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Overview of Slagging Coal Combustor Systems as Applied to Army Central Heat Plants

by

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It was determined that the SCC is not ready for implementation on Army-sized boilers due to both technical infeasibility and economic impracticality. No SCC developer has simultaneously achieved ash slag capture, carbon conversion, nitrogen oxide and sulphur oxide reductions, and turndown. It is recommended that the Army continue its investigation of this technology for future development.

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The U.S. Army is interested in increasing its consumption of coal because coal is the most reliable domestic source of energy. Research is being done on methods of retrofitting oil- and/or gas-fired boilers to coal and on new environmentally sound methods of coal combustion. To evaluate these methods, researchers conducted an extensive literature search and industry survey on the slagging coal combustor (SCC) as it pertains to Army boilers. An evaluation of the commercial readiness and an assessment of the economic feasibility of retrofit were performed.

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FOREWORD

This work was performed for the U. S. Army Engineering and Housing Support Center (USAEHSC) under Project 4A162781AT45, "Energy and Energy Conservation"; Task Area DO, Work Unit 006, "Coal Use Technologies." The USAEHSC Technical Monitor was Mr. Bernard Wasserman, CEHSC-FU.

The research was conducted by Ms. Jill E. Davidson, Mr. Don K. Hartsock, Mr. A. Dale Conley, and Mr. Robert L. Hein of Schmidt and Associates, Inc., Cleveland, OH, for the U. S. Army Construction Engineering Research Laboratory, (USACERL) Energy Systems Division (ES). Dr. G. R. Williamson is Chief of ES. The technical editor was Gloria Wienke, USACERL Information Management Office.

COL Everett R. Thomas is Commander and Director of USACERL, and Dr. L. R. Shaffer is Technical Director.

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1 INTRODUCTION

Background

The U.S. Army is interested in increasing its consumption of coal as it is the most reliable domestic source of energy. Slagging Coal Combustor (SCC) technology shows great potential for direct combustion of coal in an environmentally acceptable manner. Application of this technology has the potential to allow the Army to burn more coal at retrofitted heat plants.

The SCC is an emerging retrofit technology that has been under development by a number of companies, although there have been no commercial sales. The SCC is essentially a compact two-stage cylindrical combustion chamber with attachments for air input and slag removal. The chamber would replace the oil gun or gas burner in an existing boiler. Sulfur oxide (SOx) and particulate emissions can be reduced by injecting limestone and adding a baghouse. This report reviews the slagging combustor as it applies to boilers in the size range of 25,000 to 250,000 pounds per hour (lb/hr)* steam at Army installations.

The SCC operates by firing pulverized coal (70 percent through 200 mesh) into either a water-cooled or air-cooled combustion chamber. The combustion chamber is operated under substoichiometric conditions; that is, supplying approximately 70 percent of the oxygen required for complete combustion in the first stage. The temperatures in the combustion chamber reach 3000 °F, which is hot enough to melt the residual ash material thrown to the sides of the chamber via the vortex that is developed. The molten ash, or slag, flows down the sides of the chamber to a slag tap and then to a water quench pit. The remaining combustion flue gas is then exposed to secondary air at the point between the combustion chamber exit and furnace entrance to complete the combustion process.

Due to the staged combustion effect of segregating the combustion air, SCC developers are claiming low nitrogen oxide (NOx) emission; 200 to 250 parts per million (ppm), which is required for New Source Performance Standards (NSPS). Also, sulfur capture has been reported by adding a sorbent material such as lime. The SCC developers have stated a level of success ranging from 25 to 90 percent.

The final advantage of the SCC is that up to 90 percent of the ash is caught in the combustion chamber and thus never reaches the furnace convective section. It is this point that SCC developers hope will encourage the use of slagging combustors on oil- and/or gas-fired boilers as a retrofit. Because most of the remaining ash particles are small, the fly ash that goes to the convective section will follow the path of the flue gases and not impinge on the furnace tubes. If this actually were to happen in a retrofit application, the boiler would not have to be derated and the investment payback would be quicker.

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*A metric conversion table is provided on page 58.

Objective

The objective of this work was to investigate the feasibility of SCC technologies as a retrofit for Army-scale boilers originally designed for gas and/or oil.

Approach

Researchers surveyed the literature to provide an overview of SCC technologies currently under an advanced stage of development and evaluated fuel handling, combustion, and emissions control. An economic analysis of the overall technology was conducted.

Mode of Technology Transfer

It is recommended that information in this report be summarized in a Technical Note covering coal combustion retrofit technologies.

2 DEVELOPMENTAL HISTORY

During the 1930's, the demands for higher grades of coal increased the need for new furnace designs. Mechanization in coal mining techniques increased the ash content of mined coal. New equipment was needed to handle the lower grades and ranks of coal with high ash content and low fusion temperature. The cyclone furnace concept was an outgrowth of the effort to meet these needs and to overcome some of the difficulties encountered with other firing methods.

The slagging coal combustor was originally introduced by The Babcock & Wilcox Company (B&W) as the cyclone furnace in the 1940's. B&W developed the cyclone furnace in response to the inherent advantages it had over pulverized coal (PC) systems. PC systems consume more power to drive the pulverizers, which have high maintenance costs. PC systems also produce excessive fly ash discharge from the stack (approximately 80 percent for dry ash removal furnaces without dust collectors) and erode boiler pressure parts by fly ash entrained in the flue gases (unless low gas velocities are maintained). Induced draft (ID) fan blades and scrolls also erode, even when the fans are located after dust collectors. This erosion lowers availability and increases maintenance. PC systems also require relatively large furnace volumes for good combustion.[1] The carbon dioxide (CO_2) formed during combustion tends to blanket the coal particles and retard further combustion. To maintain rapid combustion, the furnace has to be relatively large to give the necessary retention time for oxygen to diffuse through the blanketing CO_2 layer.

The B&W cyclone furnace (Figure 1) is a water-cooled horizontal cylinder in which fuel is fired, heat is released at extremely high rates, and combustion is completed. Its water-cooled surfaces are studded and covered with refractory over most of their area. Coal is crushed in a simple crusher so that approximately 95 percent will pass a 4-mesh screen and is introduced into the burner end of the cyclone. About 20 percent of the combustion air, or primary air, enters the burner tangentially and imparts a whirling motion to the incoming coal. Secondary air with a velocity of approximately 300 feet per second (fps) is admitted in the same direction tangentially at the roof of the main barrel of the cyclone and imparts a further whirling or centrifugal action to the coal particles. A small amount of air (up to about 5 percent) is admitted at the center of the burner. This is known as tertiary air.

The combustible material is burned from the fuel at heat release rates of 450,000 to 800,000 British thermal units per cubic foot per hour (Btu/cu ft/h), and gas temperatures exceeding 300 °F. These temperatures are sufficiently high to melt the ash into a liquid slag, which forms a layer on the walls of the cyclone. The incoming coal particles (except for a few fines that are burned in suspension) are thrown to the walls by centrifugal force, held in the slag, and scrubbed by the high-velocity tangential secondary air. The air required to burn the coal is quickly supplied, and the products of combustion are rapidly removed.

The heat release per cubic foot in the cyclone furnace is very high. However, there is only a small amount of surface in the cyclone and this surface is partially insulated by the covering slag layer. Heat absorption rates range from 40,000 to 80,000 Btu/sq ft/h. This combination of high heat release and low heat absorption assures the high temperatures necessary to complete combustion and provide the desired liquid slag covering of the cyclone's interior surface.

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[1] *STEAM, Its Generation and Use*, 37th Edition (The Babcock & Wilcox Company, 1963).

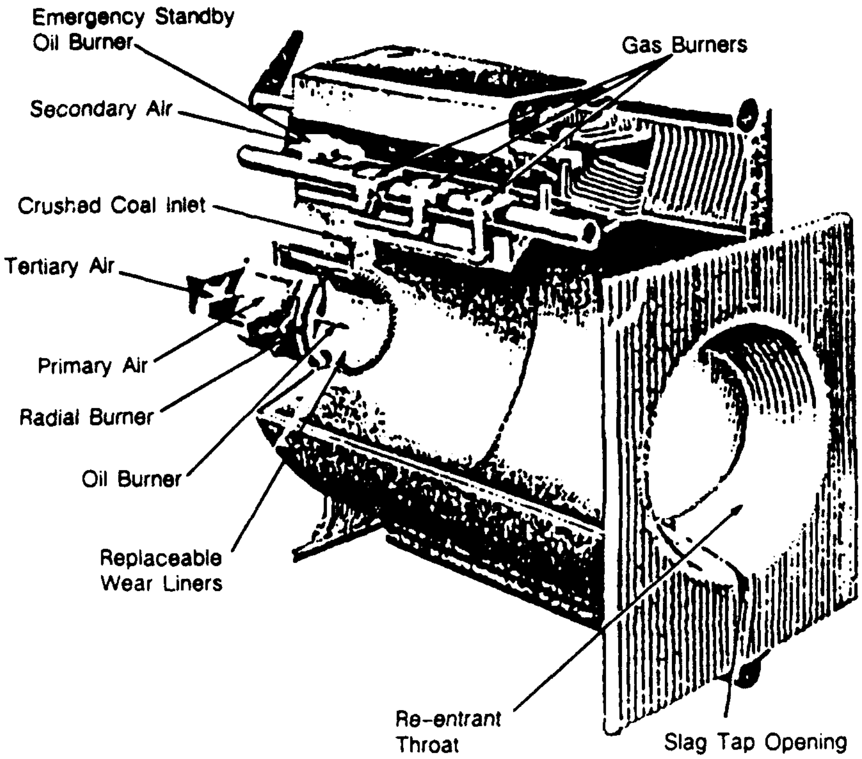

Figure 1. **The Babcock & Wilcox cyclone furnace.** (Source: *STEAM, Its Generation and Use*, 38th Edition [The Babcock & Wilcox Company, 1972]).

The gaseous products of combustion are discharged through the water-cooled reentrant throat of the cyclone (Figure 1) into the gas-cooling boiler furnace. Molten slag in excess of the thin layer retained on the walls continually drains away from the burner end and discharges through the slag tap opening (shown in Figure 1) to the boiler furnace, from which it is tapped into a slag tank, solidified, and ground for disposal. This method of combustion quickly and completely burns the fuel in the small cyclone chamber; the boiler furnace is used only to cool the flue gases. Thus, the quantity of fly ash is low and its particle size so fine that boiler heating surfaces are not eroded even at high velocities.[2]

The cyclone furnace can burn coal varying in rank from low volatile bituminous to lignite. Other solid fuels such as wood bark, coal chars, and petroleum coke may be fired in combination with other fossil fuels. Fuel oils and gases are also suitable for firing.

Coal's suitability as a fuel depends on its moisture, ash, and volatile contents, and on the chemical composition of the ash. The volatile matter should be higher than 15 percent, on a dry basis, to obtain the required high combustion rate. The ash content should be a minimum of about 6 percent to provide a proper slag coating in the cyclone; it can be as high as 25 percent. A wide range of moisture content

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[2] *STEAM, Its Generation and Use*, 38th Edition (The Babcock & Wilcox Company, 1972).

is permissible depending on the coal's rank, secondary air temperature, and fuel preparation equipment that may include the capability to predry the fuel.

One criterion defining coal suitability is the total amount of sulfur compared to the ratio of iron to calcium and magnesium. This comparison indicates if the coal tends to form iron and iron sulfide, both of which are very undesirable in the cyclone furnace. Coals with a high sulfur content and/or high iron content are not usable.

The other important criterion for establishing the suitability of coal for firing in the cyclone is the viscosity of the slag formed from the ash. Since satisfactory combustion of coal depends on the formation of a liquid slag layer in the cyclone, and since ash is removed from the cyclone and primary furnace in fluid form, the viscosity of the slag must permit the slag to flow at the temperatures in the cyclone and primary furnace. Field experience with different coal and extensive investigation of ash characteristics have provided the following information for evaluating coal suitability, from a slag tapping standpoint, without actual firing tests.[3]

Slag will just begin to flow on a horizontal surface at a viscosity of 250 poises. The temperature at which this viscosity occurs (T250) is used to determine the suitability of a coal. The T250 is calculated from a chemical analysis of the coal ash, and a value of 260 °F is considered maximum. Somewhat lower temperatures may be desirable for fuels with high moisture contents and low heating values.[4]

B&W sold more than 23,000 megawatts thermal [MW(t)] of cyclone design utility boilers in the United States before air pollution legislation was passed in the 1970's. The furnace's downfall was excessive NOx emissions. Attempts to apply conventional combustion modifications for NOx control were largely unsuccessful in meeting the U.S. Environmental Protection Agency (USEPA) NSPS.

Interest in the cyclone furnace was revitalized in 1948 by a program initiated by the British Coal Utilization Research Association (BCURA) that attempted to exploit the potential (high combustion intensity, slag rejection capability) of cyclone combustors for firing gas turbines. This effort was extended during the early 1960's to study pressurized, coal-fired, cyclone-type combustors for magnetohydrodynamic (MHD) applications. This program, which was terminated in 1963, was instrumental in providing the early technology base for pressurized coal combustion in the United States.

Experimental studies of coal combustion systems for MHD applications were also conducted in the early 1960's at Pittsburgh Energy Technology Center (PETC), which was then part of the U.S. Bureau of Mines. Based on these and other studies conducted in the early 1970's, a strong incentive emerged to develop an MHD coal combustor system capable of producing a combustion gas relatively free of coal ash.

A coal-fired MHD combustor development effort initiated at PETC in 1975 was the direct antecedent of the present Department of Energy's coal-fired MHD combustor development project. As part of this effort, a preliminary 50-MW(t) combustor design was started in 1976 and completed in 1977. A 5-MW(t) subscale model of the 50-MW(t) unit was fabricated and tested between 1978 and 1980.

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[3] *STEAM, Its Generation and Use* (1972).

[4] *STEAM, Its Generation and Use* (1972).

The design of a 50-MW(t) combustor, based on a direct scale-up of a 20-MW(t) unit, was completed by TRW in 1983. As illustrated in Figure 2, the unit is a two-stage, horizontal, all metal, water-cooled device comprising a first stage, cyclone-type gasifier and a second-stage combustor. The first stage serves to gasify coal at low (variable) stoichiometries and at pressures of 6 atmospheres. Swirl imparted to the gases by the tangential flow of the oxidizer (preheated to 2900 °F) centrifuges slag from the combustion gases before the gases' final combustion in the second stage. The inner surface of the first stage is fitted with studs that promote the retention and thickening of the insulating slag layer deposited on the walls. A scroll-shaped section, forming the outlet of tne second stage, serves to promote an aerodynamically smooth flow by minimizing residual swirl. Second stage heat loss, limited by the stage's inherently small surface-to-volume ratio, is further reduced by the insulating properties of slag.

In 1984 and 1985, the first stage of a 50-MW(t) unit was built, tested at TRW, and shipped to the Department of Energy (DOE) MHD Component Development and Integration Facility (Butte, MT). Design verification testing of the first stage was completed after 64 tests totaling 39.5 hours. Table 1 presents a summary of the initial test results versus minimum acceptance criteria for parameters such as slag recovery, heat loss, unburned carbon carry-over, stability, and slag-retention capability.[5]

In 1982, the DOE issued a Notice of Program Interest (NPI) for coal-fired systems capable of removing ash and sulfur in the combustor, thereby producing a relatively clean product gas. Systems satisfying these requirements were intended to be retrofittable, with minimum derating, to existing boilers and furnaces designed to burn oil or gas. As a result of this notice, TRW, AVCO Everett Research Laboratory (AERL), and Energy and Environmental Research Corporation (EER) received contracts for advanced combustion systems.[6] DOE selected Rockwell International to develop a 20-MW combustor for the open-cycle MHD system. In a parallel effort, General Electric (GE) developed and tested a small (0.4-MW) atmospheric coal combustor for the closed cycle MHD system.[7]

Five companies continued their efforts to develop an advanced coal-fired system that can produce a relatively clean product gas for application to retrofit oil and gas fired boilers. The five companies are: TRW, AERL, Rockwell (TransAlta), Coal Tech (GE), and EER.

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[5] Ralph A. Carabetta, Charles R. McCann, and Roy C. Kurtzrock, *An Overview of DOE's Advanced/MHD Coal Combustor Development Program*, 12th Energy Technology Conference (U.S. Department of Energy, Pittsburgh, PA).

[6] Ralph A. Carabetta, Charles R. McCann, and Roy C. Kurtzrock.

[7] T. C. Derbidge and W. Rovesti, "Review of Advanced Staged Slagging Coal Combustor Technology," *EPRI Journal* (September 1984).

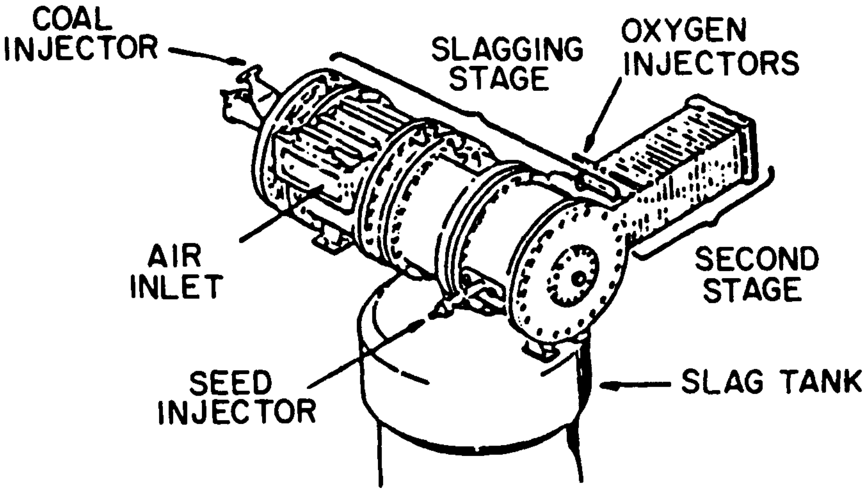

Figure 2. **A 50-MW(t) combustor assembly.** (Source: Ralph A. Carabetta, Charles R. McCann, and Roy Kurtzrock, *An Overview of DOE's Advanced/MHD Coal Combustor Development Program*, 12th Energy Technology Conference [U.S. Department of Energy, Pittsburgh, PA].)

