INDUSTRIAL POLLUTION CONTROL: 1993 PERFORMANCE UPDATE OF THE RECOVERY SCRUBBER

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ABSTRACT

A cement plant application of the Passamaquoddy Technology Recovery Scrubber™ pollution control process, an Innovative Clean Coal Technology Program project, began initial operation at the Dragon Products Company Inc. plant in Thomaston, Maine in December, 1990. During 1991 and 1992 several changes were made to improve on-line time and system reliability. Performance of the system, now in full time operation, is discussed. Results of flue gas scrubbing and waste reclamation are given. Changes that have been made, and their impact on system reliability are explained.

Marketing efforts and potential future applications are reviewed.

OVERVIEW

The Project

Information on the project goals, participants, location, cost, duration, and disposition is given in Appendix A, BASIC PROJECT INFORMATION.

The Technology

The Recovery Scrubber process was selected as part of Round 2, Innovative Clean Coal Technology Program. It is a wet flue gas desulfurization process that uses waste (fly ash, cement kiln dust, incinerator ash, biomass ash) as the chemical scrubbing reagent. Useful by-products that minimize or eliminate the need for landfill disposal of waste are produced by the scrubbing reaction. Tipping fees for consumption of waste produced by others, sale of useful by-products and emission credits, and "fee for service" pollution control, generally allow profitable operation of the scrubbing process.

DESCRIPTION OF THE TECHNOLOGY

General Information

Detailed description of the technology has been given elsewhere [see references at end of paper.] The following general information is provided as it relates to the current discussion.

The Recovery Scrubber process uses alkaline waste materials as scrubbing reagent. These may include fly ash, waste cement kiln dust, incinerator ash, biomass ash from wood fired systems, and other similar wastes in solid or liquid form. Use of these wastes has the advantage of providing low cost reagent and income from tipping fees for consumption of waste. It also has the advantage of reducing, or in some cases eliminating, the volume of waste that must enter a landfill, thereby conserving valuable landfill space. Figure 1. illustrates basic process flows and system components.

Chemical Reactants

The alkali metals sodium or potassium, rather than the alkaline earth metals calcium or magnesium, are used for combination with sulfur from flue gas. Because calcium sulfate is not formed there is no gypsum scaling within the scrubber and no requirement for disposal of gypsum or scrubber sludge. Sodium or potassium form soluble compounds with recovered flue gas sulfur (sulfate) or hydrochloric acid. They will not cause scaling, and both potassium sulfate and potassium chloride are highly valued marketable by-products.

Solids Recovery

Calcium present in the waste will react to form calcium carbonate (limestone) by combining with carbon dioxide from the flue gas. This results in scrubbing of carbon dioxide from the flue gas. The product, essentially limestone, makes the spent reagent useful as raw material for use in cement manufacture or as starting material for manufactured aggregate for use in asphalt or concrete, thus eliminating the need to dispose of spent material in a landfill. Both the environmental advantage and the cost advantage of producing a useful by-product rather than a waste sludge are important.

Energy Recovery

Waste heat from the flue gas being scrubbed is recovered and used in the Recovery Scrubber process. Recovery of the waste heat allows for economical recovery of the soluble alkali sulfate salts by simple evaporation of solution and crystallization of dissolved solids.

Alkalis Recovered

Recovered alkali sulfate salts are removed from the process as solid salt crystals of potassium sulfate or sodium sulfate. In situations where chloride is present in the waste used as reagent, or in the flue gas being scrubbed, the product will include potassium chloride and/or sodium chloride, or diatomic chlorine may be produced for sale if desired. The various salts produced can be separated to enhance their resale value. All of these products have resale value. Potassium sulfate has the highest value at \$200-\$240 per ton wholesale or up to \$400 per ton retail.

Installation and Operation

The scrubbing process was installed with minimal impact on the operating cement plant. It is an "end of the pipeline" retrofit process. The only interconnect to the cement plant that might have curtailed operation is the physical tie in of the flue gas handling duct, however, the tie in was made during a routine kiln shut-down with no impact on kiln operation.

The Recovery Scrubber operates as an integrated unit, therefore, all subsystems in the process were operable at the outset with the exception of the crystalline product pelletizing equipment which was not necessary for operation.

The process control system is by computer with operator interface and ability to override as necessary. The control panel and display are located on the desk of the cement plant kiln operator for his use. No additional operator is necessary.

CHANGES MADE AND SYSTEM RELIABILITY

Changes made since initial start-up have been reported before. They include tray flatness, gas distribution, solids-liquid mixing, and tray washing. Additional changes made since the last report in this forum include mist elimination and fine tuning of gas distribution. These two changes have made the largest improvement in operation and are described below.

Mist Elimination

The initial mist elimination system was of the mesh pad type. It is an effective means of droplet removal from a gas stream. As arranged in the Recovery Scrubber, however, the mesh pad could not be effectively washed. Particulate collected from the gas stream accumulated on mesh pad surfaces and eventually obstructed gas flow. Frequent shut down for cleaning was necessary. The mesh pad was replaced with a chevron type mist eliminator that was configured so that it could be continuously washed with recirculated wash water. The wash water is periodically purged and replaced with clear water to prevent build-up of particulate within the circuit.

Operating time with the mesh pad was limited to one to two weeks and occasionally as little as four days. The system would be stopped, opened, allowed to clear flue gas from process areas, and manually cleaned during a six to twelve hour shut down period.

Since installation of the chevron mist eliminators there has been no stoppage because of mist eliminator operation. There have been a few brief stoppages to clear plugged nozzles in the mist eliminator wash water delivery system. These stoppages are minor, requiring only an hour to clean or replace nozzles, and are becoming much less frequent as debris is gradually purged from the pipelines carrying wash water. Operating periods between nozzle cleanings are now on the order of three months.

Fine Tuning of Gas Distribution

As noted in previous reports [see references at end of paper], baffles were installed as a retrofit solution to inadequate gas distribution within the plenum under the tray reactor.

Initial design criteria called for differences in gas pressure not to exceed 0.1 inches of water at any point under the tray. The "as built" condition (which was not the "as designed" condition) exhibited pressure differences as large as one inch of water. Retrofit baffles were installed to redirect gas flow from areas of high pressure to areas of low pressure within the plenum. Distribution was corrected to yield differences of typically 0.25 inches or less, but with two corners where pressure remained low by as much as 0.5 inches. One brief shut down in May of 1993 was taken to install additional baffles as "fine tuning" of the gas distribution.

Prior to installation of the baffles the tray operated poorly. Flow of scrubbing slurry depends, in part, on the agitation provided by gas passing through the tray to keep slurry solids in suspension. Areas of low gas pressure provided little or no agitation of the slurry and sedimentation resulted. As tray surface was increasingly covered by sediment the operating pressure of the remaining tray increased to the point of having to stop for tray cleaning. Initially this period was a few days to a week. After installation of the baffles tray operation was markedly improved to periods of about a month. Now that "fine tuning" of the gas distribution has been accomplished the operating time exceeds three months and we are continuing. Additional adjustment may be necessary in the future if long term operation indicates any problems.

RELIABILITY

System reliaoility has improved markedly since initial start up and has changed by the largest measure since beginning operation in the spring of 1993. The project is designed for a thirty year lifetime so it is too early to give an in depth measure of reliability. Table 1, however, gives an indication of reliability as a function of percentage of time the scrubber is operating while the kiln is in operation, and as a percentage of waste cement kiln dust that no longer goes to landfill disposal.

TABLE 1

SYSTEM RELIABILITY

Performance Since Spring 1993 Start Up

Month	% On Line Time*	% of CKD Not Wasted**	Comments
April	65.0 % (100% cleaning time)	57.0	Scrubber did not start up until April 14th. Cleaning took place April 21 to 26.
May	78.6	85.5	Kiln down for kiln support repair. Cement plant raw material storage tank down, forcing scrubber off line to await repairs. Start fine tuning of baffles for gas flow distribution.
June	80.0	90.5	Finish fine tuning of baffles for gas flow distribution. Kiln down for trunion repair.
July 1-18th (to date)	95.9	96	-

* Percentage of time both kiln and Recovery Scrubber are in operation. Scrubber may be off-line because of kiln operating conditions.
** Percent of CKD returned to the cement plant. This is all CKD not going to landfill disposal.

SCRUBBING AND WASTE RECLAMATION

Scrubbing

On line continuous monitors measure sulfur dioxide and nitrogen oxides on the inlet and outlet of the scrubbing system. Long term removal efficiency is 90 to 92 percent. If input sulfur dioxide concentration is below 50 ppm the indicated removal efficiency is below 90 percent. This is instrument inaccuracy rather than a real drop in scrubbing efficiency. For input levels above 100 ppm the observed removal is in the 92 to 95 percent range.

Nitrogen oxides are impacted by the scrubber to the extent of 5 to 15 percent removal. The removal is NO_2 rather than NO, and removal percentage changes as kiln burning conditions change.

Carbon dioxide is removed to the extent there is calcium sulfate or calcium oxide present that can be converted into calcium carbonate. For the cement plant this is 1 to 3 percent of the flue gas CO_2. For coal or oil fired boilers CO_2 removal would typically be in the 10 to 12 percent range.

Scrubber impact on volatile organics will be tested during August and September, 1993 by the U.S. EPA and separately by an independent laboratory for Passamaquoddy Technology L.P. Results can be reported during the Third Annual Clean Coal Technology Symposium.

Particulate emissions are very low. The methods used in this process for gas liquid contact and mist elimination both lend themselves to low particulate emissions. Stack tests for State compliance will be re-run in September, 1993 to verify current performance. Past testing showed emission levels below 0.006 grains/dscf. Current levels are expected to be lower by a factor of two or three, that is, 0.002 to 0.003. This compares very favorably with the both the current BIF regulation of 0.08 grains per dscf, and the proposed new standard of 0.015 grains/dscf.

Waste Reclamation

Reclamation of CKD, fly ash, and biomass ash are discussed in the following section. CKD is currently processed on a continuing basis. Fly ash will begin entering the system in August, and biomass ash in September or October. All of these wastes can be processed to provide benefit to both the cement plant and the waste generator.

Cement Kiln Dust

Cement kiln dust (CKD) is consumed at the rate it is produced by the cement plant, typically 100 to 250 tons per day. For CKD to be useful, and more importantly not detrimental, as raw material feed to the cement plant there are two primary requirements. First is that potassium (or in other plants potassium or sodium) present in the waste be removed so that it does not become part of the cement. This typically requires that potassium content in the waste be reduced to those levels found in normal raw material. It is permissible, however, for renovated CKD to have somewhat higher potassium levels because it usually constitutes a minor portion of the total feed. The second requirement is that sulfate levels in the waste be reduced before it is returned as raw feed. This is not an absolute requirement as sulfate is always added to cement during the finish grinding process. Table 2 gives analyses for treated CKD for comparison with normal raw feed and raw feed composed, in part, of renovated CKD.

Table 2
Comparison of Renovated CKD, Type 1 Raw Material, and New Raw Material Containing Renovated CKD

Oxide	Reacted CKD	Type 1 Normal Raw Material Typical	Type 1 Raw Material (90%) Combined With Processed CKD (10%)
SiO_2	10.30	14.0	13.63
Al_2O_3	3.48	3.7	3.68
Fe_2O_3	1.69	1.6	1.61
CaO	39.80	44.8	44.30
MgO	2.84	3.0	2.98
SO_3	4.38	0.3	0.71
K_2O	2.21	1.1	1.21
Na_2O	0.37	0.4	0.39
Loss on Ignit.	33.61	35.0	34.86

Raw feed for a cement plant is made by inter-grinding a variety of raw materials in proportions that will yield a specified combination. As shown in Table 2 there are minor differences in feed prepared from treated CKD and normal raw feed. The differences, however, are small and are easily corrected by slight changes in the rate of addition of one or more of the mix components entering the raw material preparation process. Silica, for example is low by 0.37 percent. Increasing the rate of sand addition to the raw material grinding mill will correct the deficiency. Similarly limestone is low by 0.5 percent. Addition of limestone, in this case by 0.35 tons per hour in a 100 ton per hour system, will bring CaO into spec.

The result of CKD renovation is that feed prepared from processed material is entirely acceptable in cement manufacture.

<u>Fly Ash</u>

Fly ash from a coal and wood bark fired boiler will begin entering the system in August, 1993. The composition of the fly ash is very different from that required in cement manufacture. It is high in silica and alumina, low in calcium, and high in potassium. Use of the scrubbing process allows removal and recovery of the potassium without discharge to the environment. The fly ash, therefore, becomes a new silica source for the cement plant. Tipping fees received by the cement plant, based on the silica requirement for cement production, can be several million dollars per year. Savings for the fly ash generator are of similar magnitude, a win - win solution.

<u>Biomass Ash</u>

Biomass ash from a wood waste fired boiler will begin entering the system in September or October, 1993 if the current schedule holds. The ash currently costs more than $50 per ton to dispose in a landfill, and continues to carry an unknown future liability. For the cement plant it will be a source of potassium for by-product production and a source of calcium, silica, and iron for addition to the cement plant raw material preparation system.

MARKET POTENTIAL

The market potential for this technology is quite large. Because the process will frequently operate at a profit it will, in many cases, be the lowest cost means of pollution control available. It is applicable to a variety of fossil fuel or waste fired facilities and can impact a number of industries including cement, power, paper, waste incineration, and heavy manufacturing. The most immediate market is likely to be the cement industry, although applications in pulp and paper and utility boilers are currently under evaluation.

As developers of Clean Coal Technology Projects are aware, marketing a new technology is a slow process. All of the concerns about new technology, reliability, energy costs, long term wear or corrosion, etc. apply. These concerns are compounded by the current state of the U.S. and World economy. There are no solutions to these concerns, except to be a proven and ready technology if and when industries are impacted by the need for pollution control or the high cost of fuel.

Our efforts have centered on the U.S. and Canadian markets, but we have expended considerable effort in Europe and the new nations of Eastern Europe as well as in the Mid-East. We have provided detailed evaluations for, and visited most of, 31 industrial facilities where the Recovery Scrubber process is applicable. Our expectation is that these efforts will begin to bear fruit by year's end.

APPENDIX A

BASIC PROJECT INFORMATION

The Project Participants

The project participants are:

- The U.S. Department of Energy, Pittsburgh Energy Technology Center;

- Passamaquoddy Technology L.P., owner of the technology;

- Dragon Products Company Inc., a subsidiary of CDN U.S.A. and the host site providing partial funding of the installation.

Goals of the Project

Project goals were to design; build; operate and demonstrate the new Recovery Scrubber technology on a coal fired wet process cement manufacturing kiln; to eliminate landfilling of waste cement kiln dust, a waste product of cement manufacture; and to significantly reduce emission of flue gas sulfur dioxide from combustion of coal. Further goals are to assess the environmental and economic performance of the process.

Location

The project is located in Thomaston, Maine at the Dragon Products Company Inc. cement plant which is owned by CDN U.S.A. The area is a scenic Maine coastal town, heavily dependent on tourist trade and on remaining a scenic coastal community, where control of environmental pollution is of vital interest to both the State of Maine and local residents. The host plant is also located up wind from a Class 1 area in Acadia National Park and is regulated accordingly.

Project Cost

The project is currently in Phase III, the Operating Phase, and will continue in the Operating Phase for 2 months. Final project cost is, therefore, not yet available. The cost to date is approximately $17 million. Total cost will exceed $17 million when all project related costs associated with the operating period and final report are determined.

Project Duration

Construction began in April of 1990 (earthwork related to clearing the site began in the fall of 1989). The process was first operated nine months later on December 21, 1990. After system debugging and process modifications the operating period began on August 20, 1991 and will run for a period of 13 operating months. The operating period will include only that time during which the system is actually in operation. The cement plant has been shut down for several long, and several short, maintenance or inventory plant outages. Therefore completion of the operating period will require more than 13 consecutive calendar months.

Project Disposition

After completion of Phase III the project will continue to be operated by Dragon Products Company Inc. as the waste cement kiln dust and sulfur dioxide control system.

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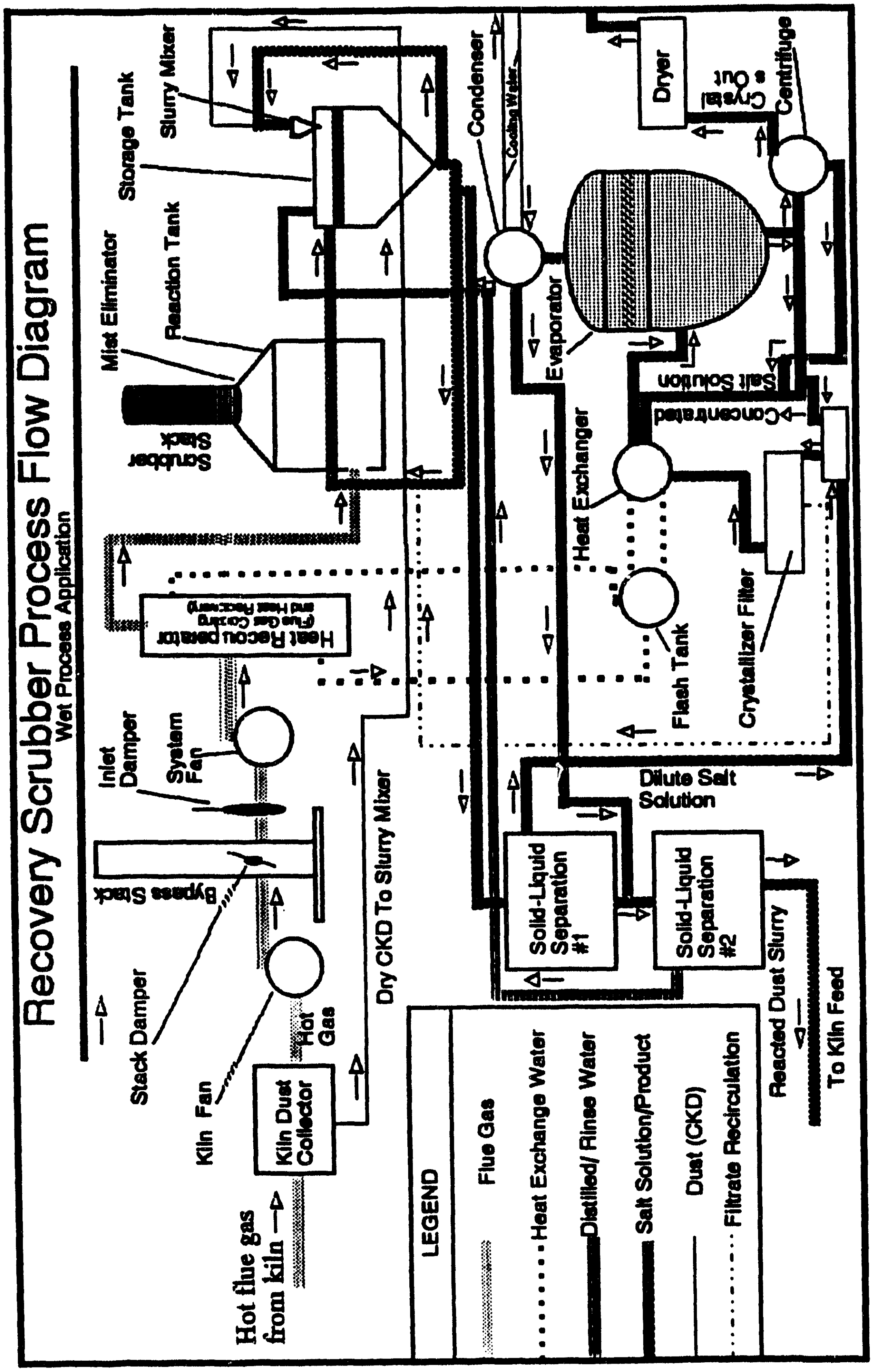
Recovery Scrubber Process Flow Diagram
Wet Process Application
Hot flue gas from kiln
Kiln Dust Collector
Kiln Fan
Hot Gas
Stack Damper
Bypass Stack
Inlet Damper
System Fan
Heat Recuperator
(Flue Gas Cooling and Heat Recovery)
Dry CKD To Slurry Mixer
Scrubber Stack
Mist Eliminator
Reaction Tank
Storage Tank
Slurry Mixer
Condenser
Cooling Water
Evaporator
Heat Exchanger
Flash Tank
Crystallizer Filter
Concentrated Salt Solution
Crystal s Out
Dryer
Centrifuge
Dilute Salt Solution
Solid-Liquid Separation #1
Solid-Liquid Separation #2
Reacted Dust Slurry
To Kiln Feed
LEGEND
Flue Gas
Heat Exchange Water
Distilled/ Rinse Water
Salt Solution/Product
Dust (CKD)
Filtrate Recirculation

Figure 1

PAPER TO BE PRESENTED AT THE

SECOND ANNUAL CLEAN COAL TECHNOLOGY CONFERENCE

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STATUS OF THE DEMONSTRATION OF PULSE COMBUSTION IN STEAM GASIFICATION

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ABSTRACT

ThermoChem's Clean Coal Technology project is a unique gasification process that uses indirect heating by combustion tubes immersed in a fluidized bed producing medium-Btu gas without needing an oxygen plant.

The concept of using pulse combustion tubes as an indirect heat source was developed by Manufacturing Technology Conversion International, Inc. (MTCI), who have licensed the technology to ThermoChem.

