuel-rich operation in the primary zone, coal reburning is no longer required. This permits a simpler, less expensive retrofit by eliminating the reburn section. The combustion system configuration suggested for commercial boiler retrofit applications is shown in Figure 2-86. It shows a refractory-lined (high density refractory, single layer) and water-jacketed pulse combustor with a straight tailpipe that is coupled tangentially to a char burnout chamber. The pulse combustor is mounted vertically and the char burnout chamber is oriented horizontally and connected to the Morrison tube of the boiler. An air plenum is coupled to the aerovalve and a coal injector is positioned close to the entrance of the pulse combustion chamber. Secondary air is injected into the char burnout chamber through tangentially staging air parts. The sorbent is fed at the entrance to the Morrison tube. This arrangement makes the system more compact, requires less footprint, and is less expensive to build than that tested during system demonstration.

Figure 2-87 shows a schematic of the updated system. It shows the additional components viz. FD fan, coal and sorbent feeders, air compressor, water recirculation pump, baghouse, ID fan, water feed pump and air rotation unit. A water recirculation pump may not be necessary if the pulse combustor can be located such that its water jacket is at a much lower elevation than the boiler water level to permit natural circulation. An air compressor is included to supply air for solids (coal and sorbent) transport and also for instrumentation.

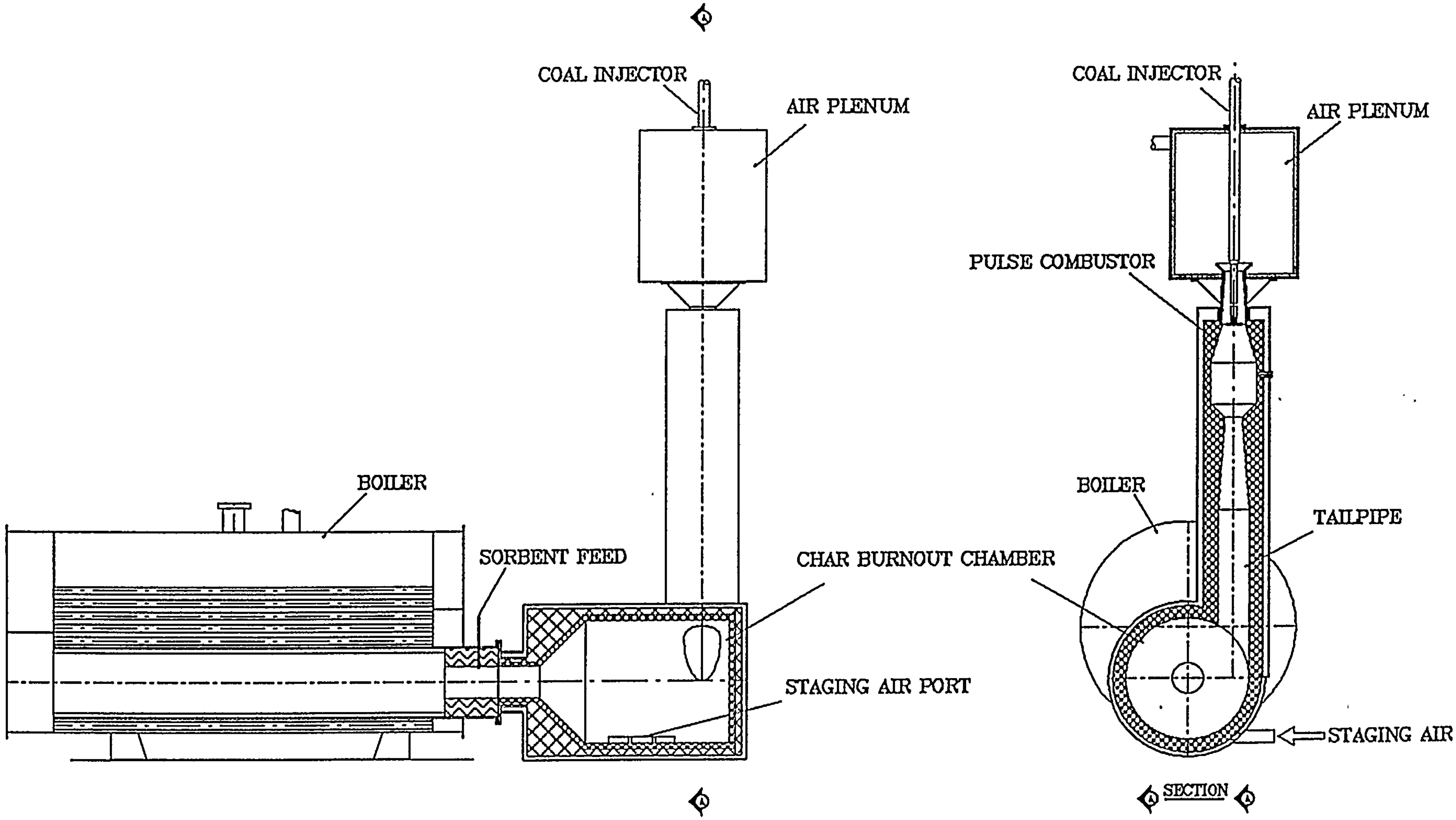


FIGURE 2-86: UPDATED COMBUSTION SYSTEM CONFIGURATION

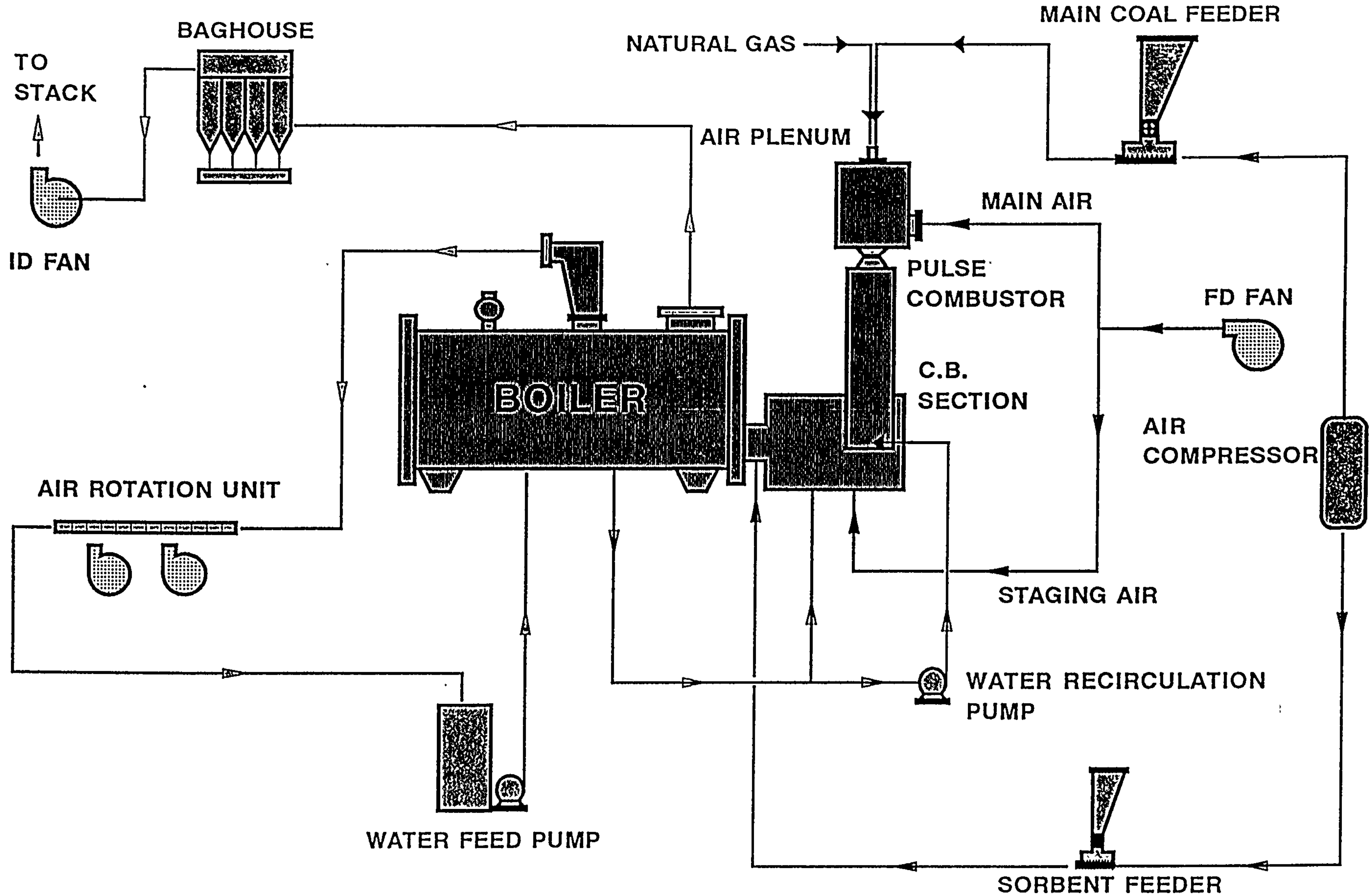


FIGURE 2-87: SCHEMATIC OF AN UPDATED COMMERCIAL-SCALE COAL-FIRED PULSE COMBUSTION SYSTEM