Table 1

Acceptance Criteria for a 50-MW(t) MHD Coal Combustor

Parameter	Acceptance Criteria	Initial Test Results
Slag recovery	Not less than 70 percent by weight of the coal mineral matter	75 percent (average, at design conditions), 95 percent peak
First-stage heat loss	Not to exceed 7.5 percent of total thermal input	Less than 7.5 percent at stoichiometric ratios of 0.635 or lower
Unburned carbon carryover with slag	Not to exceed 0.5 percent by weight	Typically less than 0.2 percent at first-stage stoichiometric ratios of 0.62 or greater
Stability	Chamber pressure variation not to exceed +0.15 atm at operating pressure of 6 atm	Less than +0.15 atmospheres variation
Slag retention capability	At least 80 percent of combustor interior surface covered with uniform thickness	Over 90 percent of internal surface evenly coated

3 TECHNOLOGY OVERVIEW

TRW

Coal Combustor System Description

The TRW slagging combustor system (Figure 3), consists of a small coal hopper with integral dense-phase feed components, a compact slagging stage combustor, a precombustor for boosting inlet air temperature, a water-filled slag tank with integral crusher, a short connecting duct, a secondary burner, and associated controls. The major characteristics are summarized in Table 2. Although previous tests ran many cycles, the total time covered was minimal. The tests did demonstrate feasibility. Longer demonstration programs, including scaling, are in progress. The system is integrated with conventional coal and ash handling systems and retrofitted to existing heat use equipment designed for oil/gas firing. Thus, by adding a relatively small coal combustion system coupled with conventional solids handling equipment, an existing kiln, furnace, or boiler can be converted to coal firing. In some applications, it may be advantageous to retain oil/gas firing capability and add the coal firing option so that the most economical operation can be selected as fuel prices and operating variables change.

Entrained Slagging Combustor. The heart of the system is the entrained slagging combustor stage. It consists of a water-cooled cylinder with a tangential air inlet and a key slotted baffle located about two-thirds of the way down the combustor's longitudinal axis. The air inlet and baffle combination promotes appropriate mixing/combustion reactions and internal slag flow patterns. Pulverized coal (70 percent through 200 mesh) is transported in a dense-phase fluidized condition to the injector located on axis in the head end of the combustor. The coal is injected conically into the combustor, entrained by the swirling airflows, and burned substoichiometrically in flight.

Ash contained in the coal is released in drops of molten slag as the coal particles burn. These drops develop a layer of slag on the water-cooled walls as a result of centrifugation from the swirling gas flow. At equilibrium, which is quickly reached, the slag is solid at the wall and liquid on the side facing the combustion volume. Once on the wall, the molten slag is driven to the baffle by a combination of aerodynamic and gravity forces. It is constrained by the baffle to flow through the key slot and into the slag tap located just after the baffle. The molten slag stream then drops into the water-filled slag tank.

Since the combustor is operated fuel rich (stoichiometric ratios of 0.7 to 0.9), the swirling hot gas is rich in carbon monoxide and hydrogen. It is ducted to the heat use equipment interface where sufficient air for combustion within the furnace volume is added. A staged combustion process results, which minimizes NOx formation. Sufficient temperature and heat flux are generated within the coal combustor volume to achieve the liquid slag flow condition, but the classical high NOx formation regime is avoided by the combination of temperature and gas composition control. SOx emissions can be reduced significantly by injecting sorbent materials, such as limestone or dolomite, into the combustion volume. The combination of temperature and gas composition control favors formation of nongaseous sulfur compounds, which can be retained in the molten slag, and fine particulates generated in the combustion process, which can consequently be removed from the system as solid material.

The combustor offers significant advantages over competitive retrofit technologies, including simplicity and compactness of design, refractory free construction, highly efficient combustion, and high ash removal. These characteristics, combined with low NOx operation, SOx control, small size particulate carryover, and a high turndown ratio (3:1), allow operational flexibility.

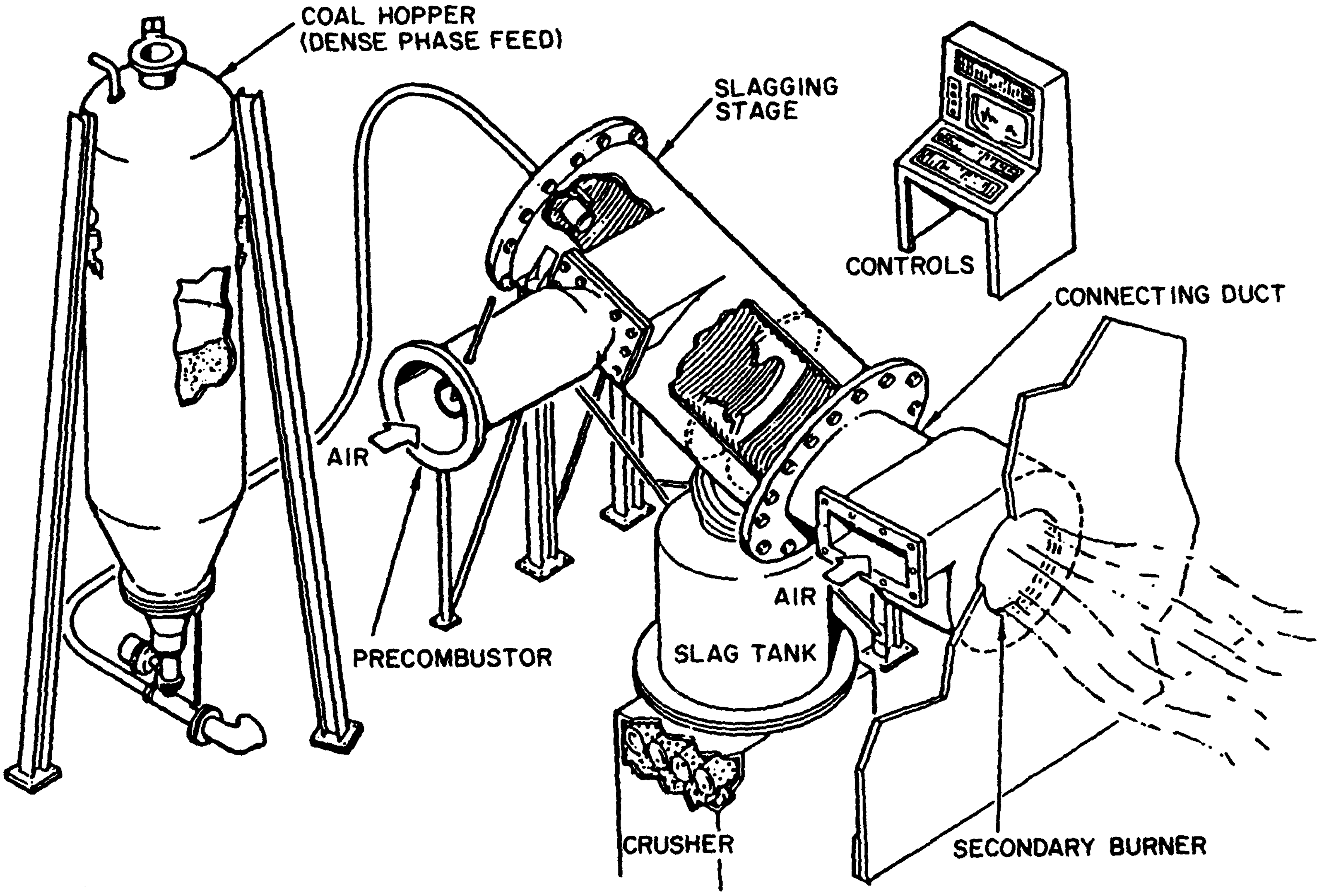

Figure 3. TRW slagging coal combustor system. (Source: *TRW Coal Combustor Demonstration Program (1984-1986)* ([October 1983]).

Table 2

Characteristics of TRW Combustor[8]

Characteristic	Value	Comment
Small size	2 ft by 4 ft to 7 ft by 11 ft (20 to 250 MBtu/h) 1 MBtu/h-cu ft	Fits available space
Simple configuration	Water-cooled cylinder	Low maintenance
No refractory liner	~ 1 in. slag on wall	Avoids failure, downtime
High slag removal	80 to 90 percent	Minimizes carryover
High carbon burnout	Greater than 99.5 percent	Efficient combustion
Low NOx	230 to 450 ppm	Meets pollution standards
Reduced SOx	40 to 60 percent	Reduces/eliminates cleanup
Flexible device	Adjustable air and coal feed	Accommodates ranges of coals and turndown ratios

The combination of simplicity and compactness make the device ideal for retrofitting existing oil- and gas-fired kilns, furnaces, and boilers within the space available. For example, a combustor 3 ft deep by 6 ft long produces 50 MBtu/h and, when scaled up by a factor of five (to 250 MBtu/h), increases to only 7 ft deep by 11 ft long.

Coal Hopper/Fluidizer.[9] The coal hopper with integral dense-phase feed components receives standard pulverized coal (70 percent through 200 mesh), through the top opening from a conventional mill. The tank is just big enough to allow efficient, steady fluidization of the coal and delivery through a connecting tube to the combustor injector. By a combination of flow elements in the hopper and bottom fluidization components, steady, dense-phase fuel feeds are maintained with a 10 to 1 weight ratio of coal

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[8] John Stansel, et al., "TRW's Slagging Combustor System Progress," 7th International Coal and Lignite Utilization Exhibition and Conference, Houston, TX, November 13-15, 1984.

[9] John Stansel, Douglas Sheppard, and Ellen Petrill, "TRW's Slagging Combustor System Tests," 6th International Coal Utilization Conference, Houston, TX, November 15-17, 1983.

to fluidizing gas. Both nitrogen and air have been used successfully as the fluidizing gas. Turndown ratios of 3:1 can be achieved by reducing combustion airflow and coal flow simultaneously.

Precombustor.[10] A precombustor is attached to the tangential air inlet of the slagging stage combustor. This component can be fired with either coal or oil. It is used to boost the air inlet temperatures from those readily available in a wide range of industrial and utility applications to the value desired for optimum combustor performance. When coal is used in the precombustor, it can be conveniently fed from the same dense-phase feed hopper used to supply the slagging combustor.

Combustion air temperatures obtained with reasonably priced waste heat recovery systems vary over a wide range; 80 to 350 °F are common in some chemical and industrial applications, whereas 400 to 650 °F can be achieved in large industrial and utility plants. An air/water heat exchanger in the main coolant loop of the combustor can produce air preheat temperatures up to 350 °F. This is attractive for applications where no other preheat capability exists or where this type of exchange is more efficient than other approaches to using the heat transferred to the combustor coolant.

Slag Removal.[11] The slag tank is a simple cylindrical structure partially filled with water. It receives molten slag through an opening in the top that is connected to the slag tap located in the bottom wall of the combustor. As the molten slag flows into the tank, it is quenched and fractured by the water. Large pieces are broken up by a crusher located at the tank bottom so the slag may be removed easily by a conventional slurry conveyor or dewatered and handled by bulk conveyor.

Secondary Burner/Duct.[12] A short duct connects the exit of the combustor to the burner port of an existing furnace, kiln, or boiler. Generally, the duct can be sized so no major modifications are necessary in retrofitted existing equipment. A secondary burner (located in the burner port) allows combustion air to be mixed with the hot combustor gases exiting the duct. Combustion is completed in the furnace volume of the heat use equipment. Hence, there are two separate combustion stages that minimize NOx production: one in the slagging combustor and the second in the furnace volume.

Control Console.[13] A final element in the coal combustor system is a control console based on state-of-the-art electronic elements coupled to selected sensors/control elements strategically placed in the major components of the combustor system. Sufficient control of fuel and airflows in both primary and secondary stages and water flows through the combustor coolant loop are important considerations in the design of such a control unit.

Each of the above components can be integrated into the slagging coal combustor system in a manner optimal for the application. For example, if space near the heat use equipment is minimal, the dense-phase coal hopper and control console may be remotely positioned. In applications where multiple small burner ports exist, a single slagging combustor and connecting ducts may be used to couple several ports.

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[10] John Stansel, Douglas Sheppard, and Ellen Petrill.

[11] John Stansel, Douglas Sheppard, and Ellen Petrill.

[12] John Stansel, Douglas Sheppard, and Ellen Petrill.

[13] John Stansel, Douglas Sheppard, and Ellen Petrill.

Development Status and Test Results

TRW has designed and fabricated various sizes of slagging combustors. Of particular interest are the 10-MBtu/h and the 50-MBtu/h units. The 10-MBtu/h system was installed in the Capistrano Test Site in California. This facility arrangement allows complete system tests to be accomplished at 10-MBtu/h, yielding data on combustion efficiency, slag removal, and NOx/SOx reductions.

Three phases of testing were carried out in the full system configuration described above. The first phase concentrated on NOx emissions and secondary burner characteristics. The results indicated that secondary combustion was efficient and the flame characteristics appeared to be independent of coal type since carbon monoxide and hydrogen were the principal fuel components being burned. NOx emissions comparable with oil firing were achieved by controlled slagging stage stoichiometry. The second phase of testing focused on sorbent injection for SOx reduction using three Eastern medium to high sulfur pulverized coals. The sorbent was expected to calcine and react at the fuel rich conditions with gaseous sulfur species to form liquid phase reaction products involving primarily calcium sulfide. The larger sized reaction products formed would be centrifuged to the wall by swirling gas flows in the combustor, mixed with the flowing slag layer, and removed at the slag tap. The smaller sized reaction products (less than 10 micrometers [μm]) would normally be carried out of the combustor with the finer slag particulates into the secondary flame zone and subsequently cooled as they pass through heat use and downstream baghouse equipment.

In the second test phase, Kentucky coal (1.7 percent sulfur) was used with powdered dry limestone for initial screening tests. Oil firing in the precombustor boosted combustion air temperatures from between 400 and 600 °F up to between 1000 and 1500 °F at the main combustor inlet. The limestone was relatively coarse ground (65 μm) and was injected at varying calcium/sulfur (Ca/S) molar ratios in the following locations (Figure 3):

- Mixed and injected with the powdered coal,
- Mixed and injected with the incoming combustion air stream,
- Separately injected in the head end region of the combustor,
- Separately injected in the aft regions of the combustor,
- Separately injected into the slagging stage combustor exhaust flow, but before the secondary burner.

All SOx measurements were made at the exit of the large secondary combustion chamber, a simulated boiler, after all combustion was completed. The exhaust temperature at this location was approximately 1500 °F since cooldown had occurred via heat transfer to the secondary chamber walls. This crudely simulates conditions in typical heat use equipment such as kilns and some industrial boilers.

The initial test results indicated a wide range of SOx reduction values from 10 to 45 percent depending on the location of sorbent injection and the Ca/S ratio. Separate limestone injection into the slagging stage proved superior to the other mixed conditions listed above. Since the limestone used in these screening tests was rather coarse, subsequent testing with finer sorbent materials would result in significant additional SOx reduction. It is worth noting that the limestone sorbent also reduced the high T250 value (the temperature at which molten slag has a viscosity of 250 poise). This enhances combustor slag flows so that lower slagging stage temperatures (by about 300 °F) can be used, which in turn reduces both NOx and SOx emissions.

In subsequent testing, two typical Eastern high sulfur coals, Illinois No. 6 (3.63 percent sulfur) and Blacksville No. 2 (3.05 percent sulfur), were pulverized and fired. Four separate sorbent materials, Vicron (a commercial calcite), dolomite, hydrated lime, and pressure hydrated dolomitic lime, all pulverized to average particle sizes in the range of 8 to 30 μm, were transported to the combustor via a dense-phase feed system similar to that used for transporting pulverized coal. Molar ratios of 2 to 3 for calcium plus magnesium to sulfur reduced SOx values about 40 to 60 percent for Illinois No. 6 coal with Vicron or dolomite. The hydrated lime initially gave comparable results which dimished as the molar ratios increased; it was also harder to transport. The data for Blacksville No. 2 coal and sorbents were similar but less pronounced, probably due to the 20 percent lower sulfur content in the coal.

All SOx values were obtained by sampling exhaust gases at the large secondary combustion chamber exit where the gas temperature was approximately 1500 °F. TRW feels that in actual industrial and utility applications, further SOx reduction will occur as the exhaust gases, carrying some partially spent fine sorbent particulates, cool and finally pass through the filter cake in a baghouse. TRW therefore set initial air pollution control goals of NOx emissions comparable to oil firing (about 250 parts per million [ppm]) and sulfur capture approaching 90 percent when physical coal cleaning and the entire combustor, boiler, and baghouse system are considered.

Based on the extensive pulverized coal tests conducted at the 10-MBtu/h combustor and scaling information contained in a TRW proprietary computer code, a 50-MBtu/h commercial test combustor (the workhorse unit) was fabricated and installed in a new position at the Capistrano Test Site. This combustor is capable of operating at power levels of 17 to 50 MBtu/h (3:1 turndown). The workhorse combustor is mounted on a structural frame with a 15-degree inclination to enhance slag flows. The cylindrical section of the combustor is approximately 3 ft in diameter and 5 ft long. It is fabricated in individually cooled sections that are flanged and bolted together to accommodate geometric changes and to acquire axial heat flux profiles. A precombustor was later attached to the rectangular air inlet. The aft region of the combustor can be adapted to a particular application. A vertical exhaust duct opposite the slag tap is used to minimize slag spillover, since the bulk flow velocity and resulting wall shear loads are relatively small compared to the gravity forces that pull the slag to the bottom tap. An elbow turns the vertical exhaust flow horizontally to allow direct connection to a secondary burner located just downstream of the combustor exhaust exit.