MTCI has completed a successful field testing of the pulse indirect heater (72-tube bundle) in a pulp and paper mill sludge/rejects gasification at Inland Container Corporation, Ontario, California in 1992. There is another field testing project of the pulsed indirect heater well underway in a distillery effluent treatment application aiming at zero-discharge by Esvin Tech, in Tamil Nadu, India. A third field testing of a three-heater (each with 72-tubes) fluid bed system for black liquor recovery is in the final stages of construction at a Weyerhaeuser paper mill in New Bern, North Carolina.

The proposed Clean Coal project is a scale-up of the pulse heater from 72-tubes to 252-tubes each. The Clean Coal gasifier would have 8 to 10 heater bundles to handle 300 T/D of dry coal.

Because of the large potential market for the ThermoChem process for the pulp and paper industry, the project was originally planned to the located in a Weyerhaeuser paper mill in Springfield, Oregon. After the project was selected under the Clean Coal Fourth round, ThermoChem requested DOE to move the project to the Caballo Rojo Coal mine site in Gillette, Wyoming to supply gas and steam

for "K-Fuel," coal-upgrading plant that would be built by Enserv, Inc., an affiliate of Wisconsin Power & Light.

The K-Fuel process upgrades low-rank coals producing a high Btu containing solid fuel called "K-Fuel" (to be substituted in power stations as low sulfur coal), and also generates wastewater and off-gas both of which need to be treated before discharge. The ThermoChem gasifier can not only use K-Fuel wastewater and off-gas, but it can gasify the fine coal that is not marketable or usable by the K-Fuel plant.

A preliminary test using K-Fuel effluent water and Caballo Rojo Coal fines was done in 1992 in MTCI's laboratory-scale gasifier facility in Santa Fe Springs, California at 20 lb/hr. This test showed that the organics in the K-Fuel effluent could be destroyed in the MTCI gasifier. Further testing in a larger facility (1,000 lb/hr) at Baltimore, Maryland is being planned for design verification of the process chemistry. A 252-tube bundle will be built and tested as part of the design verification in 1993.

PURPOSE OF TESTING

The purpose of the test run utilizing MTCI's gasifier facilities in Santa Fe Springs, California was to establish the following:

1. Efficient of the gasifier in destroying the organics found in the K-Fuels heat 2 water.

2. Produce gasifier char utilizing Caballo Rojo coal fines.

Detailed engineering of the demonstration facility will be completed by early 1994.

MTCI/THERMOCHEM BIOMASS STEAM REFORMING TECHNOLOGY

Manufacturing and Technology Conversion International, Inc. (MTCI) is an energy conversion and environmental control development company focusing upon the development of innovative technology applications based upon the phenomenon of pulsating combustion. Generally speaking, combustion instabilities are not only undesirable from both performance and environmental considerations, but can result in mechanical failures in the combustor or the furnace (boiler).

Over the years, many attempts have been made to harness those pulsations for a variety of applications. Many failed, a few were successful from the standpoint of performance but could not compete favorably in the marketplace. Some, primarily gas-fired home heating units, are available today but sales have been very sluggish in comparison to standard home heating systems.

About eight years ago, MTCI came to the realization that these combustion instabilities could provide many benefits when converted into well behaved oscillations. The company envisioned a host of applications for "stable" pulsating combustors; at first for clean and effective coal combustion, then for indirectly heated gasification systems and coal-fired fluid-bed combustors and finally for environmental control devices primarily aimed at coal-fired power plants.

In the following discussion, I will spend the first few minutes discussing pulse combustion and the performance and environmental benefits that can be derived therefrom. The rest of the discussion will be aimed at the specific applications available and finally to product improvements and development work now in progress.

PRINCIPLES AND BENEFITS OF PULSE COMBUSTION

The process of pulse combustion results from combustion-induced flow oscillations that are intentionally incorporated in combustor design to achieve process and system advantages for various combustion and gasification applications. The benefits accruing from controlled combustor oscillations are enhanced heat release rates (compact equipment), mass transfer rates (higher reaction rates, yields), heat transfer rates (indirectly fired heat exchangers), and the ability to develop a pressure boost that aids in reducing parasitic forced and induced draft fan power. The process has ancillary environmental benefits in drying applications, ash agglomeration, enhanced sulfur capture by dry sorbents, soot blowing and filter/baghouse cleaning.

The pulse combustor type used by the MTCI and ThermoChem equipment design is based on the Helmholtz configuration (Figure 1). The basic configuration consists of an aerodynamic air inlet valve (fluidic diode), a combustion chamber, and a tailpipe (or resonance tube). The combustion chamber and the resonance tube comprise a Helmholtz enclosure having a quarter-wave resonant frequency. There are no moving parts (flapper valves) thereby making it ideal for coal combustion as well as for other solid, gaseous and liquid fuels. The selection of this configuration was made primarily because of its excellent suitability and reliability for coal burning.

In conventional coal burners (cyclone, vortex, bluff body, etc.) combustion efficiency is highly dependent on the flow pattern and the extent of the relative motion between the burning coal particle and the surrounding gases. As the coal particles burn, they become smaller and increasingly ash-laden (char) while oxygen concentrations are decreasing. Oxygen diffusion from the surrounding gas to the burning ash-laden char particles also decreases requiring additional residence time and turbulence to achieve higher carbon burnout. This is caused by a boundary layer of products of combustion (CO_2 and CO) forming a diffusion barrier between the oxygen and the smaller ash-laden coal particle. The entrainment prone nature of small particles, as carbon depletes from the burning coal particle, prevents significant relative motion between the particle and the surrounding gases,requiring the expenditure of high levels of parasitic power to create the flow patterns and forces necessary to drive the combustion process to completion.

In pulse combustion, the oscillating flow field, itself, provides high oscillatory relative motion between the burning coal particles and the surrounding gases. The boundary layer formed by the products of combustion, leaving the burning particle, is quickly swept away leaving little to no diffusion barrier as an impediment for oxygen reaching the burning coal particle. The reaction rate is, therefore, essentially kinetically limited rather than diffusion limited. Heat release rates can reach as high as 6 MMBtu/hr.cu.ft., more than an order of magnitude higher than in conventional combustion processes. This renders pulse combustors very compact and lower in capital cost. Combustion of standard grind pulverized coal has been achieved in 30 to 40 ms. In conventional coal burners, residence times in the order of ½ to 1½ seconds are required.

In conventional combustor and fire tubes arrangements, essentially all the heat is released by burning the fuel in the combustor. The heat is stored in the form of sensible heat in the flue gas which is at its peak temperature at the inlet to the fire tubes. This requires the use of a high-temperature material at the inlet region of the fire tube. As the heat is transferred from the flue gas through the fire tubes, the temperature of the flue gas monotonically decreases along the length of the tube. In this case most of the heat transfer on the flue gas side of the tube is convective. Radiant heat transfer may take place near the fire tube inlet if the gas is hot enough to be significantly radiant. In pulse combustion, however, not all the fuel burns in the combustion chamber but combustion persists down the resonance tubes (fire tubes) for a significant length in an oscillating flow field environment. Thus, for the same heat transfer duty, the inlet flue gas temperature to the resonance tubes is lower than in the case of conventional fire-tube systems, but the continued heat release from burning fuel in the resonance tubes maintains a higher bulk flue gas temperature than in the conventional case. Radiant heat transfer will also maintain to a longer length on the flue gas side of the resonance tube. In addition to the enhanced radiant heat transfer component along the resonance tube, a large enhancement in the convective heat transfer component is also achieved due to the oscillatory flow field of the gases. The enhancement in connective heat transfer results from an increase in both the average velocity (caused by the combustion-induced pressure boost), and the superimposed oscillatory velocity component (scrubbing of the boundary layer).

Figure 2 represents experimental heat transfer data obtained on a gasifier combustor heat exchanger. The figure represents a comparison of experimental data with theoretical non-pulsating flow values. Actual enhancement of the heat transfer coefficient was about 3 to 5 times higher than that achieved by similar indirectly heated systems.

An important benefit of enhanced heat transfer rate is the ability of the reactor to support highly endothermic reactions such as the carbon-steam reaction. Rapid heat transfer to the fluidized bed material being processed results in very high rates of devolatilization and pyrolysis. This, in turn, results in the formation of char particles that are extremely porous with high reactivity. Steam reacts with the char to provide a synthesis gas mixture containing H_2 and CO. Devolatilization and gasification reactions are highly endothermic reactions. High heat transfer rates are therefore essential to support such endothermic reactions in an economically viable reactor with a reasonable throughput.

Pulse coal combustors, properly designed, have been established to be low NO_x generators. NO_x levels as low as 83 ppm (@ 3% O_2 in the flue) have been achieved by MTCI in pulse combustion of coal and in the 10-25 range when fired with natural or synthetic gases. There are a number of combustion process related characteristics of pulse combustion that are relevant to NO_x production. The rate of combustion in these devices is sufficiently high, with short residence times, such that NO_x formation is reduced. NO_x formation is endothermic with limited kinetic rates and hence the shorter the residence time, the less NO_x formation during the combustion process. The pulse combustion process inherently contains both flue gas recirculation and reburn characteristics. During a portion of the cycle of the pulse combustor, flue gas returns to the combustion chamber from the resonance tube mixing with the fuel and air prior to ignition by the hot combustion chamber inner surfaces to trigger the next portion of the combustion cycle.

The equivalent of reburn is caused by the burning of particles after they leave the combustion chamber. Measurements of temperature profiles along the combustor length suggested that 15 to 25 percent of the heat release takes place in the tailpipe. The flow environment in the tailpipe is also oscillatory providing an intense mixing during the reburn portion of the process, leading to further reductions in NO_x formed from both fuel-bound nitrogen and thermal sources in the combustion chamber. Figure 3 gives the NO_x levels obtained in the 72-tube pulse combustor.

PULSE COMBUSTION APPLICATIONS

The following discussion addresses the hardware and technology applications based upon the essential principles of pulsed coal combustion. A summary of the related MTCI pulse combustion-based technology is provided in Table 1. For each application cited, process data and/or hardware has been successfully acquired and operated. The presentation is intended to provide a perspective that relates to the available technology data base and equipment maturity.

Indirectly Heated Thermochemical Reactor and Processes

This technology is comprised of a fluid-bed reactor that is indirectly heated by a heat exchanger that is comprised of the multiple resonance tubes of a pulsating combustor as shown in Figures 4 and 5. In this design the multiple pulse combustor resonance tube heat exchanger is fired with a portion of the product gas produced in the fluid-bed reactor or other fuel available. The module has multiple aerodynamic valves.

The reactor is employed for a number of patented endothermic processes that are also listed in the table. The status of the technology is as follows. A commercially configured, full-scale heater module (5-8 MMBtu/hr) powering a 12-tons/day fluid-bed reactor (40 ft^2) has been built, tested and demonstrated at the MTCI facility in Santa Fe Springs, California (Figure 6). This is a pilot unit that can be used at the facility for feedstock characterization, yield optimization and other system parameter information.

A smaller process development unit, 30-100 lbs/hr is also available at the Santa Fe Springs facility. This unit is primarily used for initial process development and characterization (all input and output streams).

A 17 ton/day gasification unit has been installed at the Inland Container Corporation facility at Ontario, California. This unit has been in operation since March 1992 and a long-term system test was conducted in July 1992. The system processes an industrial recycle paper mill sludge containing 50 percent solids, fiber rejects with plastic and old corrugated container lights (OCC). A photo of the system in operation is provided in Figure 7. Tables 2 - 5 present the operating parameters for a 500-hour test on this unit. This unit was modified to process black liquor and was tested at Inland with liquor trucked from the Simpson-Samoa mill. After these successful field tests, this heater development unit was moved to MTCI's Baltimore, Maryland facility. NRELsponsored straw or grass and woody biomass gasification tests and NSSC sulfite liquor tests for MEAD Container Board are planned for October 1993.

In addition, a 50 ton/day expandable to approximately 100 tons/day with the addition of two additional heat exchanger modules is being assembled at Weyerhaeuser's paper mill in New Bern, North Carolina (Figure 8). This unit processes black liquor from the pulping process, recovering energy from the lignin in the spent pulping liquor as well as process chemicals (sulfur and sodium) for reuse in the pulping process. A similar unit is now in operation for a bagasse-based spent liquor recovery process at an SPB pulp mill in Erode, Tamilnadu, India.

For coal gasification, ThermoChem, an MTCI licensee of the gasification technology, has been selected to negotiate a Clean Coal IV Demonstration Project utilizing the MTCI indirectly heated gasifier. The cost of the project, $42,000,000, will be provided by the U.S. Department of Energy ($18,700,000) and Enserv ($23,300,000). Enserv is a subsidiary of the Wisconsin Power and Light Company. The gasifier, sized at approximately 300 dry tons/day of subbituminous coal will be located at the Caballo Rojo coal mine in Gillette, Wyoming and is intended to provide a product gas for electricity generation from boilers with the waste heat from the gasifier producing a high pressure (1150 psi) steam for a coal beneficiation process. The low-cost hydrocarbon-laden wastewater from the beneficiation process will also be processed in the gasifier as a source of steam for the reaction permitting recovery of the energy and sensible heat and destruction of organic toxics. An overall material and energy balance for the process is provided in Table 6. A simple schematic of the gasifier is shown in Figure 9. The tube exchanger bundles to the reactor contain over 250 tubes each for providing the endothermic heat of reaction.

The versatility of the MTCI Thermochemical reactor/gasifier for processing a wide spectrum of carbonaceous materials can be derived from Tables 7 and 8. A generalized schematic of the process is shown in Figure 10. Table 3 provides test data from lignite, subbituminous coal (Black Thunder, BT) and char as well as for a mild gasification process designed to provide a suite of gaseous, liquid and solid fuel products. Table 4 provides data for a variety of biomass and waste materials including Refuse Derived Fuel (RDF) and municipal wastewater sludge. Table 9 indicates the levels of dioxin and furan reductions achieved in the gasification of chlorine biomass wastes. The tests were conducted with a paper mill waste sludge feedstock.

Figure 11 shows integration of the ThermoChem gasifier with the K-Fuels process.

A preliminary test using K-Fuel effluent water and Caballo Rojo coal fines was done in 1992 in MTCI's laboratory-scale gasifier facility in Santa Fe Springs, California at 20 lb/hr (Figure 12). This test showed that the organics in the K-Fuel effluent could be destroyed in the MTCI gasifier. Further testing in a larger facility (1,000 lb/hr) at Baltimore, Maryland is being planned for design verification of the process chemistry. A 252-tube bundle will be built and tested as a part of the design verification in 1993.

Purpose of Testing

The purpose of the test run utilizing MTCI's gasifier facilities in Santa Fe Springs was to establish the following:

1. Efficiency of the gasifier in destroying the organics found in the K-Fuels heat 2 water.

2. Produce gasifier char utilizing Caballo Rojo coal fines.

Test Facilities and Feedstock Coal

The test facilities included a steam generator, a gasifier vessel with ThermoChem's single-tube pulse combustor, cyclones for char collection, and a venturi scrubber for condensation of water vapor (see Figure 12).

Summary of Analytical Results

1. Based on the leaching tests, none of the chars would be considered hazardous waste by EPA.

2. The compositional analysis indicates small quantities of aromatic hydrocarbons (intermediate products of the coal gasification), and inorganic constituents normally found in coal ash.

3. Leaching tests indicate the organics found in the char are not readily leached out and the inorganics are typical of alkaline coal ash leachates.

4. Although not specifically tested, the carbon content and fineness of some of the chars would warrant design consideration to manage the dustiness and reactivity with oxygen prior to disposal.

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MTCI, "Testing of an Advanced Thermochemical Conversion System," Final Report, DE-AC06-76RLO1830, January 1990, PNL7245, UC-245.

Mansour, M.N., K. Durai-Swamy, D.W. Warren, U.S. Patent No. 5,059,404, "Indirectly Heated Thermochemical Reactor Apparatus and Process," October 22, 1991.

TABLE 1:

SUMMARY OF MTCI PULSE COMBUSTION-BASED TECHNOLOGIES AND APPLICATIONS

TECHNOLOGY	DESCRIPTION	APPLICATIONS
Indirectly heated thermochemical reactor	Multiple resonance tube gas-fired pulse combustor heating a fluid-bed thermochemical reactor	■ Biomass steam reforming ■ Low-rank coal steam reforming/gasification ■ Black liquor recovery (Pulp & Paper) ■ Mild coal gasification ■ Catalytic steam re-forming of heavy end residual hydrocarbons ■ Sewage sludge steam gasification ■ Industrial sludge processing ■ Indirect drying ■ Toxic waste to energy processing ■ Steam gasification of RDF
Pulsed Atmospheric Fluid Bed Combustor (PAFBC)	A hybrid combustion system employing a pulse coal combustor and a fluid-bed combustor	■ Clean combustion of low-quality crushed coal fuels
Tandem slagging pulse coal combustor	Two pulse combustors that operate in the slagging mode for ash rejection. The combustor operates out of phase to cancel pressure oscillations emanating from the tail-pipes in a decoupler/slag chamber	■ Industrial, oil and gas designed boiler, retrofit for clean coal firing
Multiple-resonance tube coal-fired pulse combustors	Pulse coal combustor having one or multiple aerovalves and multiple resonance tubes	■ Commercial boiler retrofit applications ■ Indirect-fired gas turbine

TABLE 2:
SUMMARY OF THE OVERALL SYSTEM OPERATION FOR TEST 500-HOUR TEST
(JULY 1992)

TOTAL HOURS FOR PULSE COMBUSTOR OPERATION:	516 Hours
TOTAL HOURS FOR SLUDGE FEEDING:	432 Hours
TOTAL WEIGHT OF SLUDGE FED:	275,730 Pounds
AVERAGE SLUDGE FEED RATE:	640 lbs/hr

TABLE 3:
TYPICAL MATERIAL FLOW SUMMARY FOR 500-HOUR TEST
(JULY 1992)

INPUT	lbs/hr	MMBtu/hr
SLUDGE FED	500 - 900	2.30 - 3.2
FEED MOISTURE (% wt.)	50% to 75%	
STEAM FOR FLUIDIZATION	1700	1.94
NATURAL GAS TO PC (based on LHV)	350 - 360	7.5 - 7.7
OUTPUT		
PRODUCT GAS	367 - 700	3.1 - 5.8
STEAM	4000	5.0
LOSSES	---	1.0 - 2.0

TABLE 4:
TYPICAL PRODUCT GAS ANALYSIS
(JULY 1992)

AVERAGE BED TEMP. (°F)	1515	1470
GAS COMPOSITION	(%V)	(%V)
H_2	34.7	44.3
CH_4	11.6	5.4
CO	22.5	18.1
CO_2	27.0	29.8
C_2	4.3	2.5

TABLE 5:
PULSE COMBUSTOR DATA
(JULY 1992)

FIRING RATE (HHV) = 8.20 - 8.45 MMBtu/hr
(LHV) = 7.4 - 7.7
FREQUENCY = 62 Hz
PEAK-TO-PEAK = 4 psi
FLUE GAS EMISSION, DRY BASIS

Conditions	#1	#2	#3
O_2 (%v/v)	1.4	1.8	0.3
CO (ppm)	23	0	97
NO_x (ppm @ 3% O_2)	25	30	32
SO_2 (ppm)	0.0	0.0	0.0

TABLE 6:

OVERALL MATERIAL AND ENERGY BALANCE FOR STEAM REFORMING OF SUBBITUMINOUS COAL

	MASS	ENTHALPY	HHV
INPUT	(lb/hr)	(KBtu/hr)	(KBtu/hr)
Coal	35,714	300,000	300,000
Process Water	52,191	31,943	6,741
Boiler Feedwater	73,929	15,007	
Vent Gases	5,582	16,486	15,094
Combustion Air	127,044	0	
TOTAL IN	294,460	363,436	321,835
OUTPUT			
Product Gas	31,250	188,352	187,834
Steam @500 psi	33,202	41,466	
Steam @ 1150 psi	49,726	64,296	
Sulfur	332	1,322	1,322
Char/Ash	2,817	16,958	16,095
Solids from Scrubber	232	1,742	1,738
Water from Venturi Scrubber	17,489	739	
Condensate from H2S Removal	1,450	48	
Flue Gas to Stack	157,916	17,766	
Heat Rejected in Cooler		24,117	
Heat Losses		6,630	
TOTAL OUT	294,414	363,436	206,989
CLOSURE, percent	100.0	100.0	

Cold Gas Efficiency 57.6 % (HHV of Gas - HHV of Vent Gas)/ HHV of Coal

Overall Thermal Efficiency 80.9 %

TABLE 7:

