COMBUSTION IMPROVEMENTS IN STOKER FIRED BOILERS

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Introduction

Today, stoker fired boiler plants are common throughout Eastern Europe. The small and mid-sized coal combustion plants utilize travelling grate stokers to produce steam or hot water that is used by district heating companies and industries. When these plants were first designed 25 to 50 years ago, reliability was the key concern. Now, the 1990's, there is considerable attention being paid to increasing efficiency and reducing emissions.

It is because of the environmental concerns and age of the plants that some believe that stoker plants should simply be replaced. This may be true in certain cases for very small plants or where it is economically feasible to replace or eliminate a plant. For example it might be more economical to eliminate a small district heating plant if it is close to the distribution lines of a large system. The smaller distribution system could be connected to the larger system. However, there are some points in favor of keeping an existing stoker plant. First the equipment and the infrastructure are already in place in an existing system. Second, although the equipment may be old, some older equipment was built to last longer and to be more durable than newer equipment. This reinforces the fact that the plants were origanally built for reliability. Third, dramatic improvements can be made to the efficiency and emissions level of these plants for significantly less money than replacement cost. The application of upgrading plants and improving efficiency has been documented in the United States. These proven methods along with new technological advancements can be applied in Eastern Europe to make significant improvements to the performance and emissions from existing stoker plants.

In Krakow, Poland, Control Techtronics of Harrisburg, PA has teamed with The Pennsylvania State University (Penn State) to provide an economical solution to the problem of improving efficiency and reducing emissions from stoker fired boiler plants in the Polish/American DOE Krakow Clean Fossil Fuels and Energy Efficiency Program. A multi-disciplinary approach to improving the stoker operations can be classified into three areas as follows:

1. Fuel Characteristics.
2. Automatic Control of Equipment.
3. Operator Training.

Work conducted under Phase I of the DOE program in Krakow recognizes these areas of need[1]. Although, these areas are inter-related, they are addressed individually in this paper for the sake of clarity.

Fuel Characteristics

For stoker applications, combustion is governed primarily by the physical properties of the fuel bed and air distribution throughout the bed and not by the inherent reactivity of the coal or even by the percentage of ash in the coal. The physical properties of the coal bed are particle size, particle size distribution, caking properties and ash fusion temperature of the coal which govern the flow of air through the fuel bed.

For proper combustion, the air must rise up through the grate and diffuse through the bed of coal. The combustion air must have intimate contact with the coal particles throughout the combustion process. This principle of securing proper distribution of air through a stoker fuel bed is fundamental; most of the difficulties that arise in burning solid fuel are the result of poor distribution of combustion air. Coal particle size and size distribution affect the air distribution within the bed, the void ratio and the pressure drop. Void ratio and pressure drop can then be correlated to carbon burnout of the coal during combustion. Research conducted on a series of low volatile coals helps to illustrate these principles. Figure 1 shows a plot of initial pressure drop across the fuel bed versus carbon burnout of the fuel, which is a measure of combustion efficiency[2]. A higher initial pressure drop across the bed results in lower burnout of the fuel. This result can be explained qualitatively by considering a coal that has a wide particle

Figure 1
Burnout on LV Coals vs. Initial dP

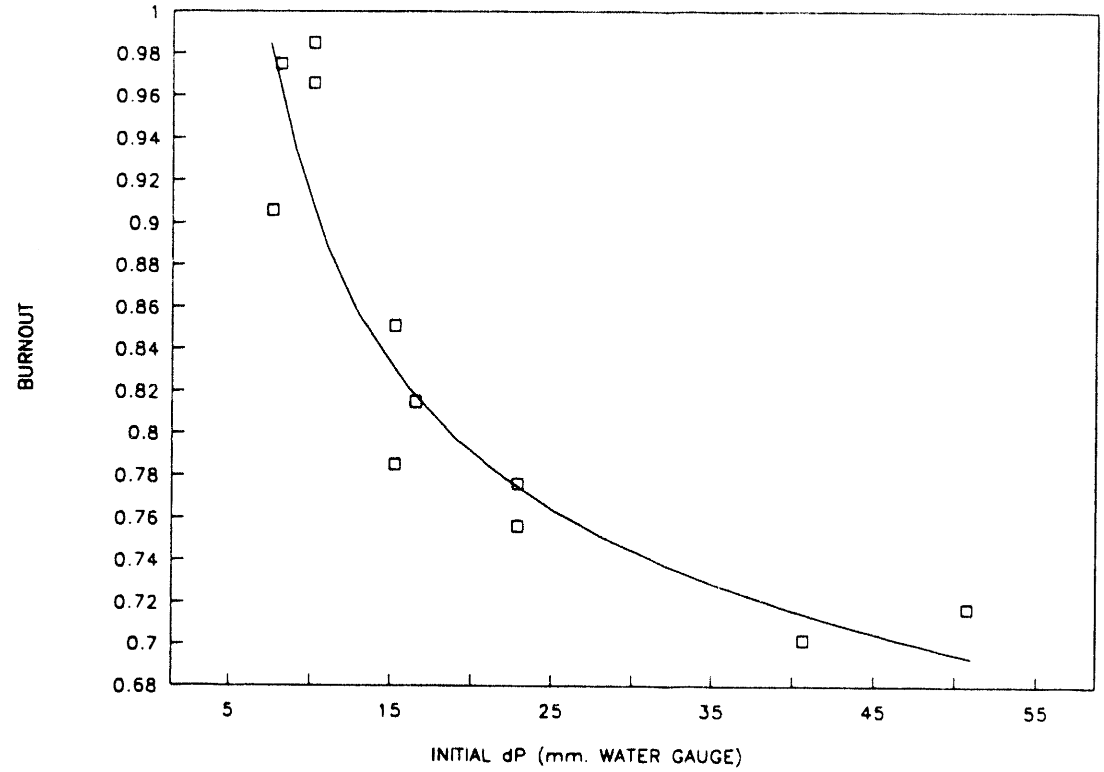
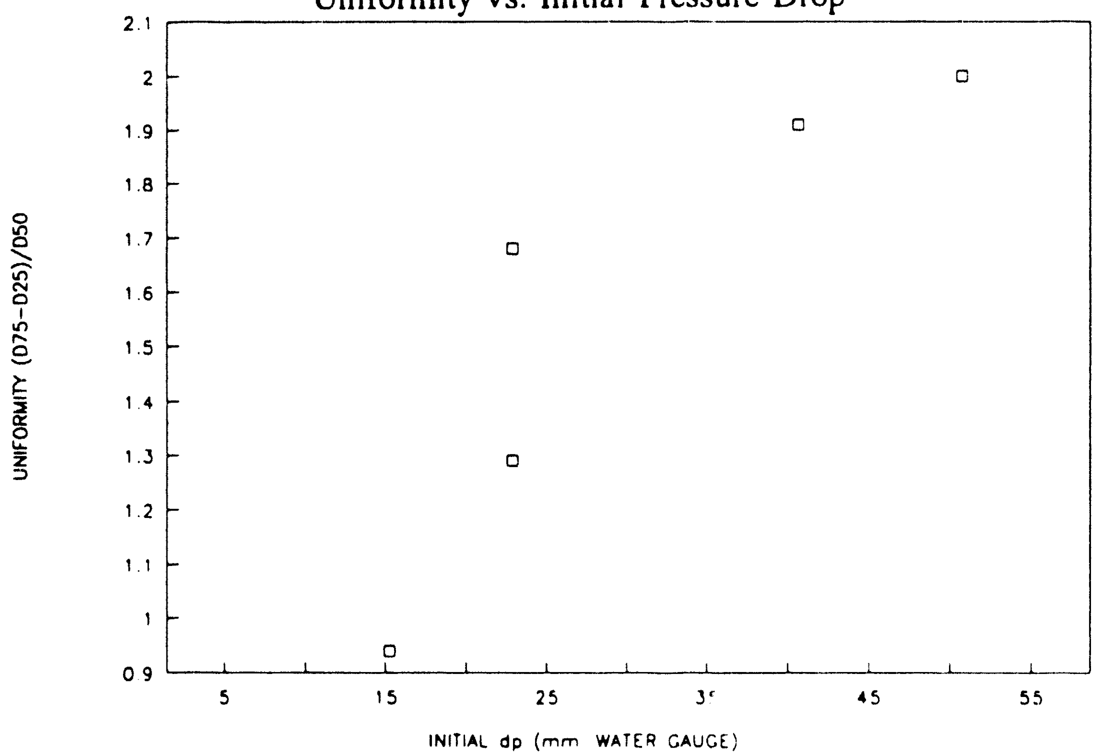


Figure 2
Uniformity vs. Initial Pressure Drop



size distribution. The finer particles fall into and take up the voids between the larger particles. They tend to pack and clog the bed, increasing the bed density, increasing the pressure drop and causing poor distribution of air throughout the bed. When air does not reach the coal particle or have intimate contact, it will not burn completely. Therefore, coals with wide particle size distribution or a high percentage of fines create combustion problems. Figure 2 is a plot of initial pressure drop versus uniformity coefficient for the same coals[2]. A low uniformity coefficient indicates a narrow particle size distribution. This plot shows that the more uniform the size, the lower the pressure drop. Therefore, coals with more uniform particle size distribution burn more efficiently in stoker boilers than those with a wide particle size distribution and a high percentage of fines.

Although initial particle sizes of a coal can be determined by a sieve analysis, the sizes of the particles in the bed change during combustion. They decrease in size due to a loss of mass during the combustion process. They may also increase in size by agglomerating or fusing due to clinkering and swelling. A caking coal or a coal with a high free swelling index (FSI) will expand when heated. This tends to close off the voids between coal particles causing poor air distribution within the bed. A coal with a low fusion temperature (below 1350°C) will melt into a mass on the stoker grate. This mass does not easily allow air to penetrate, and will also cause poor air distribution, and incomplete combustion. The various problems described above can compound upon one another. When air distribution is poor, local holes develop in the bed and allow relatively large quantities of air to pass. Excess temperatures or "hot spots" are then created which increases the possibility of fusion of the coal. In turn new or larger blow holes are created in the bed.