Initial checkout and scaling verification tests were run using Ohio No. 6 high sulfur coal. Generally, the large combustor performed as well or better than the small unit, even without optimization testing. The entire system could be cold started; using fan air at 100 °F and a conventional ignitor, good ignition and stable flames were produced in both the precombustor and the main combustor. This means that as the plant preheats for initial startup, combustor operation will remain smooth and trouble free. The slagging stage performed very well with stable, well-anchored combustion, excellent slag coverage, and good slag flows to the exit tap. Slag recovery exceeded 80 percent and, based on optimization testing at the smaller scale, it can be expected to increase. Carbon conversion exceeded 99.5 percent with measured stack NOx values in the range of 230 to 450 ppm, depending upon run conditions.

TRW culminated the 10-year research and development effort by constructing a retrofit demonstration on an industrial boiler at a TRW aircraft component parts plant in Cleveland, OH. Figure 4 illustrates the SCC system in Cleveland.

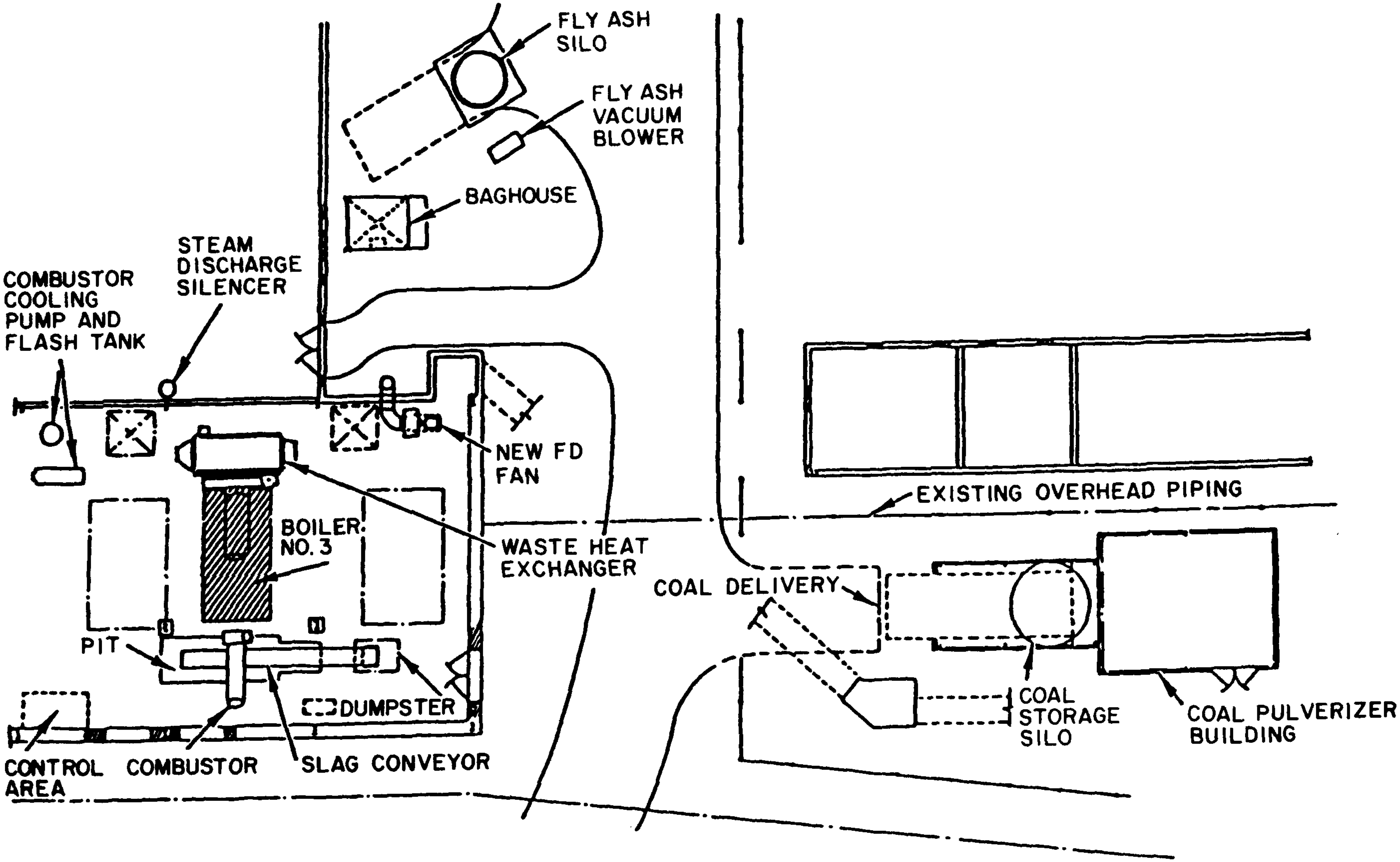

Figure 4. Cleveland plant system diagram.

The boiler house at the Cleveland facility contains 10 active gas/oil packaged boilers used to supply steam to the plant for process and space heating. In addition, three 30,000-pounds-per-hour (pph) field-erected boilers are housed within the boiler plant. The field-erected boilers originally burned coal, but were later converted to gas/oil. They are rated for 30,000 pph of saturated 125-pounds-per-square-inch-gauge (psig). Boiler No. 3 was retrofitted with a 40-MBtu/h slagging combustor. Other modifications to the plant included:

- New coal-receiving, storage, reclamation, pulverizing, and feed system,
- New forced draft (FD) and induced draft (ID) fans and ductwork,
- Combustor cooling and heat recovery systems,
- Tubular air heater,
- SO_x spray dry scrubber,
- Baghouse and ash handling system,
- Slag removal system, and
- New control system and data acquisition.

The coal receiving facilities are 200 ft from the retrofitted boiler. An auto-tripper with a capacity of 25 tons receives coal from trucks. The tripper transfers coal to a 140-ton live storage silo using a "Denseveyor," dense-phase transport system. Inside the coal handling building, a 25-ton/day bin is located above a standard ball mill. An insulated duct carries heated air into the ball mill from a direct gas-fired air heater. Pulverized coal is transferred from the ball mill through a cyclone and baghouse to the dense-phase coal feed system. Pulverized coal is transferred to the combustor through two parallel, 2-in. diameter tubes located above the combustor; one for the precombustor and one for the main combustor. Fluidizing and carrier air are provided by the existing air supply system.

The slagging combustor is designed to remove from 70 to 90 percent of the ash as molten slag that flows through a slag tap in the bottom of the combustor into a submerged drag chain conveyor. The remaining fly ash is removed after the boiler in a conventional baghouse with felted fiberglass bags.

The retrofitted boiler has run for more than 2,000 hours using Ohio No. 6 seam coal at power levels of 10, 18, 24, 37, and 40 MBtu/h. Tables 3 and 4 show some of the test results.

TRW is undertaking a 4,000-hour program to assess the effects of variations in key operating variables on performance. A vigorous sulfur reduction program will follow the demonstration. This program will involve installing limestone injection equipment for implementing simultaneous furnace SO_x and NOx control to industrial standards. TRW had not as yet demonstrated the ability to obtain 80 percent sulfur capture while maintaining combustor efficiency and slag capture with a variety of coals.

Table 3

Test Summary and Comparison of Commercial Test Unit Characteristics[14]

Characteristic	Low	High
Nominal Power Level (Mbtu/hr)	10	40
Diameter (in.)	17	34
Length (in.)	26-62	62
Operating Pressure (atms)	1.05 - 1.2	1.05 - 1.1
Air Preheat Temperature (°F)	400-700, 1500 excursions	100 - 500
Equivalence Ratio Range (first stage)	0.7-0.9, 1.2 excursions	0.7-0.9, 1.2
Maximum Slag Capture (%)	91	83
Carbon Burnout (%)	>99.5	>99.5
NOx (ppm)	230 - 450	230 - 450
SOx Reduction (%)	40 - 60	*
Outlet Temperature (°F)	2800 - 3600	2800 - 3600
Total Number of Firings	375	20**
Total Run Duration on Coal (hrs)	690	33
Individual Runs (hrs)	1 - 8	1 - 2

* Not tested as of October 1, 1984.

** Initial checkout tests and scaling verification.

AVCO Everett Research Laboratory

Coal Combustion System Description[15]

AERL reactivated their pressurized MHD slagging combustor modified for atmospheric operation as a test unit for the development of a compact retrofit burner for replacing oil/gas burners, one for one. Instead of the cyclonic swirling turbulence used by the other developers, the flow in the AERL design consists of a toroidial vortex in the upper head dome region of the combustor created by several air-fuel input jets. This design considers pressure drop, ash separation, combustion efficiency, heat loss, and pollutant emissions. The combustor body is water-cooled steel. A slag coating provides an insulating barrier and protects the body from erosion during operation (Figure 5).

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[14] John Stansel, et al.

[15] Burns and Roe Services Corporation, *Market and Equipment Performance Analysis for the Application of Coal-Based Fuels/Advanced Combustion Systems, Technical/Economic Assessment of Coal-Fired Slagging Combustors* (March, 1986).

Table 4

Workhorse Combustor Performance for Steady Run[16]

Operating Parameters	
Coal Type	Ohio No. 6
Power (MBtu/hr)	38
Combustor Pressure (atm)	1.06
Air Preheat (°F)	1500
First Stage Equivalence Ratio	0.75
Overall Equivalence Ratio	1.2
Performance Characteristics	
Slag Recovery (%)	83
Carbon Burnout (%)	99.8
NOx (ppm)	262-289
Outlet Temperature (°F)	~ 2900

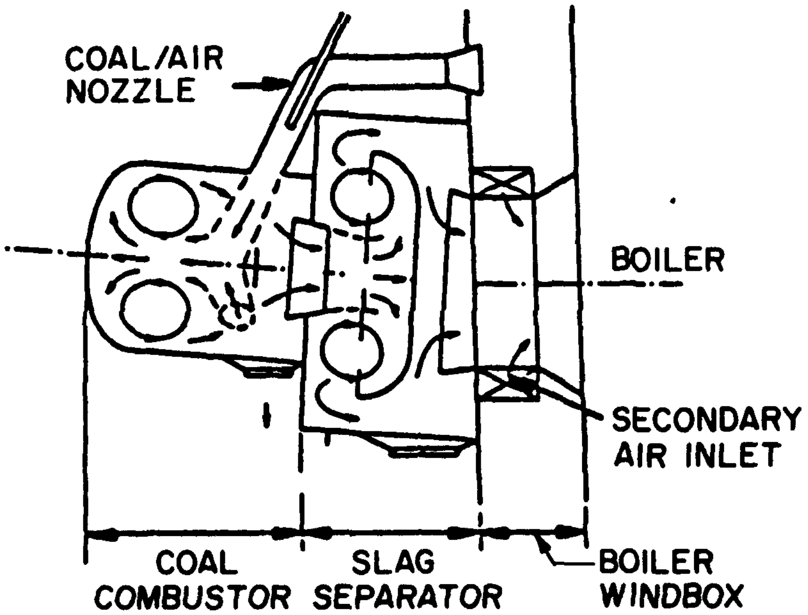

Figure 5. AERL combustor. (Source: *STEAM, Its Generation and Use*, 38th Edition [The Babcock & Wilcox Company, 1972]).

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[16] John Stansel, et al.

In the AERL combustor, coal and mineral particles are impacted on the wall to form a steady-state flow of molten slag. The combustion products of the external combustor are discharged into the slag separator where more than 90 percent of the slag is inertially separated and collected. The hot gas product of the external combustor system is mixed with secondary air at the entrance to the boiler. Combustion is completed in the boiler radiative heat exchange volume.

Developmental Status and Test Results

Test results and data from the modified MHD unit were used to design a 25-MBtu/h development test combustor that was installed and tested at the AERL Haverhill Test Facility. These results, plus scale model flow tests and analytical modeling, will then be used to design a combustor with a thermal input of 50-MBtu/h. When completed, the larger unit will be installed and tested at the Riley Stoker Corporation burner furnace test facility in Massachusetts to simulate retrofit conditions of a boiler installation.

Rockwell International (TransAlta)

Coal Combustor System Description[17]

Rockwell has emphasized low NOx/SOx operation. Their burner design optimizes the time and stoichiometry required for simultaneous SOx and NOx control. Preliminary concept verification testing was performed from 1979 to 1981 in their 17-MBtu/h pressurized (6 atmospheres) test unit (Figure 6). The first section of this unit was refractory-lined and the second section was water-cooled.

In this burner (7.5-in. ID), about 50 percent of the molten ash particles were deposited on the combustor walls. A slag/fly ash separator, designed to increase overall slag/fly ash removal to about 80 percent, was also tested. The inertial impact separator consists of rows of studded metal tubes oriented vertically across the gas stream (Figure 7). Because the larger fly ash particles cannot negotiate the sharp turns around the tubes, they impinge on the tube surfaces. The molten slag then runs to the bottom, joins the slag from the combustor walls, and flows to the slag port near the end of the combustor.

Rockwell's commercial combustors are designed to be direct fired; coal is pulverized and blown directly into the combustor, with pulverizer air as the carrier. All testing to date, however, has used indirect coal feed systems. The 17-MBtu/h burner used a dense-phase coal feed. Most of the testing was done without a separator or slag removal system. Slag deposits were collected in a well inside the combustor and periodically removed during down times. Two Eastern coals from Kentucky and Illinois and two Western coals from Utah and Montana were tested in this mode of operation. Two coal-water slurries (origin not given), a high sulfur residual oil, and shale oil were also tested.

Rockwell's burner was initially conceived as a method of providing low cost SOx and NOx control in combustion. Under contract to Southern California Edison, Rockwell fabricated and tested an inertial slag separator for the 17-MBtu/h unit. The separator was equipped with an internal well for slag storage; slag was not continuously removed from the combustor. Testing was performed with Utah coal.

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[17] T.C. Derbidge and W. Rovesti.

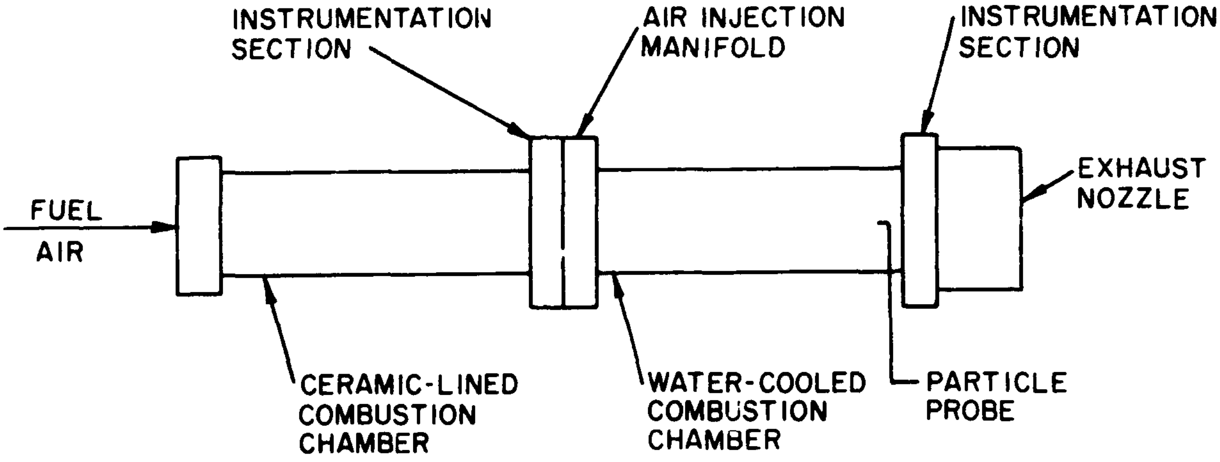

Figure 6. **Rockwell pressurized concept verification slagging combustor.** (Source: T.C. Derbidge and W. Rovesti, "Review of Advanced Staged Slagging Coal Combustor Technology," *EPRI Journal* [September 1984].)

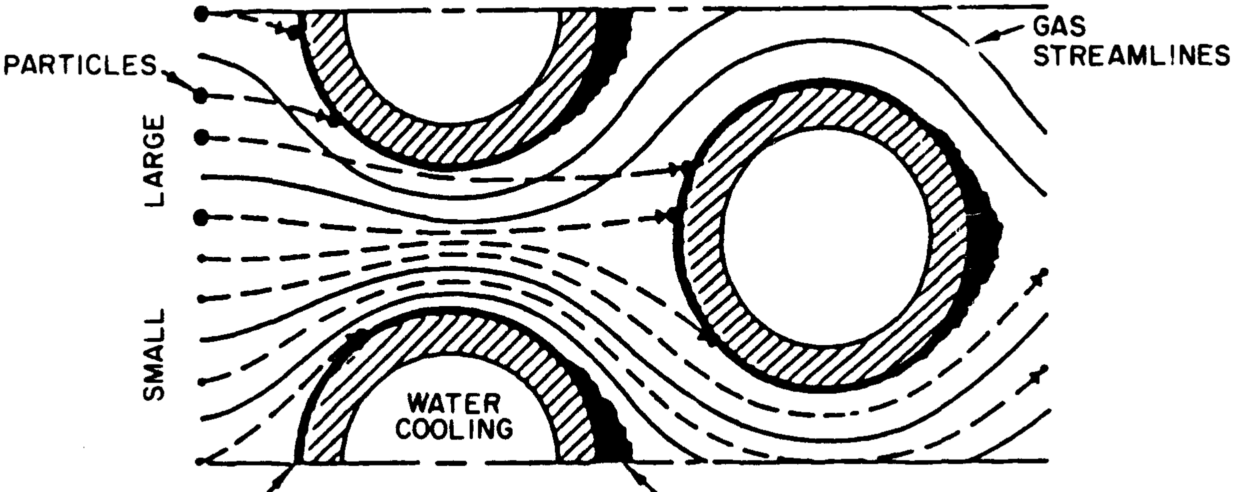

Figure 7. **Rockwell fly ash/slag separator.** (Source: T.C. Derbidge and W. Rovesti, "Review of Advanced Staged Slagging Coal Combustor Technology," *EPRI Journal* [September 1984].)