ANALYSIS FOR FEEDSTOCKS TESTED IN PULSE-ENHANCED INDIRECT GASIFIER

Feed Material	Lignite	Lignite	BT Coal Dir. Gasif	Char	Char	BT Coal Mild Gasif
Bed Material	Limestone	Sand	Limestone	Limestone	Sand	Char
Temperature (F)	1370	1430	1390	1456	1467	1150
Feed Rate (lb/hr, as rec'd)	15.1	7.3	16.9	24.0	24.0	90.0
Steam Rate (lb/hr)	30.6	28.3	28.3	53.5	50.5	98.4
Steam/Feed Ratio	2.03	3.88	1.67	2.23	2.10	1.09
C Gasification Eff. (%)	96.1	95.7	85.9	90.6	88.0	N/A
H_2 Yield (SCF/lb MAF Feed)	44.4	37.0	23.0	31.9	38.8	N/A
Dry Gas Composition (Vol %)						
<u>Component</u>						
H_2	69.38	62.27	55.60	53.32	56.93	33.48
CO_2	21.46	26.47	28.35	23.67	23.95	23.22
CO	6.14	8.83	12.22	21.69	17.37	8.24
CH_4	2.40	1.77	3.13	1.28	1.54	28.57
C_2H_4	0.26	0.;28	0.32	0.00	0.13	1.45
C_2H_6	0.12	0.07	0.15	0.00	0.00	1.64
C_3H_6	0.04	0.04	0.05	0.00	0.00	1.07
C_3H_8	0.01	0.00	0.00	0.00	0.00	0.38
i-Butane	0.00	0.00	0.01	0.00	0.00	[illegible]
n-Butane	0.03	0.02	0.103	0.00	0.00	0.69
Pentane	0.00	0.00	0.00	0.00	0.00	0.32
Hexane	0.00	0.00	0.00	0.00	0.00	0.44
CH_3SH	0.00	0.00	0.00	0.00	0.00	0.06
COS	0.00	0.00	0.00	0.00	0.00	0.06
Toluene	0.00	0.00	0.00	0.00	0.00	0.19
H_2S	0.16	0.26	0.14	0.04	0.08	0.19
Total	100.00	100.00	100.00	100.00	100.00	100.00
Dry Gas (SCFM)	9.7	4.4	8.8	18.8	21.4	4.7
HHV (Btu/SCF)	279.2	258.3	263.2	256.5	259.6	570.3
Carbon (lb/hr)	5.6	3.1	7.4	16.7	17.4	7.2

* Nitrogen was used as fluidizing gas for mild gasification for char production

TABLE 8:

PRODUCT GAS COMPOSITIONS AND YIELDS FOR BIOMASS TESTS CONDUCTED IN THE MTCI INDIRECTLY HEATED GASIFIER

COMPOSITION (Vol.%)	PISTACHIO SHELLS	PISTACHIO SHELLS	WOOD CHIPS	RICE HULLS	RECYCLE MILL FIBER WASTE	RECYCLED WASTE PAPER W/PLASTIC	KRAFT MILL SLUDGE	RDF SAND BED	MSW SAND BED	MSW LIMESTONE BED
H_2	37.86	35.04	48.11	42.83	38.86	50.50	52.94	45.54	55.21	54.40
CO	18.84	23.43	22.91	19.67	23.34	19.26	11.77	25.26	28.10	25.46
CO_2	28.73	25.20	20.18	24.40	23.27	20.10	21.94	14.51	5.95	5.66
CH_4	10.65	11.31	8.32	11.56	8.31	8.42	8.95	8.30	5.00	5.86
C_2	3.92	5.02	0.48	1.54	6.40	1.72	3.00	6.38	5.74	8.62
TOTAL	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
HHV	370	406	329	367	412	364	372	418	374	448
TEMP. (F)	1317	1216	1286	1326	1250	1326	1250	1450	1410	1306
YIELD (% Carbon)	94.1	92.1	93.0	N/A	86.8	N/A	56.0	83.6	93.7	83.8

TABLE 9:

FURAN/DIOXIN LEVELS IN SLUDGE FEED AND GASIFIER EFFLUENTS

	TOTAL FURAN	TCDF	2,3,7,8-TCDF	PCDF	HXCOF	HPCDF	OCDF	TOTAL DIOXIN	TCDD	2,3,7,8 TCDD	PCDD	HXCDD	HPCDD	OCDD
FEED SLUDGE	550	440	84	110	N/D	N/D	54	1543	74	33	69	580	150	670
BED MATERIAL	1.1	N/D	N/D	N/D	1.1	N/D	N/D	10.1	N/D	N/D	N/D	N/D	2.9	7.2
CYCLONE ASH	177	170	4.0	7.0	N/D	N/D	N/D	100.2	53	27	14	14	9.5	9.7
CONDEN-SATE	0.51	0.46	N/D	N/D	0.02	N/D	0.03	0.33	0.23	0.07	N/D	N/D	N/D	0.33

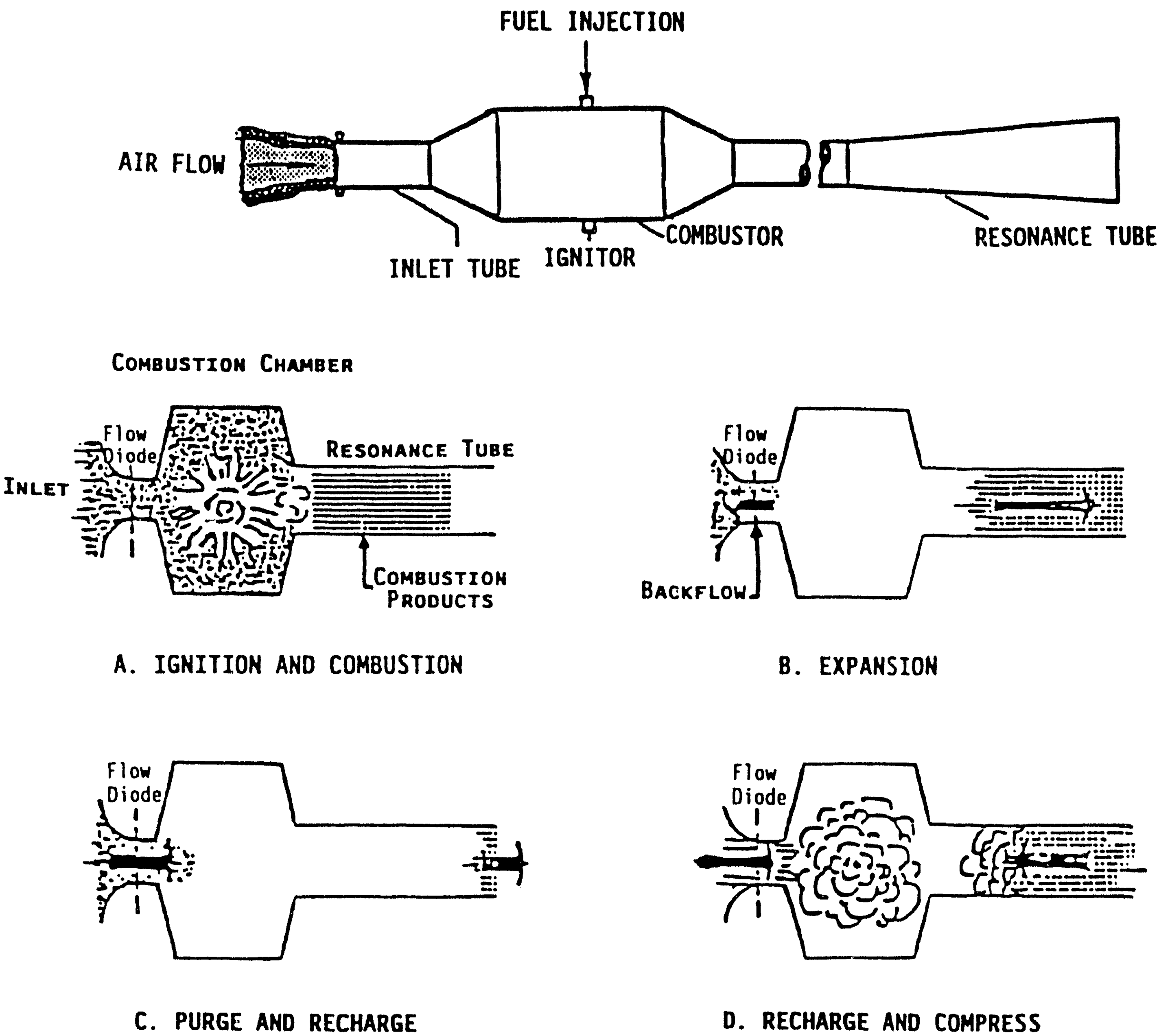

FIGURE 1: PULSE COMBUSTOR CONFIGURATION

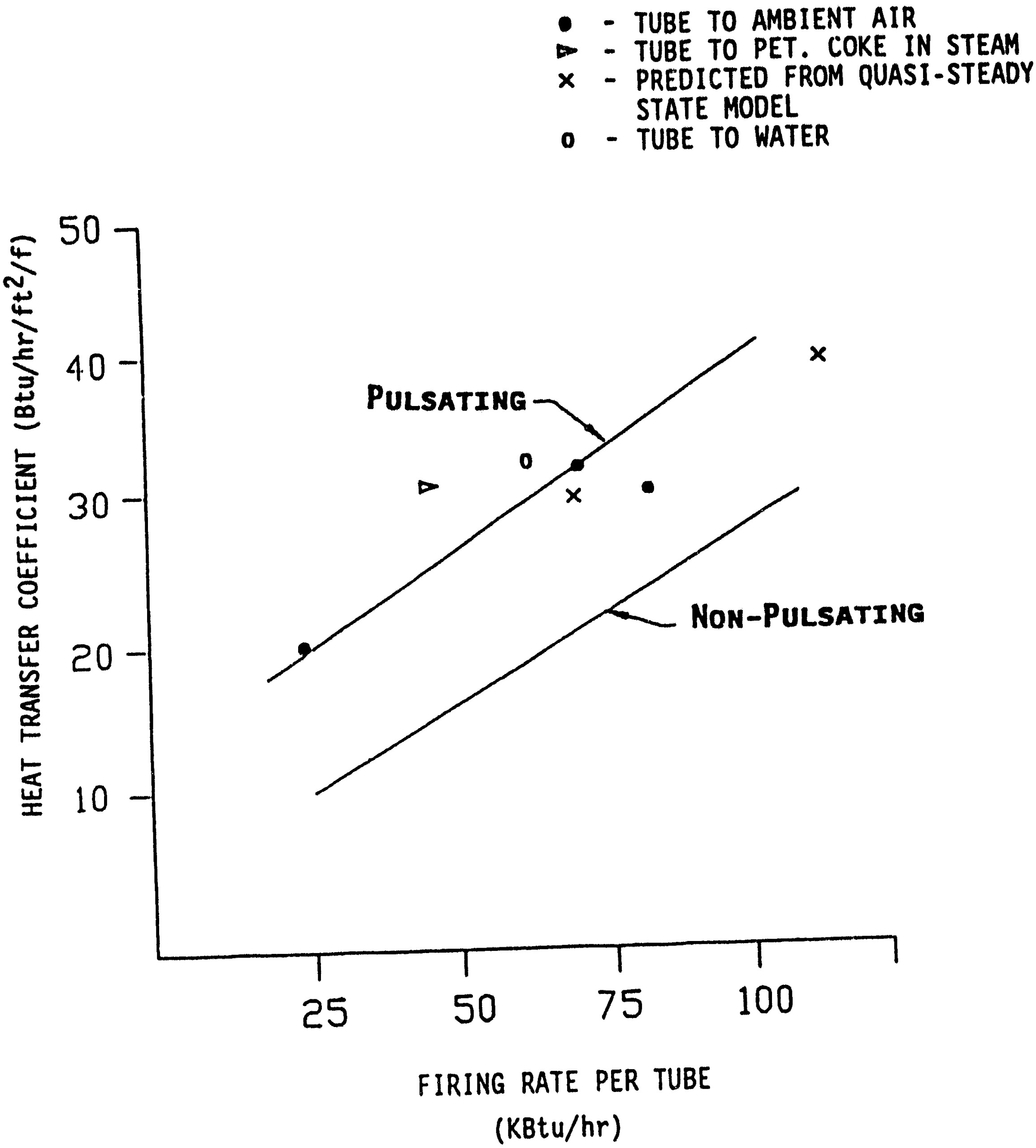

FIGURE 2: THEORETICAL HEAT TRANSFER COEFFICIENTS UNDER NON-PULSATING CONDITIONS COMPARED TO MEASURED DATA IN PULSATING FIRE TUBES