A primary task in improving boiler efficiency and reducing emissions in the Krakow region, is to analyze the quality and characteristics of the coal. Boiler plants in Krakow receive their coal from the Upper Silesian Basin. The run of mine coal from this region may go through various coal preparation processes that include crushing, screening, heavy media mineral separation or differential density separation. The most common coal that is used in the stoker plants of Krakow is 20 x 0 m.m. coal that is not cleaned by any mineral separation process. An analysis of one such coal is shown on Table 1. Several properties shown in the analysis are highly desirable for stoker coal. The caking indicated by the free swelling index is zero meaning that the coal does not swell upon heating. The ash softening temperature is 1400°C which is acceptable and means that the coal does not have a tendency to fuse together during combustion. The Hardgrove Grindability index of 53 is relatively low indicating that the coal is hard and particles do not easily degrade. This is important because extremely soft coal that is initially sized properly will degrade during transport and handling, thus creating a high percentage of fines in the coal. As stated earlier, the high percentage of fines results in poor air distribution in the stoker fuel bed and reduced combustion efficiency. The volatile content of the coal shown on Table 1 is 23.5 - 25.5%. This is relatively low and no overfire combustion air is required for efficient combustion. However coals with higher volatile content may require overfire air and coals with a volatility greater than or equal to 30% require properly controlled overfire air for efficient combustion.

Although the ash content is relative high 18%-25%, it is acceptable because stokers are capable of burning such material. Results of testing conducted by Brookhaven National Laboratory under Phase I of the U.S. DOE Krakow Clean Fossil Fuel and Energy Efficiency Program showed that cleaning coal does not significantly improve combustion[1].

Figure 3 shows a particle size distribution of the coals used in the tests by Brookhaven. The washed and unwashed coals have similar particle size distributions with the washed coal having a slightly higher percentage of fine particles. The high percentage of fines (over 50% smaller than 5 mm) causes packing of the bed and disrupts the flow of air through the fuel bed which hinders combustion. This demonstrates that cleaning improperly sized coal does little to improve combustion and further confirms that sizing and not ash content is the key for gaining combustion improvements for this application. It should be noted that although ash content is not the main parameter governing stoker combustion, reduced ash content does have some benefits. The higher calorific valve means less coal must be purchased and there is less ash to be disposed.

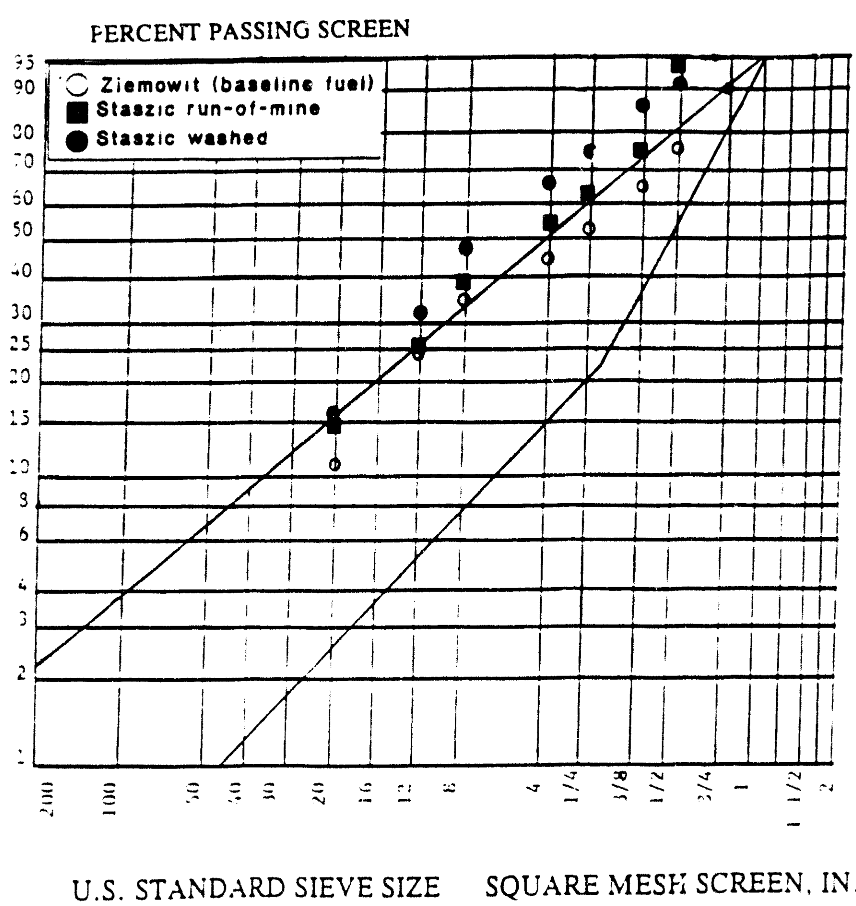
In developing a program to improve efficiency in stoker boilers in Krakow, it was necessary to analyze how to improve the characteristic of the fuel bed. During this investigation, we performed the following:

a) observed the combustion of the coal presently used
b) studied results of combustion tests conducted under earlier phases of the project
c) visited a mine and cleaning plant which is a source of coal for Krakow
d) obtained samples of coal
e) analyzed our results along with results from other's testing
f) obtained cost information on various grades of coal

TABLE 1
Analysis of 20 x 0 mm. coal from Upper Silesia

Ash Content	18-25%
Total moisture	7-11%
Calorific value	23000-21000 kw/kg
Volatile content	23.5%-25.5%
Sulfur content	0.7%-0.8%
Ash softening temperature	1400°C
Free Swelling Index	0
Hardgrove Grindability	53

Figure 3
Particle Size Distribution of Test Coals[1].



As a result, we found that the most economical solution is to properly size the coal without cleaning. Screening the coal to obtain the proper sizing increases the price only 10% to 20% and will allow for more significant improvements when used with automatic controls. As part of preliminary work for this project, we found existing production facilities in Upper Silesia that will provide a variety of specified sizes for a price moderately higher than the current fuel. In addition many of these coals have other characteristics which make them an excellent stoker coal. The result is that a graded unwashed coal 20 x 8 mm. will be utilized on the stokers included in our work.

Automatic Control of Equipment

With the proper fuel in place, the next step is to automatically match the fuel and air inputs to the boiler with the output required. It is fundamental to boiler plant engineering that if you take a piece of coal, you can calculate how much air is required to burn it. The same is true regardless of the amount of coal. For a certain quantity of fuel, there is an optimum amount of air that should be utilized to efficiently and cleanly burn the fuel.

Too much air results in an excessive discharge of hot gases from the stack with a correspondingly high heat loss. For example, at optimum conditions, stokers can be operated down to 40% excess air. At various loads and conditions that are less than optimum, a properly controlled stoker fired boiler can operate between 40% and 100% excess air. Results from the Phase I DOE work at the MPEC Balicka Plant in Krakow show that excess air ranging from 107% at the best testing point to over 500% in tests with the most inefficient results.[1] The excess air rates averaged about 240% which translates to an efficiency loss of about 15%. However, at some conditions efficiency loss was over 20%. These losses are in excess of what would be expected with an efficient automatic combustion control system. Increasing the efficiency by properly controlling combustion with an automatic combustion control system will reduce the cost of fuel significantly. Since emissions can be calculated as a function of the quantity of fuel used, increasing combustion efficiency not only saves fuel costs but also reduces emissions. Reduction in emissions have an economic benefit to the plant owner because emission fees have been imposed and have an environmental benefit to the community.

While an excess of air in the boiler is inefficient, a deficiency of air is also inefficient. When insufficient air is supplied to the boiler, some of the fuel passes through the furnace on the grate as unburned coal or partially burned coal with the ash or as volatile hydrocarbons in the flue gas. Incomplete combustion also represents an unsafe operating condition. Combustion gases that are not completely oxidized will explode if exposed to oxygen at high enough temperatures.

The function of the automatic combustion control system is to properly match the air flow rate to fuel input so that there is enough air to extract all the energy from the fuel while maintaining a minimum of excess air. The control systems measure the steam pressure or hot water temperature for a hot water boiler and modulates the air and fuel input accordingly. If the steam pressure begins to drop, the air and fuel are increased and if the steam pressure increases, air and fuel decrease. There are many ways to accomplish this based on the equipment and fuel used. It is also important to a have proper level of sophistication in the control system that matches the design to the response time of a stoker. Some engineers believe that stokers can be controlled just like pulverized coal boilers in utilities or like gas and oil burners. This is not true, so it is important to understand what can be done with a stoker system.

There are three basic types of modulating combustion control systems. They are:

* Single point positioning
* Parallel Positioning
* Metering

The simplest type of modulating combustion control system is a single point positioning type. A pressure transmitter measures the steam pressure and sends a signal to a controller which in turn sends a reverse proportional output signal to an actuator. The actuator is modulated in response to output of the controller to move a jackshaft. This movement of the jackshaft changes the input of air and fuel. The air changes by changing the position of a fan damper. The fuel flow changes by movement of the position of a fuel valve. Since the fuel valve and forced draft damper are linked together, the system will not compensate for any variations in the fuel. To do so, would require adjustment of mechanical components in the system that are normally fixed during system start-up or when making calibration adjustments to the controls. For this reason, a single point positioning system is normally only used in natural gas and fuel oil fired applications.

A parallel positioning system utilizes the signal from a pressure transmitter to regulate the fuel and the forced draft air inputs in parallel. A pressure transmitter in the steam header generates a signal that responds to changes in the boiler output steam pressure. It is a reverse proportional signal that increases as the boiler output pressure decreases to provide more fuel and air. For a hot water boiler the signal would be generated by the output hot water temperature. Separate control actuators are installed to automatically regulate a damper on a constant speed forced draft fan and the speed of the stoker drive. This provides for automatic control of the air and the fuel independently so that the air/fuel ratio can be characterized for each boiler. This is the most effective and economical type of system for small and medium sized stoker fired boiler plants since it usually matches the physical equipment layout of such plants. It can also be supplied with the components to make it flexible for changing conditions.

A metered system is similar to a parallel positioning system except that it has an additional level of sophistication. Fuel flow and air flow are metered and a signal is fed back into the controllers to correct air/fuel ratios that may change due to variation in the fuel quality, variations in the temperature and humidity of the air, and mechanical linkage of the control system over time. A feature known as cross-limiting can also be incorporated into metered controls to assure that there is always sufficient air for complete combustion. This is a very good type of control system, but is usually not applicable to stoker systems because very precise fuel feed is required. In most stoker plants, fuel is batch weighed to the boiler or not metered at all. Although changes could be made to accommodate metering, they would be expensive. Therefore metered systems are most applicable for large electrical generating plants and very large industrial boilers.

On first appearances, small stoker boiler plants in Poland look similar to ones in the United States. Three to six boilers are coal fed by an overhead bunker to a traveling grate stoker. Some other features are also similar such as location and arrangement of fans, pumps, deaereator and basic flue gas cleaning devices. Some key specifications relative to combustion control of the Balicka Plant owned by the MPEC in Krakow are shown on Table 2. It should be noted that it is missing some significant components that are critical to efficient operation of the plants. Very little was built into the Balicka plant to monitor or control plant efficiency. Most stoker boiler plants in Poland contain no measurement of the input of fuel or the output of the steam or hot water. There is no automatic control of the combustion process. The forced draft fan and induced draft fan are usually maintained at a maximum rate while fuel may be changed manually with load conditions. This means that there is high excess air, fuel feed probably does not match the load conditions and certainly there is no optimization of the air/fuel ratio at any given fuel feed rate or load condition.