Subsequently, a 25-MBtu/h atmospheric pressure pilot scale facility was constructed (Figure 8), and testing began. This pilot scale combustor is refractory lined. Initially, the refractory was backed up with water cooling, but the burner is now operated entirely uncooled. The combustor exhausts into bare steel ducting, which is cooled by an external water spray to simulate the radiant section of a boiler. This is followed by a commercial waste-heat boiler, which simulates the back-end convective section of a boiler. The burner uses an intermediate PC storage silo from which the PC is picked up in carrier air and pneumatically transported to the burner. Two Eastern coals (Kentucky No. 9 and Gauley Eagle) and one Western coal (Black Mesa) have been tested. The pilot scale facility was not originally equipped with a slag/fly ash separator and did not provide continuous slag removal. However, a separator incorporating continuous slag removal has now been installed and is being tested. A patent was issued to Rockwell for application of the technology to low NOx combustion.

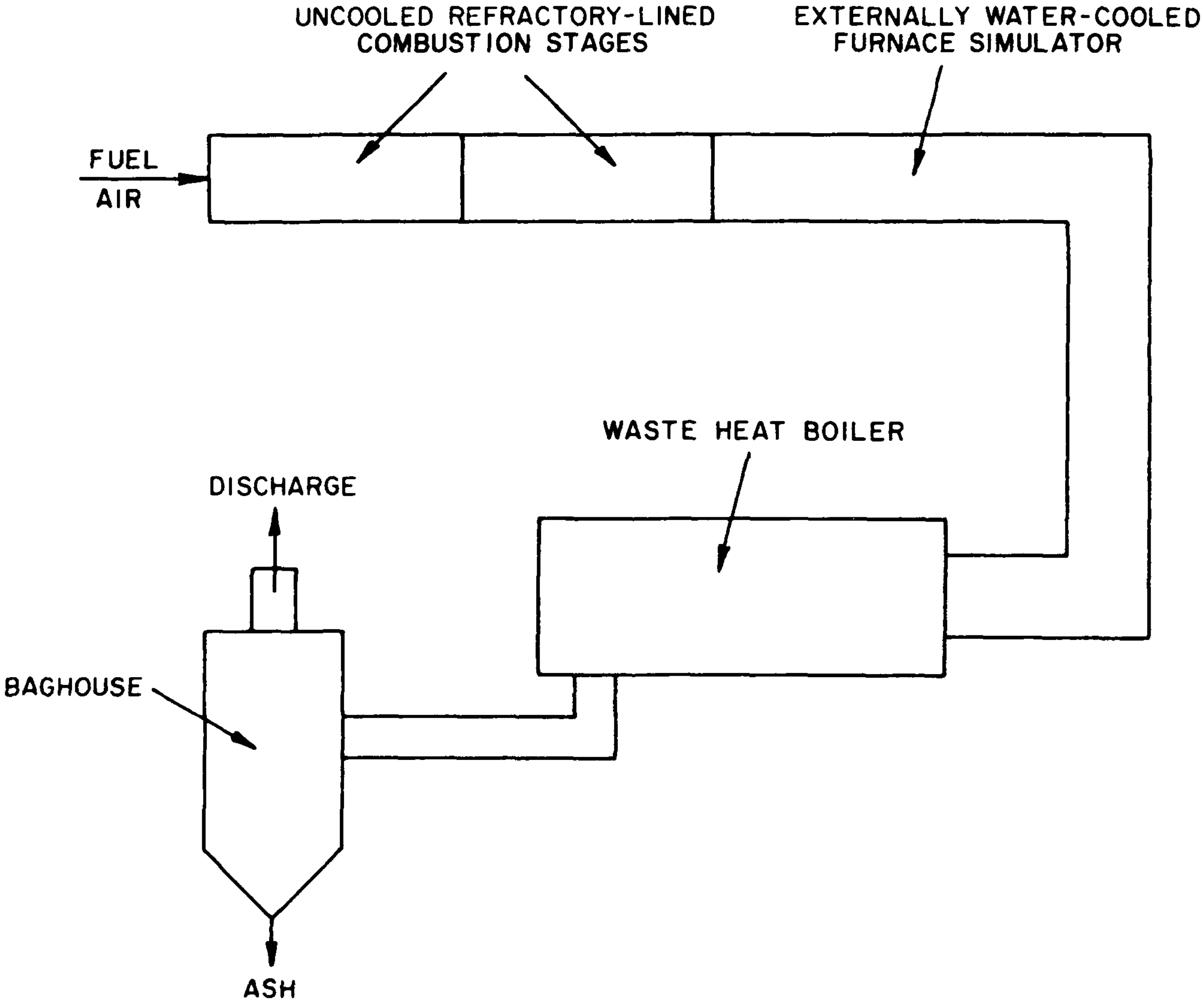

Figure 8. **Rockwell pilot scale slagging combustor.** (Source: T.C. Derbidge and W. Rovesti, "Review of Advanced Staged Slagging Coal Combustor Technology," *EPRI Journal* [September 1984].)

To guide and support the development effort, Rockwell formed a utility consortium. Current members include Southern California Edison Company, Niagara Mohawk Power Corporation, TransAlta Utilities Corporation of Calgary, Canada (with the Canadian Electric Association), Houston Lighting and Power Company, and Wisconsin Public Service Corporation. Each consortium member makes a financial contribution and participates on a steering committee. Testing will continue on the pilot scale 25-MBtu/h combustor with the support of the utility consortium. The purpose of this test program is to develop design criteria for full-scale commercial utility boiler-burners.

Rockwell has performed preliminary design studies for retrofits to both tangentially-fired and wall-fired units. Figure 9 shows a conceptual schematic for a 100-MBtu/h commercial combustor. The large size of the unit is due to the relatively long residence time needed to achieve the necessary degree of carbon burnout and low NOx/SOx emissions, as well as to accommodate the slag/fly ash separator.

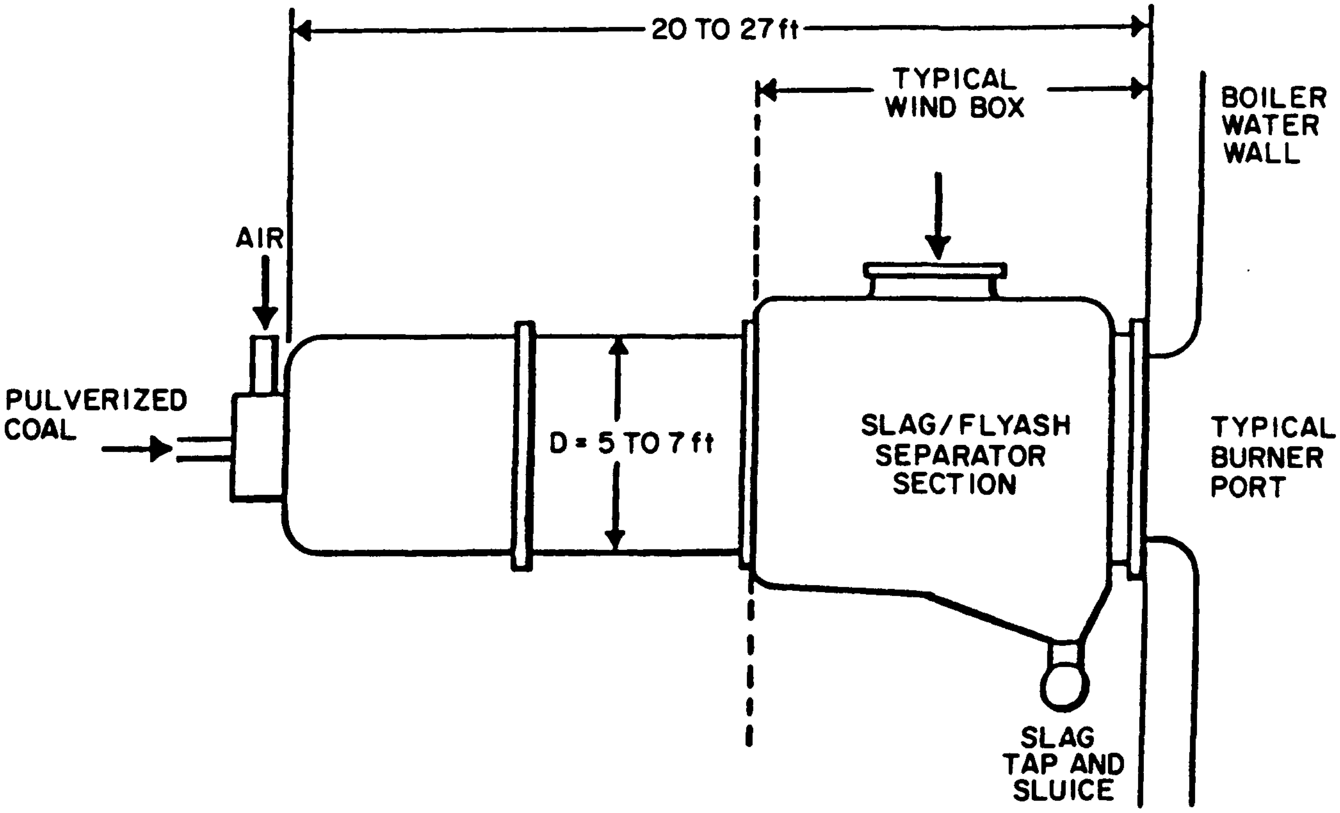

Figure 9. Rockwell commercial scale slagging combustor. (Source: T.C. Derbidge and W. Rovesti, "Review of Advanced Staged Slagging Coal Combustor Technology," *EPRI Journal* [September 1984].)

Developmental Status and Test Results[18]

Combustion concepts developed at Rockwell indicate that, at least theoretically, both SOx and NOx emissions from coal combustion could be reduced essentially to zero by what appear to be rather simple modifications to the coal combustion process. Each control process involves two subprocesses. The SOx control process consists of sulfur capture and retention of that captured sulfur through the rest of the burner and boiler. The NOx control process consists of converting the fuel-bound nitrogen to molecular nitrogen in the burner and then preventing formation of new thermal NOx in the boiler. Within the burner, sulfur from the coal is captured by solid calcium. It does not matter if that calcium is physically added to the coal (before pulverizing) or is inherent in the as-received coal. However, most alkaline low sulfur coals contain sufficient calcium.

A subscale test program was conducted at the 17-MBtu/h firing level to verify the proposed SOx and NOx control theory. Low sulfur Western subbituminous and high sulfur Eastern bituminous coals were tested. Test results confirmed theoretical predictions. In the best performance cases, SOx emissions were reduced by over 90 and 95 percent with the bituminous and subbituminous coals, respectively. With both coals, NOx emissions were repeatedly reduced to levels unmeasurable by the available instrumentation (less than 7 ppm). A total of 80 percent removal of coal fly ash was also demonstrated. The 95 percent SOx control when burning low sulfur Western subbituminous coal was achieved without adding any calcium, or any other additives, to the system and no additives were necessary to achieve the very low levels of NOx emission. Early testing also indicated that overall carbon burnout (combustion efficiency) would be very high.

The concept verification program was conducted at 6 atmospheres of pressure in the burner simply because that hardware was readily available at the time. The subsequent pilot scale development program at the 25-MBtu/h firing level was at atmospheric pressure.

The overall program had only one fundamental goal: to simultaneously control both SOx and NOx emissions. Table 5 shows the current status of the subscale Research and Development (R&D) program.

Basically, all important goals have already been achieved with subbituminous coals. Sulfur capture at both pressure levels met or exceeded the NSPS goal of 70 percent reduction, and essentially 100 percent of this captured sulfur was retained throughout the rest of the burners and test facilities. Similarly, control of NOx formed from fuel-bound nitrogen at both pressure levels met or exceeded the established program goals. Thermal NOx was formed in the simulated boiler, but this is expected and can be prevented by controlling combustion temperatures if desired. In all cases, the program's NOx goals are so far below all but the most stringent regulations that little interest has been expressed in any further reduction. Similarly, all but two of the important goals have already been achieved with bituminous coals. The exceptions are sulfur capture and retention at atmospheric pressure, in the pilot scale burner.

Four of the 36 tests in the pilot scale program were conducted with 3 different bituminous coals. In these 4 tests, only about 70 percent of the sulfur was captured. About 30 percent of this captured sulfur was lost (oxidized to SOx) in the downstream high-temperature, oxidizing regions of the burner/simulated boiler. To date, then, only about 50 percent overall SOx control has been demonstrated with bituminous coals.

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[18] O.W. Dykema and W.L. Fraser, "Development and Commercialization of a Low NOx/SOx Burner," *Proceedings of the American Power Conference* (1987).

Table 5

TransAlta 17-MBtu/h Test Results

Function	Combustor Pressure	Achieved Low Sulfur Western	 High Sulfur Eastern	Goal
Sulfur capture	6	95	90	NSPS (70/90)
	1	70	70	NSPS (70/90)
Sulfur retention through stack	6	100	100	100
	1	100	60-70	100
NOx control in burner	6	0	0	<60
	1	50-100	30-60	<60
NOx control through stack	6	Not Tested	Not Tested	100
	1	100-150	80-140	100

This result does not necessarily represent failure of SOx control. Theory indicates that, given the same degree of combustion throughout the burner, greater fractions of sulfur should be captured with high sulfur bituminous coal than with low sulfur subbituminous coal. In the higher pressure testing, this degree of combustion was achieved with both coal types, and the goal of 90 percent or better sulfur capture was also achieved. In atmospheric pressure testing, the necessary degree of combustion was achieved with subbituminous coals but not with bituminous. Given the lesser degree of combustion, theory indicates less than desired sulfur capture; this is what was observed in the initial bituminous coal tests.

Even in the limited testing with bituminous coals to date, both the capture and retention problems were recognized and corrective action was taken. For example, in the final test of this 4-test series, the coal was ground slightly finer (38 versus 42 μm surface-mean coal particle diameter), resulting in the highest degree of combustion and the highest sulfur capture (72 percent) of this test series. Also, in the last test, retention was improved from between 60 and 70 percent to between 80 and 85 percent. Subsequent detailed study of the overall sulfur retention mechanism indicates that the special problem with bituminous coals is not as severe with lower rank coals. A short test program will be necessary to demonstrate that the retention problem has been resolved.

A number of actions known to improve coal gasification rates have been identified, including the finer coal grind mentioned above. A follow-on pilot scale program, including some laboratory work, was initiated to develop, optimize, and test several techniques that are expected to demonstrate improved gasification and better than 90 percent sulfur capture with bituminous coals at atmospheric pressure.

As mentioned earlier, the primary goal in the R&D program is related to SOx and NOx control. To broadly apply this emissions control technology, however, requires that certain other goals be met at the same time. These include adequate fly ash/slag removal within the burner (to allow conversion of gas-/oil-fired boilers to coal), negligible carbon monoxide emissions and high combustion efficiency (carbon burnout). These other important goals have also been met. About 80 percent fly ash removal has been demonstrated with a pilot scale separator. Common problems have been experienced with a molten-slag tap. However, the operational concept, similar to other slag tap systems, has been demonstrated in a limited way. Concentrations of carbon monoxide in the stack gases are negligible. With carbon balances accurate to about 2 percent, overall carbon burnout is 98 to 99 percent. With successful completion of the remaining pilot scale program, all major goals will have been successfully met or exceeded.

The next, most important generic step to commercialization is a long-term demonstration of the durability, operability, and reliability of a commercial size slagging combustor operating on a utility boiler. This project is called the Wabamun Demonstration Project. The Rockwell (TransAlta) Wabamun plant is located 37 miles west of Edmonton, Alberta, Canada. Unit 2, selected for this program, is a 66-MWelectric(e) B&W radiant, natural circulation, balanced draft steam generator firing natural gas or coal. The existing 100-MBtu/h burners are arranged in a 3 by 3 face-fired array. Each burner burns approximately 10.5 tons per hour of a Western subbituminous coal supplied from the local Whitewood mine. This coal contains 0.24 percent sulfur, 22 percent moisture, 16 percent ash, and 7600 Btu/lb.

An additional objective is to demonstrate integration of the slagging combustor into an existing plant. It has been necessary to address some of the integration questions during preliminary engineering. The questions concern (1) the optimum compromise in the carrier air-to-coal weight ratio between that best for the pulverizer and that best for the burner, (2) minimum combustion air preheat temperatures at maximum turndown, and (3) burner support to allow for thermal growth of the boiler. Many of these answers will be quite site specific, although generic answers will be developed.

The project is scheduled in two phases over a 3-year period. Figure 10 is a sketch of the proposed installation. In the first phase, one 100-MBtu/h burner was fitted to one of the burner ports in the 3 by 3 array. Since this unit is coal capable, a fly ash separator was not necessary. However, the burner incorporated a fly ash separator for the demonstration test. The first burner was operated by plant operators in the normal duty cycle of electric power generation at this plant for 1 year. In the second phase, two additional burners were fitted to burner ports in the same row as the first burner, and the three burners were operated for at least another year. The additional burners did not incorporate a separator. The single burner was fed from a smaller pulverizer, procured especially for this testing. The row of three slagging combustors was fed from the existing pulverizer.

The Wabamun program began with the burner design. Rockwell personnel knowledgeable in the slagging combustor established critical design criteria to be sure that the process operated optimally. The design criteria was then passed on to a major burner manufacturer where all other aspects of burner design were established and the first burner was manufactured. While the burner was being designed and manufactured, the necessary plant modifications were accomplished. Installation took about 2 months. During the test year, the slagging combustor operated simply as one of nine burners used to generate electricity. During a 2-month startup period, and periodically throughout the year, special gas and solids sampling was conducted to evaluate burner performance. In the second phase, with three combustors installed, the boiler was operated with the slagging combustors only, at maximum plant turndown. In this case, performance was evaluated by analyzing the gases going out the stack.