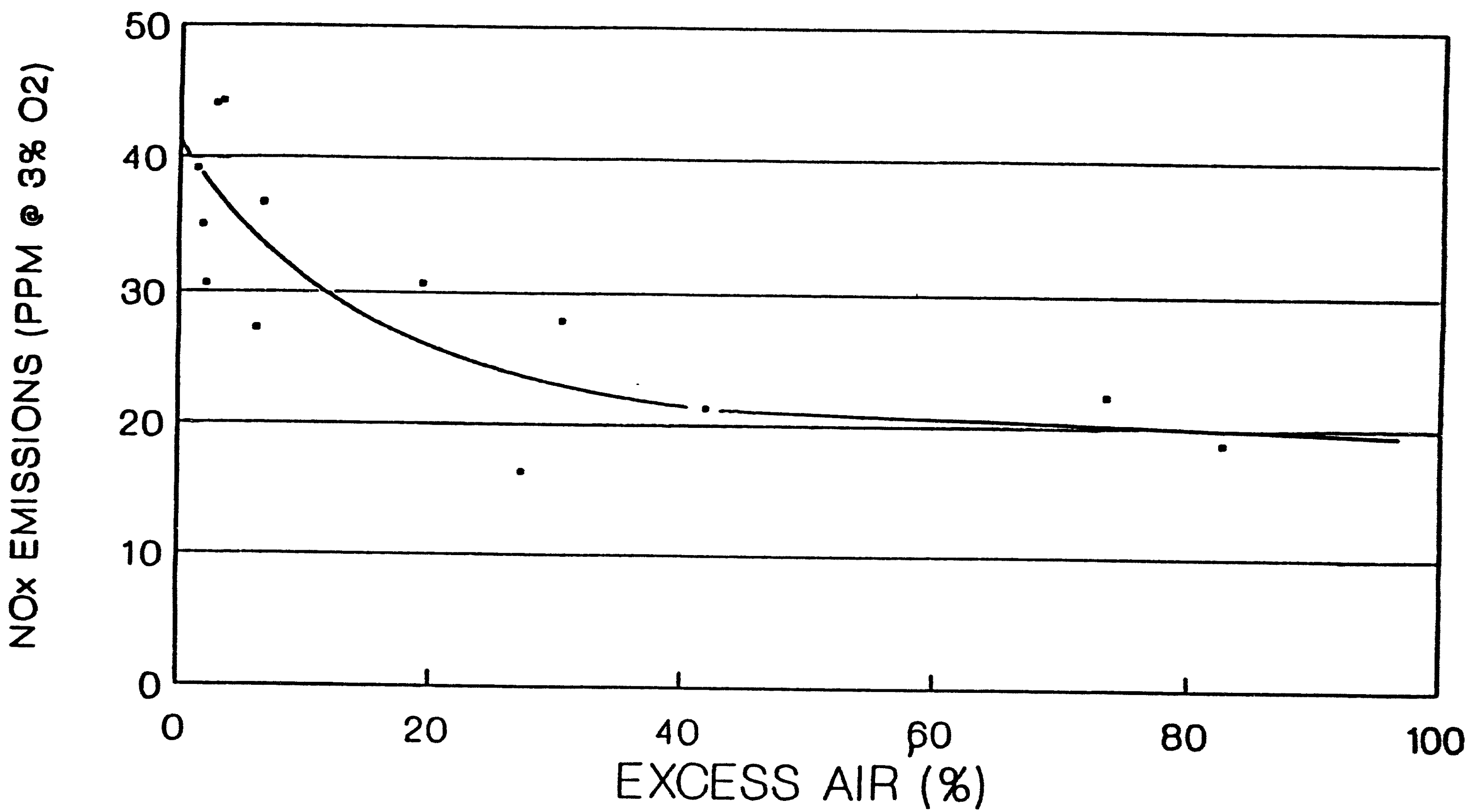

FIGURE 3: EFFECT OF STOICHIOMETRY ON NOx EMISSIONS FROM A PULSE COMBUSTOR

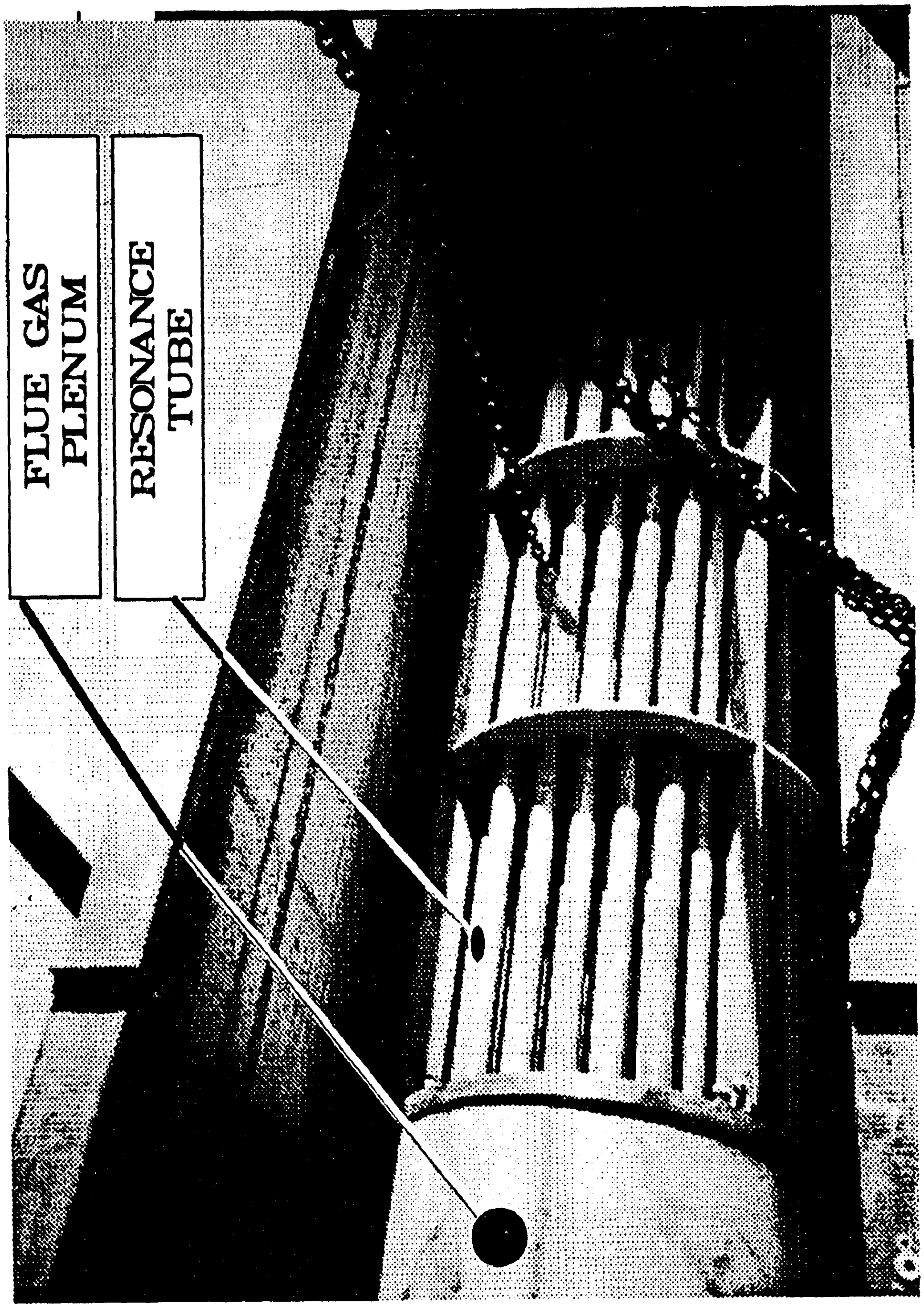

FIGURE 4: MULTIPLE RESONANCE TUBE PULSE COMBUSTOR

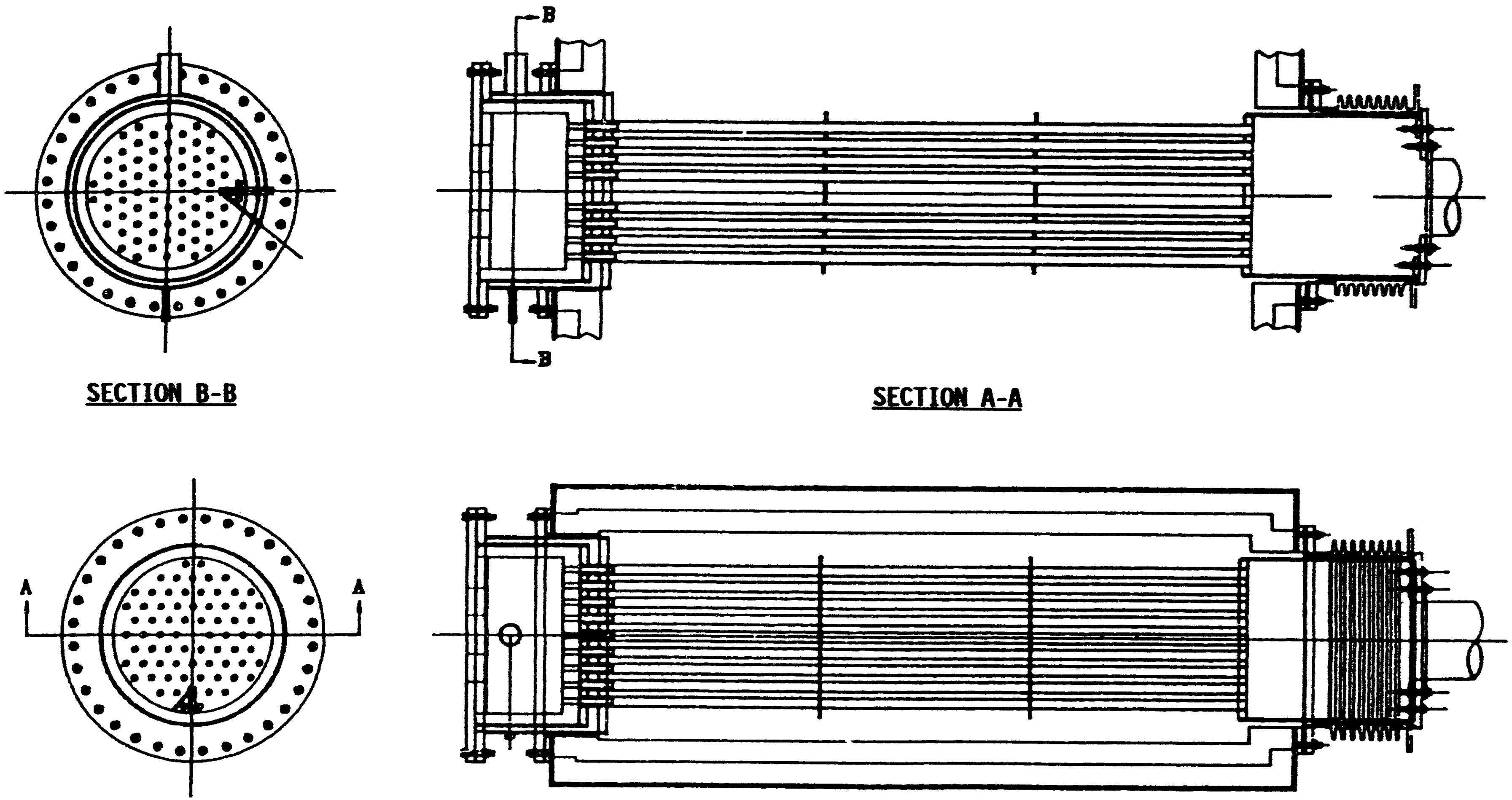

FIGURE 5: GASIFIER HEATER MODULE

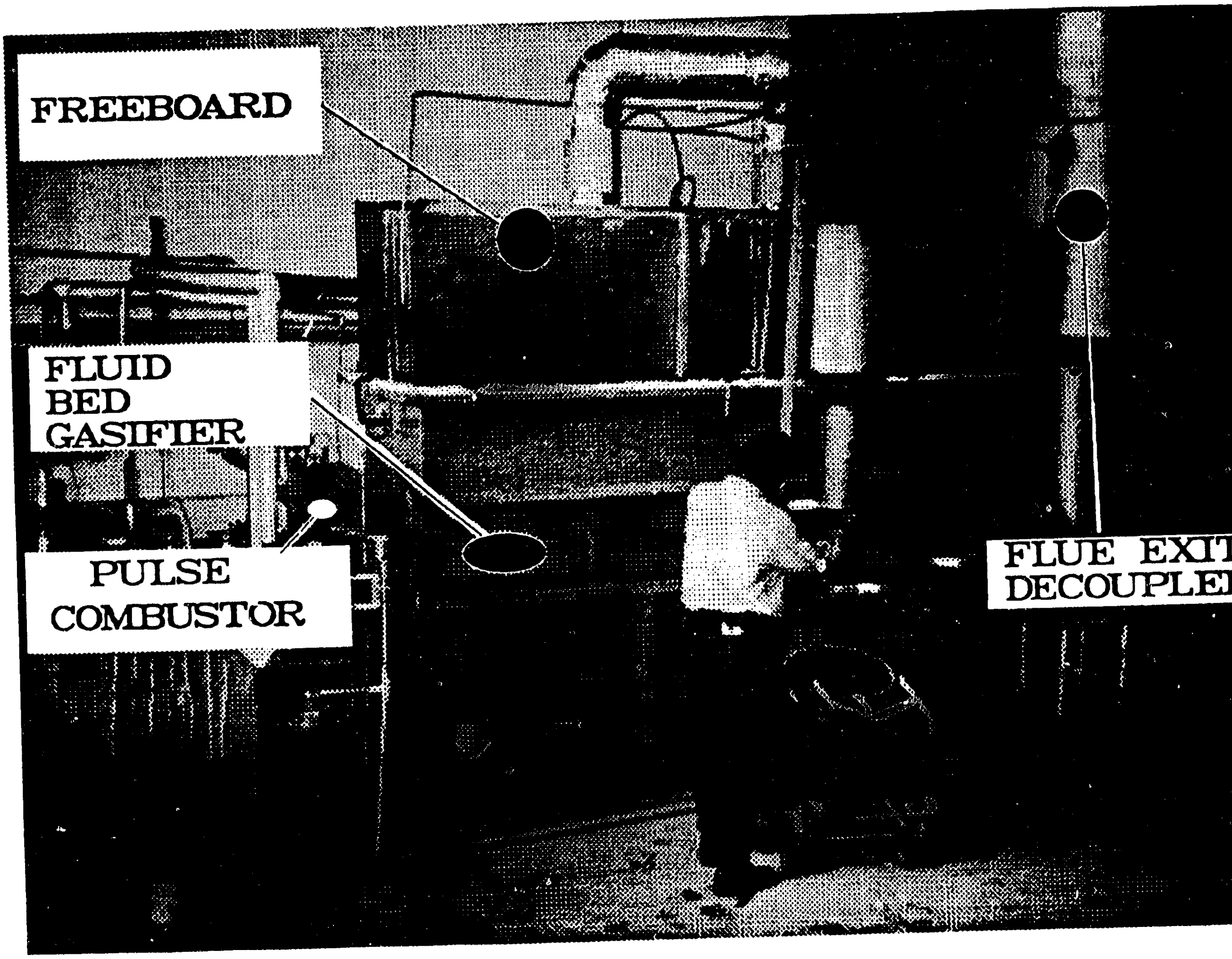

FIGURE 6: INDIRECTLY HEATED GASIFIER PILOT UNIT
(12 TONS DAY)

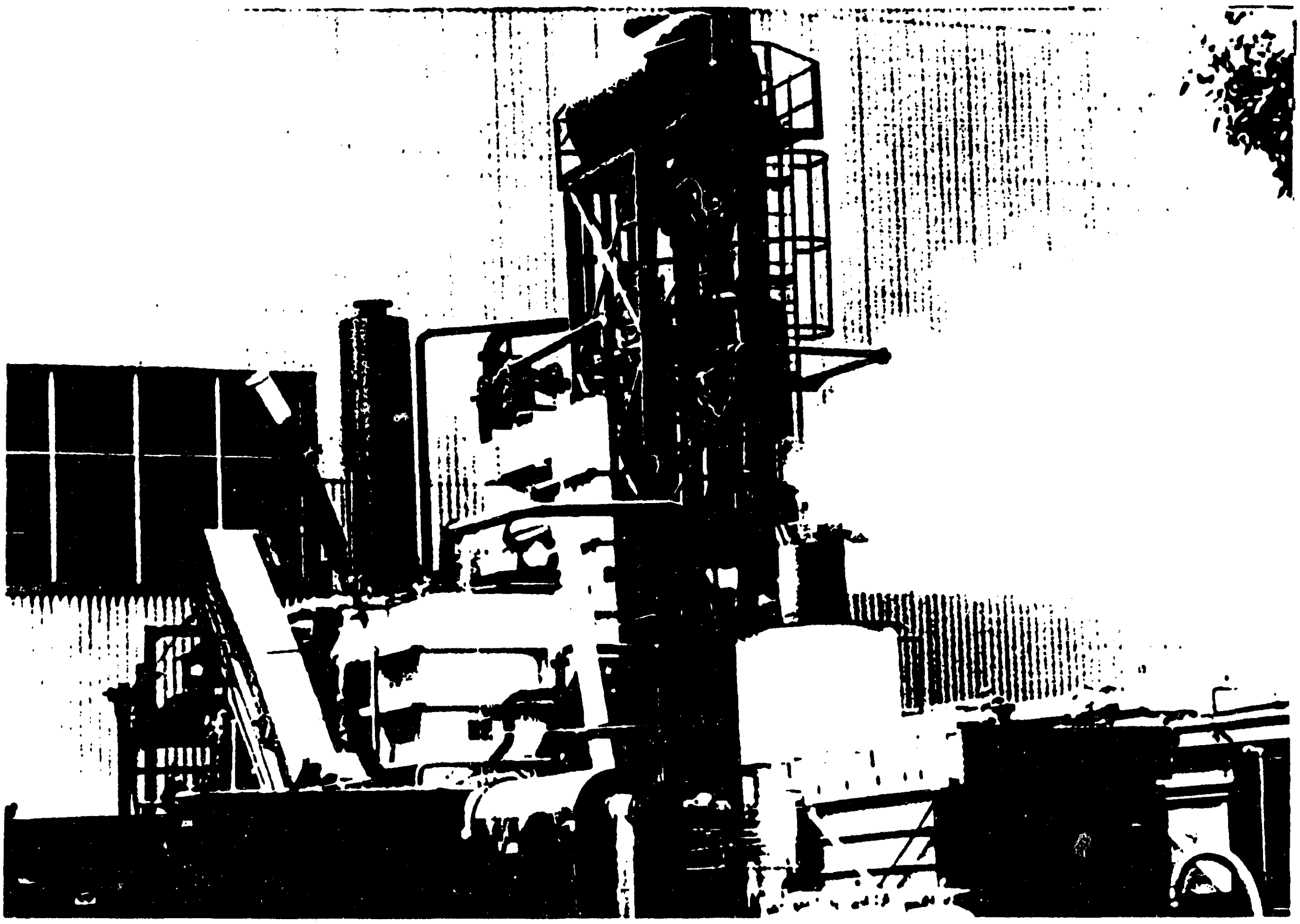

FIGURE 7: INLAND CONTAINER CORPORATION GASIFICATION UNIT
(24 TONS/DAY GASIFIER)