The extent of natural gas addition is expected to vary with coal type and coal fineness. The finer the coal and the more volatile it is, the less the projected requirement for support gas. The nominal requirement (for combustion stability) for support gas is projected to be about 10 percent of the firing rate with a ± 5 percent deviation about the mean depending on coal volatility and coal fineness. The space requirement for retrofitting the pulse combustion system (air plenum, pulse combustor, char burnout section, and the water recirculation pump) with the boiler is projected to be about 6′ x 8′ (floor area) by 20′ height.

The calcium utilization was low in the system demonstration tests primarily due to the relatively large size of sorbent particles (67% by weight greater than 150 ppm diameter). The calcium utilization can be significantly improved by either feeding a much finer grind sorbent or scrubbing downstream of the boiler but upstream of the baghouse.

The pulse combustor typically operated in the self-aspirating mode and produced a pressure boost of between 5 and 10 inches of water. This reduces the fan power requirement.

Fouling of fire tubes was not apparent and this is attributed to the pulsations induced in the flow by the pulse combustor. This eliminates the need for soot blowers common in conventional coal-fired boilers.

Coal firing or a switch to coal from gas or oil does not derate the boiler in the case of pulse combustor integration but up rates the boiler due to the additional steam generated in the pulse combustor water jacket.

In view of the modified configuration suggested above, the economic evaluation presented in Section 2.4 was revisited. The steam cost model calculations were again performed. The revised capital cost estimates and the economic analysis projections are given in Tables 2-34 and 2-35, respectively.