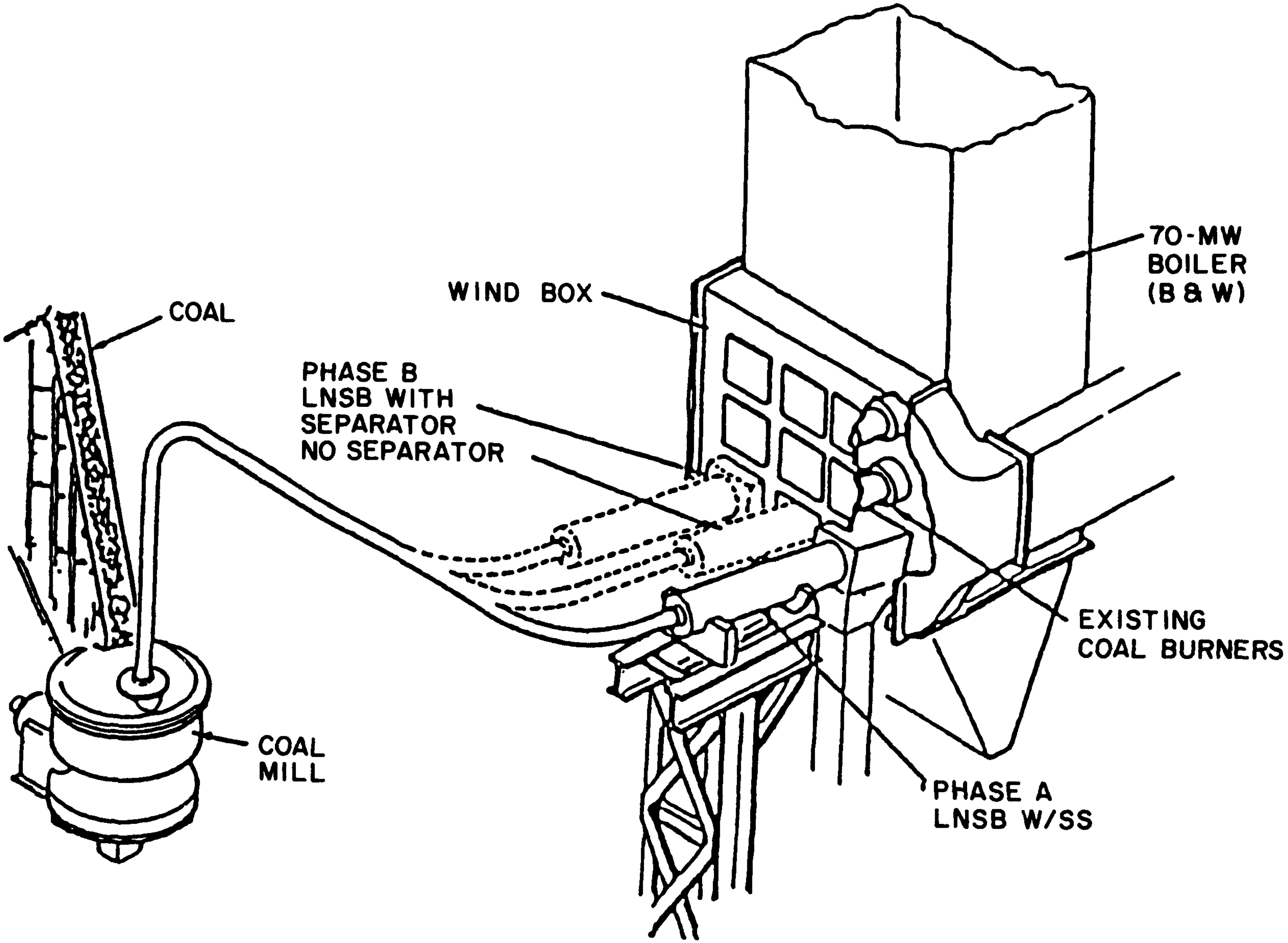

Figure 10. Wabumum demonstration burner installation. (Source: O.W. Dykema and W.L. Fraser, "Development and Commercialization of a Low NOx/SOx Burner," *Proceedings of the American Power Conference* [1987].)

Coal Tech

Coal Combustor System Description[16]

Coal Tech was formed by members of GE's MHD group. Under their DOE-sponsored MHD work, GE tested a 1-MBtu/h, air-cooled, ceramic-lined, slagging combustor (Figure 11). Testing with Illinois and Utah coals was discontinued after more than 200 hours of coal firing.

Based on experimental results from the test unit and theoretical calculations, Coal Tech is developing a design for a commercial-scale (100 MBtu/h) slagging combustor. The design retains the basic features of the test unit, including:

- Predominantly air-cooled, with cooling air used as preheated combustion air,
- Ceramic-lined,
- Highly swirled air that throws slag out to the walls,
- Short combustor residence time, which results in a compact design (internal length/diameter ratio of about 1.5),
- A dense-phase feeding system that transports pulverized coal from a storage hopper to the burner.

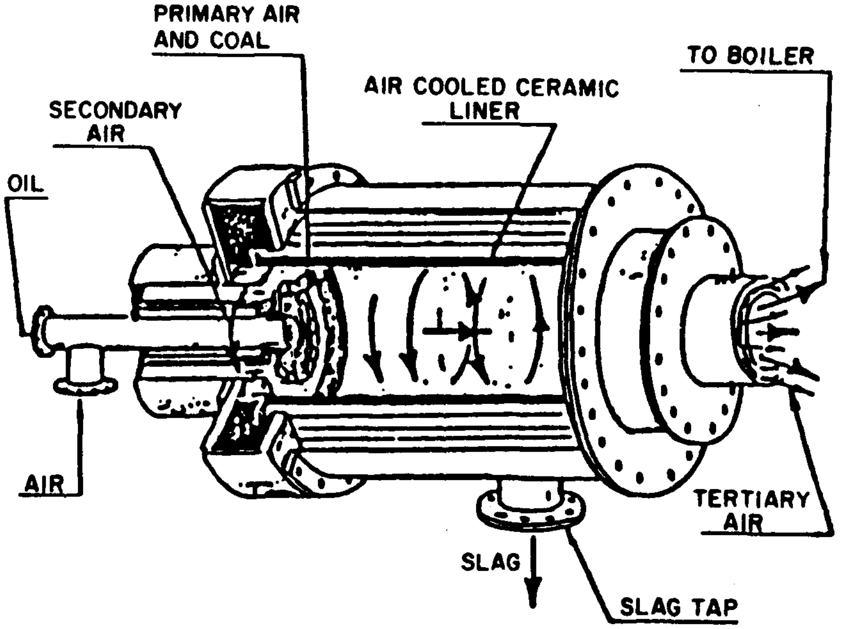

Figure 11. Coal Tech's air-cooled cyclone combustor. (Source: B. Zauderer, et al., *Application of an Air Cooled Cyclone Coal Combustor to Oil Fired Boiler Conversions and Environmental Control in Coal Fired Boilers*, 7th International Coal & Lignite Conference, Houston, TX, November 13-15, 1984.)

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[16] T.C. Derbidge and W. Rovesti.

Developmental Status and Test Results[20]

Coal Tech is testing a 30-MBtu/h advanced cyclone coal combustor which, as part of another project, was recently retrofitted onto a boiler designed for oil or gas firing with an input heat capacity of 23 MBtu/h. This project, intended to demonstrate the commercial readiness of this combustor for retrofit applications, is being conducted at the Keeler/Dorr-Oliver boiler plant in Williamsport, Pennsylvania.

The project is being conducted in three distinct phases. Phase I consisted primarily of designing equipment peripheral to the combustor and boiler, and acquiring necessary environmental regulatory operating permits. During Phase II, Coal Tech installed the conventional equipment for receiving, storing, and feeding pulverized coal; slag handling; scrubbing particulates from the flue gas; and sampling and analysis of flue gas for SOx and NOx. Also during Phase II, Coal Tech performed shakedown tests burning coal for up to 30 hours. During Phase III, long-term testing will be conducted. This long-term testing will be divided into two periods of 470 and 400 hours. The overall program, shakedown, and the two long-term periods, comprise 900 hours of coal-fired testing, and is being conducted over a 25-month period. Between specific tests, data analysis will be conducted and the combustor and boiler internals will be inspected.

The test objectives for the Coal Tech project are to validate:

- Operation with two coals with sulfur contents of 2 and 4 percent,
- Material durability, combustor startup and shutdown, and trip operation of combustor,
- SOx reduction of 70 to over 90 percent at the stack,
- NOx reduction to 100 ppm or less,
- Minimal or no derating with oil designed boiler operation,
- That the solids products of the combustor (slag-sorbent-sulfur compounds) are environmentally inert or can be readily converted to an inert form, and
- The combustor turndown (3:1 is the objective).

As of March 1988,[21] 100 hours of combustor operation were completed. The significant results achieved thus far include the following:

- Improvement of carbon burnout to near 99 percent,
- Combustor slag rejection of up to 80 percent with continuous slag tap operation,
- NOx reduction of 60 percent with staging,
- Nonoptimized SOx reductions of up to 45 percent with limestone injection,
- Slag reactivities well below EPA standards for cyanides and below or near standards for sulfides,
- Slag leaching of hexachrome below limits of detection,
- Heavy metal discharged with scrubber water well below Sanitary Authority limits, and
- Scrubber fan discharge opacity of about 10 percent.

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[20] Coal Tech Corporation, *The Demonstration of an Advanced Cyclone Coal Combustor With Internal Sulfur, Nitrogen, and Ash Control for the Conversion of a 23-MBtu/h Boiler to Coal*, Quarterly Report on DOE Cooperative Agreement (July 1987).

[21] Coal Tech Corporation, *The Demonstration of an Advanced Cyclone Coal Combustor With Internal Sulfur, Nitrogen, and Ash Control for the Conversion of a 23-MBtu/h Oil Fired Boiler to Pulverized Coal*, Fourth Quarterly Report on DOE Cooperative Agreement (January 1 to March 31, 1988).

Energy and Environmental Research Corporation

Coal Combustor System Description[22]

EER's coal combustor system is called a vortex containment combustor (VCC). The VCC works primarily on the principles of cyclonic separation. As Figure 12 shows in cross section, coal and primary combustion air are injected tangentially into a large diameter, shallow region where the fuel is suspended in an annular cloud and an intense combustion zone is formed. As the combustion gases flow radially toward the system centerline, the geometry of the chamber holds the radial velocity nearly constant while the tangential velocity increases by a factor of two, resulting in high centrifugal forces and improved ash retention efficiency. The plan view of the combustion zone shows that the particle cloud is dispersed according to size, with the smaller ash particles being selectively removed and carried into a conical region. Here the ash particles are thrown or bounced on a molten slag layer that runs down and out of the bottom of the combustor. The key aerodynamic features of the system are:

- Relatively high radial velocities in the combustion zone to prevent excessive wall deposition,
- Reversed vortex flow for more efficient particle separation,
- An extended exhaust lip to prevent particles from leaking out of the end wall boundary layer, and
- A large axial expansion near the centerline to reduce the radial velocity and provide a long escape path for particles entrained in the exiting vortex at the rear of the combustor.

Results from bench and prototype scale combustor testing in previous programs successfully demonstrated the potential of the VCC as a coal-fired retrofit burner while identifying the crucial issues to be addressed in the continued development of the VCC.

Developmental Status and Test Results[23]

The pilot scale VCC was tested and evaluated in the following four areas:

1. Aerodynamic performance
    - ash retention efficiency
    - system pressure drop

2. Combustion performance
    - carbon utilization
    - combustion stability

3. Mechanical performance/operability
    - slag drainage
    - refractory integrity
    - startup and shutdown procedures
    - load control

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[22] J.F. LaFond, et al., *Development of a Vortex Containment Combustor: Pilot Scale Studies, Final Report* (Energy and Environmental Research Corporation, June 1987).

[23] J.F. Lafond, et al.

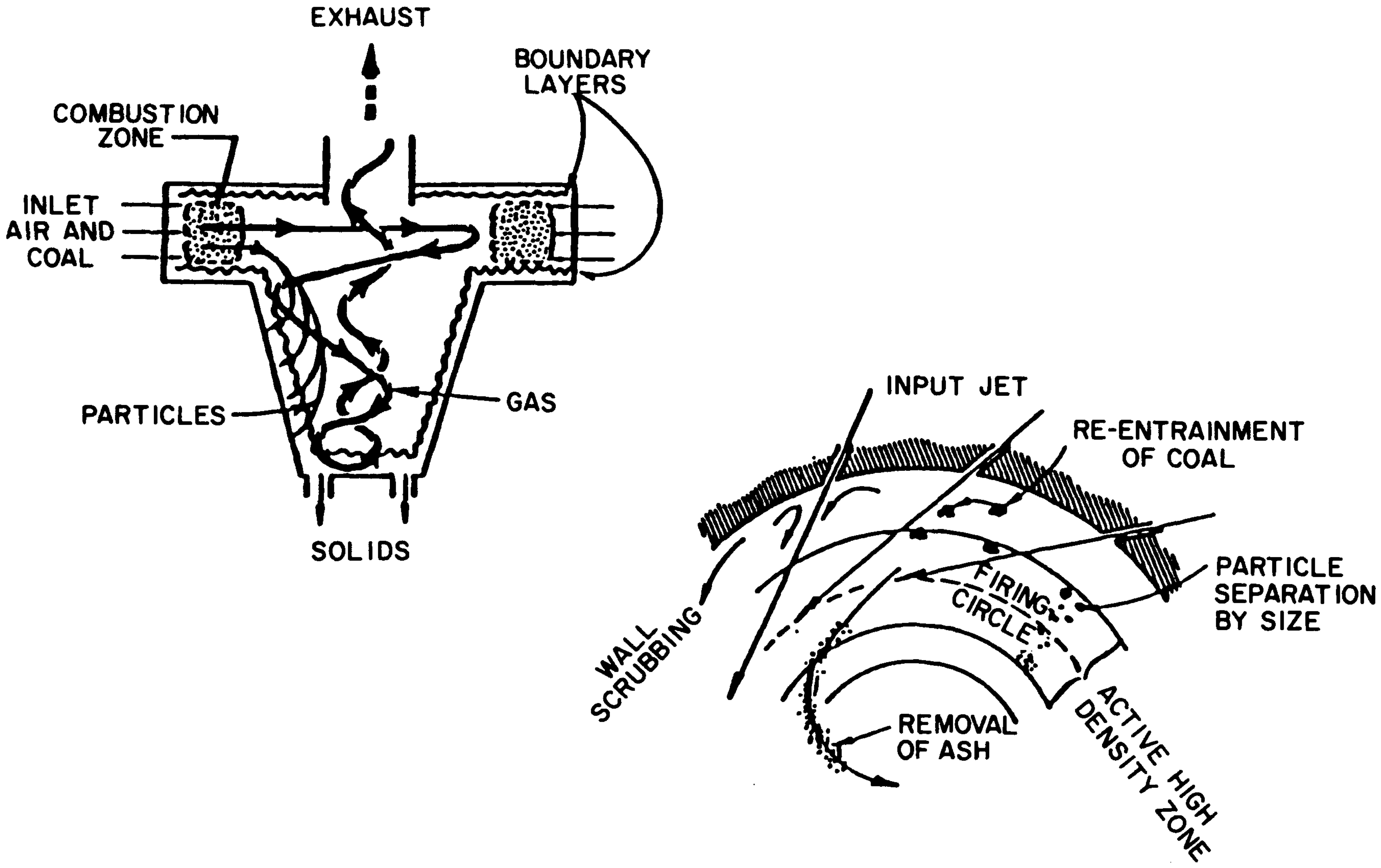

Figure 12. EER vortex containment combustor. (Source: *Development of a Coal Burning Vortex Containment Combustor*, Pittsburgh Energy Technology Center, Coal Utilization and Environmental Control Contractors Review Meeting, Energy and Environmental Research Corporation, July 21-23 [1986].)

4. Pollution control performance
    - NOx control
    - SOx control.

Before beginning the testing program, a thorough sequence of shakedown tests was performed to check controls, cure the combustor refractory, and identify the system pressure drop characteristics.

The objectives of the pilot scale testing were to obtain additional operational experience at a larger scale, evaluate the scaling methodology, and determine the practical limitations of the VCC concept. Performance goals for the pilot scale VCC include:

- High ash retention efficiency (over 90 percent),
- Low system pressure drop (less than 20 in. water),
- High carbon conversion (over 99 percent),
- Stable combustion,
- Continuous slag drainage,
- Good operability (2:1 turndown), and
- Low NOx emissions (less than 0.5 lb. NOx per 106 Btu).

It was expected that the combustion testing would be somewhat iterative as modifications were implemented to improve performance and operability. An installation layout for the pilot scale VCC on the small watertube simulator (SWS) facility is shown in Figure 13. The combustor was designed with the expectation that operational problems would require minor modifications. Thus, the incorporation of modifications was a critical step in the overall effort to develop a practical VCC system.

Isothermal testing of the pilot scale combustor was performed before the combustion tests. These simple measurements of system pressure drop as a function of airflow reinforced the fact that viscous effects play an important role in determining the vortex strength in the combustor, and consequently, the system's ability to separate ash particles from the exhaust. These tests also provided evidence that the effects of viscosity or vortex weakening get worse as scale is increased. As a result, both pressure drop and ash retention efficiency were lower than predicted by the scaling analysis.

Isothermal tests under strong vortex conditions showed that a decrease in exhaust diameter could produce significant increases in retention efficiency. This was not the case for the pilot scale combustor; all measurements of ash retention efficiency were near 70 percent. An improvement, to 80 percent, was achieved when a coarser coal grind was used (the grind was not specified by EER). Higher retention efficiencies can be a achieved by modifications to the air inlet vanes and a corresponding rise in operating pressure.