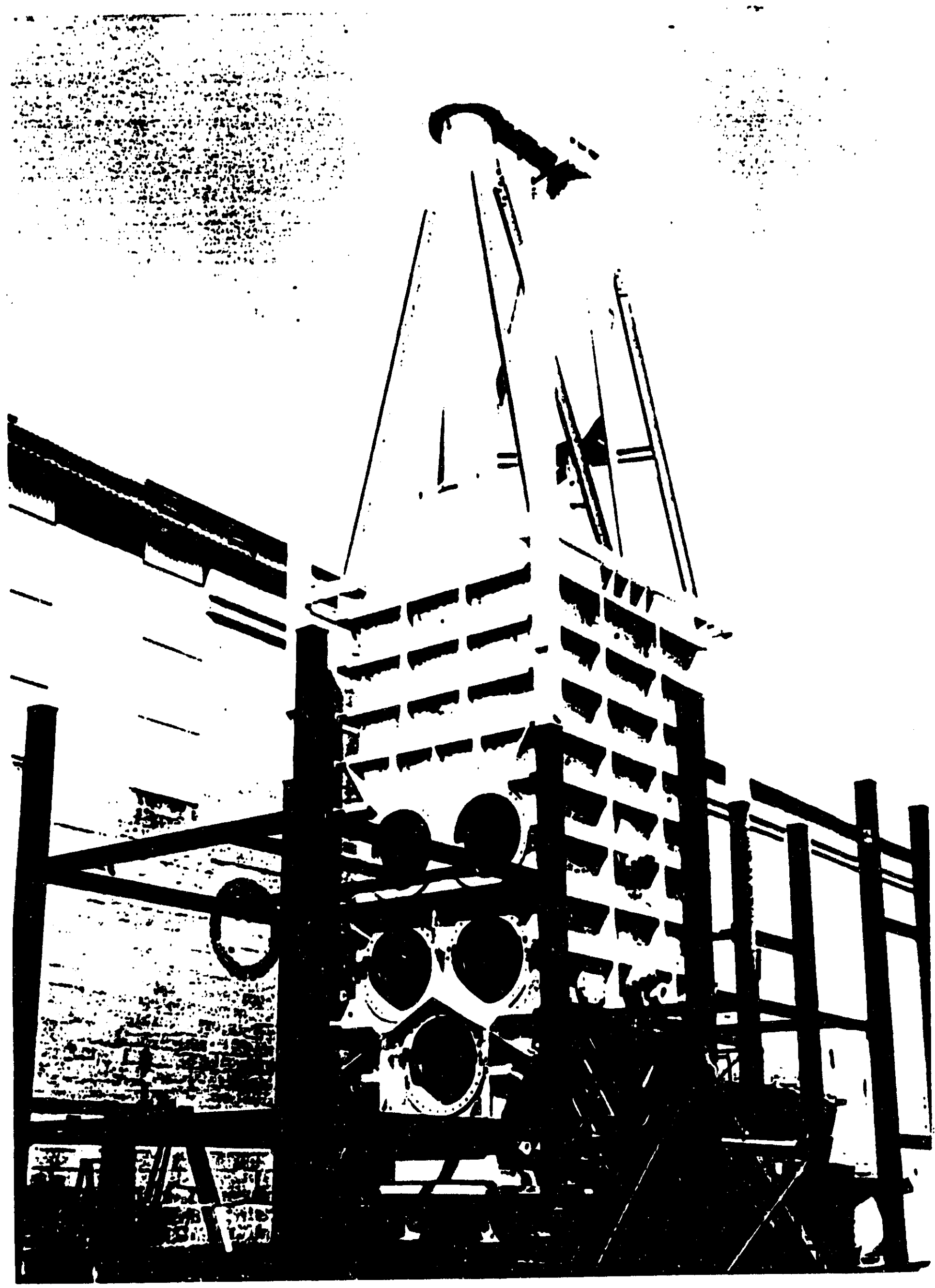

FIGURE 8: BLACK LIQUOR UNIT FOR WEYERHAEUSER

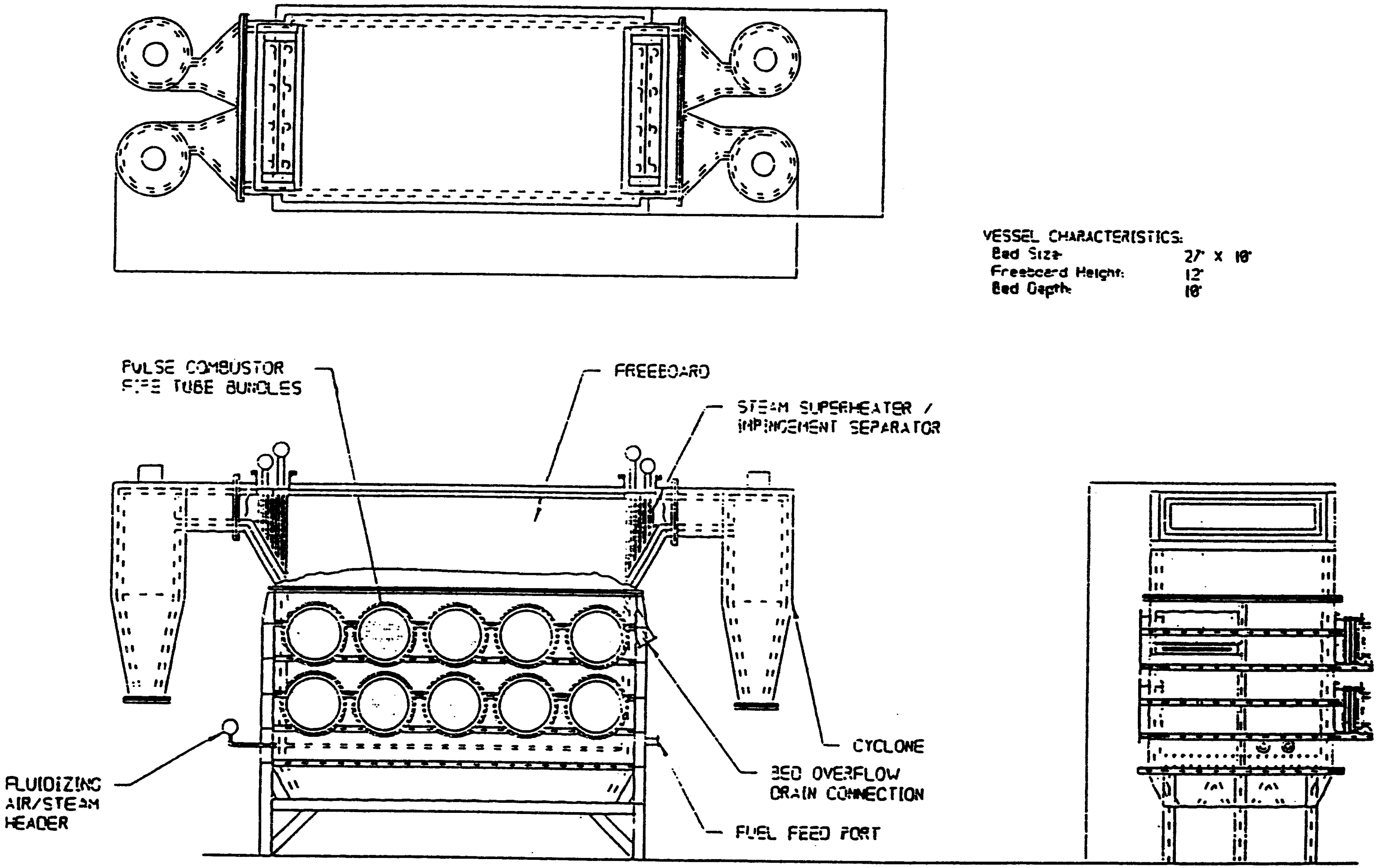

FIGURE 9: 300-TON PER DAY GASIFIER

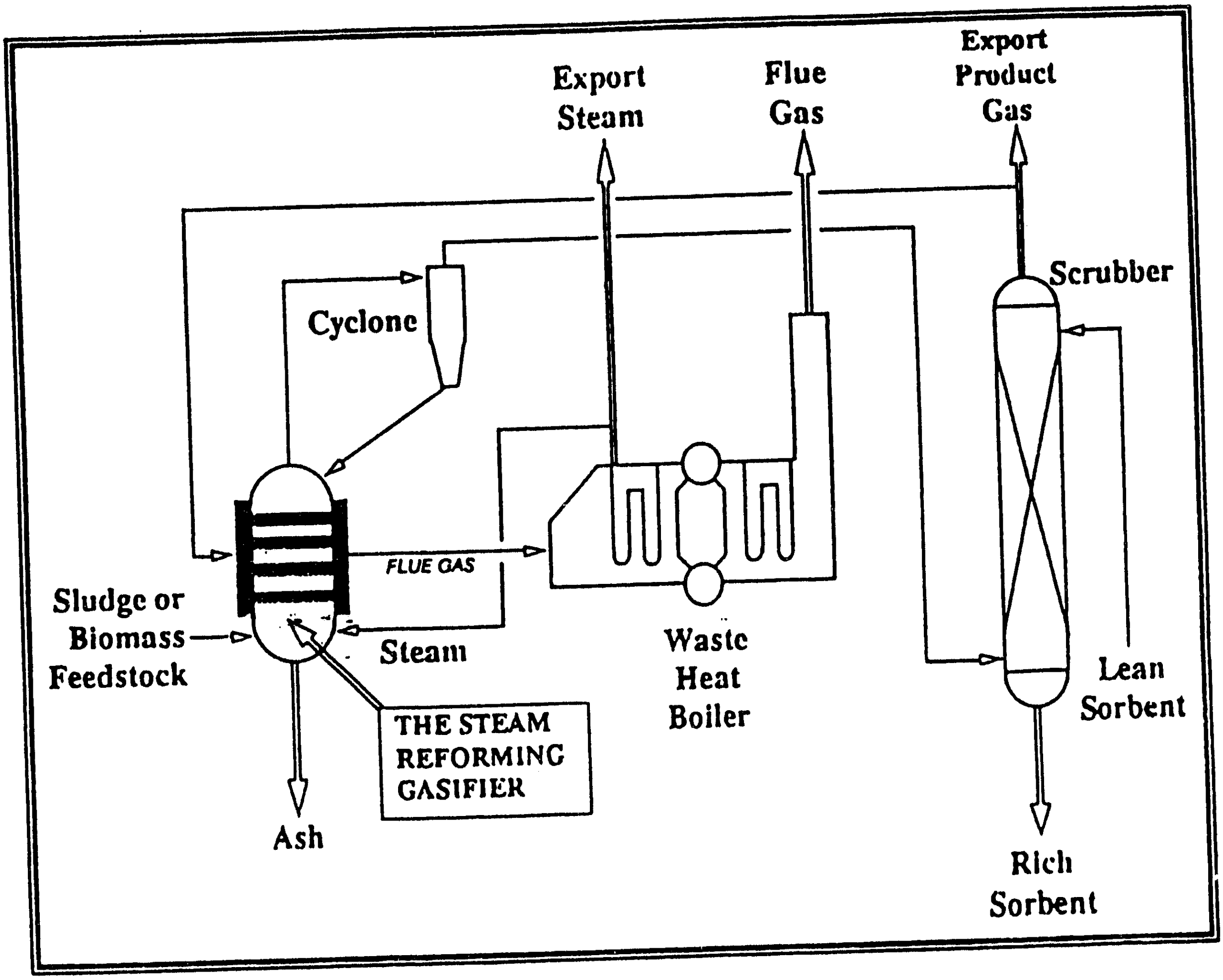

FIGURE 10: SIMPLIFIED SYSTEM SCHEMATIC

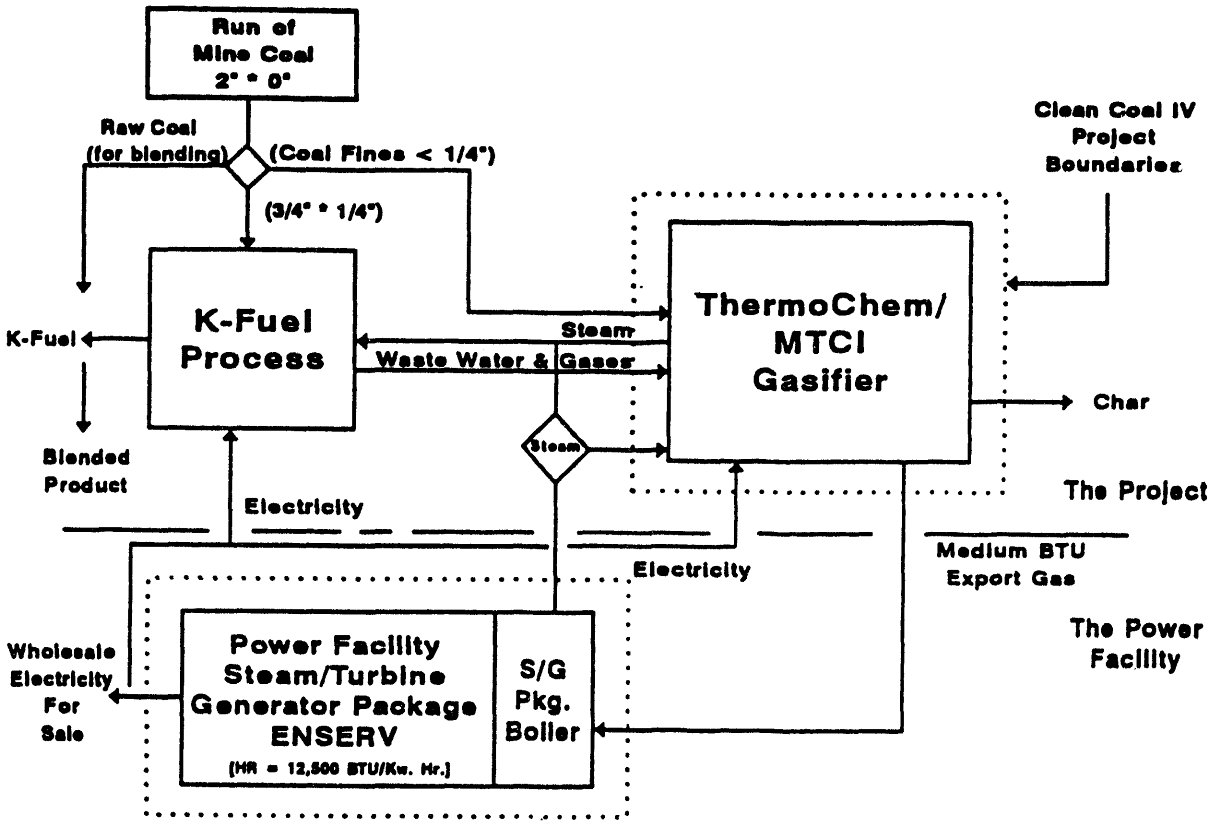

FIGURE 11: K-FUELS/THERMOCHEM COMMERCIAL PROJECT PROCESS STRUCTURE

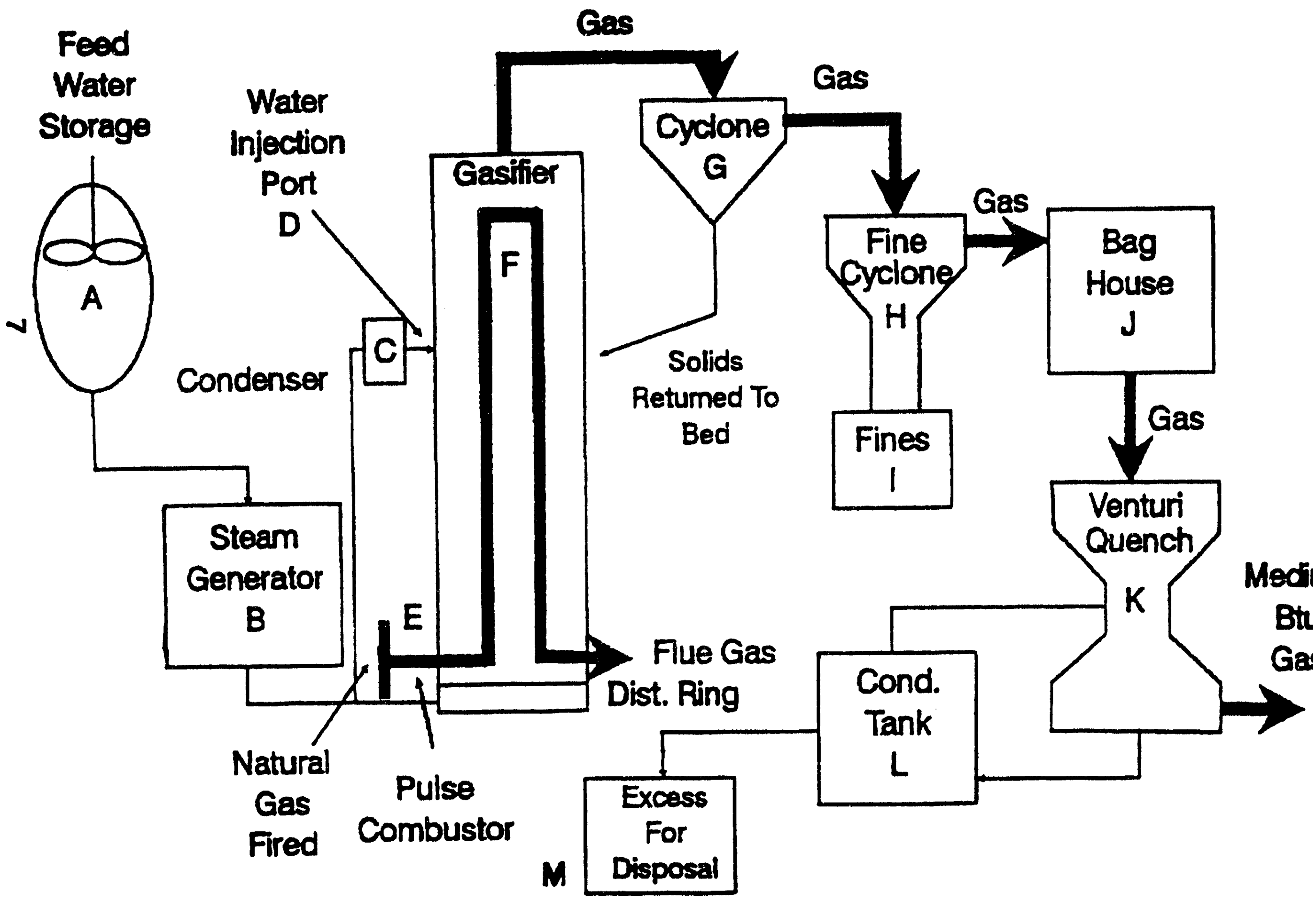

FIGURE 12: MTCI GASIFIER TESTS OF CABALLO ROJO COAL - DIAGRAM OF TEST FACILITIES

BLAST FURNACE
GRANULAR COAL INJECTION

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ABSTRACT

A blast furnace coal injection system will be constructed and tested on large high productivity blast furnaces at the Burns Harbor plant of the Bethlehem Steel Corporation. This project will demonstrate injection facilities on two blast furnaces and will permit a comparison of operation with both granular (coarse) and pulverized (fine) coal injection. Injection rates up to 400 lbs/ton hot metal will be demonstrated with a variety of domestic coal types. With the completion of the National Environmental Policy Act (NEPA) process and issuance of a construction/air permit from the State of Indiana, the project has moved into the detailed design and construction stage with commissioning scheduled for early 1995.

INTRODUCTION

BACKGROUND - COAL INJECTION FOR BLAST FURNACES

Blast furnaces produce hot metal, which is used in the basic oxygen furnaces for refinement into various grades of steel. Major ingredients in the production of hot metal are iron ore, coke and limestone. As shown on Figure 1, the ironmaking blast furnace is at the heart of the integrated steelmaking process. Fine iron ore is agglomerated by pelletizing or sintering. The prepared ferrous materials, along with coke, are charged alone or in combination with lump iron ore into the blast furnace. Preheated air is injected near the bottom of the furnace and ferrous materials are reduced and melted by hot combustion products from the burning coke to produce molten iron. The molten iron is combined with scrap and flux and is refined in the steelmaking process. The basic oxygen furnace is the predominant method used in integrated steelmaking.

Figure 2 provides more detail on the blast furnace operation. As shown, the raw materials (ore, coke and limestone) are conveyed to the top of the furnace either on a conveyor belt or in a "skip" car. All or part of the limestone (and dolomite), which is used as flux to remove contaminants in the coke and ore, can be charged directly or combined in the ferrous sinter and pellet feed during their production.

The raw materials are charged to the top of the furnace through a lock hopper arrangement to prevent the escape of pressurized hot reducing gases. Air needed for the combustion of coke to generate the heat and reducing gases for the process is passed through stoves and heated to 1500-2300°F. The heated air (hot blast) is conveyed to a refractory-lined bustle pipe located around the perimeter of the furnace. The hot blast then enters the furnace through a series of ports (tuyeres) around and near the base of the furnace. The molten iron and slag are discharged through openings (tapholes) located below the tuyeres. Resultant molten iron flows to refractory-lined ladles for transport to the steelmaking shop.

A schematic showing the various zones inside the blast furnace is given on Figure 3. As can be seen, the raw materials, which are charged to the furnace in batches, create discrete layers of ore and coke. As the hot blast reacts with and consumes coke at the tuyere zone, the burden descends in the furnace resulting in a molten pool of iron flowing around unburned coke at the furnace bottom (bosh area). Reduction of the descending ore occurs by reaction with the rising hot reducing gas that is formed when coke is burned at the tuyeres.

The cohesive zone directly above the tuyeres is so called because it is in this area that the ore, which has been reduced is being melted and passes through layers of unburned coke. The coke layers provide the permeability needed for the hot gases to pass through this zone to the upper portion of the furnace. Unlike coal, coke has the qualities needed to retain its integrity in this region and is the reason that blast furnaces cannot be operated without coke in the burden.

The hot gas leaving the top of the furnace is cooled and cleaned. Since it has a significant heating value (80-100 BTU/scf), it is used to fire the hot blast stoves. The excess is used to generate steam and power and for other uses within the plant.

Over the years many injectants (natural gas, tar, oils, etc.) have been used in blast furnaces to reduce the amount of coke used. Their use is a matter of economics with each location making choices considering the site specific relative costs of coke and injectants available. Natural gas has been a common injectant used in this country. Recent technological developments in Europe and Asia, where coal has been widely used as an injectant, have established that the highest levels of injection and subsequent displacement of coke can be obtained by using coal.

A major consideration in evaluating coal injection in the United States is the aging capacity of existing cokemaking facilities and the high capital cost to rebuild these facilities to meet emission guidelines under the Clean Air Act Amendments. The increasingly stringent environmental regulations and the continuing decline in domestic cokemaking capability will cause significant reductions in the availability of commercial coke over the coming years. Due to this decline in availability and increase in operating and maintenance costs for domestic cokemaking facilities, commercial coke prices are projected to increase by more than general inflation. Higher levels of injectants, such as coal, enable domestic integrated steel producers to minimize their dependence on coke.

COAL PREPARATION AND INJECTION AT BURNS HARBOR

Natural gas is the injectant currently being used in the production of iron in the Burns Harbor blast furnaces of Bethlehem Steel Corporation. Even with maximum use of natural gas, the plant lacks sufficient cokemaking capability to support its ironmaking capability. That situation led Bethlehem to the decision to submit a proposal to the DOE to conduct a comprehensive assessment of coal injection in the Burns Harbor blast furnaces. The program is designed to provide the industry with comparative data on a variety of U.S. coal types, grind sizes, etc. Following an extensive review by the DOE, Bethlehem's Blast Furnace Granular Coal Injection System Demonstration Project was one of thirteen demonstration projects selected to enter into contract negotiations. During negotiations, the scope of the project was expanded to include improvements to the blast furnaces to enhance the potential for a successful demonstration.

The DOE financial assistance will enable Bethlehem to demonstrate and compare granular (coarse) coal injection with pulverized (fine) coal injection using a technology successfully employed by British Steel plc. Under the terms of the DOE financial assistance, Bethlehem will demonstrate both granular and pulverized coal injection at rates of up to 400 pounds per net ton of hot metal for a number of domestic coals.

PROJECT GOALS

As shown on Figure 4, this project will obtain comparative data for a variety of coal types, grinds and injection level. The primary thrust of the work is to demonstrate (a) conversion for, (b) optimization of and (c) commercial performance characteristics of granular coal as a supplemental fuel for steel industry blast furnaces. The technology will be demonstrated on large, hard-driven blast furnaces using a wide range of coal types available in the U.S. The planned tests will assess the impact of coal particle size distribution as well as chemistry on the amount of coal that can be injected effectively. Upon successful completion of the work, the results will provide to others the information and confidence needed to assess the technical and economic advantages of applying the technology to their own facilities.

TECHNOLOGY DESCRIPTION

Bethlehem's decision to utilize the Simon Macawber Blast Furnace Granular Coal Injection (BFGCI) System which can produce both granular and pulverized coal rather than a system which produces only pulverized coal (as has been more widely employed), is due to a variety of technical and economic advantages which made this system potentially very attractive for application in the U.S. basic steel industry. A schematic showing the application of the technology to the blast furnace is given on Figure 5. Following are some of the technical advantages associated with utilization of this system:

1. The injection system has been proven with granular coal as well as with pulverized coal. No other system has been utilized over this range of coal sizes.

2. The potential costs for granular coal systems are less than for pulverized.

3. Granular coal is easier to handle in pneumatic conveying systems. Granular coals are not as likely to stick to conveying pipes if moisture control is not adequately maintained.

4. Research tests conducted by British Steel indicate that granular coal is more easily maintained in the blast furnace raceway (combustion zone) and is less likely to pass through the coke bed. Coke replacement ratios obtained by British Steel have not been bettered in any worldwide installation.

5. Granular coal's coarseness delays gas evolution and temperature rise associated with coal combustion in the raceway. Consequently, it is less likely to generate high temperatures and gas flows at the furnace walls which result in high heat losses, more rapid refractory wear and poorer utilization of reducing gases.

6. System availability has exceeded 99 percent during several years of operation at British Steel.

7. High injection levels require accurate variable control of injection rates, both for individual tuyeres and the complete system. The unique variable speed, positive displacement Simon-Macawber injectors provide superior flow control and measurement over other coal injection systems.

HISTORY OF THE TECHNOLOGY

Coal injection into blast furnaces dates back more than 100 years; it was the first fuel known to have been injected. In the United States, pulverized coal has been injected into blast furnaces at the Ashland Kentucky Plant of Armco Steel since the mid-1960's. However, different economic situations at other facilities in the United States precluded wide application of coal injection technology. That situation has changed and a number of steel companies in the U.S. have installed or are planning to install coal injection facilities.

As with other companies, Bethlehem Steel has monitored the progress of blast furnace coal injection developments worldwide for a number of years. The development and application of a process that permits the use of granular (as well as pulverized) coal caught our interest. The equipment provides the capability of using either grind size, with the option of long-term use of the less expensive granular type.

The joint development between British Steel and Simon-Macawber for the injection of granular coal into blast furnaces began in 1982 on the Queen Mary Blast Furnace at the Scunthorpe Works. (1,2) The objective of the development work was to inject granular coal into the furnace and test the performance of the Simon-Macawber equipment with a wide range of coal sizes and specifications. Based on Queen Mary's performance, coal injection systems were installed on Scunthorpe's Queen Victoria, Queen Anne and Queen Bess (operational standby) blast furnaces and on Blast Furnaces 1 and 2 of the Ravenscraig Works. Queen Victoria's system was brought on line in November, 1984 and Queen Anne's in January, 1985. The Ravenscraig systems were started up in 1988. The success of the GCI systems at Scunthorpe and Ravenscraig, although demonstrated on smaller blast furnaces, led Bethlehem to conclude that the system could be applied successfully to large blast furnaces.

INSTALLATION DESCRIPTION

The coal preparation/injection facility will be retrofitted to blast furnaces, Units "C" and "D", at our Burns Harbor plant located in Porter County, Indiana, on the southeast shore of Lake Michigan. Highlights of the blast furnace and coal injection facilities are given on Figure 6. As noted on this Figure, Burns Harbor has experience with the injection of tar and oil as well as natural gas. This experience will be an asset when the coal injection trials begin.

A simplified flow diagram for the process is shown on Figure 7. The Raw Coal Handling Equipment and the Coal Preparation Facility includes the facilities and equipment utilized for the transportation and preparation of the coal from an existing railroad car dumper until it is prepared and stored prior to passage into the Coal Injection Facility; the Coal Injection Facility accepts the prepared coal and conveys it to the blast furnace tuyeres.

SITE LOCATION

The Coal Preparation Facility, the Coal Injection Facility and a utilities and control center for the facilities will be located within one building consisting of three attached structures. The building will be located between the two blast furnaces on a site currently occupied by a blast furnace warehouse and maintenance building which will be relocated. This location was chosen because it is the closest equidistant site to the two blast furnaces. Such location will minimize pressure drop and power requirements for transporting the coal to the blast furnaces.

RAW COAL HANDLING EQUIPMENT

Raw Coal Handling. Coal for this project will be transported by rail from coal mines to Burns Harbor similar to the way in which the plant now receives coal shipments for the coke ovens. The coal will be unloaded using an existing railroad car dumper, which is currently part of the blast furnace material handling system. A modification to the current conveyor will be made to enable the coal to reach either the coke ovens or the coal pile for use at the Coal Preparation Facility.

This modification will require a new 60-inch wide transfer conveyor to be installed from the existing conveyor and run east about 162 feet (40 feet above the ground) to a junction house. There the coal will be transferred to a new 60-inch wide stockpile conveyor which will run 760 feet to the north and end at the space for the new raw coal storage pile. The coal pile will be formed using a 200-ft. long radial stacker capable of building a 10-day storage pile (approximately 28,000 tons). The new material handling system from the car dumper to the coal storage pile will be sized at 2,300 tons per hour to match the output of the car dumper.

Raw Coal Reclaim. The raw coal reclaim tunnel will be installed underground beneath the coal storage pile. The concrete tunnel will be about 12 feet wide and 16 feet high and will contain three reclaim hoppers in the top of the tunnel. The reclaim hoppers, which are directly beneath the coal pile, will feed a 36-inch wide conveyor in the tunnel. The 500-ft. long reclaim conveyor will transport the coal at a rate of 400 tons per hour above ground to the south of the storage pile. A magnetic separator will be located at the tail end of the conveyor to remove tramp ferrous metals. The conveyor will discharge the coal onto a vibrating screen which will separate coal over 2 inches in size from the main stream of minus 2-inch coal. The oversized coal will vary depending on the weather (more during the winter when frozen lumps are expected) and will pass through a precrusher which will discharge minus 2-inch coal. The coal from the precrusher will join the coal that passed through the screen and will be conveyed from ground level by a 36-inch wide plant feed conveyor to the top of the building that houses the Coal Preparation Facility.

The reclaiming of coal from the pile will be done by gravity as long as there is coal above each of the reclaim hoppers. It will be necessary to have a bulldozer on the pile to push coal from the "dead" storage areas to the "live" storage areas above each of the reclaim hoppers.

COAL PREPARATION FACILITY

The plant feed conveyor will terminate about 95 feet high at the top of the building that houses the Coal Preparation Facility. Coal will be transferred to a distribution conveyor, which will enable the coal to be discharged into either of two steel raw coal storage silos. The raw coal silos will be cylindrical in shape with conical-shaped bottoms. They will be completely enclosed with a vent filter on top. Each silo will hold 250 tons of coal, which is a four-hour capacity at maximum injection levels. Air cannons will be located in the conical section to loosen the coal to assure that mass flow is attained through the silo.

Coal from each raw coal silo will flow into a feeder which controls the flow of coal to the coal preparation mill. In the preparation mill the coal will be ground to the desired particle size. Products of combustion from a natural gas fired burner will be mixed with recycled air from the downstream side of the process and will be swept through the mill grinding chamber. The air will lift the ground coal from the mill vertically through a classifier where oversized particles will be circulated back to the mill for further grinding. The proper sized particles will be carried away from the mill in a 52-inch pipe. During this transport phase, the coal will be dried to 1-1.5% moisture. The drying gas will be controlled to maintain oxygen levels below combustible levels.