TABLE 2-34:

CAPITAL COST ESTIMATE

PURCHASE PRICE	
BAGHOUSE	$12,036
ID, FD, & STAGING AIR FANS	$12,505
ELECTRIC AIR COMPRESSOR	$14,500
WATER PUMPS	$ 1,800
SCREW CONVEYORS	$ 9,300
CONTROL SYSTEMS & INSTRUMENTATION	$40,000
TOTAL	$90,141
FABRICATION COST (MATERIALS & LABOR)	
AIR PLENUM	$ 1,600
PULSE COMBUSTOR	$16,050
BURNOUT SECTION	$13,930
COAL & LIMESTONE SILOS	$ 8,900
TOTAL	$40,480
COST PLUS 10% PROFIT PER UNIT	$143,683
COST FOR 10 OR MORE UNITS	$114,946

TABLE 2-35:

ECONOMIC ANALYSIS PROJECTIONS

DIRECT INVESTMENT EXPENDITURES	$114,949 - $143,683
SHIPMENT	$2,500 - $10,000
SITE MODIFICATIONS COSTS	$15,000 - $40,000
INSTALLATION CHARGES	$28,737 - $35,721
ENGINEERING, DESIGN & START-UP COSTS	$19,368 - $17,961
MAINTENANCE	$7,903 - $9,879
CONSUMABLES	
WATER	30 or 550 gallon/hr
NATURAL GAS	13 SCFM
COAL	370 lb/hr
SORBENT	55 lb/hr
ELECTRICITY	78 KW

Figure 2-88 indicates the variation in allowable capital cost for the pulse coal combustion system with differential fuel cost for a unit operating at different capacity factors. Figure 2-89 presents the results for different payback periods but at 75 percent capacity factor. The inferences are all similar to those drawn earlier in Section 2.4 (with reference to Figures 2-61 and 2-62). Due to the reduced capital cost estimate stemming from the simpler system arrangement (see Figures 2-86 and 2-87), the economics are slightly more favorable than that given earlier. A problem, however, arises in that pulverized coal may not be available in many of the potential market areas overseas. Either the system would then have to include a pulverized or the user would have to pay a premium to obtain pulverized coal. The differential fuel cost for breakeven ranges between \$4 and \$4.50 and suggests many countries in Europe and the Far East as possible candidates for this technology. Of course, the system proposed here is a high-end system with top-of-the-line controls and sophisticated feed systems. The capital cost could be significantly reduced by simplifying the instrumentation and controls, substituting a blower for the electric air compressor, and fabricating/acquiring components (except pulse combustor) overseas. Consequently, the potential exists for marketing this technology abroad if engineering and fabrication are tied to the local demands and market drivers.