Figure 4 schematically shows the type of systems that Control Techtronics is installing in Poland on stoker fired steam boilers. It is a parallel positioning system with bias and manual override capability. It automatically controls the air and the fuel independently so that the air/fuel ratio can be characterized for each boiler. The controls have the ability to be switched to a manual mode for start-up and shut down operations or for other occasions when manual operation may be required. The bias function adds to or subtracts from the output signal of the controller while it is still in automatic operation. This gives the operator more flexibility by allowing him to make minor control changes while maintaining the system in the automatic mode. Such changes may be desired due to changes in the fuel supply or an anticipated load change. Sometimes the operators know that the load will increase or decrease by a drastic amount at a certain time each day. This is an example of an anticipated load change.

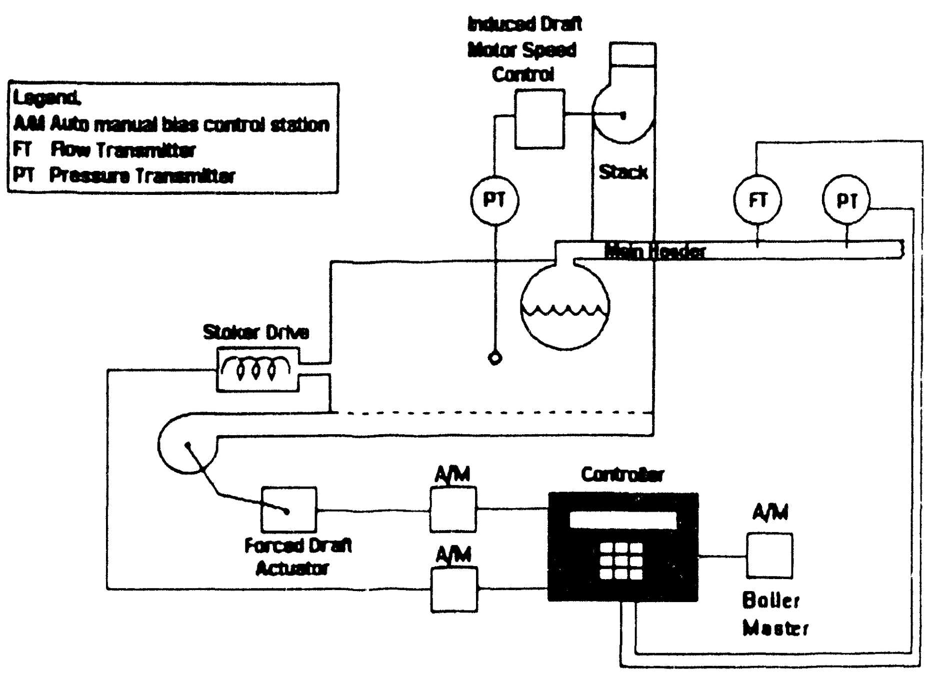
In the stoker systems, control of furnace pressure is an additional independent control loop that is critical to safe, efficient operation. Stoker furnaces cannot operate under a positive pressure without causing damage to equipment and safety hazards to operating personnel. Therefore, a negative pressure must be maintained. In boilers without automatic controls, the induced draft fan operates at full speed with dampers that are fully open. The fan and dampers are maintained in this manner to assure safe operation. The high negative draft draws ambient air into furnace openings causing extremely high excess air. Under automatic operation, the furnace pressure can be set at a slightly negative pressure of about 2mm water gauge by the controller. Traditionally, for boilers of this size, the furnace is controlled by modulating a boiler outlet damper or induced draft fan damper. With the availability of reliable, affordable variable frequency controllers, the draft in the Control Techtronics system will be controlled by modulating the speed of induced draft fan motor. A pressure transmitter will measure the furnace pressure and send a signal to the controller. The controller will then signal the variable frequency controller to increase the speed when more draft is required and to reduce the speed if the draft increases. Thus a properly controlled draft system safely evacuates combustion gases from the boiler without drawing excessive ambient air.

Since cyclone dust collectors are most commonly used in stoker plants, there is concern that the reduction in excess air will reduce the velocity through the collectors thus reducing the collection efficiency of the cyclones[3]. This concern is addressed in two ways. First, high excess air also increases the velocity through the fuel bed and boiler causing a higher carryover of particulate matter out of the boiler. By reducing excess air, particulate exiting the

TABLE 2 SELECTED BOILER PLANT INFORMATION ON THE MPEC BALICKA PLANT IN KRAKOW	
Stoker Type	Travelling Grate
Overfire Air	[1]Yes
Emission Control Devices	Mechanical Collectors
Air/Fuel Ratio Control	Manual
Control of Firing Rate	Manual
Control of Furnace Pressure	Manual
Measurement of Plant Output	Estimated
Measurement of Coal Input	[2]Estimated
Plant Input-Output Efficiency	62.6%

1. Not normally used
2. Estimated by the speed of the stoker, depth of the bed and bulk density of the coal.

Figure 4
Parallel Positioning Combustion Control.



boiler will decrease. Second, improvements to the cyclone collectors will offset the efficiency reductions or actually improve the collection efficiency of the cyclones.

The Control Techtronics controller is a multi-loop microprocessor based controller that accepts 32 analog inputs and has up to 8 analog outputs. A digital input/output board includes up to 24 relays that can be selected for either inputs or outputs. The controller as well as all of the displays used in Poland will be in metric units and in the Polish language. The Control Techtronics controllers are functioning successfully on stoker fired boilers as well as natural gas, fuel oil, and refuse boilers in the pollution sensitive areas of the northeast United States, southern California, and Mexico. With this experience, the application of these controls to stoker fired boilers in Poland will not be an experiment but a matter of applying proven engineering solutions to solving these problems.

Operator Training

The third aspect of the program that is integral part of improving efficiency and reducing emissions is operator training. Even with the proper fuel and automatic controls, many aspects of plant operation require good operating techniques to insure safety, reliability and efficiency. Boiler operators also need to be trained to recognize the early signals of emissions or plant equipment problems, and must be able to determine the quality of the coal they are going to burn. This aspect of boiler operations might seem obvious, but it is often ignored or undervalued.

One example of the importance of operator knowledge relates to regulating fuel feed tc the stoker. There are two ways to regulate the amount of coal supplied to the furnace: by controlling the speed of the stoker and by controlling depth of the coal in the bed. Most manually operated plants control fuel feed by changing the depth of the bed. On the other hand, with an automatic control system, the fuel feed rate is controlled automatically by the speed of the stoker drive. Under automatic operation, the bed depth is set at one level and may be changed only occasionally by plant personnel to account for seasonal load changes or changes in the fuel. However, the operator must be aware of initial settings and how much and when to change the bed depth.

A second example of how an operator must use good judgement relates to distribution of air in the stoker. The automatic combustion controls will modulate the total quantity of air to the boiler, but there are manual adjustments to determine the distribution of the air to various zones in the stoker. These adjustments are also made infrequently, but when required, judgement must be used in such matters. In addition, the supervising operator should frequently observe the combustion and values of instrument readouts to see if adjustments to the automatic controls are required. Such observations include flue gas temperature, flue gas oxygen readings and burnout of the coal as it discharges to the ash pit.

In the Control Techtronics, Penn State project, each boiler operator will be trained not only on the operation of new controls but also on proper stoker boiler plant operation. This includes topics on combustion of fuels, operation of stokers, boiler control systems, boiler water treatment and plant safety. The Penn State Facilities Engineering Institute works primarily with district heating and small industrial type boilers, the majority of which are stoker fired boilers. Training material developed by personnel at Penn State for this application and currently used for operator training by hundreds of operators in the United States will be the basis of the training curriculum. The material will be modified and translated using the Polish language and copyrighted.

To overcome cultural and language barriers, we will be working with the Polytechnika Krakowska to translate and modify the training material. Native Poles will conduct the actual training sessions with boiler operators. We will then work with the Polytechnika in the second period of this work to establish a training center in Krakow as a long term resource. As part of the training center, a boiler control simulator will be built for classroom training.

The individuals who will install, start-up and service future control systems in Poland will also require training. Initial training will take place at Penn State University with subsequent field training in the United States by Control Techtronics.

Predicted Results

Table 3 shows current estimated emissions, fuel usage and efficiency from the MPEC Balicka Plant in Krakow and compares it to predicted results after implementation of the program described herein. The average annual efficiency is currently about 62.5%. With properly graded fuel and automatic combustion controls an average efficiency of 72.5% is achievable. Currently, the plant uses 19,000 tonnes/year of coal. The predicted fuel consumption can then be calculated based on the efficiency, the calorific value of the fuel, and the annual production as follows:

TABLE 3
A COMPARISON CURRENT ESTIMATED EMISSION AND PREDICTED EMISSION WITH PROPOSED ENHANCEMENTS AT THE BALICKA PLANT

	Current Estimated	Predicted
Plant Input-Output Efficiency	62.5%	72.5%
Annual Fuel Usage	19,000 tonnes	14,100 tonnes
Annual Heat Production	225,580 GJ	225,580 GJ
Particulate Emissions	220 Mg/year	53.6 Mg/year
SO_2 Emissions	215 Mg/year	160 Mg/year
CO Emissions	19.0 Mg/year	14.1 Mg/year

$$\text{Fuel Used} = \frac{225{,}580 \times 10^9 \text{ J.}}{(.725 \text{ eff.})(1000\text{kg/tonne})(22{,}000{,}000\text{J/kg})}$$

$= 14{,}100$ tonnes

A particulate emissions limit of 0.40#/MMBtu is required for older stoker plants in the United States. Stoker plants meet or exceed this requirement by using mechanical collectors, automatic combustion controls and properly sized fuel. Using this experience as a model, a maximum of 0.40#/MMBtu is the projected particulate emissions for our program. The 0.40#/MMBtu is equivalent to 172g/GJ. Based on the calorific value of the fuel, a predicted 53.6Mg/year of particulate will be emitted. This is a 75% reduction in particulates from the current 220Mg/year. Predicted reductions in SO_2 and CO are a function of the increased efficiency and reduced coal consumption. The SO_2 emissions will reduce from 215Mg/year to 160Mg/year while CO should reduce from 19.0Mg/year to 14.1Mg/year.

The savings in fuel costs realized from the predicted gain in efficiency is estimated at $55,700/year by the following:

(19,000T)($20/T)-(14,100T)($23/T)=$55,700/year

Current fees for emissions are: 600 zl/kg for particulates, 1100 zl/kg for SO_2, and 300 zl/kg for CO.[4] Based on the projected reduction of emissions shown in Table 3, the annual savings in emissions fees would be $8,090/year.