The product coal will then be screened. Two full capacity parallel screens will be provided so that a screen can be changed without shutting down the coal preparation plant. The dried ground coal will be transported into one of four 180-ton product storage silos and will then be fed into a weigh hopper in one-ton batches. The one ton batches will be dumped from the weigh hopper into the distribution bins which are part of the Coal Injection Facility. There will be two grinding mill systems. Each system will produce 30 tons per hour of pulverized coal or 60 tons per hour of granular coal.

COAL INJECTION FACILITY

The Coal Injection Facility will include four distribution bins located under the weigh hoppers described above. Each distribution bin contains 14 conical-shaped pant legs. Each pant leg will feed an injector which allows small amounts of coal to pass continually to an injection line. Inside the injection line, the coal will be mixed with high-pressure air and will be carried through approximately 600 feet of 1-1/2-inch pipe to an injection lance mounted on one of the 28 tuyere blowpipes at each furnace. At the injection lance tip, the coal will be mixed with the hot blast and will be carried into the furnace raceway. The fourteen injectors at the bottom of the distribution bin will feed alternate furnace tuyeres.

Each furnace requires two parallel series of equipment, each containing one product coal silo, one weigh hopper, one distribution bin, 14 injectors, 14 injection lines and 14 injection lances.

TEST PLAN

The project will address a broad range of technical/economic issues as shown on Figure 8.

COAL GRIND SIZE

The project will evaluate coal injection over a broader range of coal particle sizes than has ever been conducted at any plant in the U.S. Only pulverized coal, defined as 70-80% minus 200 mesh (74 microns), has been injected commercially in the U.S. The primary focus of this project will be on granular coal, defined as 100% minus 4 mesh (5 mm), 98% minus 7 mesh (3 mm) and less than 30% minus 200 mesh (74 microns). The work will demonstrate on a commercial scale in the U.S. the coal preparation/injection system that can produce granular as well as pulverized coal. More important, it will show the effects of injected coal particle size on blast furnace performance. If the successful experiences of European operations with granular coal can be repeated or improved upon in the CCT III Project, then the advantages of granular coal over pulverized coal injection systems for commercial applications in the U.S. will have been demonstrated. These potential advantages include reduced capital cost for the grinding facilities and reduced consumption of electric energy (and other operating cost factors) for grinding the coal. The data to be generated on both fine and coarse injected coal will be of value in the planning of future U.S. commercial installations.

COAL INJECTION RATE

The plan for this project includes evaluating operations over a range of coal injection rates. We intend to push the upper boundaries of coal injection to 400 lbs of coal/NTHM. By operating and evaluating at coal injection rates ranging up to 400 lbs/NTHM, we will determine the technical limit for the coal injection system, establish the relationship between coal injection rate, furnace wall heat load, and any excessive wear of refractory lining to blast furnaces such as those at Burns Harbor; and confirm the operating costs and economic advantages that have been projected for coal injection.

COAL SOURCE

Our project will generate comparative data on coals with distinctly different chemical and physical characteristics. The plan is to use an Eastern bituminous coal with low ash and sulfur content; an Eastern bituminous coal with moderate ash and higher sulfur content; a Midwestern bituminous coal with higher inherent moisture but with low ash and moderate-to-high sulfur content; and a Western sub-bituminous coal with high inherent moisture but with low ash and sulfur content.

Each coal will be utilized for a sufficiently long period of time (about two months) to assess how it performs as a blast furnace injectant. Coal handling (i.e., grinding rates, injection system performance) and blast furnace parameters such as production, coke replacement, hot metal chemistry and slag volume are anticipated to be affected by the physical and chemical properties of the coal used for blast furnace coal injection. Data derived from this evaluation will make it possible for blast furnace operators to determine for themselves which coal would be most attractive for injection in their specific cases, including raw coal costs, transportation costs, coal grinding and injection costs, and the effects on blast furnace operations.

BLAST FURNACE CONVERSION METHOD

Neither of the two blast furnaces at Burns Harbor is equipped with coal injection facilities. In this project, we propose to convert both blast furnaces for coal injection during 1994. "C" Furnace is scheduled to be out of service for an extended reline in mid-late 1994. It is during this period that "C" Furnace will be fitted for coal injection. We propose to make the coal injection changes for "D" Furnace "on-the-fly", during very brief, perhaps eight hour outages. Thus, we will demonstrate the successful implementation of the modifications for blast furnace coal injection during both out-of-service and in-service modes. These will include planning and facilities for coal storage and handling, grinding, injection and alterations in the vicinity of the blast furnace itself (including work at the tuyeres).

Many of the physical components utilized in the coal injection system are also utilized in other commercial systems. The major portion of the technology envelope for this system is the integration of this equipment into a system that prepares coal as required for injection, allows flow to be controlled individually for each injection point into the blast furnace or allows all to be varied simultaneously, monitors the total amount injected and the flow to each tuyere, and includes the necessary know-how for injecting solid, granular fuel into a blast furnace. Key elements in this technology package are the weigh system, the variable flow injectors, lance sizing and positioning, and knowledge of how the factors of coal size, coal source and coal injection rate interact. Key elements of the portion of the project that pertain to blast furnace conversion methods involve the integration and coordination of engineering, construction and operations functions.

PROJECT SCOPE

To achieve these objectives, the demonstration project is divided into the three Phases (Figure 9).

Phase I	-	Design
Phase II	-	Construction
Phase III	-	Operation

At the present time, a turnkey contract has been placed with Fluor Daniel for the facility. Design Engineering is nearing completion. Equipment purchase orders have been placed with ATSI/Simon Macawber for the injection systems and site preparation is in progress. Regarding blast furnace improvements, those upgrades scheduled for the D furnace were completed during the last reline in late 1991. Planned major improvements to the C furnace will be completed during the reline of that furnace in the summer/fall 1994. The coal injection system is scheduled to be completed early in 1995 with testing to begin shortly thereafter.

REFERENCES

1. D. S. Gathergood, "Coal Injection Into the Blast Furnace", International Iron & Steel Institute Committee on Technology, April 26, 1988.

2. D. S. Gathergood and G. Cooper, "Blast Furnace Injection - Why Granular Coal"? Steel Technology International, 1988.

FIGURE 1

THE STEELMAKING PROCESS

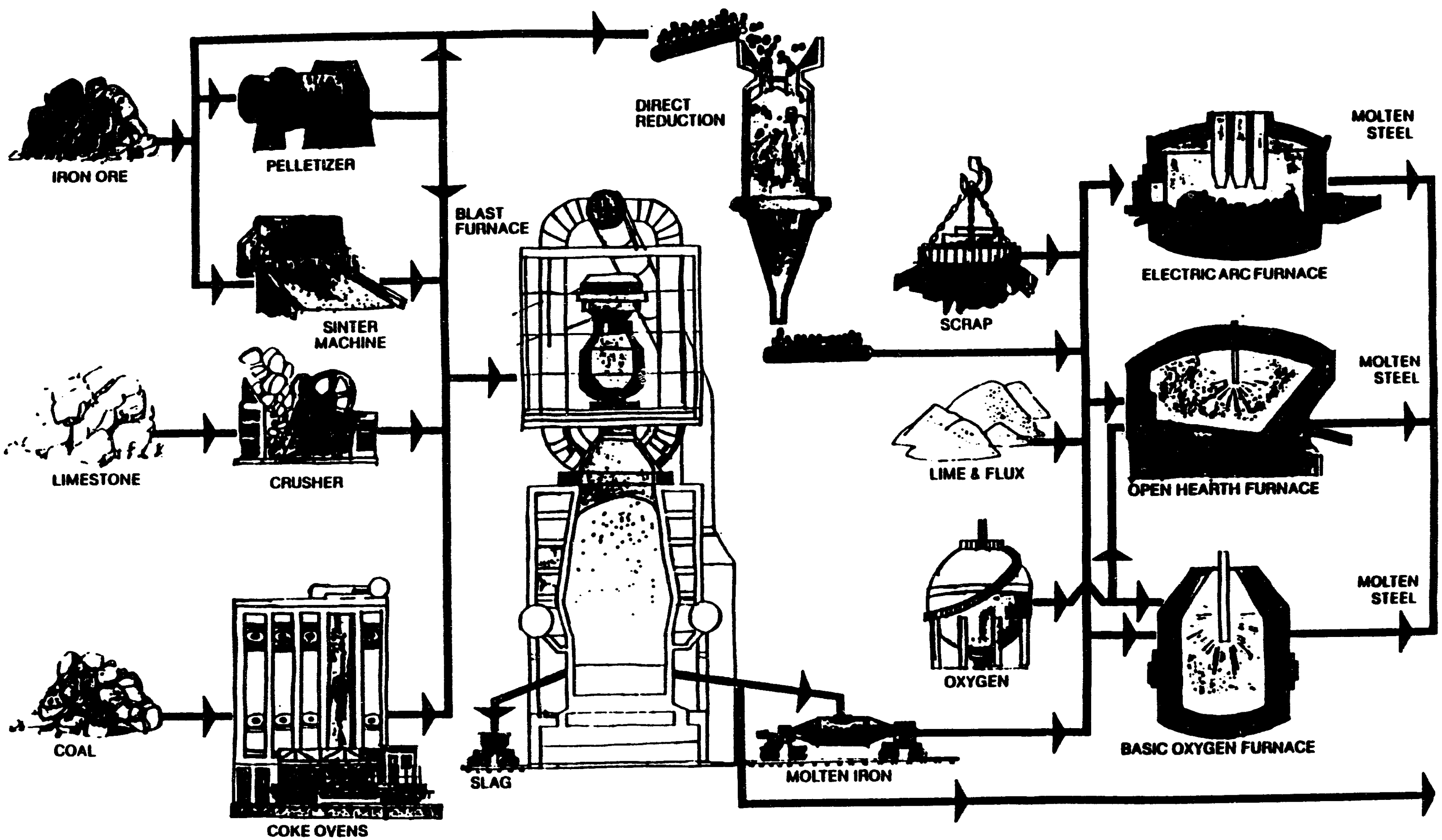


FIGURE 2

THE BLAST FURNACE COMPLEX

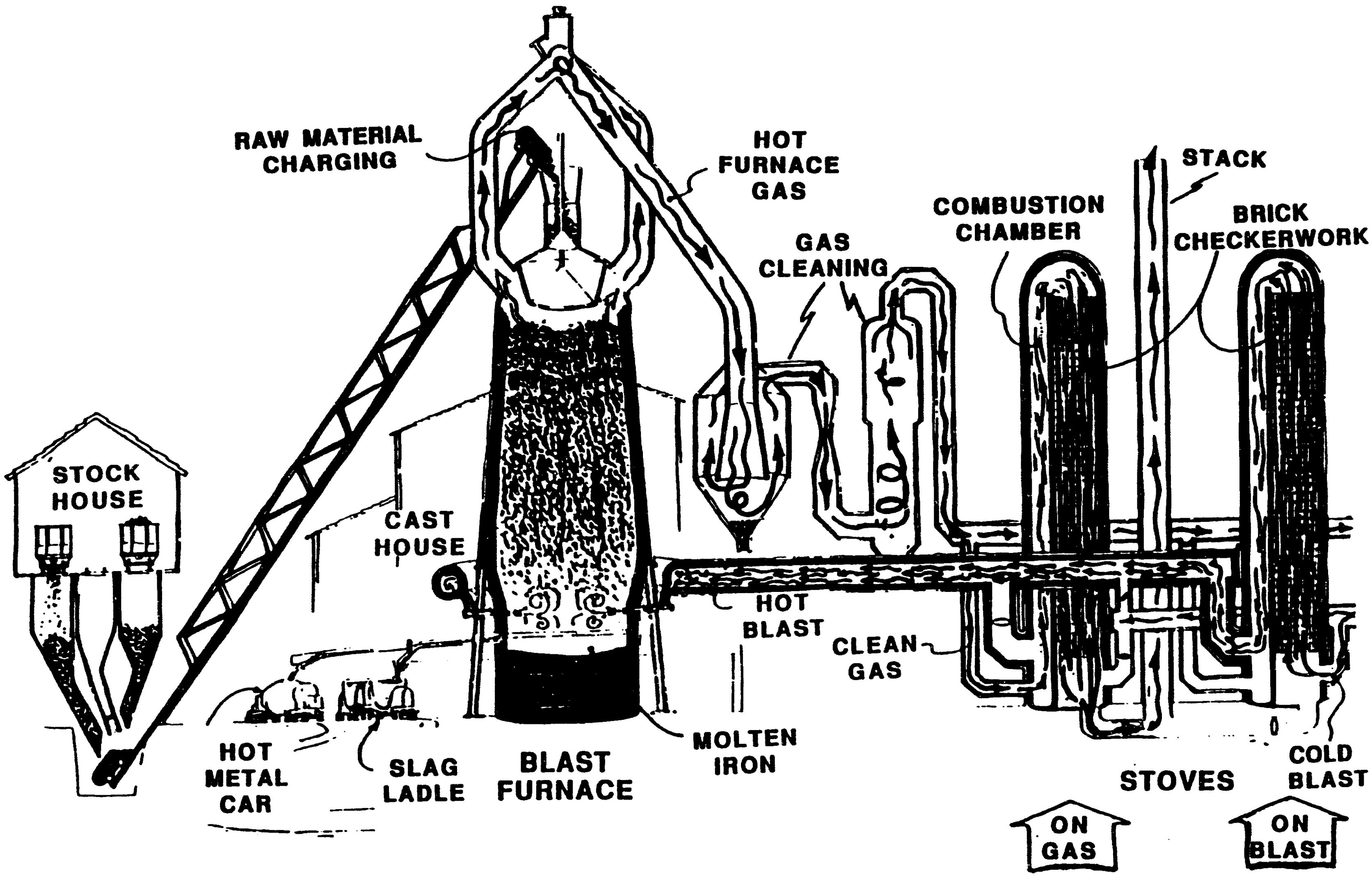


FIGURE 3

ZONES IN THE BLAST FURNACE

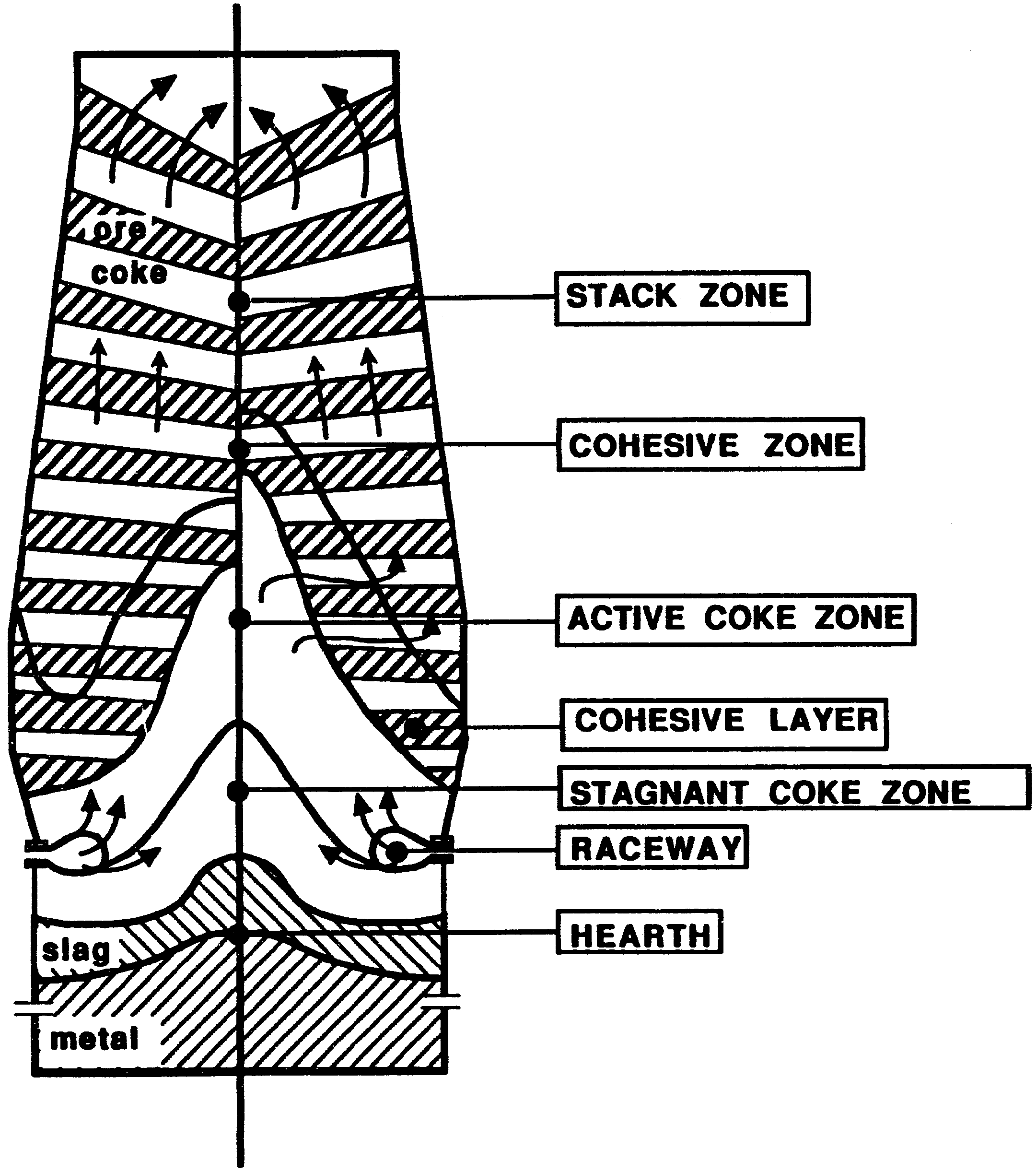


FIGURE 4

Coal Injection Test Program Parameters

Coal Grind Size	-	**Granular (100% -4 mesh) to Pulverized (75% -200 mesh)**
Injection Level	-	**Up to 400 lbs per NTHM**
Coal Types	-	**East, Midwest and West (Differing Chemical and Physical Characteristics)**
System Installation	-	**During Furnace Reline and "On-the-Fly"**
Reduced Coke Requirement	-	**Less Reliance on Foreign Coke and/or Environmental Problems Associated with Domestic Coke Production**

Bethlehem Steel Corp.

FIGURE 5
APPLICATION OF COAL INJECTION

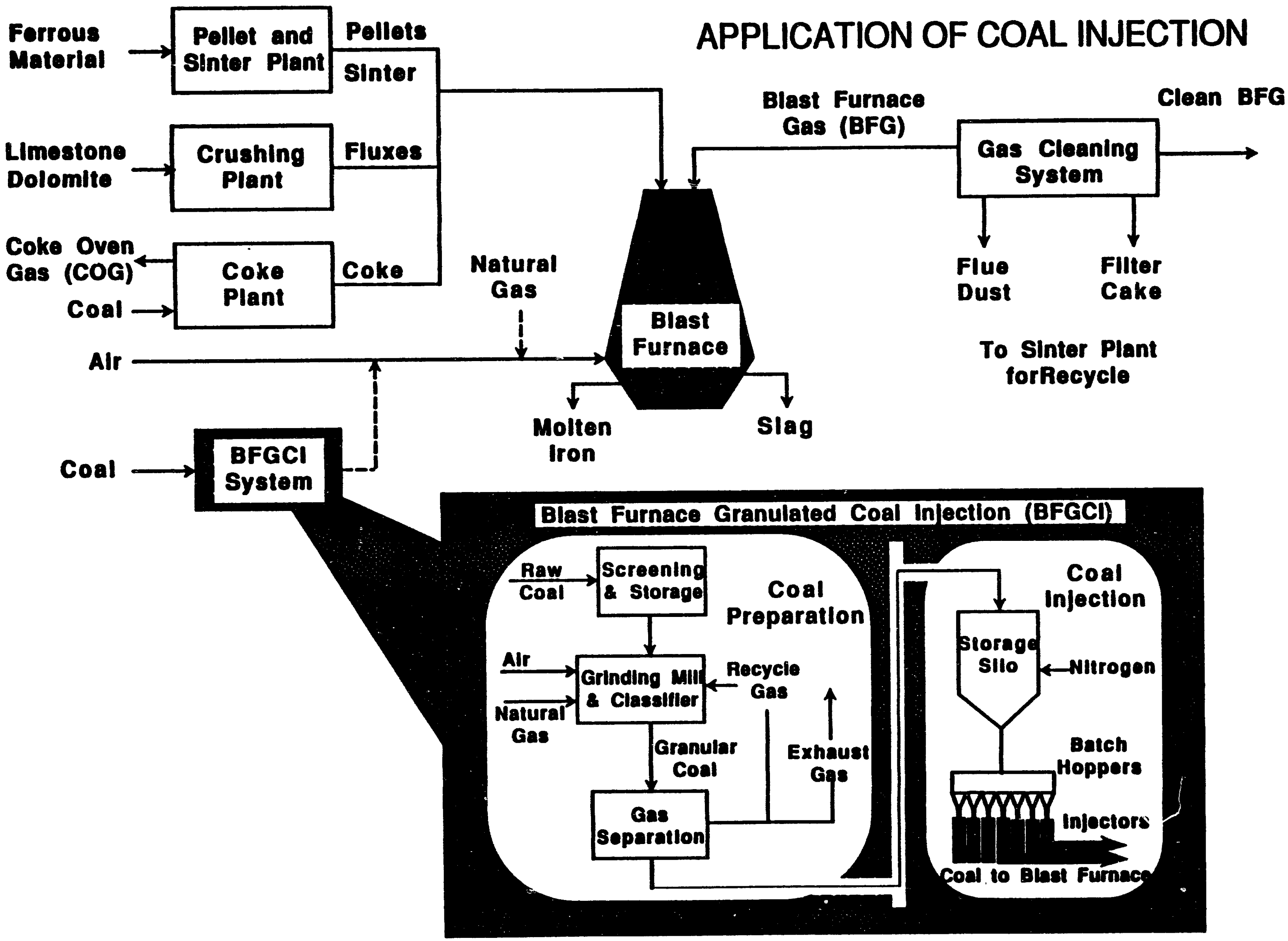


FIGURE 6
Coal Injection Test Site/Facilities

Location	-	**Bethlehem Steel Burns Harbor Plant, Porter County, Northern Indiana**
Blast Furnaces		
- **Number**	-	**2**
- **Size**	-	**35 & 38 ft. Hearth Diameter**
- **Production Rate**	-	**Approximately 7,000 tons/Day Pig Iron/Furnace (8 TPD per 100 cu.ft. Working Volume)**
- **Fuel Injection**	-	**Natural Gas, Oil, Tar**
Coal Injection Facilities	-	**Simon-Macawber**

Bethlehem Steel Corp.