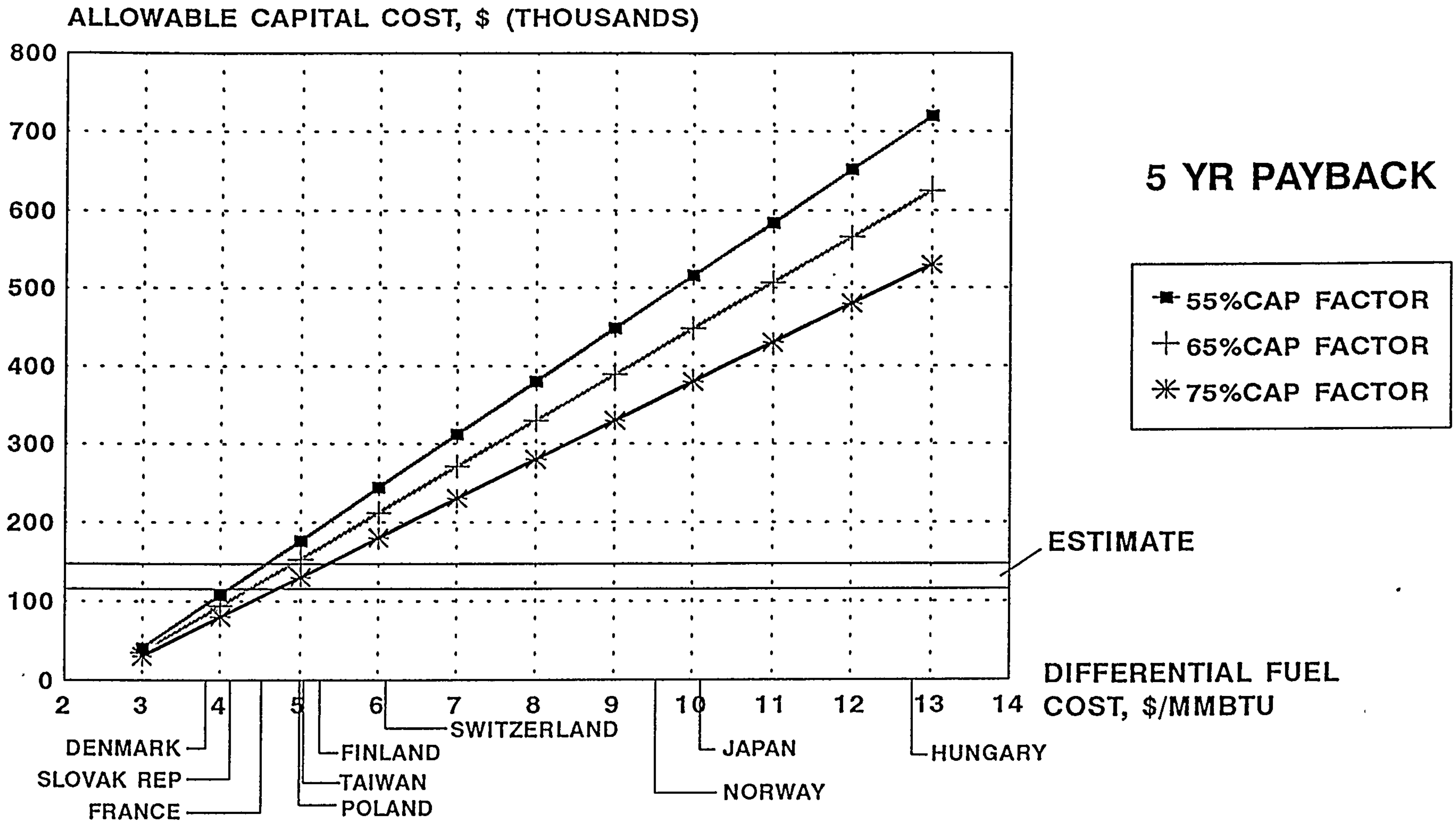


FIGURE 2-88: PULSE COAL COMBUSTION SYSTEM FOR BOILER RETROFIT - NATURAL GAS/OIL COMBINATION BURNER REPLACEMENT

ERRZ-50F.2D

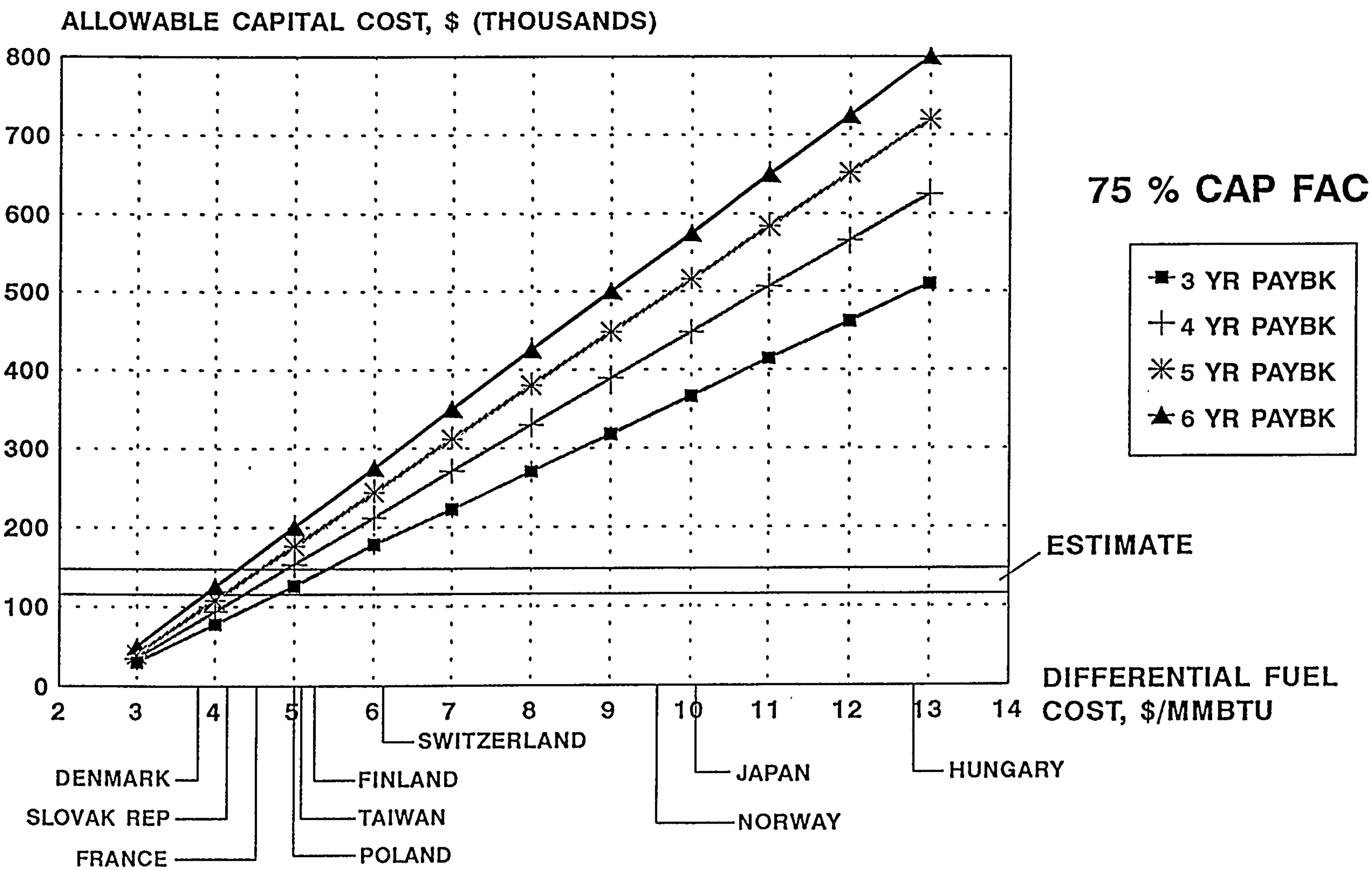


FIGURE 2-89: PULSE COAL COMBUSTION SYSTEM FOR BOILER RETROFIT - NATURAL GAS/OIL COMBINATION BURNER REPLACEMENT

SECTION 3.0

COMMERCIAL PLAN

The MTCI Commercialization Plan is a company-wide plan for commercializing all of its technologies as they progress through the feasibility stage to field testing and demonstration.

In this pipeline, the order of technologies is discussed below with the pulse combustor technology being planned to enter this pipeline at some point after the pulsed-heater, spent-liquor reforming technology enters the marketplace.

The nature of the pulse combustion technologies and the wide spectrum of applications of the technology motivated a relationship between MTCI and ThermoChem in which a strategy was defined by ThermoChem for the commercialization of the MTCI technologies under a license from MTCI. The preferred strategic configuration for some of the MTCI technologies, steam reforming in particular, is to establish an owner-operator relationship with the end-users. This can best be accommodated by forming joint ventures or partnerships with key and reputable organizations already providing this type of service for end-user industries and then capitalizing this organization on a project-by-project or industry-by-industry sector. The fundamental considerations and elements of the overall strategy are provided below:

1. The technology Commercialization Plan must maximize the opportunity for the commercialization of all the embodiments of the technology with the least time delay and at a minimum possible cost.

2. Under this Plan, MTCI, the technology development company, shall maintain a strongly correlated technical data base fully capable of translating pilot and demonstration test data from one embodiment and its implication on all other embodiments to the greatest extent possible.

3. Private-sector funding will be sought from reputable and reliable end-user organizations first so as to accelerate without delay the market introduction of the Technology and secondly, from investment capital institutions and finally, if necessary, from venture capitalists.