Other savings not quantified here are reduced ash disposal costs, reduced power consumption by plant equipment, and reduced plant maintenance costs. Based on an implementation cost of $125,000 to $175,000, the savings quantified above will provide a simple payback of two to three years.

Conclusions

Existing stoker fired boiler plants in Eastern Europe need to reduce air emissions and increase operating efficiency. The cost to eliminate or replace many of these plants is too great. Therefore an economical means of achieving these goals is necessary. Control Techtronics and Penn State have examined and analyzed the needs of these plants and then developed a multi-disciplinary approach to reducing emission and operating costs. The approach outlined in this paper provides sound solutions to the problems encountered in stoker fired boiler plants based on the analysis and proven field experience. It is anticipated that the analysis used here and similar solutions can be applied throughout Poland and Eastern Europe.

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COMPLIANCE ADVISOR: A SOFTWARE TOOL FOR FUEL SWITCHING/BLENDING TO MEET SO_2 REGULATIONS AT COAL-FIRED POWER PLANTS

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1. OBJECTIVES AND APPROACH

Because of the stringent sulfur dioxide emissions regulations imposed by the Clean Air Act amendments, a considerable number of utilities are switching to or blending with low-sulfur coals such as Powder River Basin subbituminous coals. Switching to or blending with "non-design" coals, however, can cause many boiler operational problems such as slagging, fouling and failure of particulate collection systems. Guidelines are needed for utilities to select and blend coals which meet SO_2 regulations while minimizing operational problems.

The project is designed to develop a user-friendly software environment for utility and coal companies which provides users with blending strategies that meet sulfur dioxide emissions regulations while saving fuels costs and minimizing operation costs. The idea behind the software environment is that prediction of performance of a coal in a given boiler is possible by carefully studying interaction among coal constituents during and after combustion. The software is being built on existing software packages for the prediction of slagging (Slagging Advisor of PSI Technology) and electrostatic precipitator performance (ADAPCESP of ADA Technologies). The software is also being verified through laboratory-scale and full-scale testing.

The technical objectives to achieve the goal are as the following:

1. Identify input and output parameters for the software environment and develop a user-friendly input/output shell for the software product;
2. Identify the partitioning of inorganic coal constituents among vapor, submicron fume, and flyash products generated from pulverized coal combustion;
3. Investigate the gas-solid reaction between calcium in ash and sulfur dioxide in flue gas at various gas temperatures and compositions;
4. Investigate the heterogeneous catalytic oxidation reaction of sulfur dioxide on iron-containing ash surfaces at various gas temperatures and compositions;
5. Integrate submodels;
6. Perform field tests to investigate the fate of sulfur in coal in utility boilers with emphasis on the interaction between ash and sulfur dioxide.

A Windows-based input/output shell has been developed using a C++ compiler. Submicron ash formation model has beed developed based on vaporization data obtained from laboratory-scale experiments (Quann, 1982). Kinetic data on sulfation of calcium in ash by sulfur dioxide have been obtained at PSI Technology Company from entrained flow reactor experiments. Kinetic data on heterogeneous oxidation of sulfur dioxide in the presence of pyrite-derived ash are also being collected from a bench-scale isothermal differential reactor. Existing submodels for Compliance Advisor are being improved and integrated. The first field test is planned in May 2, 1994, in Salem Harbor Unit 3 of New England Power Company.

2. SULFATION OF CALCIUM IN ASH BY SULFUR DIOXIDE

Laboratory-scale experiments have been performed to demonstrate the feasibility of the capture of sulfur in coal by calcium from the flyash in a temperature environment similar to utility boilers. Experiments have also been performed with coal ash to determine the kinetic parameters for sulfation of calcium in coal ash by sulfur dioxide in flue gas. Two coals and one coal ash were selected for the study: an Eagle Butte subbituminous coal (EB), a Kentucky No. 9 bituminous coal (K9), and an ESP hopper ash from Detroit Edison. Coal blends were prepared by adding a weighed amount of a coal to the other, and thoroughly mixing with a tumbler.

Combustion experiments were carried out in an entrained flow reactor at a wall temperature of 1200°C. The total gas flow rate was 1.06 scfm (standard cubic feet per minute) allowing 3s of total residence time. Experiments were carried out at 21% oxygen in nitrogen. Three sets of experimental runs were done with various coal blends and sulfur sources injected into the entrained flow reactor:

Run 1: ESP hopper ash from Detroit Edison as sulfur sorbent and bottled SO_2 in gas stream as the sulfur source;

Run 2: Ash generated in situ by combustion of EB coal as sulfur sorbent and bottled SO_2 in gas stream as a major sulfur source;

Run 3: Ash generated in situ by combustion of coals and coal blends as sulfur sorbent, and SO_2 released from coals and coal blends as sulfur sources;

The inlet and outlet concentrations of SO_2 were measured using a Horiba sulfur dioxide monitor (Model CFA-311A) and a ThermoElectron sulfur dioxide monitor. SO_2 readouts from the two SO_2 meters were also checked against concentrations determined by titration.

The first set of experimental runs was carried out at gas temperatures ranging from 900 to 1200°C. The calcium-rich ESP hopper ash from Detroit Edison was first heat-treated to remove sulfur in coal ash. Figure 1 shows a typical SO_2 concentration change with time at the outlet of the entrained flow reactor. At time 160s, the feeder was turned on (point A in Figure 1). The SO_2

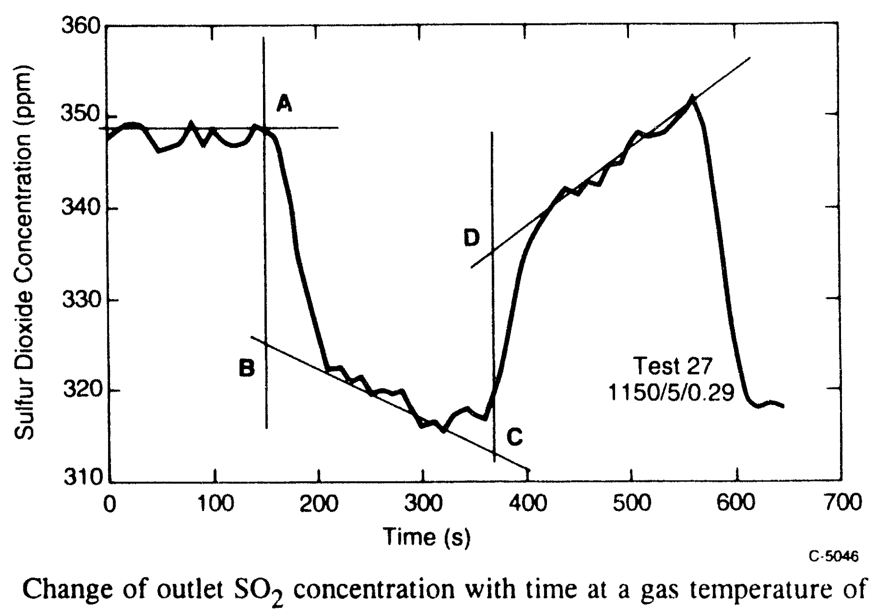

Figure 1. Change of outlet SO_2 concentration with time at a gas temperature of 1150°C

concentration dropped from the background level of 348 ppm down to 322 ppm, and kept decreasing until the feeder was turned off at time 360s (point C). As the feeder was turned off, the SO_2 concentration went up to 340 ppm and kept increasing.

The decrease of SO_2 concentration between point A and B by 20 ppm is due to the reaction between the injected ash and sulfur dioxide in gas. The slow decrease between point B and C is due to the reaction between deposited coal ash in the entrained flow reactor and sulfur dioxide in gas. During the experiment, part of the coal ash continuously deposited on the reactor inner wall. The slow increase beyond point D is due to the further sulfation of partially sulfated ash deposits.

The amount of SO_2 captured by in-flight ash was measured by the difference between points A and B, or points C and D. From these measurements at various temperatures as well as the ash data, i.e., surface area and surface chemical composition, the sulfation rate of ash was determined as shown in Figure 2.

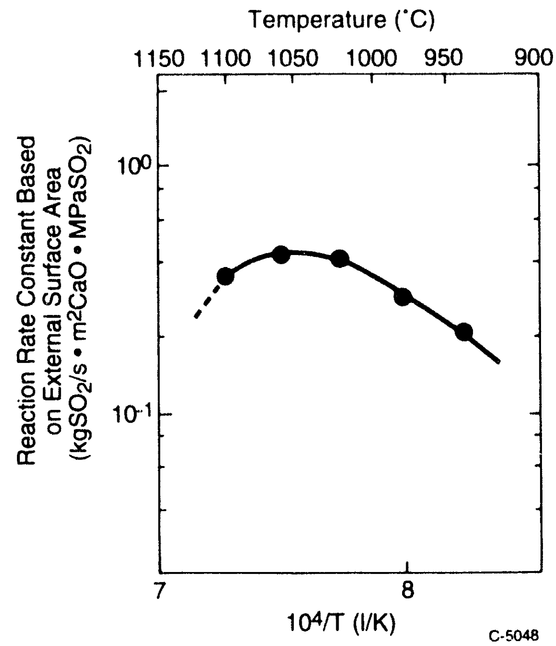

Figure 2. Ash sulfation rate constant determined at various gas temperatures

The second set of experimental runs was made with EB coal and SO_2-doped air to see if calcium-containing ash generated in situ could also react with SO_2. Figure 3 shows a typical change of inlet and outlet SO_2 concentrations as the EB coal is injected. The main gas was doped with 480 ppm SO_2. At 250s, the pump feeder was turned on. As soon as the EB coal was injected, the outlet SO2 concentration decreased to 440 ppm indicating that SO_2 in main gas was absorbed by calcium in EB coal ash. In this run, the sources of SO_2 were (1) SO_2 injected at the inlet, and (2) SO_2 released from the coal fed into the reactor.