Carbon utilization was noticeably affected by the coal nozzle orientation. When the coal nozzles were rotated to a vertical orientation, carbon utilization increased from between 98 and 98.5 percent to between 99 and 99.5 percent. This improvement is attributed to a reduction in carbon loss through the slag drain. Coarser coal grinds and higher load operation also improved carbon utilization.

When testing the pilot scale VCC over a range of firing rates and stoichiometric ratios, slag drainage through the vane area slag tap was continuous and reliable for most operating conditions. Firing rate had little impact on the slag drainage behavior, while a stoichiometry range of 0.6 to 0.9 was found

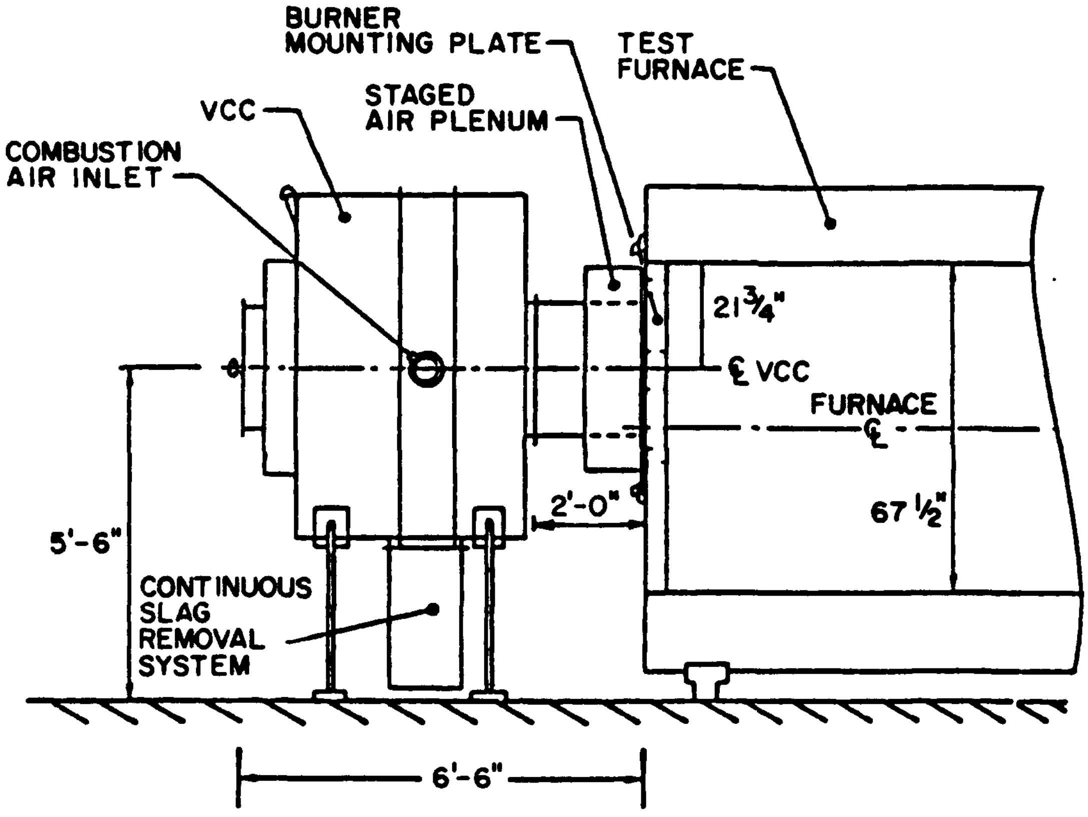

Figure 13. Layout of the pilot scale VCC on the test furnace. (Source: J.F. LaFond, et al., *Development of a Vortex Containment Combustor: Pilot Scale Studies, Final Report* [Energy and Environmental Research Corporation, June 1987].)

to be optimum for continuous slag removal. Mechanical breakers and oxygen enrichment were not necessary to maintain fluid and continuous slag flow.

The biggest slag accumulation problem did not occur in the combustor or slag drainage tap, but rather in the transition from the combustor to the furnace. The small amount of slag that inevitably collected on the exhaust throat walls flowed smoothly towards the furnace until reaching the furnace entry plane. At that point, either because of the radiant heat loss or recirculation of secondary air into the exhaust, the slag began to build up. Periodically, the accumulated slag was removed by hand when the system was shut down for maintenance.

Some refractory cracking and spalling was experienced due to heavy thermal cycling and repeated disassembly for inspection. Little erosive wear was evident. Longer operating times and more concentrated refractory designs in critical areas should alleviate these problems.

The area in the combustor that requires the greatest degree of durability and strength is the exhaust throat, particularly the lip that extends into the combustion chamber. After repeated mechanical problems in this area, a water-cooled, refractory-lined exhaust piece was designed and used without any problems for the remainder of the test program.

Load control, turndown, ignition, and combustion stability posed no difficulties to general combustor operation. The pilot scale VCC operated smoothly and reliably.

Operation with combustion staging was standard procedure. Stoichiometric ratios of 0.8 in the upper portion of the VCC and 1.2 at the furnace throat were used. Reductions down to 0.33 lb NO/106 Btu, far below NSPS regulations of 0.6 lb NO/106 Btu, were achieved.

Sulfur control in the VCC was not attempted at the pilot scale, but this is considered a critical issue facing the implementation of all precombustor systems and is worthy of future investigation. Although other studies by EER indicate that the VCC can potentially be operated in a way that makes internal sorbent injection an effective means of controlling sulfur emissions, many obstacles (grinding, sorbent storage, pneumatic transport) must be overcome before this becomes a reality.

4 IMPLEMENTATION GUIDANCE

The following issues must be considered when integrating slagging combustors into the overall steam generator system and its operation: mechanical integration, operating flexibility, combustor air supply and control, coal and limestone feed and control, and cooling-water system integration.

Mechanical/Structural Design[24]

The size and weight of a slagging combustor generally precludes direct support on the furnace tube wall. Utility boilers are usually top-supported. Since there could be considerable thermal expansion at the combustor burner levels, the combustor supports must be capable of accommodating the expansion differential (furnace down, combustor up). The duct transferring the hot combustion gases into the furnace must be refractoried or water-cooled and flexible to accommodate the thermal expansion differential. Smaller size (shop-erected, some field-erected) industrial boilers are bottom-supported, thus both combustor and furnace walls will expand upwards. Nevertheless, flexible combustor and transfer ducting structural supports will still be required. Available space within and around the boiler building is usually limited in oil designed plants. Space limitations will increase the layout difficulties for accommodating slagging combustors, coal storage bunkers, pulverizers, coal conveying pumps, and slag handling and storage equipment. Specific implementation guidance for both water-cooled and air-cooled slagging combustors is provided below for three of the more developed combustors.

Coal Tech

The demonstration design of the Coal Tech combustor with a rating of 100 MBtu/h would have a nominal outside diameter of 6 ft, length of 11 ft, and weigh about 7 tons; Coal Tech believes an optimized design could be reduced in size. Coal Tech believes that the maximum capacity of a single combustor is governed by many factors such as pressure drop, coal-particle size, slag retention, and heat transfer capability of the air-cooling system. Coal Tech has estimated a maximum size of 200 to 300 MBtu/h, but this estimate is approximate, and demonstration data will be needed to make a firm determination.

Coal Tech has considered various mounting and clustering arrangements. It has also considered retrofits to both wall-fired and tangentially-fired utility boilers in the 125- to 800-MW size range. Tangentially-fired units present the greatest retrofit difficulties because the combustor exit nozzle is incompatible with existing corner-fired oil burners. Thus, extensive rework of the water walls would be required in the corners. Coal Tech has suggested converting from tangential firing to wall firing. Such a major modification would require close support and integration with the boiler manufacturer.

Another area of concern is flame impingement on the boiler walls due to high exhaust velocity from the combustor. Coal Tech believes that the high exhaust velocity can be dissipated by swirl motion generated in the combustor or by opposed wall firing.

The Coal Tech design for mounting the cyclone is a swivel that would pivot on trunnions as the boiler expands and contracts. There would be a flexible seal between the cyclone discharge nozzle and the walls of the boiler. This would require that all of the other connections to the cyclone, such as coal and limestone feeds, air connections, and the slag tank connection be able to accommodate this tilting during operation. It is proposed to use the same flexibility procedures that are currently used to connect

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[24] Burns and Roe Services Corporation.

feed lines to large boilers, although no details were given. For Coal Tech's proposed 100 MBtu/h single-burner test at the Philadelphia Electric Delaware boiler, the combustor would be supported on the swivel-mount design.

Rockwell International (TransAlta)

The Rockwell combustor intended for demonstration in a utility boiler is rated at 100 MBtu/h. This preliminary design measures about 6 ft in diameter by 25 ft long and weighs about 25 tons. A significant portion of the length and weight of the combustor is comprised of the slag/fly ash separator. The separator could be eliminated in retrofits on coal-capable boilers. The maximum design capacity of a single combustor is estimated to be about 500 MBtu/h.

Rockwell has a field demonstration in a 60-MW(e) wall-fired, coal design boiler (Wabamun). For this retrofit, they are proposing that the burners be supported from the floor. The discharge will be through an existing burner opening with some enlargement. The burner, without the separator, could possibly fit into the width of the existing windbox. The burner with the separator would extend appreciably beyond the windbox. This arrangement requires a flexible seal between the combustor discharge nozzle and the walls of the boiler.

Rockwell has conducted design retrofit studies for boilers of both wall- and tangentially-fired configurations. These studies suggest a floor-mounted arrangement in which the combustors and the bottom of the boiler are stationary and are connected to the rest of the boiler through a water seal. Since the demonstration in the 60-MW(e) boiler is only a partial retrofit (only one-third of the coal-firing capacity), these burners will discharge through existing burner ports.

TRW

TRW envisions commercial combustors for utility boilers in the 100 to 250 MBtu/h range. The 250 MBtu/h combustor would be about 7 ft in diameter by 11 ft long and would weigh 7.5 tons (including cooling water). TRW has considered a number of orientations for the combustor, and both horizontal or vertical discharge ducts, in order to maximize arrangement flexibility. Testing of several arrangements at the 10 MBtu/h size has been completed. TRW has also considered both wall-fired and tangentially-fired retrofits. The company anticipates that the combustor mount will be stationary and that the movement of the boiler will be accommodated in the connection between the combustor and the boiler. The connecting duct is to be water-cooled. Also, water cooling increases the amount of thermal energy that must be integrated into the existing boiler steam cycle or otherwise used. The design allows for either replacing the existing gas or oil burners with the coal combustor, one-for-one, or using larger burners ducted to multiple burner ports. No mention was made of any requirement to enlarge existing burner ports. TRW's industrial boiler retrofit in their Cleveland plant does not require a flexible connection between the combustor and boiler.

Operating Flexibility

The primary areas of interest with respect to operating flexibility are: (1) startup time and procedures, (2) shutdown times and procedures (especially trip situations), and (3) turndown. The major factors affecting combustor operations are: (1) maintaining slag flow and (2) minimizing thermo-mechanical stress in refractory and in mechanical connections to the host unit.

Coal Tech

Specific startup or shutdown times were not presented for the Coal Tech combustor. However, Coal Tech makes extensive use of refractory in the design: startup and shutdown procedures and times will have to allow for this. Some indication of startup and shutdown times can be drawn from GE's 1 MBtu/h test unit, which used an 8-hour ramped heatup (or cooldown) firing gas or oil. Coal Tech indicates, however, that the test unit experienced some sudden shutdowns in which only cooling air entered the combustor, and there was no visible damage to the ceramic liner.

The Coal Tech combustor is air-cooled, with the cooling air subsequently used as combustion air. During a boiler trip, some airflow is required through the combustor to burn the inventory coal in the combustor and also to purge the boiler of combustible gases. There is some concern that if cooling air continued to flow through the combustor, it could shock refractory. Because of the large thermal storage in the combustor, Coal Tech does not believe that refractory shock will occur.

Coal Tech is predicting at least a 2:1 turndown ratio; the ultimate goal is 5:1. At partial load, the cooling air required is less than the combustion air required. The additional combustion air will be supplied directly from the boiler air heater by using an additional blower to provide approximately 1 psi pressure for the cyclone. With multiple combustors on a boiler, one option is to remove units from service to increase overall boiler turndown ratios. However, if startup and shutdown times are long, these out-of-service combustors may have to be fired with oil or gas pilot flames at some fraction of the rated output to maintain them in readiness for load swings. Determining turndown ratios is one of the objectives of Coal Tech's proposed test program.

Rockwell (TransAlta)

Startup and shutdown requirements for the commercial version of the Rockwell combustor will depend on the amount of refractory incorporated into the final design. However, the 25-MBtu/h test combustor requires 2 hours of warmup (firing gas), followed by 1 hour to stabilize operation on coal. Shutdown is by tripping. Some special procedures are required to avoid shocking the refractory. Rockwell experienced loss of coal flow in this combustor for as long as 20 minutes and abruptly reinitiated full coal flow, with no apparent problems.

Slagging combustors require that the combustion temperature in the slagging area be well above the fusion temperature of the coal ash. During turndown of an operating unit, the temperature of the flue gases entering the preheater normally decreases. So, therefore, does the level of combustion air preheat. This can be the case even if burners are shut off during unit turndown. Rockwell's major concern regarding turndown is to maintain air preheat temperature. Air preheater modifications or the use of an auxiliary air preheater may be required for that portion (about half) of the combustion air that passes through the burner. Given sufficient burner combustion air preheat, however, Rockwell's combustor has been stably operated at loads as low as 25 percent of rated capacity with no apparent problems. Turning off a row of Rockwell burners for more than about half an hour would require some burner preheat to avoid excessive thermal shock to the refractory before restarting coal flow.

TRW

Because the TRW combustor contains no refractory, it can achieve very rapid startup and shutdown: 5 minutes to coal firing, and only 15 minutes to steady-state slagging operation. Shutdown is by tripping and has also been very rapid. TRW predicts similar performance for their full-scale commercial units.

However, both startup and shutdown times can be controlled to match boilers that have much slower transient requirements to control drum differentials and to protect superheater and reheater metals. Turndown is limited by slag flow considerations and is predicted to be 3:1. Turndown testing on the test combustors is in progress with demonstrated values in excess of 2:1.

Airflow Supply and Control

All of these combustors require higher air pressure than is required for traditional oil, gas, or coal systems. In particular, the air-cooled Coal Tech design requires up to 5 psig air pressure, and the other systems need up to 1 psig air pressure for various fractions of the total air. Retrofits will therefore require additional fan capacity and/or high-pressure blowers. In some cases, boosters to the existing fan systems may be used.

Control of airflow is also important in these combustors because fuel/air ratios affect emissions control and proper slag flow. Furthermore, airflow control for large boilers is more difficult than for small units having only one combustor, because in large boilers, both the total airflow and the distribution of airflow to each combustor must be controlled.

Another concern in controlling airflow to multiple combustors is the reliable measurement of combustor operation. The interior of these combustors presents a difficult measurement environment because of the high temperatures, and because gases are particle-laden and reducing.

Coal Tech

The Coal Tech combustor is air-cooled, and the air pressure required is approximately 5 psig. The main advantage of this approach is that it minimizes the problem of overall thermal integration, since the cooling air is used as preheated combustion air. The air would be taken from the boiler air heater and boosted through a positive displacement blower. Typical air heater temperature is 400 to 600 °F, and therefore, the boost blower would have to be designed for these temperatures. After passing through the wall-cooling tubes, the air is then used as combustion air in the combustor. At partial load, the cooling air required is less than the combustion air required. The additional air required for combustion will be supplied directly from the boiler air heater by using an additional blower to provide approximately 1 psi pressure to the cyclone.

Secondary air is introduced tangentially at the front of the combustor near the coal injection tubes. Tertiary air is introduced directly into the host furnace. A small amount of air is used to cool the nozzle at the exit of the combustor and may also be used as tertiary air. The pressure drop through the combustor is approximately 1 psi.

Rapid slag flow in the Coal Tech combustor would be achieved by controlling refractory temperature through changes in the amount of air cooling. Slag flow conditions would be determined by a video camera opposite the slag tap. Some provision would be needed to protect the blower from fly ash erosion for boilers equipped with regenerative air heaters. Also, there is concern regarding fly ash erosion and/or fouling of cooling passages within the combustor. Coal Tech suggests that air filtering may be required, although this is yet to be determined, since the fly ash will presumably be fine (less than 10 μm).

Rockwell (TransAlta)

The pressure drop through the combustor itself is approximately 30 in. water gauge (w.g.). Therefore, a primary air fan would be required to boost the air for the combustor by this amount. Approximately 40 percent of the total air supply would pass through the combustor and require pressure boost. No additional air preheat is included in the Rockwell design, and the nominal assumed air inlet temperature is 650 °F. Preheated air will contain some fly ash if a regenerative air heater is used, so the booster fan may require maintenance. However, the pressure is no higher than for a hot air fan used on a pulverizer, and there is experience with such an application. The air is admitted in two or more locations, so there will have to be a flow measurement and a control system to admit the proper quantities at the various locations. Combustion air other than that admitted in the first-stage air injection system does not require the higher pressure and could very likely be supplied from the normal forced-draft supply. Air preheat temperatures typically available from existing boiler air heaters range from 450 to 650 °F. Temperatures this high are often not available. The effect of lower air preheat temperatures on the operation of the Rockwell unit was not discussed.

TRW

Pressure drop through the combustor is expected to be approximately 30 in. w.g. The preheat temperature of the combustion air will depend on the type of waste heat recovery system available in different plants. For most utilities, air preheat temperatures of 400 to 650 °F can usually be achieved. Lower air preheat can be compensated for by firing a greater fraction of the coal in the precombustor incorporated in the design. For example, the Cleveland industrial boiler demonstration uses a combination of steam preheating and flue-gas heat recovery to obtain 400 to 450 °F air preheat temperatures. Also, approximately 10 to 20 percent of the total coal flow is used in the precombustor.