4. Benefits to the end-user in the form of reduced equipment and process royalties should be the mechanism by which the end-user can profit from his cost sharing of the technology development and demonstration activities. This approach has already established an excellent working relationship with several clients for the demonstration of other technologies.

5. Only exclusive licenses for more than one licensee will be offered with regional subdivision of the licensed region of the U.S. and overseas. Non-exclusive licensing is counter productive in incentivizing capital formation for projects particularly during initial market service.

6. Manufacturing of the key equipment and high technology components will be maintained under the control of ThermoChem in the U.S.

7. No licensing of key technology to foreign companies. However, joint ventures for specific applications will be the preferred mechanism employed overseas. Key technology items will be manufactured in the U.S. and exported to overseas markets. In this regard ThermoChem was approached by Ahlstrom with respect to the MTCI spent-liquor, steam-reforming technology.

8. A network of vendors and A&E firms has been developed to support ThermoChem in the commercialization of the technology, nationwide and overseas.

9. Equipment quality and service support is the key to success of technology commercialization.

With the above in mind, a presentation of how the MTCI pulse combustor technology is intended to be commercialized follows:

The first pulse combustor based technology that was field tested by MTCI was a steam-reforming, indirectly heated thermochemical process for processing recycle paper mill sludge for production of a hydrogen-rich gas. The field test unit had a nominal capacity of 24 tons per day and was successfully demonstrated at this pilot scale in 1992 at the Inland Container Corporation's recycle paper mill in Ontario, California.

The second pulse combustor based technology that has just completed field testing is a spent liquor chemicals and energy recovery process for recovery of all types of spent liquor found in the pulp and paper industry (Kraft, sulfite, soda, BCTMP, etc.). This pilot unit field test was at the Weyerhaeuser pulp mill at New Bern, North Carolina. The mill employs a Kraft process for pulp production. A joint organization for owner-operator initiatives is now being formed by ThermoChem and Stone & Webster Engineering Corporation for projects in the United States and Canada. The equipment sales by ThermoChem for this process is aimed initially at incremental capacity in spent liquor recovery. This will be followed by modular capacity offering for incremental retirement of old Tomlinson boilers rather than for greenfield pulp mills. Stone & Webster is the exclusive sublicensee for this application in the United States and Canada. They also provided cash and in-kind support for the demonstration at New Bern. Stone & Webster Engineering Corporation is now offering commercial units and owner-operator processing services up to 150 tons/ day to the pulp and paper industry in the United States and Canada.

ThermoChem was originally approached by both Babcock & Wilcox (B&W) and Ahlstrom regarding the spent liquor and paper mill sludge technologies. ThermoChem executed disclosure agreements with both companies with B&W providing cash and design support pending negotiations of a sublicense from ThermoChem. At the same time, ThermoChem also offered a joint venture arrangement to Ahlstrom for the European sector. However, ThermoChem has now awarded an exclusive sublicense for the spent liquor technology to Stone & Webster Engineering Corporation for U.S. and Canada only. Esvin Advanced Technologies Ltd.

(EsvinTech) of Madras, India has been granted an exclusive license for India only for the spent liquor recovery.

The third pulse combustor based technology was devoted to steam gasification of low-rank coals. This was the subject of a Clean Coal IV, full-scale demonstration in cooperation with the DOE Clean Coal program and Enserv. Enserv is a non-regulated subsidiary of Wisconsin Power & Light Holdings which also owns Wisconsin Power and Light (WP&L), a regulated electric utility. A license for the exclusive use by WP&L of the ThermoChem/MTCI technology in conjunction with low-rank coal upgrading was being negotiated with WP&L. Manufacturing rights under the license agreement between ThermoChem and WP&L would be retained by ThermoChem. This demonstration project and negotiations are now being held in abeyance until some final determination by the DOE with respect to the project's future.

All of the above technologies are either natural gas or liquid fuel fired (propane and oil) with the product gas produced replacing or supplementing combustor fuel. The following pulse combustor technology applications are all coal-based and are obviously much lower in commercialization priority than the liquid- or gas-fired applications. In these applications, MTCI has accepted the fact that the utility and power producing industries are the largest coal-using market in this country but require demonstrations at significantly higher levels in the commercial, industrial and retrofit markets. However, new applications for gas or oil replacement in any of the above markets is ill-advised, at least in this country, and at present this is primarily the result of the availability and convenience of low capital operations and feed costs for oil and gas installations.

In addition to the fundamental considerations and overall strategy provided earlier, the following additional considerations will be primarily applicable to coal-fired pulse combustor applications:

1. Under the New Clean Air Act, the retrofit utility market is the key near-term large market for the MTCI low NO_x pulse coal combustor with

SO_x dry sorbent injection. ThermoChem will team with U.S. utility equipment manufacturers for this market as well as end-users.

2. Industrial and institutional market and institutional end-users have current needs and will provide an opportunity to demonstrate the technology in an actual commercial service environment at an adequate scale for both the industrial and utility markets at a reasonable cost.

3. Non-regulated profit oriented industrial end-users provide more assistance and help to a demonstration project than electric utilities. It is therefore prudent to introduce the technology in an industrial setting first.

4. Key technology components for a manageable size range (units up to 200 MMBtu/hr in firing rate) may be manufactured in-house with larger equipment sizes or all sizes licensed to U.S. firms such as Babcock & Wilcox, particularly higher steam pressure cogeneration and modular utility applications.

5. Initial commercial service introduction of the technology is to be in the small electric utility retrofit market and the industrial market.

6. The European market is perhaps the place for introduction of coal-fired burners and their applications.

Therefore, the first coal-fired technology in the que that is pulse combustor based is the Pulsed Atmospheric Fluid Bed Combustor (PAFBC) which is being supported by the DOE in a Cooperative Agreement with Clemson University. This technology will soon be ready for a field demonstration followed by an in-service use at Clemson University at the 50,000 PPH of steam for the heating of campus buildings. Clemson has traditionally used coal for its campus heating needs.