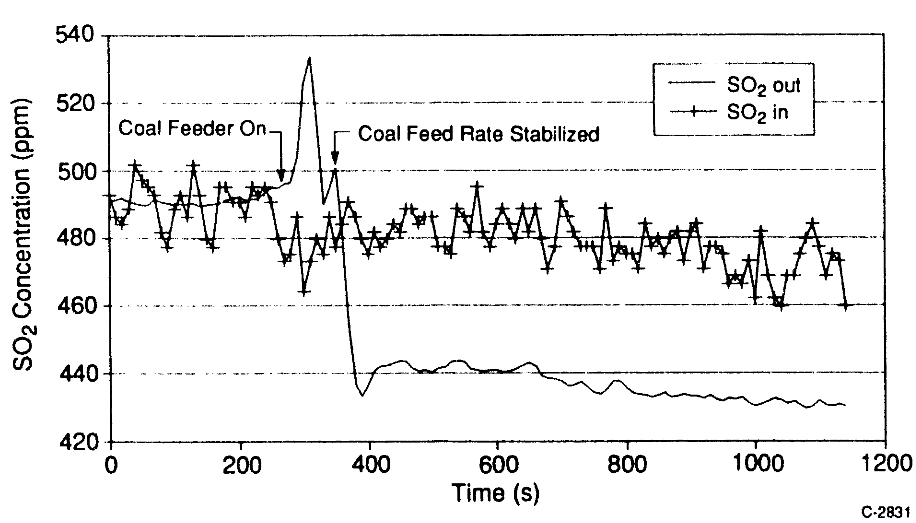

Figure 3. Inlet/outlet concentrations of SO2 with time (gas temperature = 1200C; gas flow rate = 1 cfm; coal feed rate = 0.43 g/min)

The level of SO_2 released from the coal is equivalent to 50 ppm SO_2. Taking the SO_2 released from the coal itself into account, about 90 ppm, or 18%, SO_2 reduction was achieved by ash from the injected coal.

The third set of experiments was made by injecting coals and coal blends and measuring the SO_2 concentrations at the outlet. These measured outlet concentrations were compared with the SO_2 concentrations calculated from the sulfur content in coals and coal blends, as shown in Figure 4. A blend with 50% K9 coal showed 49 ppm, or 32%, reduction of SO_2. The calculated SO_2 concentrations were consistently higher than the measured concentrations. The percent reduction of SO_2 increased with the amount of EB coal in coal blend.

These coal blending experiments indicate that the levels of SO_2 emitted from coals and coal blends may be lower than those predicted from the sulfur content of the coals and coal blends. This sulfur reduction has been found to increase with the increase of calcium content in coals and coal blends.

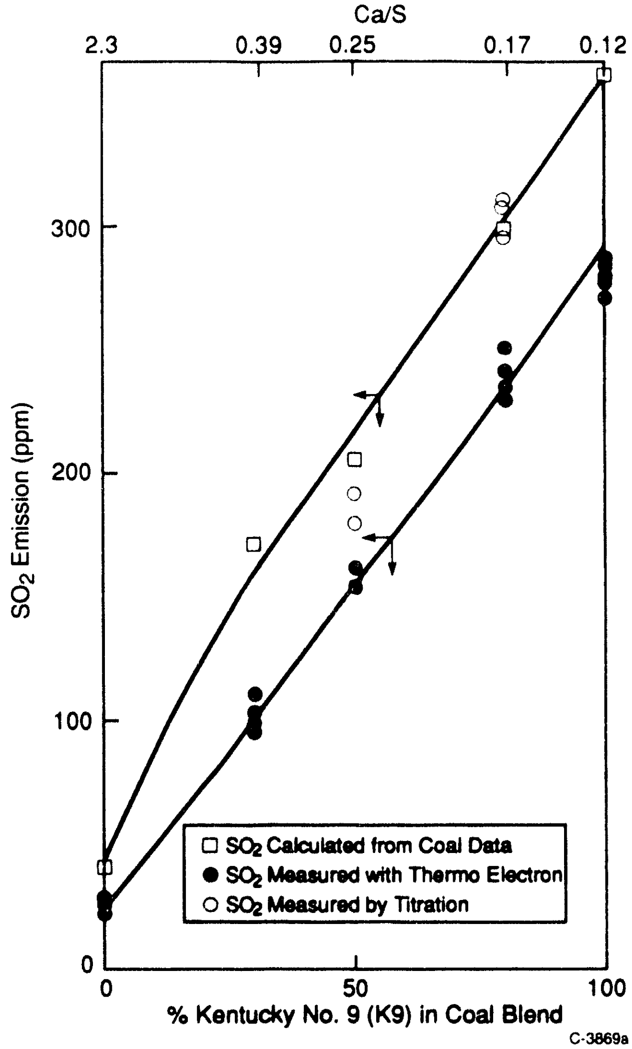

Figure 4. SO_2 emissions from EB-K9 coal blends

3. OXIDATION OF SULFUR DIOXIDE BY CATALYTIC REACTION WITH IRON IN ASH

Determination of kinetic data on the catalytic oxidation of SO_2 on iron-containing ash is in progress. An isothermal differential reactor similar to Graham (1991) was designed to measure the oxidation rate. The isothermal differential reactor is a quartz tube enclosed in a horizontal electrical furnace and is connected to a sampling train. Ash samples are dispersed on a quartz fiber disc, which is placed in the center of the quartz tube. As SO_2-doped N_2-O_2 gas mixture passes through the ash-laden fiber disc, it oxidizes to form SO_3. The extent of conversion is calculated from the amounts of SO_2 and SO_3 collected by impingers filled with isopropanol solutions and hydrogen peroxide solutions.

Coal ash containing iron oxides as well as pyrite-derived ash are being used for the measurements. Figure 5 shows preliminary kinetic data obtained from experimental runs made with pyrite-derived ash. The extent of conversion of SO_2 was measured with 2000 ppm SO_2/5% O_2/95% N_2 and 1.3 mg of pyrite-derived ash. The extent of conversion has its local maximum at the gas temperature of approximately 700°C. It increases with gas temperature until it reaches its maximum at around 700°C and then decreases.

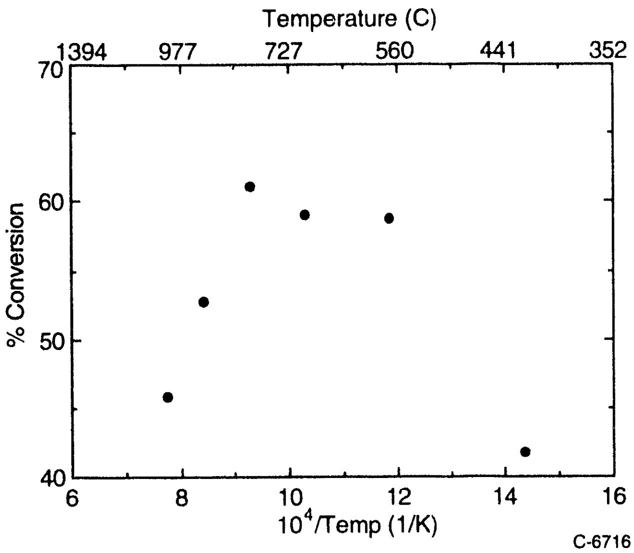

Figure 5. Extent of conversion as a function of temperature

4. DEVELOPMENT AND INTEGRATOIN OF SUBMODELS

Figure 6 shows a general flow of information among fifteen submodels of Compliance Advisor and their relationship with one another. Many of the models (model 1, and 4 to 11 in Figure 6) have already been developed at PSIT under various government-funded research projects. The ESP performance prediction model (model 15) has been developed by ADA Technologies. Model 2, 3, 12, 13, and 14 are being developed under the current project. Following paragraphs describe the information flow among the submodels.

The impact of a coal or a coal blend on a boiler performance can be accurately predicted when the behavior of *individual* coal and mineral particles is accurately addressed. In order to keep track of individual coal behavior, PSIT takes

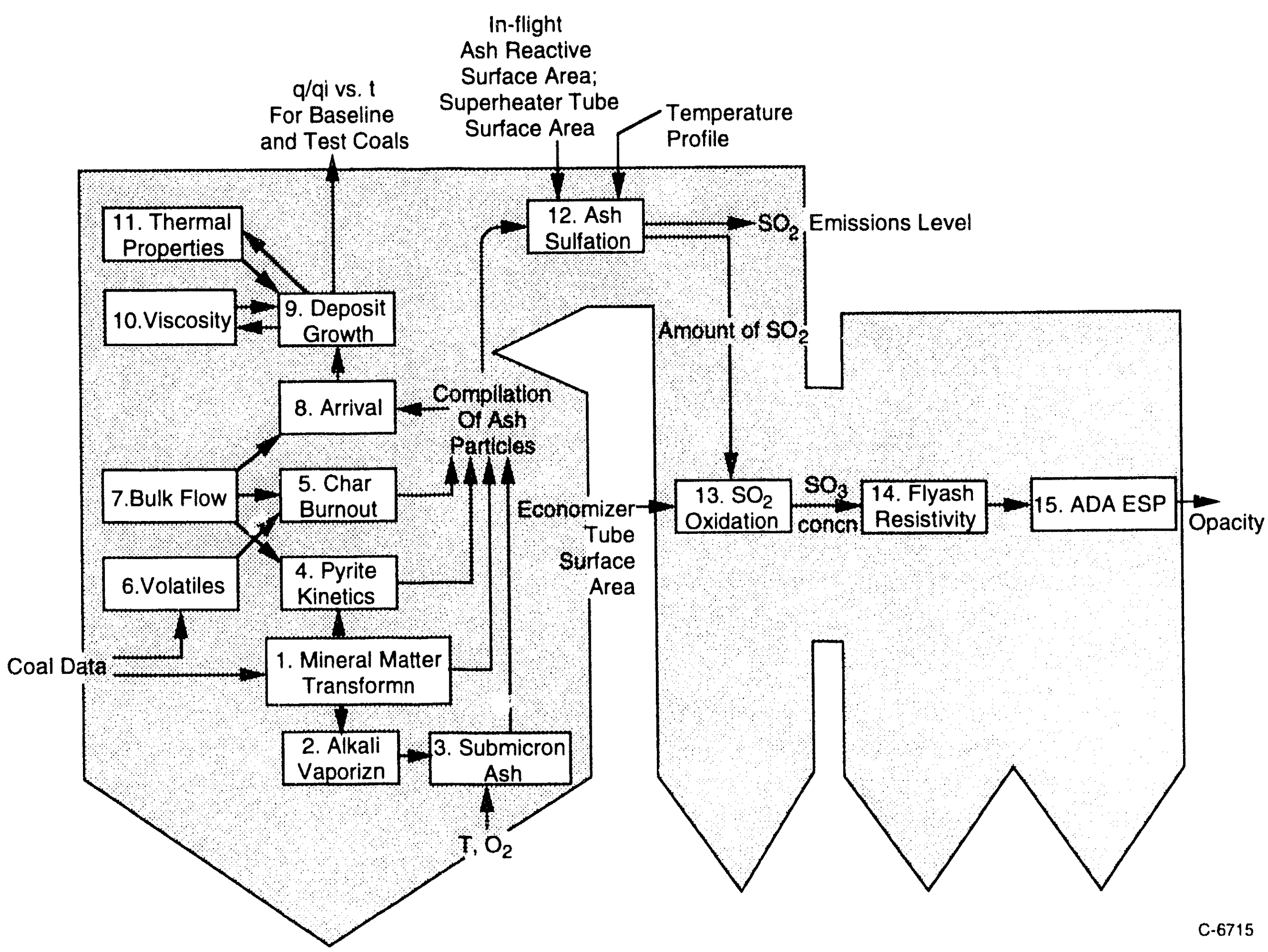

Figure 6. Relationship among Compliance Advisor submodels

computer-controlled scanning electron microscopy (CCSEM) analysis data as input for a given coal. Although CCSEM provides mineral size and composition information, it does not identify the size of coal particles associated with certain minerals. The mineral matter transformation model (model 1) takes CCSEM data, reconstructs coal particles of various sizes, and generates *residual ash* ($> 1\ \mu m$) particle size and composition distribution.