FIGURE 7

COAL INJECTION - BURNS HARBOR PLANT

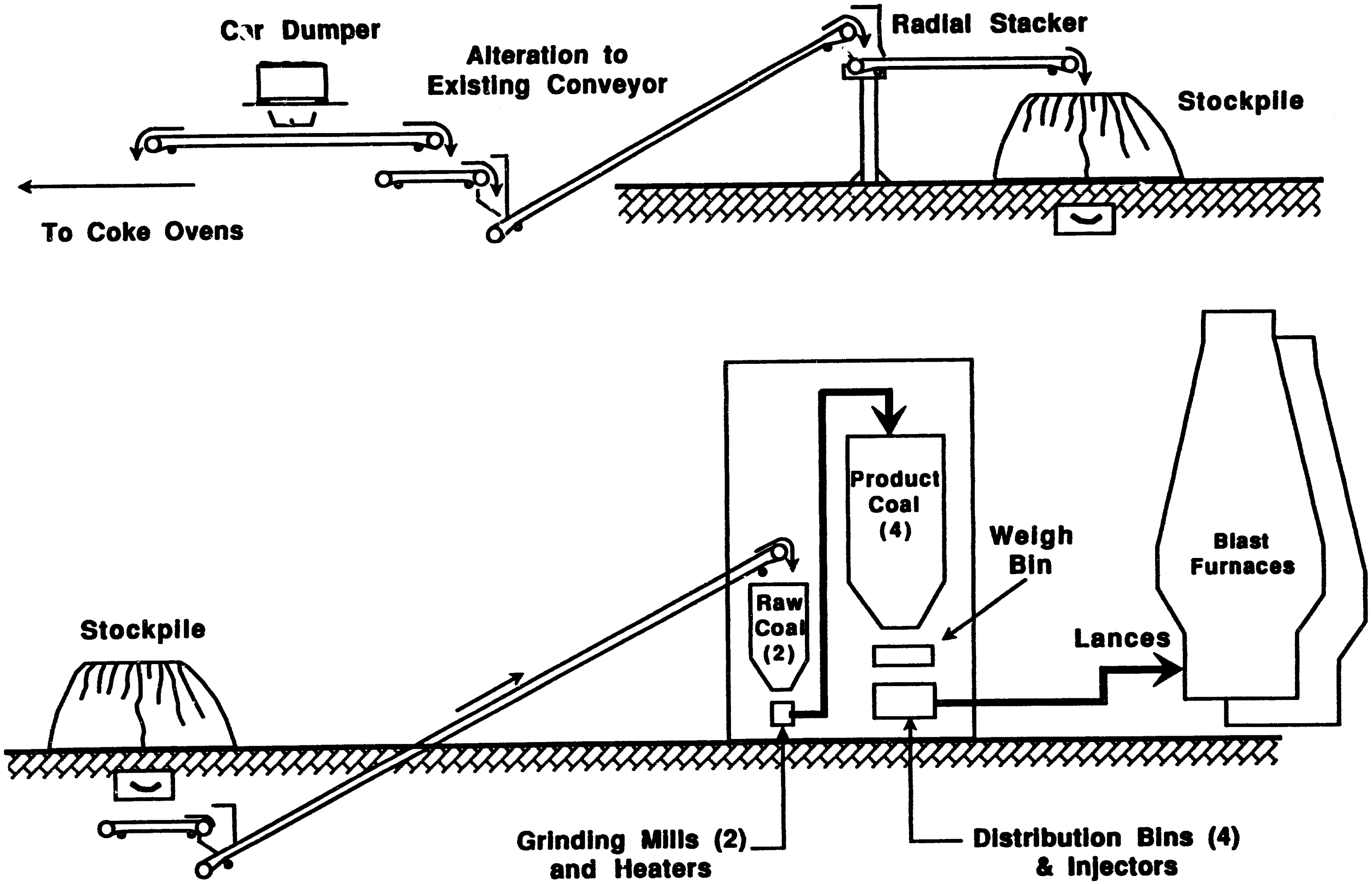


FIGURE 8

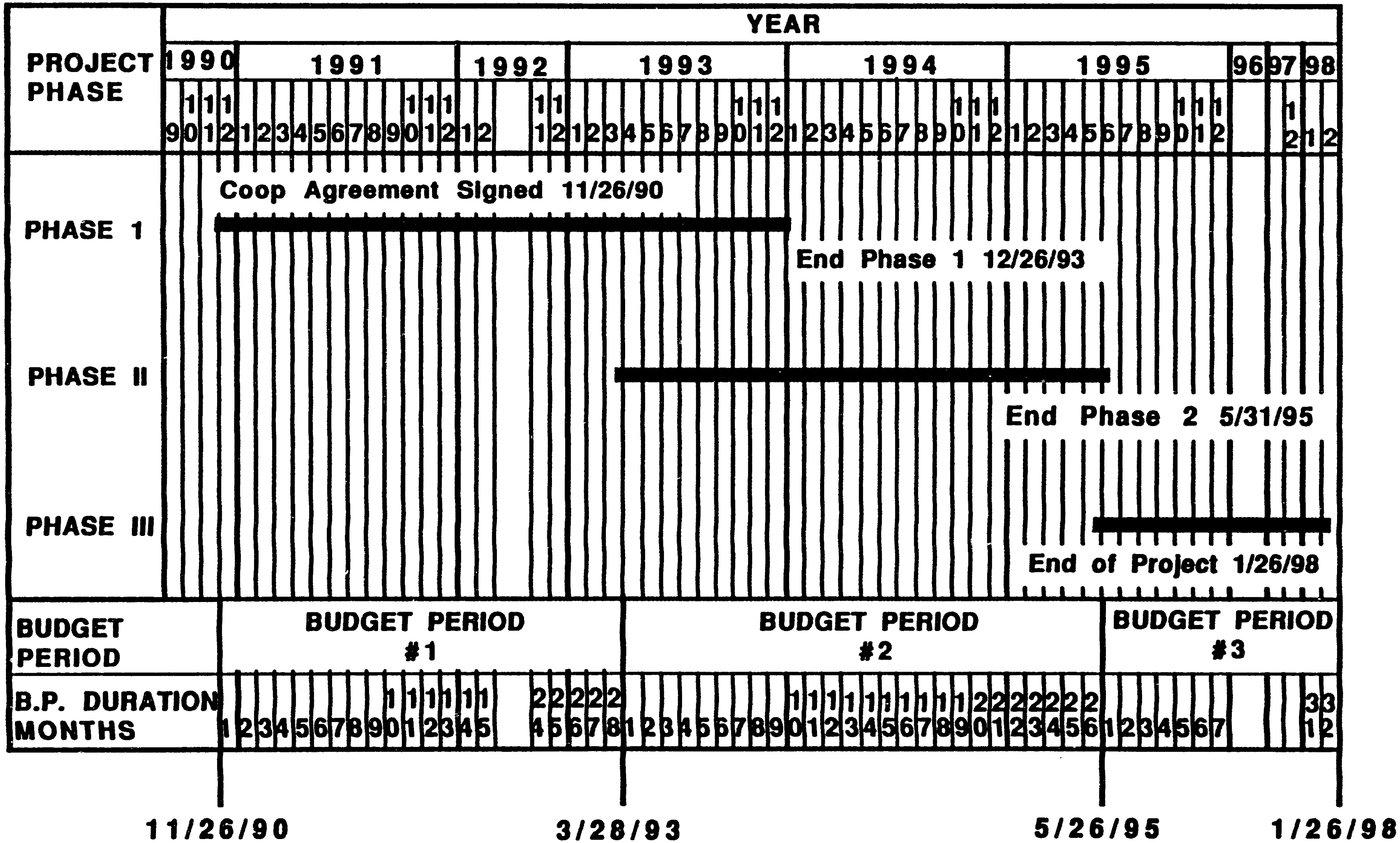
Coal Injection Test Program Goals

Coal Grind Size	-	**Granular (100% -4 mesh) to Pulverized (75% -200 mesh)**
Injection Level	-	**Up to 400 lbs per NTHM**
Coal Types	-	**East, Midwest and West (Differing Chemical and Physical Characteristics)**
System Installation	-	**During Furnace Reline and "On-the-Fly"**

Bethlehem Steel Corp.

FIGURE 9

PROJECT SCHEDULE



STATUS OF COAL TECH'S AIR COOLED SLAGGING COMBUSTOR-

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ABSTRACT

This paper summarizes the status of a six year development effort on a 20 MMBtu/hr slagging, coal combustor that was retrofitted to an oil designed package boiler. In addition to the efficiency benefits of regenerative air cooling, the combustor internally controls SO_2 and NO_x emissions. The combustor also substantially reduces dioxin emissions from coal and from coal cofired with refuse derived fuel. It has vitrified fly ash containing a wide range of unburned carbon. To date, the combustor has operated for about 1600 hours, with about one-half of this time on coal, and the balance on oil and gas. Current test efforts are focused on automatic computer control of the combustor in order to demonstrate its durability in continuous coal fired operation. In addition, systems and cost analyses have been performed on applications of the combustor to retrofit and repower industrial boilers and combined gas turbine-steam turbine power plants. Installed retrofit costs for the combustor are estimated at under $10/lb of steam for industrial boilers, and from $86/kW for small power plants to $172/kW for a 250 MW power plant. The estimated cost of a 20 MW greenfield combined cycle plant system is in the $1200 to $1400/kW range.

INTRODUCTION

This paper summarizes the status of Coal Tech's commercial scale demonstration of a patented air cooled, slagging coal combustor. Air cooling recycles the combustor wall heat transfer loss to the combustion air, which makes it available to the peak of the thermodynamic cycle . On the other hand, water cooling of the combustor yields low temperature heat which is difficult to utilize in a thermodynamic cycle. Typically, the heat losses to the water cooled sections of this combustor are between 2 and 3%, compared to 8 to 10% if the entire combustor were water cooled. By proper combustor design, the energy needed to drive the cooling air can be as little as 1 to 2% of the total heat input. Therefore, the overall efficiency loss in an air cooled combustor can be as little as one-half that of the water cooled combustor. A portion of the SO_2 and NO_x emissions are controlled inside the combustor. The combustor is designed for new and retrofit boiler applications. The air cooled combustor development began in the late 1970's using a 1 MMBtu/hr air cooled cyclone combustor [1]. Development continued in the mid 1980's with SO_2 and NO_x control tests in a 7 MMBtu/hr water cooled cyclone combustor [2]. This work was followed by the design, construction, and installation of the present 20 MMBtu/hr, air cooled, combustor between 1984 and 1987 [3]. The combustor was first tested in 1987 with coal water slurry fuels, and then converted to pulverized coal operation.

The first three years of the demonstration effort were conducted under DOE Clean Coal Program sponsorship. During the Clean Coal project, which began in 1987, many of the operational issues involved in using an air cooled combustor were resolved during nearly 800 hours of combustor operation. About 1/3 of the test hours were on coal.

Since the completion of the Clean Coal tests, the combustor has been used on other test projects. Tests were conducted on ash vitrification [10] and refuse derived fuel combustion [15]. During these tests, the data base developed during the manually controlled Clean Coal combustor tests was used to automate the combustor's operation. For this purpose, a process control software was specialized for the combustor's operation and installed on a micro-computer. In addition, major progress was made on improving the combustion efficiency, SO_2 reductions, reliability, and durability.

Current DOE sponsored tests focus on round-the-clock, coal fired operation under automatic computer control. The objectives are to acquire a data base on durability of combustor components, durability of the auxiliary components needed to operate the combustor, and on the impact of the combustor on the boiler efficiency, fouling and corrosion. Another key objective is to remove essentially all of the coal sulfur in the combustor with sorbent injection. Finally, the application of the combustor to a wide range of end uses, such as the retrofit and repowering of industrial boilers and power plants, combined cycle industrial power plants, cofiring of coal and waste fuels, firing low grade high ash coals, and vitrifying high carbon content fly ash, is being investigated.

Progress reports on the air cooled combustor tests were presented at the 5th Annual Pittsburgh Coal Conference [4] in September 1988, the 82nd Air Pollution Conference [5] in June 1989, and the 7th Annual Pittsburgh Coal Conference in September 1990 [6]. The economics of emission control in utility boilers with this combustor were first presented in March 1990 [7]. A detailed report on the Clean Coal Project was published in August 1991 [8]. More detailed descriptions of the work described in this paper were recently reported elsewhere [12,17,18,19,24,27]. Due to recent progress in the development effort, there have been significant improvements in the combustor performance and in the design of the combustor-boiler system. These design changes have substantially lowered the projected installed combustor cost from previously reported levels. Designs have been developed for combustors rated up to 150 MMBtu/hr for application to boiler retrofit and to new boilers whose design is integrated with the combustor.

Coal Tech's Advanced Air Cooled, Cyclone Coal Combustor

The cyclone combustor is a high temperature (> 3000^{o}F) device in which a high velocity swirling gas is used to burn crushed or pulverized coal. The ash is separated from the coal in liquid form on the cyclone combustor walls, from which it flows by gravity toward a port located at the downstream end of the device. A brief description of the operation of Coal Tech's patented, air cooled combustor is as follows (see Figure 1): A gas and oil burner, located at the center of the closed end of the unit, is used as a pilot to pre-heat the combustor and boiler during startup. Dry pulverized coal and sorbent powder for SO_2 control are injected into the combustor in an annular region enclosing the gas/oil burners. Air cooling is accomplished by using a ceramic liner, which is cooled by the swirling secondary air. The liner is maintained at a temperature high enough to keep the slag in a liquid, free flowing state. The liquid slag is drained through a tap located at the downstream end of the combustor.

Nitrogen oxide emissions are reduced by operating the combustor fuel rich. Between 67% and 80% NO_x reductions were measured in pilot combustors rated at 1 MMBtu/hr [9] and at 7 MMBtu/hr [10]. In the 20 MMBtu/hr combustor, about two-thirds stack NO_x reductions to less than 200 ppm (normalized to 3 % O_2) have been measured under staged operation with combustion efficiencies of 95% to 99% . Efficient combustion under fuel rich conditions requires either uniform solids feed or combustion gas temperatures in the 3400°F range. With feed non-uniformities and gas temperatures in the 3000 to 3200°F range, the measured combustion efficiencies in the 20 MMBtu/hr air cooled combustor averaged around 85% at a 0.7 stoichiometric ratio. At this condition, NO_x emissions are reduced to only 350 ppm (at 3% O_2), or about 33% below excess air levels.

A major focus in the air cooled combustor's development was the control of sulfur emissions by means of Coal Tech's patented, sorbent injection process into the combustor. The process is based on non-equilibrium chemical capture of the sulfur by the sorbent particles during the 0.1 second gas transit time in the combustor. The sulfur bearing sorbent particles can exit the combustor with the combustion gas into the lower (<2000°F) temperature zone in the boiler before the reaction reverses itself. Alternatively, the sulfur bearing sorbent particle can impact and dissolve in the slag and exit from the combustor before the reaction reverses itself. To retain the sulfur in the slag, the liquid slag transit time in the combustor must be less than several minutes. This is difficult to achieve, and to date, the highest sulfur concentration measured in the 20 MMBtu/hr combustor has been 20% of the coal sulfur. On the other hand previous results obtained in the 7 MMBtu/hr combustor tests [10] yielded SO_2 reductions approaching 100% [measured at the stack exhaust] with limestone injection in the first stage. After extensive testing, during the past year, SO_2 reductions in the 85% [illegible] range were measured at the stack using calcium hydrate injected into the 20 MMBtu/hr c[illegible]r at a Ca/S mol ratio of 3 to 4. Testing is in progress to determine the relative magnitude of sulfur capture in the combustor and boiler due to sorbent injection in the combustor. Recent sulfur capture results will be summarized in this paper.

Description of the 20 MMBtu/hr Combustor-Boiler Test Facility

The design of the 20 MMBtu/hr Coal Tech combustor is based on the detailed design of an air cooled combustor at thermal input ratings of 100 MMBtu/hr [11]. The latter size was initially selected because it was the most probable market size for this combustor. The 20 MMBtu/hr combustor was initially selected for application with coal water slurry fuels, and subsequently for commercial applications to small industrial boilers. The 20 MMBtu/hr combustor was installed on a 17,500 lb/hr steam boiler in an industrial plant in Williamsport, PA in early 1987. Figure 2 shows a side view drawing of the combustor attached to the boiler. The coal is pulverized off-site, and stored in a 4 ton capacity coal storage bin next to the boiler house. The coal is metered and fed into a pneumatic line to the combustor. The bin is refilled from a 24 ton trailer parked outside the boilerhouse without combustor shutdown. Since the combustor's best slag retention is in the 70% to 80% range, it does not meet local particulate emission standards of 0.4 lb/MMBtu. Therefore, a wet particulate scrubber is used for this purpose. Slag drains from the combustor through an opening at the downstream end of the combustor (See figures 1 and 2) into a water filled tank. The slag is removed from the tank by means of a mechanical conveyor and deposited in a drum. The fuel and air streams to the combustor are computer controlled using the combustor's thermal performance as input variables. Diagnostics consist of measurement of fuel, air and cooling water flows, combustor wall temperatures, and stack gas measurements, including O_2, CO_2, CO, SO_2, NO_x, and HC. Gas samples are taken in the stack above the boiler and in the exhaust from the wet scrubber. Gas samples are also taken at the exhaust from the combustor into the boiler with a water cooled probe that is inserted through the rear boiler wall.

TEST RESULTS

Test Activities Dealing with the Combustor's Operation

A systems approach has been taken to the development of the combustor because auxiliary sub-systems, such as coal feed, sorbent feed, combustion air supply, slag removal from the combustor, ash control in the boiler, and the combustor-boiler interface, directly impact the combustion efficiency, environmental control, and durability of the combustor. For example, high combustion efficiency and substantial SO_2 reductions were achieved only after a method for uniform coal and sorbent feed into the combustor was developed. Another area of extensive development was on the method to remove liquid slag from the combustor. A decrease of only several hundred degrees Fahrenheit in the slag temperature increases its viscosity to the point where slag flow ceases. Therefore, designs and procedures had to be developed which would maintain liquid slag flow in the combustor, and to clear the frozen slag that periodically accumulated in the slag tap. These consisted of adding local heaters to the slag tap section and adding an automated mechanical device that periodically breaks loose accumulated frozen slag from the slag tap.

In the first years of the present test effort, the combustor was operated under manual control. These tests showed that continuous real time control of the combustor's operation is very critical for durability, efficient combustion, and environmental performance. This control is critical with air cooled combustor walls because wall materials can rapidly degrade with wall temperature excursions. Therefore, beginning in 1990, a computer based control system was developed which allows completely automatic operation of the combustor. With computer control, it has been possible to replenish the ceramic walls of the combustor with frozen coal slag, essentially eliminating the need for periodic patching of the ceramic wall material. For this procedure to function properly, it is essential to maintain the ceramic liner-combustion gas interface at a constant temperature of about 2000°F, within a variation of about 50°F. This degree of wall temperature control has been recently achieved in continuous combustor operation tests, each of which extended over 24 hours. No refurbishment of the refractory lined combustor wall was required between these tests. Tests of longer continuous operation are planned in the near future.

To date about 1600 hours of operation have been accumulated. In the course of testing, design improvements to the combustor and boiler system were installed and tested. For example, the 20 MMBtu/hr combustor was originally designed for cyclic operation with daytime coal firing and nighttime shutdown or pilot gas heat input operation. As a result, certain components, such as the combustor-boiler interface section, were not designed for round-the-clock coal fired operation at peak rated heat input. In the current test effort, these components were redesigned and tested for round the clock operation. Round the clock operation at steady heat inputs were recently implemented with scheduled 24 hour periods of continuous operation at 14 to 19 MMBtu/hr with 10 hours of coal firing, followed by 10 hours of No.2 oil, followed by 3 to 4 hours on coal. Post test evaluation of the combustor revealed no degradation of the combustor's internal wall. As a result, longer duration test will be implemented shortly.