In actuality, the PAFBC technology also represents an additional demonstration of a coal-fired combustor as well as a pulsating fluid-bed combustor. This is because the PAFBC is a hybrid system in which the coal fines are separated from the feed to the fluid bed and simultaneously burned in the pulse combustor with the exhaust entering at the bottom of the fluid bed.

MTCI believes that this additional demonstration can also help to accelerate commercialization both as part of the PAFBC system and as a stand-alone retrofit or new burner application. Unfortunately, the burner market in the U.S. for new technologies is probably non-existent. However, the European market is a distinct possibility for market entry.

As an example of how the pulse combustor will be commercialized, we can follow the path described below for the PAFBC with the exception of those steam-producing applications at the lower end of the commercial, industrial market.

The initial market entry in the United States for the PAFBC is targeted for high capacity factor steam production and cogeneration applications. This includes hospitals (with co-firing with medical wastes and coal), universities, shopping centers and the like in the size range of 50,000 lbs/hr to 200,000 lbs/hr of steam production. Steam pressure ratings for this segment of the market is anticipated to be between 50 psig to 250 psig.

The initial market entry for the cogeneration systems is targeted for industrial and institutional cogeneration applications. This is to be followed by introduction of 100 MW_e to 200 MW_e modules for use by the electric utility industry. This is because the utility industry is more conservative and having industrial cogeneration units operating first will be necessary to gain acceptance by the utilities.

For the cogeneration applications, 600 psig to 1200 psig systems in the range of 400,000 lbs/hr (2 modules of the demo size) to 800,000 lbs/hr (4 modules of the demo size) will be employed. Nominal electricity production from these cogeneration units is in the range of 25 MW_e to 50 MW_e, respectively.

In Europe the initial market for steam units in the size range of 50,000 lbs/hr to 200,000 lbs/hr is available now for the PAFBC technology due to the larger differential price between oil/gas and coal. Superior environmental performance will be the key to the penetration of the European market. Joint venture arrangements, such as that being sought by Ahlstrom with ThermoChem, will be employed for Europe and Scandinavian countries in order to provide for sales and service in EC and Scandinavian countries.

Similarly, cogeneration systems in the size range of 50 MW_e to 100 MW_e will be offered in EC and Scandinavian countries followed by 100 MW_e to 200 MW_e electric utility systems.

ThermoChem will continue to secure more vendor base, licensees and joint venture arrangements as it has on the early technologies to serve the new markets. In all cases ThermoChem policy is to keep manufacturing of key subsystems and high technology components in the U.S. so as to enhance our own economy.

The overall technology Commercialization Plan (Figure 3-1) is presented from the inception of the technology to its commercialization. This is intended to provide a broad perspective of the origin of the technology, the spectrum of applications for which the technology has been applied in it various embodiments and the business aspects associated with issues of manufacturing, licensing, engineering, joint ventures, own and operate opportunities, and equipment sales, etc.

At the onset of this technology development, four principal inventions initiated the activities. One invention being the pulse coal combustor concept the second being a catalytic steam reforming fluid-bed reactor, the third being the pulsed atmospheric fluid-bed combustor and, finally, the Bimodal pulse combustion island for application to coal-fired gas turbine installations.

This brings the path and history of the development of the technology up to date and places the wide spectrum of applications related to the technology in proper perspective. In particular, the status of the technology on the various application fronts is hopefully made clear by the above discussion.

The ThermoChem commercialization strategy is based on control of the manufacturing of the pulse combustor equipment. Licensing or forming joint ventures