A primary air fan is used to boost the FD fan air to that used for the combustor. This is a similar application to some pulverized coal installations and there is some experience with this technology. The primary air goes to a coal-fired precombustor where the air temperature is raised to between 1000 and 1500 °F. Approximately 10 to 20 percent of the total fuel is used in the precombustor. TRW has included a coal-fired precombustor in tests at both 10 MBtu/h and 50 MBtu/h. Primary air is admitted tangentially near the front of the combustor. Secondary air is admitted in an annulus around the short connecting duct from the combustor to the host furnace. Another approach uses the registers of the host boiler. In either case, air could be used from the normal FD supply. Since air is admitted in two locations, there will have to be a flow measurement and a control system to admit the proper quantities at each location.

Coal and Limestone Feed and Control

SCC manufacturers use coal ground to the nominal fineness used in regular pulverized coal firing (70 percent through 200 mesh). Rockwell has elected to use conventional direct firing, in which pulverized coal is pneumatically transported directly from the pulverizers to the combustors, without intermediate storage. Coal Tech and TRW use indirect firing, wherein ground coal from the pulverizers is conveyed to an intermediate bin from which it is pneumatically transported as dense-phase to the combustors.

The conventional direct-fired system has the advantage of not requiring the intermediate bin and feeding equipment needed with indirect firing. However, direct firing imposes certain limitations on coal feeding and flexibility. Specifically, in order to pulverize coal, it must also be dried. Heated air is used to dry, classify, and transport ground coal from the pulverizer. Thus, the amount of pulverizer air required is determined by air preheat temperature and coal moisture content. Coal moisture exceeding the design limits of a system could require the use of oil- or gas-fired duct burners to increase air temperature. For a typical direct-fired, PC boiler, 15 to 20 percent of theoretical combustion air is required as pulverized air at full load (corresponding to 1.5 to 2.0 lb air/lb coal). At partial load, this percentage increases. Theoretical air at 20 percent is a substantial fraction of the air requirement in the first stage of the combustors under consideration because of the highly substoichiometric conditions required in the first stage. Thus, changes in the pulverizer air requirement due to changes in coal moisture content or load level could have a significant effect on combustor first-stage stoichiometry and aerodynamics. Also, for direct-fired arrangements, the pulverizers are usually located relatively close to the burners. This may be difficult in retrofit applications.

In the indirect-fired designs, coal is pneumatically transported from the pulverizer to a coal/air separator consisting of a cyclone and a fabric filter. Pulverized coal from the separator is conveyed to a bin and fed to the combustors by dense-phase conveying air. In dense-phase air conveying, as little as 0.1 lb air/lb coal is used (corresponding to 1 percent of theoretical combustion air). Thus, only a very small amount of the combustion air is required for coal transportation. An operational advantage of indirect firing is that the moisture incorporated during coal pulverizing is discharged with the filtered air at the separator and does not enter the combustor. Therefore, the combustor firing temperature is less dependent on initial coal moisture content.

A disadvantage of indirect firing is the extra equipment required for coal/air separation, coal bins, and dense-phase reentrainment. A further disadvantage is that the high velocity and pressure drop required for dense transport could produce erosion problems at control points on multiple-burner systems. Although this type of equipment is not normally used in utility power plants, certain prototype systems have been installed and operated in power plants. One of these systems is the Direct Ignition Pulverized Coal (DIPC) system manufactured by Combustion Engineering and installed at the Bullrun Station of the Tennessee Valley Authority (TVA). The DIPC system uses coal/air separation, pulverized coal storage and retrieval, and dense-phase transport. Due to the explosive nature of pulverized coal, special precautions must be used in its handling and storage.

Control of coal feed in boilers involves control of both total coal feed and the distribution of coal feed to each combustor, since there would probably be several combustors for each feeder/pulverizer. This is true for both direct- and indirect-fired systems. Coal feed control will be important in these slagging combustors for control of substoichiometric combustion needed in the first stage.

Coal Tech

Coal Tech proposes an indirect-fired system. Limestone is ground in a separate mill to the same size as the coal and fed to the combustor in nozzles interspersed between the coal nozzles. The coal feed system on the GE 1-MBtu/h test unit was an indirect system using nitrogen carrier gas in a 1:1 weight ratio. Presumably, nitrogen was used for convenience because of the small size of the system. The limestone feed was similar to coal, but with separate lines to the combustor.

Coal Tech's proposed 100-MBtu/h single-burner test at Philadelphia Electric's Delaware boiler (120 MWe) would demonstrate coal and limestone feed at utility scale but not for multiple combustors.

Rockwell (TransAlta)

Rockwell proposes to use a direct firing method. When it is necessary to supplement calcium inherent in the coal, limestone for sulfur capture will be added to the coal going to the pulverizer and delivered to the combustor with the coal. This will require feeding control to maintain proper ratios and size.

Tests to date in the 25-MBtu/h atmosphere pilot-scale facility have used a feed system whereby pulverized coal and limestone are stored in bins and pneumatically transported to the combustor. The pilot scale tests use about 10 percent of theoretical combustion air for pneumatic transport, which is below the 15 to 20 percent required for coal-drying in a commercial pulverizing system.

TRW

The TRW combustor uses indirect firing in which coal is fed from a pressurized bin in a dense-phase to the combustor. In the test setup at Capistrano, pulverized coal is pneumatically transferred in batches by a coal pump to a 2 to 5 ton bin. This bin is hung via load cells so that the coal flow rate and total coal consumed can be determined. A dense-phase fluidizer located on the bottom of the bin delivers coal through 50- to 100-ft connecting lines to either of the two commercial test combustors (with attached precombustors) at densities of approximately 10 lb coal/lb of fluidizer gas. In the Cleveland demonstration program, coal is similarly transferred, except that screw pumps and in-line continuous flow measuring devices are used. Erosion in control valves may be a concern, but TRW has not experienced any problems to date. Sorbent materials are ground to particles the same size or smaller than the coal and conveyed to the combustor in the same way the coal is. An advantage of this coal/limestone feed system is that pulverizers and bins may be located up to 200 ft away from the combustors, which allows considerable flexibility for retrofit applications.

Water System Integration

Two of the combustor designs make extensive use of cooling water, which represents a significant fraction (8 to 10 percent) of the total plant thermal input. To avoid substantial energy loss, the cooling water must be integrated in the overall plant thermal cycle. Integration of this amount of energy represents a significant perturbation to both boiler and steam turbine cycles; it will require additional heat transfer equipment and will result in a loss in overall plant heat rate. A loss in the range of 2 percent is estimated.

Coal Tech

Only the front part of the Coal Tech combustor is to be water-cooled; thus, the amount of heat rejected to cooling water is relatively small (approximately 2.5 percent of the total heat input). Presumably, this energy could be used to heat boiler feedwater, but details of how this heat would be recovered were not given. Coal Tech is also considering an alternate air-cooled injector to completely eliminate water cooling.

Rockwell (TransAlta)

In the Rockwell combustor using the slag/fly ash separator, it is predicted that 8 percent of the heat of the coal will go into the cooling water. Presumably this will be integrated into the feedwater circuit of the boiler, but details of this integration were not given.

TRW

The water cooling of the combustor will absorb about 8 to 10 percent of the heat input. Several methods of returning this heat have been proposed. In one method, the cooling water would be circulated by its own pump to a heat exchanger in the normal feedwater heating circuit and back to the combustor in a closed loop. The amount of steam extracted from the turbine would decrease so the final feedwater temperature would remain the same. This approach would result in a reduction of overall plant efficiency by about 2 percent. The modification would significantly alter the distribution of steam extraction from the turbine and, therefore, would have to be carefully examined by the turbine manufacturer.

If there is a demand for low-pressure steam in the plant, the water could be flashed to provide that steam. A normal utility power plant would probably not require as much low-pressure steam as could be supplied from this source, but for industrial applications like the Cleveland demonstration plant, this approach looks promising. In many applications, the cooling water could be used to preheat the air for the combustor, if additional air heating is required. With the latter scheme, the heat is reinjected directly back into the combustor. All of these proposed approaches require that equipment be added to the power plant. The methods to be used would depend on individual plant requirements and would need careful engineering and cost/benefit studies.

5 ECONOMICS

The slagging combustor has been proposed for several different industrial/utility applications such as:

- Retrofit of gas and/or oil boilers to coal firing,
- Retrofit of existing coal-fired boilers for reduced NOx and SOx emissions without postcombustion controls, and
- New coal-fired boilers for low NOx and SOx emissions without postcombustion controls.

Each different application is subject to its own set of site-specific economic considerations. Some of these considerations include:

- Fuel handling, storage, and transfer,
- Furnace modifications,
- Boiler derating,
- Ash collection, handling, and disposal, and
- Environmental considerations.

Fuel Handling, Storage, and Transfer

The fuel handling, storage, and transfer costs for converting an oil-fired boiler to pulverized coal are also directly applicable to retrofit where cyclone combustors are incorporated. Therefore, the primary effort in developing capital and operating costs was on the pulverized coal system.

The retrofit of an oil boiler to coal firing is contingent on the availability of space for the required coal handling and storage facilities. The facilities required for coal firing (Figure 14) will be new additions to the steam plant with the following components included in the development of the costs:

- Coal receiving,
- Primary coal preparation,
- Coal delivery to boiler plant, and
- Coal delivery to slagging combustor.

Table 6 shows the capital equipment costs for the coal preparation and handling for various sizes of industrial boilers typical at Army installations. The engineering and home office fees were set at 10 percent; engineering is typically included in the subcontractor's cost. Due to retrofit considerations (such as space constraints) and the level of cost estimation, a project contingency of 30 percent was chosen. The operating and maintenance costs are estimated to be 10 percent of the process capital. These costs are anticipated to be incurred above and beyond those experienced with fuel oil.

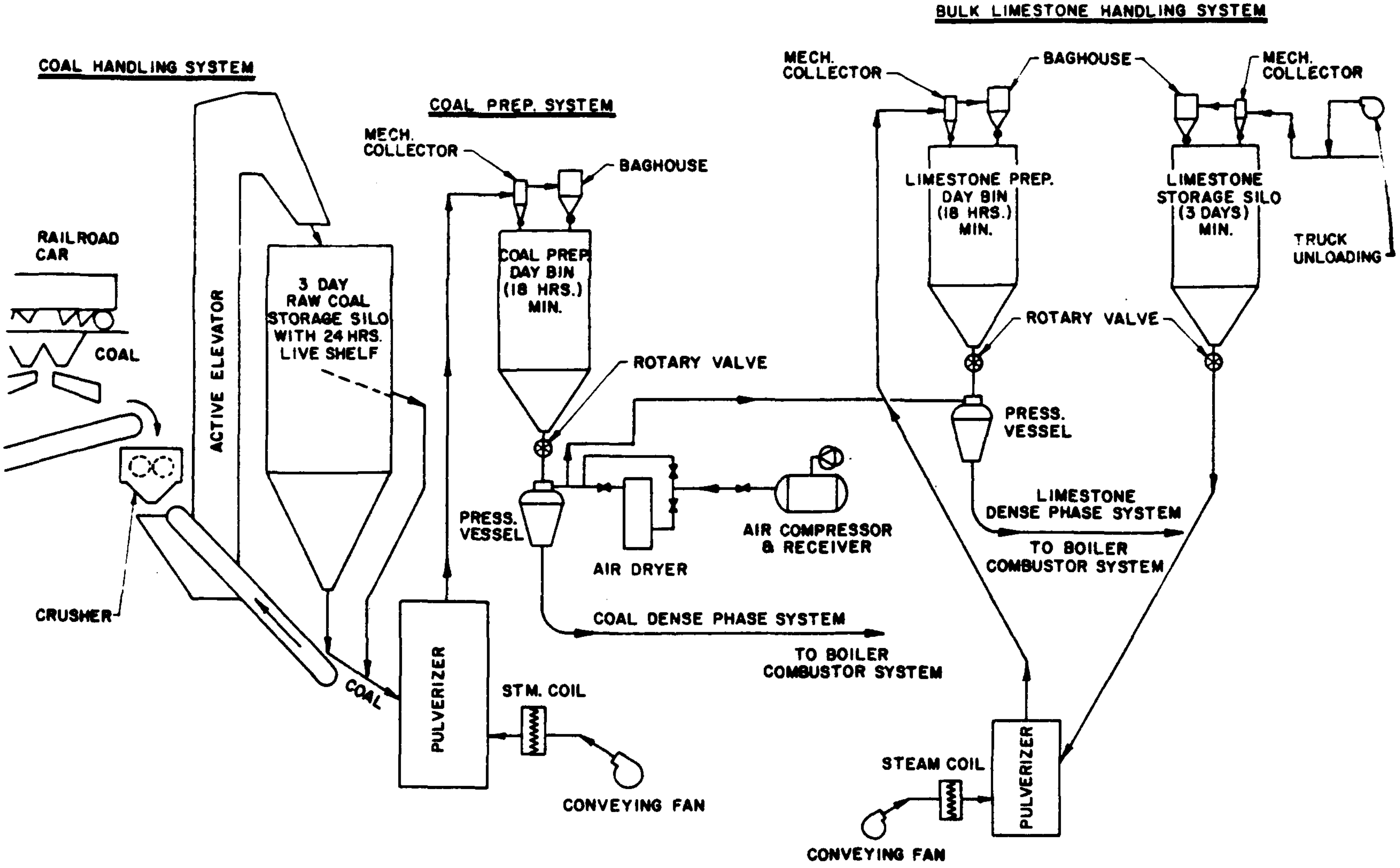

Figure 14. Combustion evaluation information index and flow sheet—bulk limestone handling system.

Table 6

Capital and O&M Costs for Coal Preparation and Handling

Boiler Capacity Lbs/Hr	Bulk Coal Handling System	Pulverizer, Trans. Sys. & 18-Hr Bin	Coal Feed Dense Phase System	Capital Equipment Costs	Contingency 30% of Equipment	Engrg. 10% of Equipment	O&M 10% of Equipment	Coal Equipment Total	$/PPH Capacity
25,000	$485,000	$278,000	$125,000	$ 888,000	$266,400	$ 88,800	$ 88,800	$1,243,200	$49.73
50,000	$520,000	$363,000	$125,000	$1,008,000	$302,400	$100,800	$100,800	$1,411,200	$28.22
75,000	$575,000	$474,000	$125,000	$1,172,000	$352,200	$117,400	$117,400	$1,643,600	$21.91
100,000	$635,000	$478,000	$125,000	$1,238,000	$371,400	$123,800	$123,800	$1,733,200	$17.33
150,000	$750,000	$645,000	$125,000	$1,520,000	$456,000	$152,000	$152,000	$2,128,000	$14.49
200,000	$890,000	$725,000	$125,000	$1,740,000	$522,000	$174,000	$174,000	$2,436,000	$12.18
250,000	$980,000	$782,000	$125,000	$1,887,000	$566,100	$188,700	$188,700	$2,641,800	$10.57

Lime Handling, Storage, and Transfer

The system for the lime handling, storage, and transfer costs when converting an oil-fired boiler to a slagging combustor consist of bulk handling with a 3-day minimum lime storage, a pulverizer, conveying fan, an 18-hour-day bin, and a pressure vessel (Figure 14). The engineering and home office fees were set at 10 percent. Due to retrofit considerations, a project contingency of 30 percent was chosen. The operating and maintenance costs are estimated to be 10 percent of the process capital. Table 7 summarizes the lime handling, storage, and transfer costs.

Slag and Bottom Ash Removal System

Figure 15 shows the equipment required for the slag and bottom ash removal system. It consists of a water quench trough, a drag conveyor, and a 3-day bottom ash storage silo. Again the engineering and home fees were assumed as 10 percent of the process equipment cost. For a retrofit application, a 40 percent contingency factor was used. This high factor is due to unknown excavation conditions that may be required to install the bottom ash removal system. The operation and maintenance costs were estimated to be 5 percent. Table 8 summarizes this cost information.