Model 2 calculates the amount of alkali and alkaline earth metal species vaporized during combustion from empirical correlations developed using literature data (Quann and Sarofim, 1982; Helble, 1988). Taking a self-preserving ash particle size distribution approach, model 3 calculates submicron ash particle size distribution, which is used later for the ESP performance model. Using pyrite size distributions from mineral matter transformation model, model 4 calculates the amount of sticky pyrite-derived particles at a given location of the boiler (Srinivasachar and Boni, 1989).

By considering the combustion of volatiles and char particles, model 5 and 6 calculate the location of ash release from coal particles as a function of coal size. A two-dimensional bulk flow model (model 7) predicts the trajectory of bulk ash particles in the furnace. Model 8 calculates the flux of ash particles arriving at waterwalls in the furnace assuming ash transport by turbulent diffusion. Ash particles arriving at waterwalls either stick to the waterwalls and form deposits or bounce back to the gas stream. Model 9 simulates the deposit growth both by sticky particles sticking on waterwall surfaces and by nonsticky particles sticking on sticky portion of ash deposits. Stickiness is determined by the viscosity of the ash particles, which is in turn determined by the chemical composition and the temperature of the ash particles. Model 10 and 11 respectively predict the viscosity and thermal properties based on the chemical composition and the temperature of the ash particles.

Model 12 calculates the amount of SO_2 captured by ash and is being developed based on the experimental results described in the previous section. The amount of SO_3 in gas stream affects the flyash resistivity, which in turn affects ESP performance. Model 13 calculates the amount of SO_3 formed by catalytic oxidation of SO_2; model 14 calculates the flyash resistivity at the given SO_3 concentration. Model 13 will be developed based on the experiments currently underway. ADA Technologies, a subcontractor of PSIT for the current project, has developed an ESP performance prediction model called ADAPCESP in one of their DOE-funded projects. PSIT and ADA Technologies are incorporating the ADAPCESP into Compliance Advisor. With the SO_3 concentration and the complete ash particle size distribution calculated by Compliance Advisor submodels, ADAPCESP will allow a better prediction of the performance of a coal in a given ESP system.

The submodels described above will be packaged in a user-friendly input/output shell recently completed. For example, Figure 7 shows a window for inputting boiler design information.

5. FUTURE EFFORTS

During the year of this program, field tests to verify submodels will be carried out. Laboratory-scale experiments will be completed to support development of some of the submodels. Submodels currently under development will be completed. Integration of submodels will be carried out. Finally, testing of the software will be carried out using PSIT coal evaluation database.

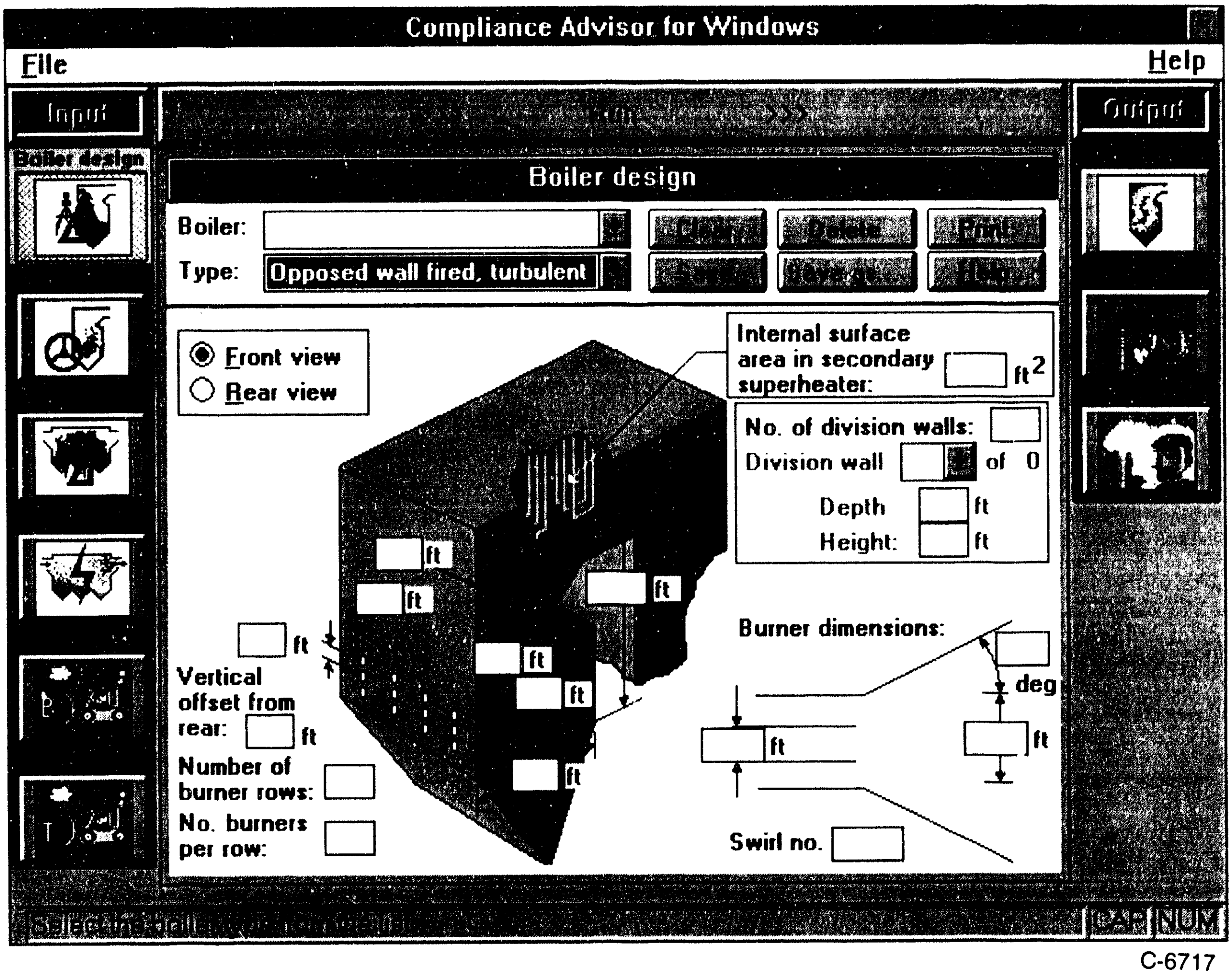

Figure 7. A Compliance Advisor window for inputting the boiler design information

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STATUS REPORT ON THE DEVELOPMENT OF A LOW NO_x COMBUSTOR

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This paper presents a progress report on an innovative, proprietary combustor design for nitric oxides (NO_x) reduction from coal combustion. Pre-mixed natural gas is co-fired in an opposed flow configuration to the coal/primary air stream. Thus, intense mixing is produced and coal is devolatilized in an oxygen poor environment to minimize fuel NO_x. The products of devolatilization are then burned with secondary air in a conventional manner.

Cold flow tests were conducted on a small scale model using opposed water jets. Laser Induced Fluorescence and LDV measurements were carried out for flow visualization and characterization. Mixing increased significantly with increasing momentum ratio of the opposed jets. Drawing upon these results, a scaled-up combustor was built and tested at the Riley Stoker 3 million BTU/hr Pilot Scale Combustion Facility. Three days of tests showed that using natural gas firing at a small percentage of coal firing can consistently reduce NO_x emissions, without adverse effects on furnace emission or thermal performance. In fact, coal flame stability was improved at low load. Problems were encountered, but they appear very tractable.

INTRODUCTION

Nitric oxides (NO_x) are among the major pollutants produced by the combustion of fossil fuels. In 1993, BlazeTech Corp. was awarded a Phase I grant from the Department of Energy under the SBIR program to investigate the feasibility of an innovative, proprietary combustor design for nitric oxides (NO_x) reduction from fossil fuels. The Technical Monitor was Dr. Soung Kim. At the outset of this project, we found little information in the literature on the mixing of opposed jets. Further, the small budget of this program can afford only limited tests in the combustion facility at Riley Stoker. Therefore, preliminary experimentation was conducted in a simpler cold flow model. The results of these tests were used to design the combustor.

COLD FLOW TESTS

The mixing of opposed jets was investigated using water jets in a model geometrically similar to the combustor. The momentum ratio of the opposed jets was preserved between model and combustor. The tests were carried out by BlazeTech staff at the Tufts University Laser Anemometry and Fluid Mechanics Laboratory. We used a recirculating water tank and an 8 Watt Argon Ion Laser to perform Laser Induced Fluorescence (LIF) flow visualization and conduct LDV velocity measurements over a range of momentum ratios.

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The model of the coal devolatilization stage is constructed of clear acrylic tubing and Plexiglas stock. The primary flow issues along the centerline of the model in the axial direction. The side jets emerge from 2 diametrically opposed circular orifices pitched at a 45° angle to the centerline (see schematic in Figure 1). They are positioned so that they will merge into a single jet in opposed flow to the primary jet. The model was designed with a polynomial contraction nozzle (2.25:1 area ratio) at the exit to make the profile as uniform as possible. The model was placed into the tank so that the primary flow was produced by the water tank's issuing orifice. The side jets were driven by a centrifugal pump. The flow rates were easily set and monitored with conventional controls and instrumentation.

Flow Visualization by Laser-Induced Fluorescence

Flow visualization was accomplished via a laser-induced fluorescence (LIF) technique with a fluorescein dye. When excited by laser light, fluorescein emits light of varying intensity increasing with pH in the range between 5 and 9. Below a pH of 5, light emission becomes slight to nonexistent while above a pH of 9, the light intensity remains at its maximum. Visualization was performed by illuminating the area of interest with a laser sheet. Images were captured on video tape via a Sony Handycam 8 mm camcorder.

For good flow visualization while keeping the concentration of fluorescein constant in the system, we initially kept the tank at a low pH (acidic). When visualization was desired, we introduced a basic solution through the side jets. As the acid and the base mixed, the pH of the mixture varied in intensity allowing the mixing to be seen.