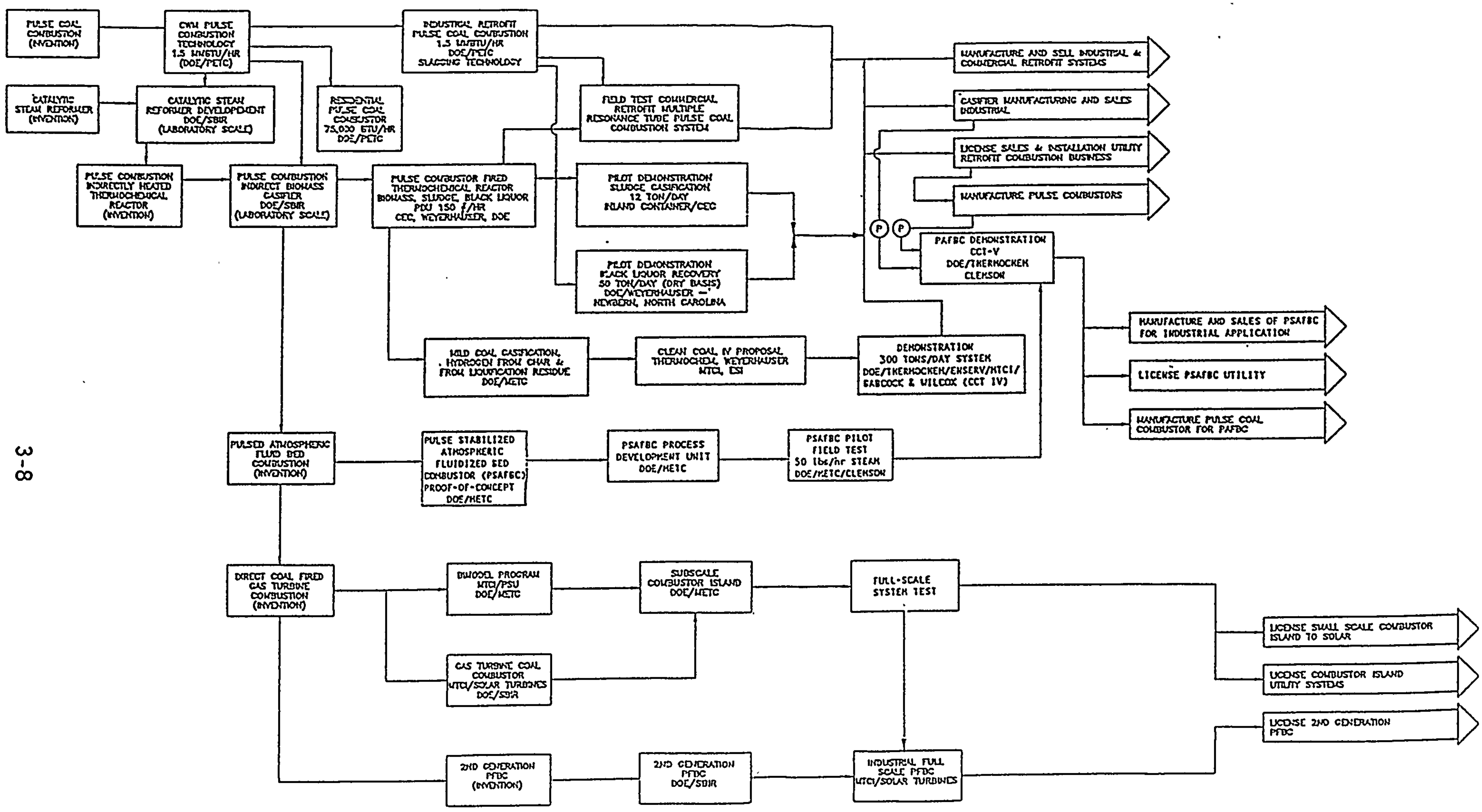


FIGURE 3-1: COMMERCIALIZATION PLAN

for the balance of plant will be employed for large equipment for utility and large industrial applications.

In addition, ThermoChem will retain the right to design manufacture and sell industrial and commercial coal fired retrofit systems in the U.S. and the export of such equipment overseas. ThermoChem will also keep the rights to gasifier manufacturing for moderate size gasification plants (up to 1000 tons/day) for black liquor recovery, paper mill sludge gasification, low rank coal steam reforming, sewage sludge gasification, etc.

Manufacture, sales and service will also be licensed, after the demonstration phase for the large utility applications but ThermoChem may retain the industrial size business.

ThermoChem employs A&E firms and vendors to undertake commercial projects. Financing is usually provided through a down payment by the end-user (35%) and progress draw against a letter of credit. If such contract is not possible, ThermoChem provides a one-time license to large A&E firms who serve as prime on such jobs in return for the A&E firm securing the financial resources for the job. Some clients prefer to finance the project and avoid using large A&E firms to reduce the overall cost capital of the undertaking.

For the smaller commercial industrial market (3-15 MMBtu/hr) for export in the near term to countries with a coal infrastructure in places Europe and perhaps China. For example, ThermoChem would license the technology for manufacture to a U.S. boiler manufacturer or enter into joint ventures with foreign firms to manufacture all but the key component (pulse combustor) abroad.

With the spectrum of business relationships, ThermoChem established since its inception in 1989 and the worldwide recognition it secured, the comprehensive strategy for the end-use products and clean Coal Technology applications will provide a major impact through the commercial deployment of this advanced equipment worldwide not only in the energy sector but also in the U.S. export of high capital cost equipment.

SECTION 4.0
CONCLUSIONS AND RECOMMENDATIONS

The system demonstration tests indicated that the pulse coal combustion system could meet all the project target goals save for the turndown. The system was unable to meet the NO_x emissions goal of 0.3 lb/MMBtu at low loads or high turndown ratios. This shortcoming is attributed to a mismatch between the original pulse combustor design specifications and the actual operating conditions during the demonstration tests. The pulse combustor was originally designed to operate in the fuel lean or superstoichiometric (~ 25% excess air) mode. Consequently, the tailpipe inlet was sized to accommodate the flow of combustion products at firing rates up to 6.5 MMBtu/hr. This full load firing rate exceeded the boiler design requirement of 5 MMBtu/hr due to the pulse combustor being water-jacketed and the need for maintaining the flue gas exit/stack temperature above the acid dewpoint. Proof-of-concept system tests, however, pointed out that NO_x emissions in the superstoichiometric mode of operation far exceeded the target goal. This required the inclusion of a reburn stage or control of primary zone stoichiometry to operate in the fuel-rich mode for controlling NO_x emissions. The reburn route was initially followed with success in achieving the target emissions goals. During this development phase, a modified coal injector was fabricated and tested as well. This demonstrated the potential for operating the pulse combustor in the substoichiometric or fuel-rich mode and in turn control the NO_x emissions.

The test results were satisfactory for operation at modest partial load (about two-thirds of full load) to full load but not at low levels (down to one-third of full load). This deficiency stems from the tailpipe inlet being much larger than that required for substoichiometric operation. The tailpipe's resonance volume was too large, especially at low loads, thereby generating a lower peak-to-peak pressure and higher backflow rate of combustion products from the tailpipe into the combustion chamber than those for a correctly sized tailpipe. This excessive backflow or low diodicity impacts combustion stability through mixture flammability, thereby improving combustor stability at substoichiometric conditions. Superstoichiometric mode of operations is therefore required at low loads to ensure stable combustion. Superstoichiometry, however, favors NO_x formation and in turn renders it difficult to meet the target goals at low loads.