An important element of the combustor test effort is analytical computer modeling to develop scaling relationships by comparing the modeling results with combustor test results. A two dimensional combustion code developed at Brigham Young University [16] is being used for this purpose. This code follows a set of coal particles that represent a typical coal size distribution from injection to final burnup or exit from the combustor. The modeling will be used to optimize the combustor's solids injection geometry and length to diameter ratio for a range of thermal inputs. Initial results are in the process of being analyzed..

Finally, the test effort yielded design improvements which simplify the combustor's fabrication and enhance its performance. As part of this performance enhancement, the air cooling and combustion air flow paths were redesigned to reduce the parasitic power that is required to drive the fans. These modifications have been recently incorporated in the design of a series of combustors ranging from 40 to 150 MMBtu/hr, whose installed cost is lower than the costs estimated from the current design. The costs given in the system section of this paper are based on these new designs.

Environmental Performance

(i) SO_2 Emissions

Sulfur capture by injected sorbents in the combustor is a non-equilibrium process. The gas residence time in the combustor is short, typically about 100 to 200 milliseconds [20,21]. A theory to fully explain all these effects has not yet been developed. The authors believe that the wide variability in SO_2 reduction data with combustor sorbent injection is due to variation in operating conditions.[22].

The following is a summary of the SO_2 reduction results in the 20 MMBtu/hr combustor: Initial results showed considerable variability due to non-uniform conditions. After major improvements in combustor performance were achieved in the past two years, especially in the area of feed uniformity, limestone injection yielded reductions of 56% at a Ca/S ratio of 2. Calcium hydrate injection in the combustor yielded SO_2 reductions in the range of 85% at Ca/S ratios somewhat greater than 3. All these measurements were obtained in the stack of the boiler, and as was recently verified some of this sulfur reduction took place inside the boiler. This will be discussed in the next paragraph. These reductions are based on the coal sulfur content. While the main controlling parameters have been identified, and SO_2 reductions as high as 90% have been measured in recent tests, past experience suggests that until this result is repeated numerous times under identical conditions, some uncertainty remains whether all the governing parameters have been identified.

During the past year, the emphasis on combustor tests has been on automatic operation and durability. SO_2 emissions have been measured in each test. Figure 3 shows a statistical average for all the tests of the past year of the SO_2 reduction measured at the boiler outlet as a function of the total Ca/S mol ratio. In the tests, calcium hydrate was injected for sulfur capture and an equal quantity of limestone was injected to improve slagging in the combustor. As noted above, limestone has been observed to be between 2 to 3 times less effective than calcium hydrate in capturing sulfur in the combustor. Therefore, the combined Ca/S mol ratio shown in figure 3 was about 1.3 times greater than would be required only with calcium hydrate. Despite non-optimized conditions, 70% reduction of SO2 has been measured as a Ca/S of 4. This is equal to a Ca/S of 3 when the effectiveness of limestone is normalized to that of calcium hydrate.

To identify the relative degree of sulfur capture in the combustor and boiler with combustor injection of sorbent, gas samples were obtained inside the boiler by placing a probe within several feet of the exhaust region from the combustor. Here the gas temperature is in the 2000°F to 3000°F range. For this one test, the SO_2 reduction due to sorbent injection in the combustor was 19% at the combustor exit and 48% at the boiler outlet, namely at the base of the stack. This was the first direct confirmation that the sorbent continues to react substantially in the furnace and convective sections of the boiler. As these measurements are repeated in future tests, parametric data on the relative effectiveness of sulfur capture in the combustor and boiler will be obtained. Finally, as noted in the Introduction, a maximum of 20% of captured sulfur was measured in the slag removed from the combustor. It is planned to focus the tests on optimization of sulfur capture with sorbent injection in the combustor after the automation and durability tests are complete.

(ii) Fly Ash Vitrification and Solid Waste Disposal

Beginning in 1988, several dozen combustor tests were performed on fly ash vitrification. Ash injection rates up to 55% of the combined ash-coal flow were achieved. Slag samples were unreactive as per the EPA Reactivity Tests for sulfides and cyanides. The trace metal leachate levels were within the EPA Drinking Water Standard. Slag chemical analysis and other properties indicate that the material is not classified as a hazardous waste. Detailed discussion of trace metal behavior in the combustor is given elsewhere [10]..

One important application of the combustor is for the conversion of high carbon content fly ash into vitrified slag. This type of ash has been found in the exhaust of pulverized coal fired boilers that have been converted to low NO_x coal burners. Recently, a test was performed with such a fly ash in which the carbon content was 30%. The ash was cofired with oil in order to obtain an accurate mass balance. In commercial use, coal would be used as the auxiliary fuel. The result showed that the slag produced in this test had no detectable carbon. From the carbon content of the fly ash that escaped the combustor and was captured in the stack particulate scrubber, it was determined that the carbon content of the original fly ash was reduced from 30% to 4.5%. An average of 85% of the carbon was found to be consumed in the combustor. The total quantity of injected fly ash was 200 pounds in a little over one hour. This was too small a quantity to perform a mass balance in order to determine the amount of slag conversion in the combustor.

Based on these results, it was determined that the cost of using the air cooled slagging combustor to vitrify a 30% carbon content fly ash from an 80 MW power plant could be recovered in about 1 year from the savings in eliminating fly ash disposal and lost heating value.

(iii) Air Toxics

The emissions of organic micropollutants from fossil fuel combustion sources is a matter of increasing importance. In 1990, a series of tests on refuse derived fuel (RDF) combustion were performed in the 20 MMBtu/hr combustor. As part of this test effort, the magnitude of organic micropollutants was measured in the stack. The RDF was cofired with coal, in various ratios up to 33% by weight of RDF. To provide a baseline for these tests, the stack micropollutants were also measured with only coal firing. Three classes of organics were measured: dioxin and furans, (PCDD, PCDF, {polychlorodibenzodioxins/polychlorodibenzofurans}) and PAH (polycyclic aromatic hydrocarbons). The dioxin compounds range from the tetra dioxins (TeCDD) to the octa-congeners (OCDD). The former are 1000 times more toxic than the latter. Measurements were taken inside the boiler and in the stack. Detailed results of the sample analyses are reported elsewhere [23,24].. The average level of PCDDs for coal only firing as measured at the stack was 22.5 ng/Nm^3, and the PCDF levels at the stack were 7 ng/Nm^3, both at 7%O2. For the cofired RDF-coal case, the corresponding levels were 1457 ng/Nm^3 and 28 ng/Nm^3. The first number is in the mid range of emissions from municipal incinerators [28]. However, the most toxic TeCDD's were only 10.3 ng/Nm^3, or 0.7% of the total 1457 ng/Nm^3 PCDD emissions in the coal-RDF case, and they were below the detection limit with coal only. Also, it is important to note that due to a temperature limitation problem with the probe used for this stack sampling, it was necessary to operate the combustor at high excess air conditions in the final burnup stage in the boiler. As a result, the CO level in the stack approached 1000 ppm, which was about 10 times greater than under normal coal firing. It is thus most probable that the level of the PCCD and PCDF emissions from RDF would be much reduced under optimum burnup conditions.

APPLICATIONS OF THE AIR COOLED SLAGGING COMBUSTOR

Use of the Combustor in a Combined Cycle Power Plant

The combustor can be used with a wide range of fuels, including pulverized coal, shredded refuse derived fuels, oil, sludge waste fuels, or natural gas. The use of air cooling makes the combustor attractive for integration into a combined gas-steam turbine power cycle. The exhaust of a natural gas or oil fired gas turbine contains sufficient oxygen and its temperature is in a suitable range for use as pre-heated combustion air in the combustor. The combustor is attached to a boiler which drives a steam turbine. Part of the steam is extracted from the turbine in order to augment the gas turbine power output with steam injection.

There are several cycle configurations that can be analyzed, depending on the ratio of gas turbine to steam turbine power output. To achieve maximum efficiency, this ratio should be greater than 50%, i.e. the gas turbine power being at the high temperature end of the cycle should be maximized. However, this cycle would require either high cost, natural gas for over 50% of its fuel input, or a high capital cost, coal gasifier for the gas turbine. The much lower cost slagging combustor cannot be used to fire the gas turbine.

For these reasons, a cycle was selected which maximizes the benefit of the combustor, although it yields a lower cycle efficiency. To quantify the thermodynamic and economic analysis, a nominal 20 MW combined cycle plant was selected in which the gas turbine produced about 25% of the power while the steam turbine produced the balance. Figure 4 shows a schematic of this combined power cycle. The base case consists of a commercial natural gas fired turbine operating at a nominal 1800^{o}F turbine inlet temperature [29]. Its rated output is 5,940 kW with steam injection. The gas turbine exhaust steam provides the combustion air for the coal fired, air cooled combustor. In the 20 MW power plant, there are two combustors, each of which is attached to a separate factory assembled industrial boiler. Each of the two boilers produces 63,000 lb/hr superheated steam at 900^{o}F, 950 psi. The steam drives a 13,200 kW turbine-generator. The steam turbine has two extraction points, one provides the steam for injection into the gas turbine, while the other (not shown in figure 4) is used for feedwater heating. The balance of the steam goes to the condenser. This arrangement yields about 25% of the power output from the gas turbine, with the balance provided by the steam turbine. The plant has a cycle efficiency of 32.48% with the commercial 1800^{o}F gas turbine. With an advanced gas turbine having an inlet temperature of 2300^{o}F, the cycle efficiency increases to 34.5%.

A plant layout and cost estimation analysis of the 20 MW power plant was performed. With the exception of the air cooled coal combustor, all other major components are commercially available. Budgetary vendor quotations for all major components and sub-systems were obtained. The total cost of this greenfield plant was $24 million for about 19,000 kW, or $1265/kW. This compares with a cost of $1400-$1750/kW for natural gas fired Cheng combined cycle [30] and a cost of $2000-$2300 for a fluid bed combustion, steam cycle [31].

<u>Application of the Combustor to a 250 MW Power Plant.</u>

The economics of retrofitting Coal Tech combustors to a 250 MW coal fired plant were analyzed using the procedures recommended by DOE for evaluating Clean Coal technologies [12]. This consists of applying a process contingency and a retrofit difficulty factor to the installed cost of the new equipment added to an existing 250 MW coal fired plant. The added equipment consisted of a sorbent storage and feed system, sixteen Coal Tech air cooled coal combustors, and a slag removal system. Details of the procedures used for this analysis are given in reference 7. For the present paper, the economic analysis was updated by using the current combustor design for estimating the cost of each 150 MMBtu/hr combustors. The installed combustor cost was increased by a factor 1.94 for the contingency factors, and the cost of the other components, which are commercial, were increased by a factor of 1.1. Environmental performance data based on the best results achieved to date, namely, NO_x reductions of 80% and SO_2 reductions of 90%, with only combustor sorbent injection, were used in the analysis. The total capital cost for the retrofit was $43 million, when the other cost factors listed in reference 12 are added to the process equipment capital cost. This cost equals $172/kW.

Since the purpose of the retrofit is to reduce SO_2 and NO_x emissions, the conversion cost analysis was structured to allow a determination of the incremental cost of meeting these requirements. The analyses of the operating and maintenance items using the procedures and consumable costs of reference 12 showed that the variable operating costs were the largest contributor to the total operating costs. The sorbent, either limestone or calcium hydrate, each at a Ca/S mol ratio of 3, was the largest contributor to the variable operating costs. Parasitic power requirements to operate the combustors were a smaller, but still a substantial contributor. Using limestone, 15 year levelized operating costs were 7.36 mills/kW-hr and 8.01 mills/kW-hr for 2.5%S and 4.3%S coals, respectively. With calcium hydrate, the 15 year levelized cost increases to 9.23 mills/kW-hr for the 2.5% sulfur coal. This analysis assumed a 25%-75% equity-debt ratio with a 10% cost of funds and a 10% opportunity cost. These operating costs are about 30% less than the values quoted in the EPA/EPRI study[14] for 10 different LIMB cases, and they are less than one-half of the equivalent wet flue gas scrubber costs. The economic assumptions used in reference 14 are not known to the authors. Based on the capital costs listed in reference 14, they could not have differed significantly for the present values.

With limestone, the 15 year levelized cost of retrofitting the 250 MW power plant with the combustor yields a cost of $308/ton of SO_2 and NO_x with 2.5% sulfur coal. For 4.3% sulfur coal, the cost is $197/ton. The unit cost decreases with increasing coal sulfur content because the capital costs are essentially independent of sulfur content.

Application of the Combustor to the Retrofit of a 120,000 lb/hr Coal Fired Boiler

A recent analysis was performed to convert a pair of 120,000 lb/hr industrial coal fired boilers with the air cooled combustor. The installed cost of the conversion was less than $10/lb of steam, i.e. $2.4 million. This cost was obtained from budgetary vendor quotations for the fabrication of the combustors, all the combustor auxiliary components, the combustor instrumentation and controls, and the installation of the combustors on the boilers. Since the use of this combustor allows selection of a lower grade high ash coal as a fuel, the potential fuel saving alone is sufficient to recover the conversion cost within two to three years. In addition, in the particular boiler under consideration, the present combustion efficiency was poor due to the design of the furnace section. Adding the fuel savings from the high combustion efficiency in the slagging combustor reduces the cost recovery to a one to two year period.

Application of the Combustor to Retrofit & Repowering of 20 MW Power Plants.

Using the same economics as in the previous sub-section, a cost of $86/kW was obtained for the retrofit of a coal fired boiler with the air cooled combustor in a 20 MW power plant. In this case, the only new equipment consisted of the combustor, auxiliary combustor components such as a blower, pumps, valves, combustor controls and instrumentation, and combustor installation on an existing boiler.

Another site specific application that was investigated was the repowering of a 20 MW power plant with the air cooled combustor. In this case, the added equipment consisted of a coal pulverization and feed system, a limestone storage and feed system, an oil storage and feed system, a boiler, a slag removal system. a system for fly ash reinjection into the combustor from the baghouse, a baghouse, a stack, and a boilerhouse and associated structures. The existing turbine-generator, feedwater heating, and power transmission system would be refurbished. The estimated installed cost, using budgetary vendor quotations, was $650/kW. A blended fuel would be used consisting of 75% (by weight) of a high ash coal waste, 20% bituminous coal, and 5% number two oil, with a combined cost of $0.66/MMBtu. Income is derived from power sales to a regional electric utility for a 10 year period. The economic analysis used 20% equity, 80% debt financing at a 7.5% interest rate, seven year amortization, and a 40% tax rate. This yielded an attractive internal rate of return on equity of 28%. Other rate of returns can be derived by varying these economic assumptions.

Application to High Carbon Content Fly Ash Vitrification

This application was discussed in the "Test Results" section of this paper. The 30% carbon content of the fly ash tested is being produced in an 80 MW power plant at the rate of 6 tons/hour. A single slagging combustor can vitrify this ash and burn its carbon with the addition of coal and sorbent. The economics of the vitrification are very site specific. They depend on the carbon content of the ash, the ash disposal costs, the power production costs, and the market value of the slag. For the 80 MW plant studied, the increased combustion efficiency from carbon recovery in the fly ash and from elimination of fly ash disposal, allows recovery of the cost of the slagging combustor installation in less than 1 year.

CONCLUSIONS

The present six year test effort is the first commercial scale demonstration of this air cooled, slagging coal combustor. The initial three year test effort provided an operational data base for the combustor. These data have been subsequently incorporated in an automatic computer controlled combustor operating system which has substantially improved its performance, its environmental control, its reliability, and the durability of the refractory combustor wall. Wall durability requires maintaining the internal wall temperature in the 2000°F range to within 2% to 3%. This has been recently accomplished by using computer control for several continuous periods of 24 hour duration, without refurbishing the combustor wall between test periods.

Peak SO_2 reductions in the 85% to 90% range have been measured in the stack with calcium hydrate injection into the combustor. NO_x reductions in the 67% range have been measured in the stack with fuel rich combustor operation. The slag removed from the combustor is chemically inert. Cofiring of coal and refuse derived fuel in the combustor has yielded substantial reductions in the emissions of organic micropollutants.

The combustor was analyzed for various application, including a new 20 MW combined gas-steam turbine power plant, retrofit to a 250 MW coal fired power plant, repowering of a 20 MW power plant, retrofit of industrial boilers, and fly ash vitrification. In all cases the combustor offers significant performance and cost advantages over competitive technologies.

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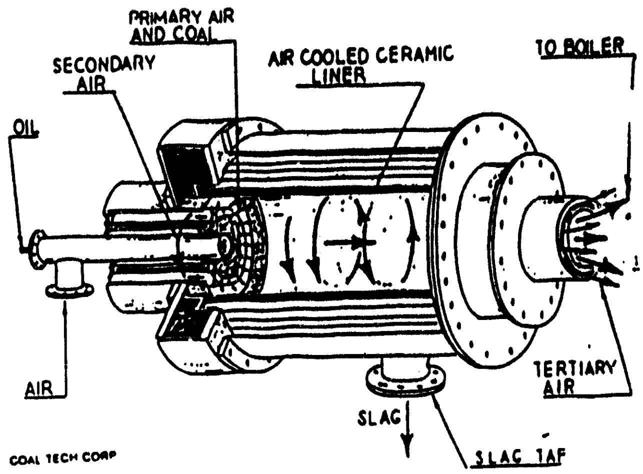

Figure 1: Schematic of the Coal Tech Air Cooled Combustor

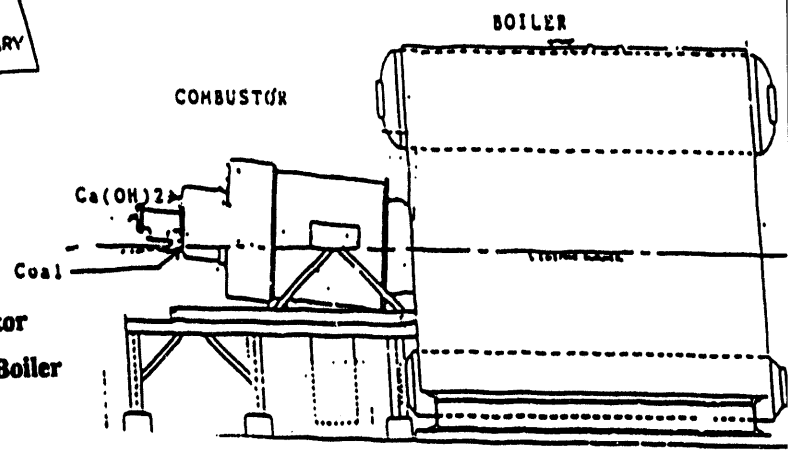

Figure 2: Drawing of Coal Tech's Air Cooled Combustor Installed on a 20 MMBtu/hr Oil Designed Boiler

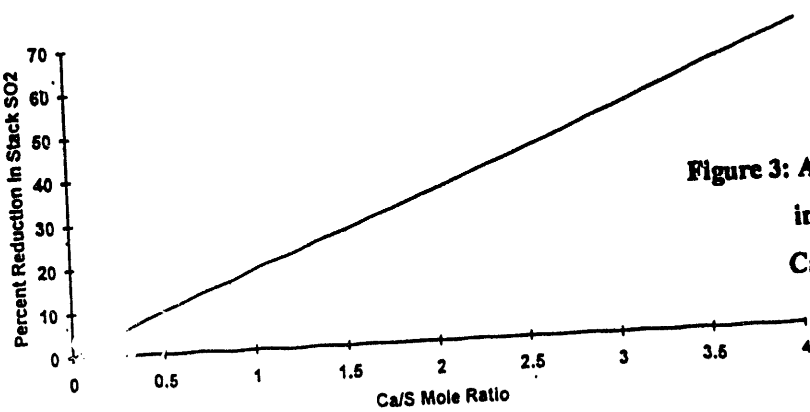

Figure 3: Average Measured SO2 reduction in the Stack SO2 in the 20 MMBtu/hr combustor versus Ca/S Mol Ratio of Injected Sorbent.

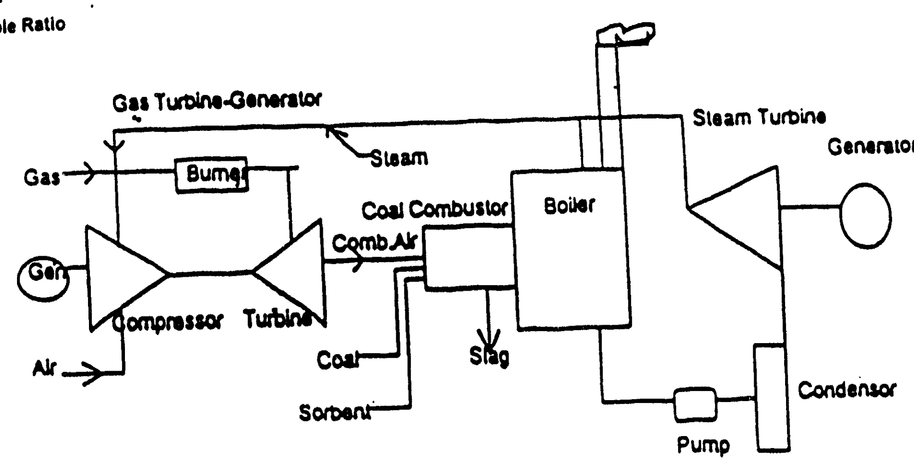

Figure 4. Schematic of An Industrial Combined Cycle Power Plant Using the Coal Tech Combustor