Figure 1 shows digitized images of axial slices along the axis of the model for increasing axial momentum ratios, M_2/M_1, from 1 to 9. (The subscripts 1 and 2 denote the primary and side jets respectively.) The image is focused on the area between the entrances of the primary and secondary jets. The dark areas correspond to acidic fluid representing the primary flow while bright regions correspond to basic fluid depicting the secondary jets (simulating the coal/primary air and the natural gas flame streams, respectively). The gray areas show where the flows have mixed.

These images provide a 2-dimensional representation of the dynamics of stream interactions and the resulting flow field. For a momentum ratio of 1, there is little to no penetration of the secondary jets into the primary jet. The primary jet even seems to break through the secondary jets. As the momentum ratio increases (side jet flow increases), the penetration of the colliding jets is more thorough thereby improving the mixing. At $M_2/M_1 = 3$ some reverse flow seems to emanate from the jet intersection point as expected. Above a momentum ratio of 3, the combined secondary jets actually push the primary flow back towards its entrance. By $M_2/M_1 = 5$, the primary flow is pushed almost all the way back to the jet orifice. As one would expect, as M_2 is increased from here the chamber becomes more and more filled with basic (bright) fluid.

Laser Doppler Velocimeter Measurements

We measured velocities within the model using a Laser Doppler Velocimeter. The system collected data at 200 Hz and each mean velocity value was the average of 1000 points. Therefore, any random fluctuations in the flow were averaged out. By mounting a fiber

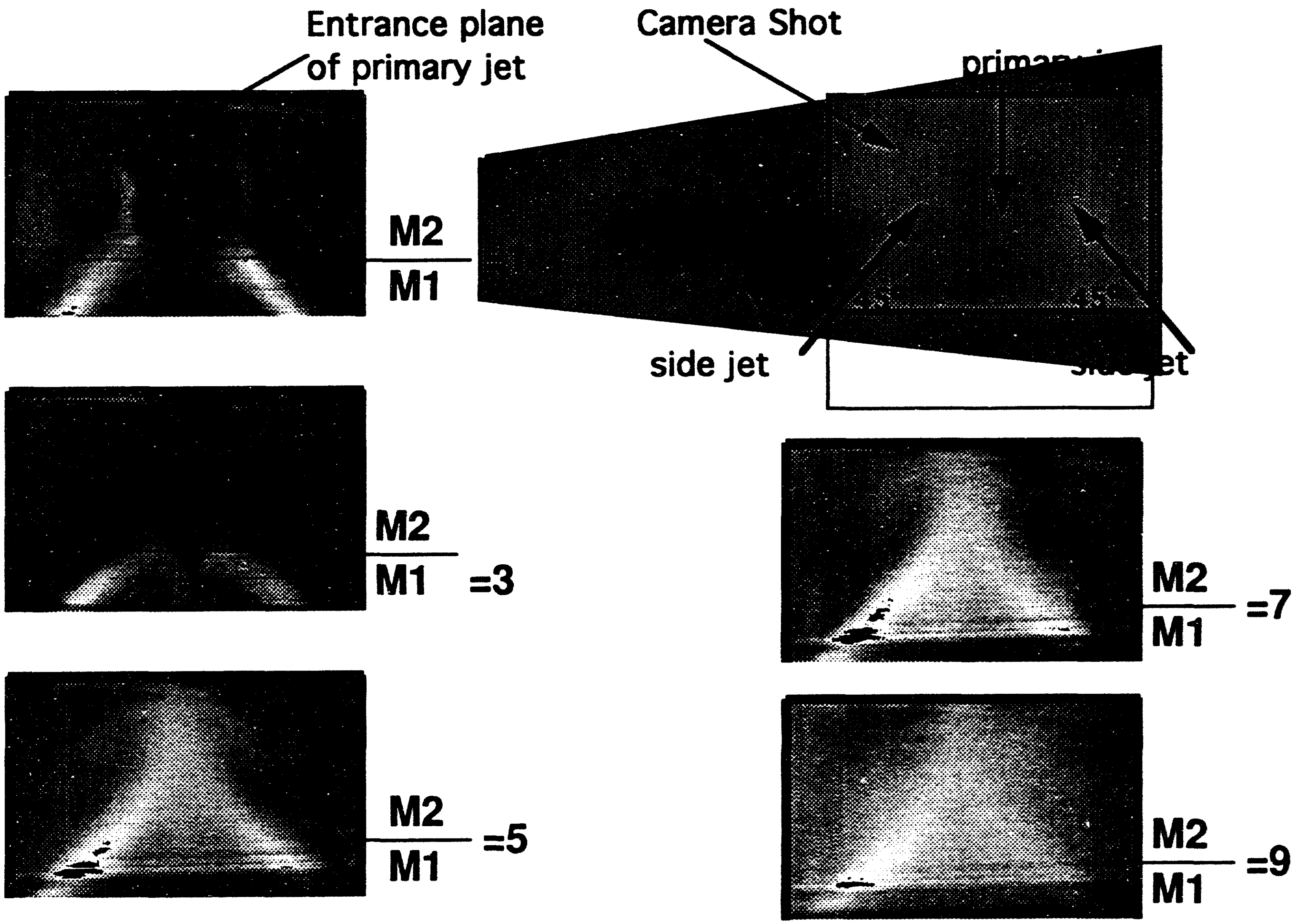


Figure 1: Laser-Induced Fluorescence of Jet Mixing for Different Momentum Ratios

optic LV probe (TSI Inc.) on a computer controlled mechanical traverse we collected mean velocity data at various radial and axial positions.

Figure 2 shows the results at $M_2/M_1=5$. The velocity in meters per second is shown on the vertical axis while the horizontal axis represents the radial position in inches. For reference, the vertical lines drawn on the plot indicate positions from the centerline of the primary jet boundaries, the contraction end walls, and the model inner side walls. We measured velocities at five axial stations: the entrance of the primary jet, the geometric intersection point of the centerline of the primary and side jets, the entrance to the contraction, and the exit of the model.

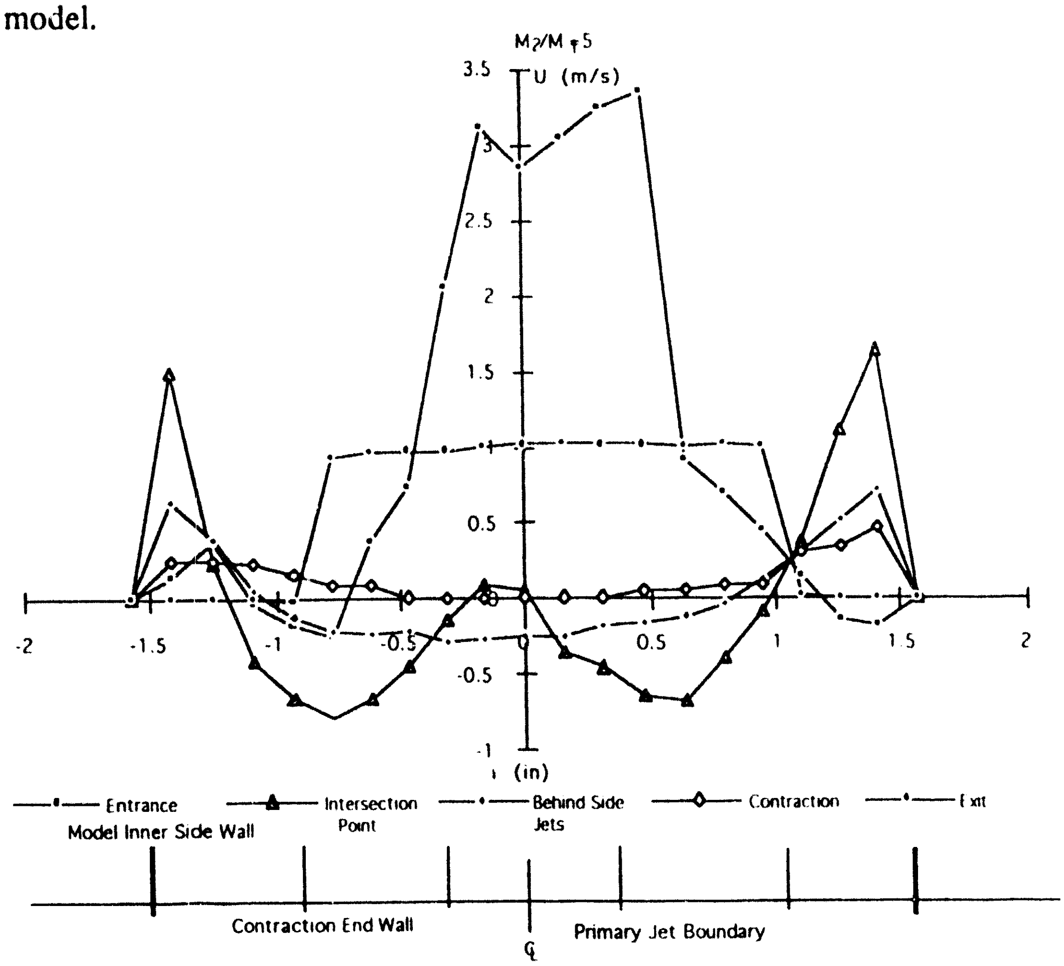


Figure 2: Axial Velocity Profiles Along a Radial Line in the Plane of the Side Jets

The entrance profile is similar to a classic top hat velocity profile. However, it is slightly off center and there is a dip at the center of the jet. Based on our qualitative observations, this distortion is a direct result of the interaction with the flow of the combined side jets. The images for this case shown in Fig. 1 show how the primary jet is driven back to its entrance and distorted by the oncoming flow. This effect is concentrated at the center explaining the reduced velocity. Further out from the center of the top hat profile, the axial velocity is reversed slightly suggesting the presence of corner vortices.

At the intersection of the three jets, we see essentially zero velocity at the center, high positive velocity near the side walls of the model, and negative velocity in between. This indicates a stagnation zone at the center where the jets meet. (The flow is then radial as seen in a transverse velocity profile at this axial position which is not shown here.) There is a gradient along the edges of the primary flow allowing the secondary flow to continue in its original direction as indicated by a negative velocity. The higher positive velocities at the side walls of the model indicate annular flow moving toward the exit of the model. Just behind the side jets, the annular flow continues along the side walls of the model moving toward the exit. In between these peaks there is low velocity movement toward the entrance of the model. This is most likely a result of the side jets entraining fluid in their wake. Further downstream, at the entrance to the contraction, the flow is still concentrated around the edges of the model. There is a gradual variation in the velocity profile and there is evidence of reverse flow. The axisymmetric contraction positioned at the exit is very effective in steering the annular flow toward the center resulting in uniform flow.