Combustion was stable for substoichiometric conditions in the combustion chamber at full firing rate. This helped reduce NO_x emissions to about 0.3 lb/MMBtu without involving reburning coal feed. However, at low firing rate, it was difficult to run the unit at low stoichiometry in the primary zone and, therefore, reburning coal at a firing rate of about 16 percent of the total rate was used to reduce NO_x emissions to below 0.27 lb/MMBtu. The high sulfur coal used in the test required higher Ca/S ratio for controlling SO_2 emissions as compared to that in low sulfur coal tests. At low firing rate, gas support fraction was higher and SO_x emissions were lower at a lower Ca/S molar feed ratio (5.28). However, sulfur capture efficiency at low firing rate was lower compared with that of a high firing rate test. The sulfur capture efficiency is affected by residence time and concentration of SO_x in the flue gas. It seems that lower concentrations of SO_x at low firing rate had more of an effect than the longer residence time and resulted in lower sulfur capture efficiency. As mentioned earlier, the higher primary zone stoichiometry in the pulse combustor at low firing rate gives rise to a higher O_2 level in the flue gas. THC emissions were, as always, very low. Combustion efficiency of the system with high sulfur coal was about 99 percent. Thermal efficiency, again, was higher than 82 percent. The temperature at the baghouse inlet was stable and suggests that there was no fouling of the boiler tubes.

MTCI pulse combustors typically operate at a turndown of between 4 to 1 and 5 to 1. Based on the test results and operating experience, it is considered easy and straightforward to configure a pulse combustor to fire coal and achieve a turndown of greater than 3 to 1 while operating in the substoichiometric mode. Since the system demonstration tests have shown that NO_x emissions can be controlled to meet the target goal by fuel-rich operation in the primary zone, coal reburning is no longer required. This permits a simpler, less expensive retrofit by eliminating the reburn section.

The extent of natural gas addition is expected to vary with coal type and coal fineness. The finer the coal and the more volatile it is, the less the projected requirement for support gas. The nominal requirement (for combustion stability) for support gas is projected to be about 10 percent of the firing rate with a ± 5 percent deviation about the mean depending on coal volatility and coal fineness. The space requirement for retrofitting the pulse combustion system (air plenum, pulse combustor, char burnout section, and the water recirculation pump) with the boiler is projected to be about 6′ x 8′ (floor area) by 20′ height.

The calcium utilization was low in the system demonstration tests primarily due to the relatively large size of sorbent particles (67% by weight greater than 150 ppm diameter). The calcium utilization can be significantly improved by either feeding a much finer grind sorbent or scrubbing downstream of the boiler but upstream of the baghouse.

The pulse combustor typically operated in the self-aspirating mode and produced a pressure boost of between 5 and 10 inches of water. This reduces the fan power requirement.

Fouling of fire tubes was not apparent and this is attributed to the pulsations induced in the flow by the pulse combustor. This eliminates the need for soot blowers common in conventional coal-fired boilers.

Coal firing or a switch to coal from gas or oil does not derate the boiler in the case of pulse combustor integration but up rates the boiler due to the additional steam generated in the pulse combustor water jacket.

In view of the modified configuration provided in Section 2.4, the economic evaluation and the steam cost model calculations were revised. However, pulverized coal may not be available in many of the potential market areas overseas. Either the system would then have to include a pulverized or the user would have to pay a premium to obtain pulverized coal. The differential fuel cost for breakeven ranges between \$4 and \$4.50 suggests that many countries in Europe and the Far East would be possible candidates for this technology even though the costs are excessive for the U.S. market. Of course, the system proposed here is a high-end system with top-of-the-line controls and sophisticated feed systems. The capital cost could be significantly reduced by simplifying the instrumentation and controls, substituting a blower for the electric air compressor, and fabricating/acquiring components (except pulse combustor) overseas. Consequently, the potential exists for marketing this technology abroad if engineering and fabrication are tied to the local demands and market drivers.

REFERENCES

1. EIA, Annual Energy Review 1986, DOE/EIA-0384(86), May 1987.

2. Marley, R.C., "Trends in Industrial Use of Energy," *Science*, Vol. 226, December 1984.

3. Annual Energy Outlook 1993 with Projections to 2010, DOE/EIA-0383(93), Energy Information Administration, Washington, DC, January 1993.

4. Burns and Roe, Market and Equipment Performance Analysis for the Application of Coal-Based Fuels/Advanced Combustion Systems, Volume A, DE-AC22-84PC72571, May 1986.

5. Gyorke, D.F., L.A. Ruth, M.N. Mansour, and R.W. Breault, "Demonstration of Commercial-Scale Coal-Fired Advanced Combustion Systems," presented at the 84th Annual Meeting and Exhibition of the Air and Waste Management Association, Vancouver, British Columbia, Canada, June 16-21, 1991.

6. Mansour, M.N., R.R. Chandran, J.N. Duqum, S. Shekarchi, K. Durai-Swamy, and D.F. Gyorke, "Development of a Pulse Coal Combustor for Industrial Retrofit Applications," Proc. Sixth Annual Coal Preparation, Utilization, and Environmental Control Contractors Conference, Pittsburgh, Pennsylvania, August 6-9, 1990, p. 118.

7. ASHRAE Handbook of Fundamentals, Chapter 21, American Society of Heating, Refrigerating, and Air-Conditioning Engineers, Inc., New York, 1976.

8. "Development of a Pulse Coal Combustor for Industrial Applications: Phase I Final Report," Manufacturing and Technology Conversion International, Inc. under Contract No. DE-AC22-87PC79654 with the U.S. Department of Energy, Pittsburgh Energy Technology Center, 1990.

9. "Development of a Coal-Fired Pulse Combustor for Residential Space Heating: Final Report," Manufacturing and Technology Conversion International, Inc. under Contract No. DE-AC22-86PC90278 with the U.S. Department of Energy, Pittsburgh Energy Technology Center, 1991.

10. "Development of a Pulse Coal Combustor for Industrial Applications: Phase IA Final Report," Manufacturing and Technology Conversion International, Inc. under Contract No. DE-AC22-87PC79654 with the U.S. Department of Energy, Pittsburgh Energy Technology Center, 1990.

11. International Energy Annual 1991, DOE/EIA-0219 (91), Energy Information Administration, Washington, DC, December 1992.

12. Perry, R.H. and D.W. Green, <u>Chemical Engineering Handbook</u>, McGraw-Hill Book Company, New York, 1984.