Table 7

Capital and O&M Costs for Lime Preparation and Handling

Boiler Capacity Lbs/Hr	Limestone Handling System	Pulverizer, Trans. Sys. & 18-Hr Bin	Limestone Dense Phase System	Capital Equipment Costs	Contingency 30% of Equipment	Engrg. 10% of Equipment	O&M 10% of Equipment	Limestone Equipment Total	$/PPH Capacity
25,000	$140,000	$180,000	$125,000	$445,000	$133,500	$44,500	$44,500	$ 623,000	$24.92
50,000	$150,000	$215,000	$125,000	$490,000	$147,000	$49,000	$49,000	$ 686,000	$13.72
75,000	$163,000	$250,000	$125,000	$538,000	$161,400	$53,800	$53,800	$ 753,200	$10.04
100,000	$175,000	$280,000	$125,000	$580,000	$174,000	$58,000	$58,000	$ 812,000	$ 8.12
150,000	$190,000	$345,000	$125,000	$660,000	$198,000	$66,000	$66,000	$ 924,000	$ 6.16
200,000	$220,000	$375,000	$125,000	$720,000	$216,000	$72,000	$72,000	$1,008,000	$ 5.04
250,000	$240,000	$442,000	$125,000	$807,000	$242,100	$80,700	$80,700	$1,129,700	$ 5.52

Table 8

Capital and O&M Costs for Combustor Slag and Bottom Ash Removal

Boiler Capacity Lbs/Hr	Slab, Bottom Ash Removal System Cost	Contingency 40% of Equipment	Engineering 10% of Equipment	O&M 5% of Equipment	Slag Equipment Total	$/PPH Capacity
25,000	$ 218,000	$ 87,200	$ 21,800	$10,900	$ 327,300	$13.09
50,000	$ 305,000	$122,000	$ 30,500	$15,250	$ 457,500	$ 9.15
75,000	$ 391,000	$156,400	$ 39,100	$19,550	$ 586,500	$ 7.82
100,000	$ 476,000	$190,400	$ 47,600	$23,800	$ 714,000	$ 7.14
150,000	$ 664,000	$265,600	$ 66,400	$33,200	$ 996,000	$ 6.64
200,000	$ 850,000	$340,000	$ 85,000	$42,500	$1,275,000	$ 6.38
250,000	$1,070,000	$428,000	$107,000	$53,500	$1,605,000	$ 6.42

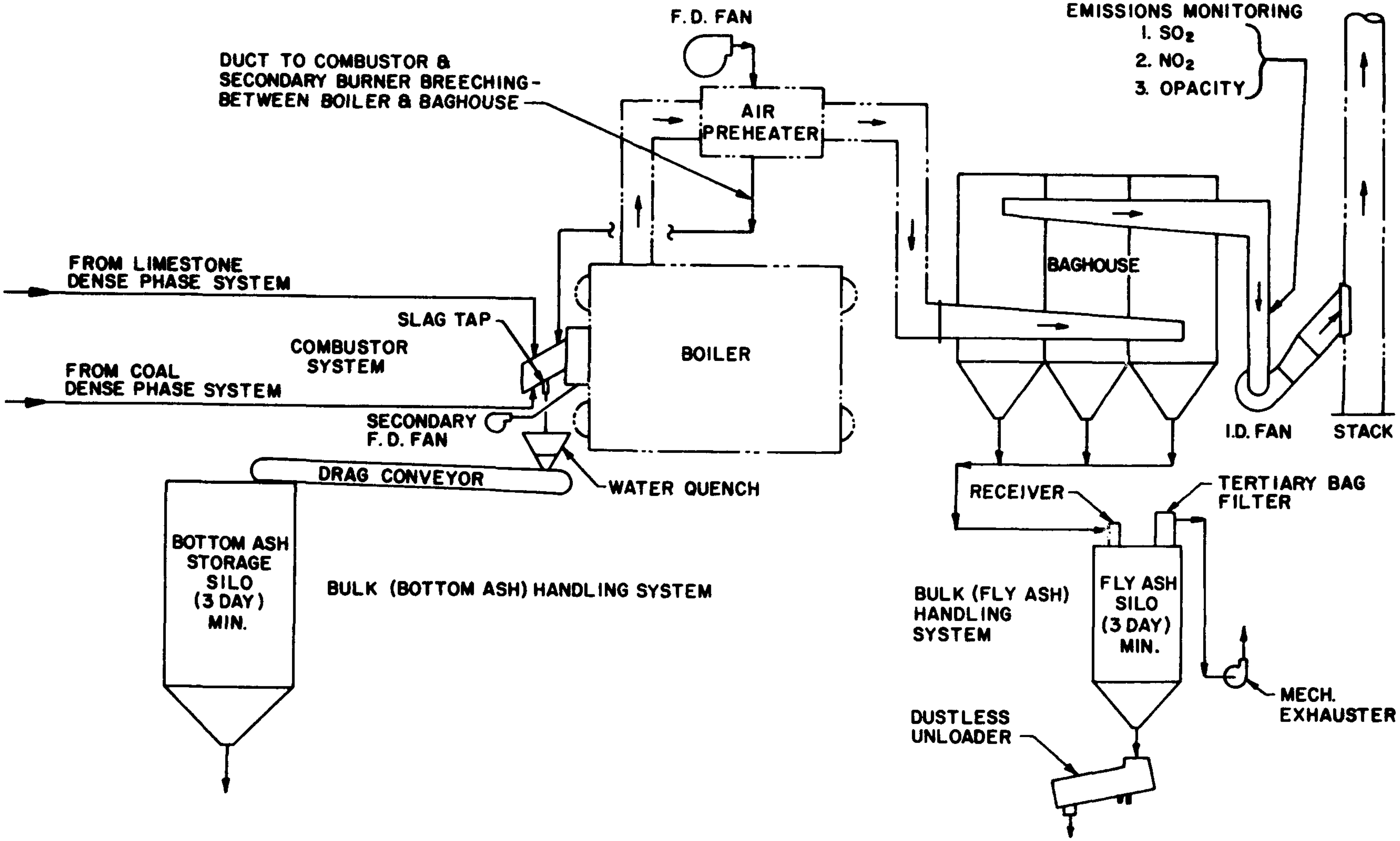

Figure 15. Combustor evaluation information index and flow sheet—bulk bottom ash handling system.

Fly Ash Removal System

Figure 15 shows the equipment required for the fly ash removal system. It consists of ductwork, baghouse, I.D. fan, fly ash collection system, 3-day silo, and a dustless unloader. The engineering and home office fees were set at 10 percent. A project contingency of 30 percent was chosen. The operation and maintenance costs were estimated to be 10 percent. Table 9 summarizes the fly ash removal system costs.

Slagging Combustor Cooling System and Controls

The retrofit costs associated with the cyclone slagging combustor incorporate the incremental cost of either the air- or water-cooled cyclone combustor. The engineering and home office fees were set at 15 percent. A project contingency of 50 percent was chosen. The operation and maintenance costs are estimated to be 15 percent of the process capital. Table 10 summarizes the slagging combustor, cooling system, and control costs.

Slagging Combustor Retrofit

The next economic consideration is retrofitting the slagging coal combustor to existing stoker coal-fired boilers to reduce NOx and SOx emissions without postcombustion controls. Under this scenario, the following modifications and equipment will be needed:

- Fuel preparation and storage,
- Limestone equipment,
- Furnace modification, and
- Slag collection.

Table 11 summarizes the capital and O&M costs for the entire slagging combustor retrofit system. Table 12 summarizes the coal handling and preparation costs. The engineering and home office fees were set at 10 percent. A project contingency of 30 percent was chosen. The operating and maintenance costs were estimated to be 10 percent of the process capital.

The retrofit slagging combustor on an existing stoker coal-fired boiler would have the same limestone handling and preparation equipment as the previously discussed oil/gas retrofit case (see Table 7). An existing stoker boiler would not have the slag quench pit as required for the SCC. (Table 8 therefore applies to this case.) It is assumed that the fly ash equipment is present. The SCC capital equipment would be the same as in the oil case (Table 10). Table 13 summarizes the cost for the SCC retrofit to an existing stoker fired coal boiler.

The last case to be considered is to build the slagging combustor on an oil- and gas-fired unit. In developing these costs, the following logic was used:

- Determine costs for new boiler,
- Add fly ash collection equipment costs,
- Add limestone preparation and handling,
- Add slagging combustor cost,

Table 9

Capital and O&M Costs for Fly Ash Removal System

Boiler Capacity Lbs/Hr	Baghouse FD & ID Fan Ductwork	Ash Silo Unloader & Transport	Capital Equipment Costs	Contingency 30% of Equipment	Engrg. 10% of Equipment	O&M 10% of Equipment	Fly Ash Equipment Total	$/PPH Capacity
25,000	$ 215,000	$125,000	$ 340,000	$102,000	$ 34,000	$ 34,000	$ 476,000	$19.04
50,000	$ 380,000	$132,000	$ 512,000	$153,600	$ 51,200	$ 51,200	$ 716,800	$14.34
75,000	$ 545,000	$140,000	$ 685,000	$205,500	$ 68,500	$ 68,500	$ 959,000	$12.79
100,000	$ 722,000	$147,000	$ 869,000	$260,700	$ 86,900	$ 86,900	$1,216,600	$12.17
150,000	$1,008,000	$160,000	$1,168,000	$350,400	$116,800	$116,800	$1,635,200	$10.90
200,000	$1,130,000	$172,000	$1,302,000	$390,600	$130,200	$130,200	$1,822,800	$ 9.11
250,000	$1,340,000	$183,000	$1,532,000	$456,900	$152,300	$152,300	$2,132,200	$ 8.53

Table 10

Capital and O&M Costs for Slagging Combustor Cooling System and Controls

Boiler Capacity Lbs/Hr	SCC Cooling System & Controls	Contingency 50% of Equipment	Engineering 15% of Equipment	O&M 15% of Equipment	SCC Equipment Total	$/PPH Capacity
25,000	$1,080,000	$ 540,000	$162,000	$162,000	$1,782,000	$71.28
50,000	$1,700,000	$ 850,000	$255,000	$255,000	$2,805,000	$56.10
75,000	$2,350,000	$1,175,000	$352,500	$352,500	$3,877,500	$51.70
100,000	$2,960,000	$1,480,000	$444,000	$444,000	$4,884,000	$48.84
150,000	$3,286,000	$1,643,000	$492,900	$492,900	$5,421,900	$36.15
200,000	$3,905,000	$1,952,500	$585,750	$585,750	$6,443,250	$32.22
250,000	$4,465,000	$2,232,500	$669,750	$669,750	$7,367,250	$29.47

Table 11

Summary of Capital and O&M Costs for Slagging Coal Combustor Retrofit

BOILER CAPACITY LBS/HR	CAPITAL COAL HANDLING SYSTEM	O&M COAL HANDLING EQUIPMENT	CAPITAL LIMESTONE HANDLING EQUIPMENT	O&M LIMESTONE HANDLING EQUIPMENT	CAPITAL BOTTOM ASH EQUIPMENT	O&M BOTTOM ASH EQUIPMENT	CAPITAL FLY ASH EQUIPMENT	O&M FLY ASH EQUIPMENT	CAPITAL S.C.C. EQUIPMENT	O&M S.C.C. EQUIPMENT	TOTAL CAPITAL COSTS	TOTAL O&M COSTS	$/PPH CAPACITY
25,000	$1,243,200	$ 88,800	$ 623,000	$44,500	$ 327,300	$10,900	$ 476,000	$ 34,000	$1,782,000	$162,000	$ 4,451,500	$ 340,200	178.06
50,000	$1,411,200	$100,800	$ 686,000	$49,000	$ 457,500	$15,250	$ 716,800	$ 51,200	$2,805,000	$255,000	$ 6,076,500	$ 471,250	121.53
75,000	$1,643,600	$117,400	$ 753,200	$53,800	$ 586,500	$19,550	$ 959,000	$ 68,500	$3,877,500	$352,500	$ 7,819,800	$ 611,750	104.26
100,000	$1,733,200	$123,800	$ 812,000	$58,000	$ 714,000	$23,800	$1,216,600	$ 86,900	$4,884,000	$444,000	$ 9,359,800	$ 736,500	93.60
150,000	$2,128,000	$152,000	$ 924,000	$66,000	$ 996,000	$33,200	$1,635,200	$116,800	$5,421,900	$492,900	$11,105,100	$ 860,900	74.03
200,000	$2,436,000	$174,000	$1,008,000	$72,000	$1,275,000	$42,500	$1,822,800	$130,200	$6,443,250	$585,750	$12,985,050	$1,004,450	64.93
250,000	$2,641,800	$188,700	$1,129,700	$80,700	$1,605,000	$53,500	$2,132,200	$152,300	$7,367,250	$669,750	$14,875,950	$1,144,950	59.50

Table 12

Capital and O&M Costs for Coal Preparation and Handling

Boiler Capacity Lbs/Hr	Pulverizer Trans. Sys. & 18-Hr Bin	Coal Feed Dense Phase System	Capital Equipment Costs	Contingency 30% of Equipment	Engrg. 10% of Equipment	O&M 10% of Equipment	Coal Equipment Costs	$/PPH Capacity
25,000	$278,000	$125,000	$403,000	$120,900	$40,300	$40,300	$ 564,200	$22.57
50,000	$363,000	$125,000	$488,000	$146,400	$48,800	$48,800	$ 683,200	$13.66
75,000	$474,000	$125,000	$599,000	$179,700	$59,900	$59,900	$ 838,600	$11.18
100,000	$478,000	$125,000	$603,000	$180,900	$60,300	$60,300	$ 844,200	$ 8.44
150,000	$645,000	$125,000	$770,000	$231,000	$77,000	$77,000	$1,078,000	$ 7.19
200,000	$725,000	$125,000	$850,000	$255,000	$85,000	$85,000	$1,190,000	$ 5.95
250,000	$782,000	$125,000	$907,000	$272,100	$90,700	$90,700	$1,269,800	$ 5.08

Table 13

Cost Summary of SCC Retrofit to a Coal Boiler

BOILER CAPACITY LBS/HR	CAPITAL COAL HANDLING EQUIPMENT	O&M COAL HANDLING EQUIPMENT	CAPITAL LIMESTONE HANDLING EQUIPMENT	O&M LIMESTONE HANDLING EQUIPMENT	CAPITAL BOTTOM ASH EQUIPMENT	O&M BOTTOM ASH EQUIPMENT	CAPITAL S.C.C. EQUIPMENT	O&M S.C.C. EQUIPMENT	TOTAL CAPITAL COSTS	TOTAL O&M COSTS	$/PPH CAPACITY
25,000	$ 564,200	$40,300	$ 623,000	$44,500	$ 327,300	$10,900	$1,782,000	$162,000	$ 3,296,500	$257,700	131.86
50,000	$ 683,200	$48,800	$ 686,000	$49,000	$ 457,500	$15,250	$2,805,000	$255,000	$ 4,631,700	$368,050	92.63
75,000	$ 838,600	$59,900	$ 753,200	$53,800	$ 586,500	$19,550	$3,877,500	$352,500	$ 6,055,800	$485,750	80.75
100,000	$ 844,200	$60,300	$ 812,000	$58,000	$ 714,000	$23,800	$4,884,000	$444,000	$ 7,254,200	$586,100	72.54
150,000	$1,078,000	$77,000	$ 924,000	$66,000	$ 996,000	$33,200	$5,421,900	$492,900	$ 8,419,900	$669,100	56.13
200,000	$1,190,000	$85,000	$1,008,000	$72,000	$1,275,000	$42,500	$6,443,250	$585,750	$ 9,916,250	$785,250	49.58
250,000	$1,269,800	$90,700	$1,129,700	$80,700	$1,605,000	$53,500	$7,367,250	$669,750	$11,371,750	$894,650	45.49

- Use 20 percent contingency on all equipment for capital costs,
- Use 15 percent of total capital equipment to determine O&M costs.

Table 14 summarizes the costs for converting an oil- or gas-fired boiler.

The cost of retrofitting an oil/gas-fired boiler to fire coal by a slagging combustor appears to be prohibitively expensive. If a specific plant is interested in pursuing this technology for retrofit, it is recommended that site-specific economic/feasibility analyses be performed. Large contingency factors have been added to the base costs because of potential problems with space in the plant and anticipated boiler modifications.

An oil- or gas-fired boiler was compared with a traditional stoker boiler and a PC boiler with flue gas desulfurization (FGD). A 150,000-lb/h stoker boiler with FGD is $11,295,000. A PC boiler with FGD is $14,230,000.[25] A comparison with a new SCC 150,000-lb/h boiler at $14,189,200 shows that it is comparable to a PC boiler. Consideration, however, must be given to the turndown ratios. SCC is, at best, 3:1 whereas PC can reach 10:1. Additionally, PC firing has been used since the 1920's and the slagging combustor is as yet unproven.

From an economic viewpoint, the SCC is not a competitively priced method of coal combustion. With further development and refinement and a more favorable environment for coal combustion versus oil and gas, the SCC may have a place in larger facilities (greater than 250,000-lb/h steam). It is only in larger boilers that the economics of scale have the potential to make the SCC competitively priced.

Table 14

Cost Summary of SCC Retrofit to an Oil or Gas Boiler

BOILER CAPACITY LBS/HR	CAPITAL BOILER EQUIPMENT	CAPITAL FLY ASH EQUIPMENT	CAPITAL S.C.C. EQUIPMENT	CAPITAL LIMESTONE EQUIPMENT	TOTAL CAPITAL COSTS	TOTAL O&M COSTS	$/PPH CAPACITY
25,000	$2,936,300	$ 493,000	$1,728,000	$ 578,500	$ 5,735,800	$ 860,370	229.43
50,000	$3,625,000	$ 742,400	$2,720,000	$ 637,000	$ 7,724,400	$1,158,660	154.49
75,000	$4,313,800	$ 993,300	$3,760,000	$ 699,400	$ 9,766,500	$1,464,975	130.22
100,000	$5,002,500	$1,260,000	$4,736,000	$ 754,000	$11,752,500	$1,762,875	117.53
150,000	$6,380,000	$1,693,600	$5,257,600	$ 858,000	$14,189,200	$2,128,380	94.60
200,000	$7,757,500	$1,887,900	$6,248,000	$ 936,000	$16,829,400	$2,524,410	84.15
250,000	$9,135,000	$2,208,350	$7,144,000	$1,049,100	$19,536,450	$2,930,470	78.15

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[25] Janet M. Gutraj and Christopher F. Blazek, *An Overview of Fluidized Bed Combustion Systems as Applied to Army Central Heat Plants* (Institute of Gas Technology, September 1988).

6 CONCLUSIONS AND RECOMMENDATION

Based on an extensive review of the available literature and informal contacts with the SCC developers, SCC is not yet ready for commercial implementation. From a technical viewpoint, none of the developers has been able to simultaneously:

- Capture 80 to 90 percent of the ash as slag,
- Convert 99.5 percent of the carbon,
- Reach NOx readings in the 200 ppm range,
- Sustain 70 to 90 percent SOx removal, and
- Maintain consistent 3:1 turndown.

Until the above items can be accomplished simultaneously, the proclaimed benefits of the SCC are unfounded.

An economic analysis was also performed. The major assumption made in this analysis is that the SCC could perform satisfactorily from a combustion and environmental standpoint. Under this optimistic scenario, the SCC still was not economically attractive, especially at the smaller boiler sizes typical of an Army installation.

It is recommended that the Army continue to follow the development of the SCC from a research standpoint. It is not considered technically feasible or economically practical to purchase an SCC in the hopes of a reliable combustion source at this time.

Metric Conversion Table

1Btu = 252 g-cal
1lb = 0.453 kg
1 ft = 0.305 m
1 cu ft = 0.028 m^3
1 sq ft = 0.093 m^2
°C = 0.55 (°F - 32)

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