Implication of the Cold Flow Results

The LIF flow visualization results showed that good mixing can be achieved over a wide range of momentum ratios. The results are particularly dramatic, however, at ratios of 4 or above. This value was used in the design of the coal combustor described below so as to permit a compact chamber. In principle, one can trade-off the momentum ratio with the chamber length to achieve the same level of devolatilization.

Further, the LDV results indicated the complexity and 3-dimensional nature of the flow field. Zones of recirculation and of low velocities were observed in cold flow, and can also occur in a hot reacting flow. Such zones can stabilize a flame inside the main chamber which is undesirable. This can be prevented by ensuring poor oxygen concentration in the chamber so that coal devolatilizes without burning. Thus, the air in the side jets needs to be consumed in the natural gas flames prior to injection into the combustor. Accordingly, we designed a flame tube to contain the natural gas flames as described below.

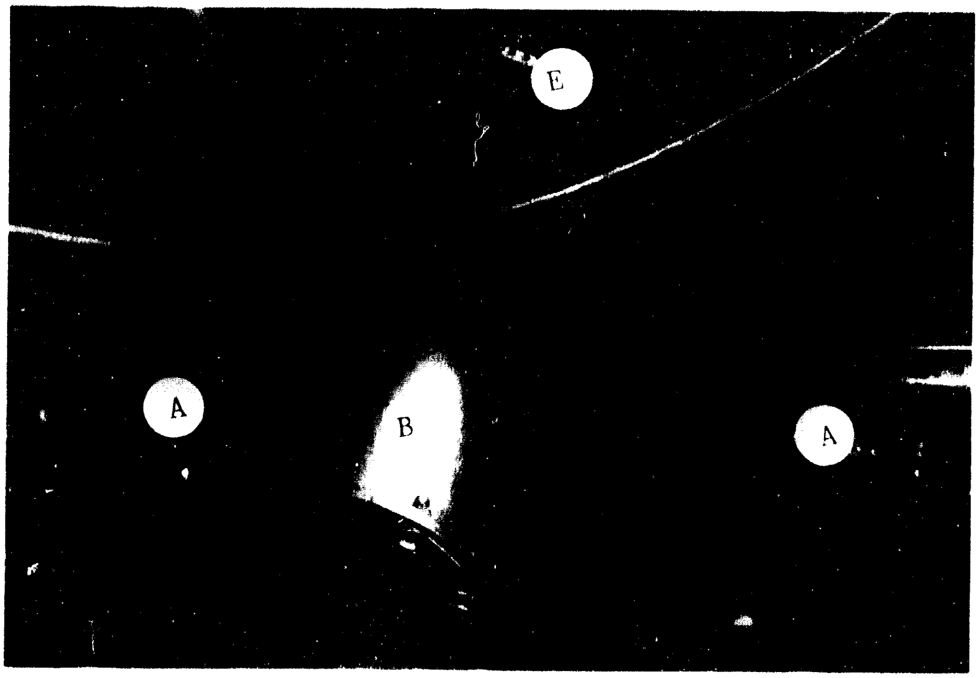
COMBUSTOR DESIGN

Based on our cold flow modeling results and parametric calculations, we designed a test section that accomplishes the objectives of this program within the physical constraints of the Riley Research test facility. The test section consists of a main chamber and natural gas burners and fits between the IFRF swirl block generator and the furnace at Riley Research as described below (See Fig. 3).

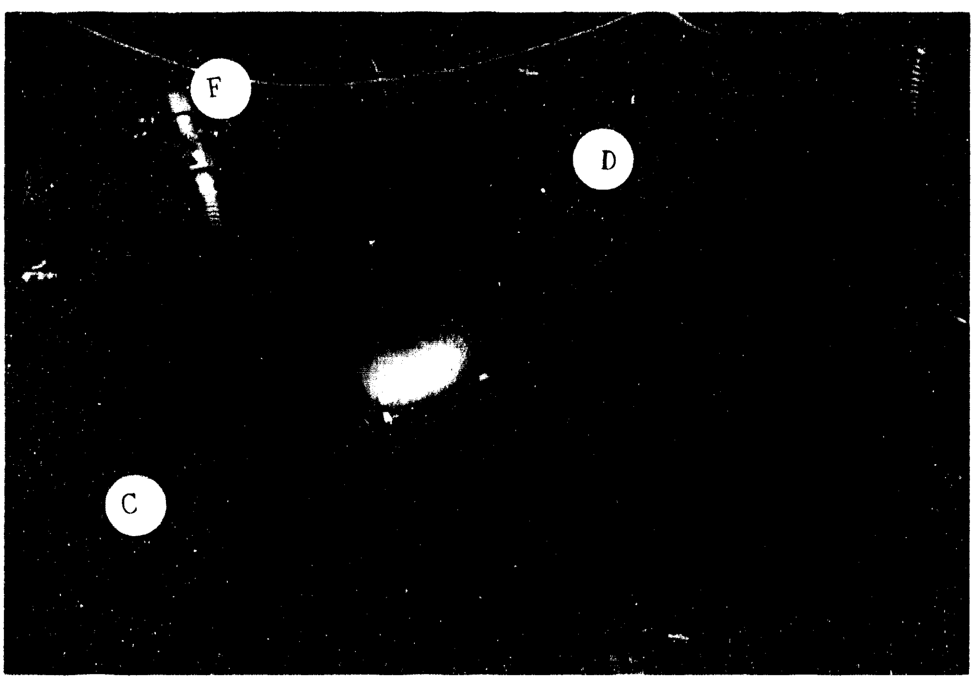
Main Chamber

The main chamber consists of 2 concentric cylinders with 2 side jet tubes crossing the annular space between the cylinders and exiting into the inner cylinder. Coal and primary air flow in the inner cylinder in opposed flow to the natural gas flames exiting the side jets. Secondary air from the swirl block generator flows in the outer cylinder parallel to the coal stream and cools the inner cylinder. The two co-annular streams mix in the furnace. A lip at one left end of the main chamber fits inside and provides a seal with Riley's coal feed pipe. The flange on this side joins the main chamber to the swirl block generator. The flange at the other end connects the system to the furnace wall.

Figure 3: Test Configuration in the 3 MMBtu/hr Pilot Scale Facility



A) Natural Gas Burner Flame Tube, B) Main Chamber, C) IFRF Swirl Block Generator, D) Furnace Front Wall, E) Thermocouple, F) Natural Gas/Air Mixing Tube



Natural Gas Burners and Flame Tubes
We selected off-the-shelf pre-mixed natural gas burners each rated for turn down from 300,000 to 90,000 BTU/hr (20% to 3% of maximum coal firing rate). The burners are self-sparking and equipped with a flame observation port.

Completion of natural gas combustion before entering the main chamber was important to ensure that coal devolatilization occurs in an oxygen poor environment. Accordingly, we designed flame tubes to contain each natural gas flame and to control its momentum as it enters the main chamber.

PROOF OF CONCEPT TESTS

Proof-of-concept tests were carried out at the Pilot Scale Combustion Facility (PSCF), at Riley Research Center in Worcester, MA. The PSCF consists of a nominal 3 million Btu/hr furnace, combustion air supply, fuel handling equipment, gas analyzers, and controls. Flue gas sampling and thermal performance data were collected continuously at one minute intervals. Testing was carried out over a period of 3 days, 8 hours each.

The natural gas burners were fired first followed by coal. The burners were adjusted to maintain the flames inside the tubes. The exit temperature of the main combustion chamber into the furnace varied from 800 to 1000 °F, with occasional excursion to 1300 °F (the desired temperature). The flow indicators showed the flames to be air poor, and increasing the amount of air extinguished the flame. Increasing the firing rate moved the flame outside the tube and increased the CO level. Thus, a smaller range of the burner rating was deemed acceptable (75,000 to 165,000 Btu/hr).

We were unable to achieve as good an opposed flow field as in the cold flow tests for 3 reasons: 1) The side jets in the main chamber were not drilled to tolerance. Instead of intersecting the chamber centerline at the same point, they intersected about one half a jet diameter away. (2) It was difficult to balance the flow rates through the two side burners. (3) A coal spreader was inadvertently placed by Riley Stoker in the coal pipe outlet, upstream of our main chamber. Correcting these problems was not possible because of the small budget and short schedule of Phase I.

Despite these difficulties, NO_x was reduced when the natural gas burner were operating under identical steady state furnace conditions. This is illustrated below where data is averaged over 10 minutes, and flue gases are based on 3% O_2. NO_x decreased by 19% and 23% when the ratio of natural gas to coal firing was 6.7% to 13.8%, respectively, with no adverse effects on furnace performance or emission.

Coal 10^6Btu/hr	N.G. 10^3Btu/hr	N.G./ coal, %	O_2 %	CO_2 %	CO ppm	SO_2 ppm	NO_x ppm	% NO_x Reduction
1.99	0	0	3.7	15.9	105	267	479	Baseline

2.15	145	6.7	3.7	15.8	177	279	387	19
1.67	0	0	4.4	16.0	127	325	494	Baseline
1.70	233	13.8	3.9	15.6	121	337	379	23

Subsequent tests were carried out while optimizing the operation of the natural gas burners. The results in the table below show that NO_x production was reduced to 203 ppm, which is comparable to commercial low-NO_x burners. This is a remarkable achievement in view of the limited effort spent so far on this burner.

Coal 10^6Btu/hr	N.G. 10^3Btu/hr	N.G./ coal,%	O_2 %	CO_2 %	CO ppm	SO_2 ppm	NO_x ppm	Comment
2.04	182	8.9	3.3	15.7	134	353	356	Increasing adjustements of N.G. burners during a 2.5 hour period
2.18	184	8.5	2.1	15.7	133	386	280	
1.66	187	11.3	3.6	15.3	281	366	218	
1.83	190	10.4	1.8	15.5	202	408	203	
1.65	170	10.3	2.3	14.2	1300	134	353	unstable coal flame, low load

It was also noted by the furnace operators that our method of natural gas firing helped stabilize the coal flame. The furnace could be turned down lower than without natural gas firing. Further reduction of furnace load leads to a significant increase in CO as shown in last row of the above table.

On the third day of testing, the throughput of the left burner dropped significantly. After the tests, we found significant coal built up in the flame tube, constricting the flow. Continuous flushing of the burner with air to prevent coal in-flow is important.

In summary, we were consistently able to reduce NO_x emissions by co-firing natural gas (as a small percentage of coal firing), with no adverse effects. In fact, coal flame stability was improved at low load. Also, our method can be fitted to existing furnaces with minimum modifications. We are confident that through further development in Phase II, we can more dramatically demonstrate the effectiveness of our method.

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