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NO_X CONTROLS FOR GROUP 2 BOILERS

by

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ABSTRACT

The Clean Air Act Amendments of 1990 require that NO, emission limits be established for two categories of coal-fired utility boilers. These categories are designated as Groups 1 and 2. Group 1 consists of dry bottom wall fired and tangentially fired boilers. Group 2 comprises all other utility boiler types including cell burner, arch fired, wet bottom and cyclone: fired boilers.

Wall fired boilers equipped with cell burners are an important segment of the Group 2 boiler population. Low-NOx Controlled Combustion Venturi (CCV®) Cell Burners have been successfully retrofitted to a 600 MW coal-fired cell burner boiler. NO, reductions of 50% have been demonstrated using this technology. This performance was achieved without increasing unburned carbon in the boiler fly ash and without boiler pressure part modifications. In addition to cell burner boilers, NOx control strategies also exist for other Group 2 boilers including the Riley dry bottom TURBO® Furnace, wet bottom, and cyclone-fired boilers. Over the past decade or more, combustion NOx controls have been successfully applied to several types of slag-tap utility boilers in Europe without adversely affecting operational performance. NOx reductions of 30 to 60% have been achieved on these units through a combination of combustion modification techniques.

INTRODUCTION

As required by Title IV of the Clean Air Act Amendments (CAAA) of 1990, the Environmental Protection Agency (EPA) has established Phase I nitrogen oxides (NOx) emission limits of 0.5 lb/MBtu for dry bottom wall-fired utility boilers and 0.45 lb/MBtu for tangentially-fired boilers[1]. These limits are based on rates achievable using low-NOx burner technology. The CAAA also requires that NOx emissions limits be established for a second category of boilers by January 1, 1997. This second category, designated as Group 2, includes boilers equipped with cell burner technology, arch and vertically-fired furnaces, wet bottom boilers and cyclone-fired boilers. Section 407 of the CAAA states that the emission limits established for Group 2 boilers shall take into account available technology and be comparable in cost to NOx controls established for Group 1 boilers, i.e., dry bottom wall-fired and tangentially-fired boilers[2].

Combustion modification techniques, such as low-NO_x burners and air staging, have been shown to be effective in controlling NO_x emissions from both wall- and tangentially-fired boilers[3,4]. This has traditionally been the first strategy employed by boiler owners in reducing NO_x. These same combustion modification techniques are also being considered for Group 2 boiler designs. Recently, Riley Stoker successfully retrofitted low-NOx cell burner technology on a 600 MW coal-fired boiler. In addition, Riley developed a low-NOx burner and air staging system for its arch-fired dry bottom TURBO® Furnace design. Riley's parent, Deutsche Babcock, has also applied retrofit low-NO_x combustion controls to wet bottom furnaces and cyclone-fired boilers in Europe. The following paper reviews NO_x combustion control experience and retrofit options for each of these Group 2 boiler types.

CELL BURNERS

A cell burner boiler is a dry bottom wall-fired boiler that utilizes two or three closely coupled burners arranged in a single assembly or cell. In 1993, Riley Stoker was awarded a contract by American Electric Power (AEP) to demonstrate its low-NO_x cell burner technology at Unit No. 5 of Ohio Power's Muskingum River plant. Muskingum River Unit No. 5 is a 600 MW coal-fired supercritical boiler. Built originally by B&W in the early 1960's, the unit generates 4,035,000 lb/hr of superheated steam at 1000° F and 3800 psig.

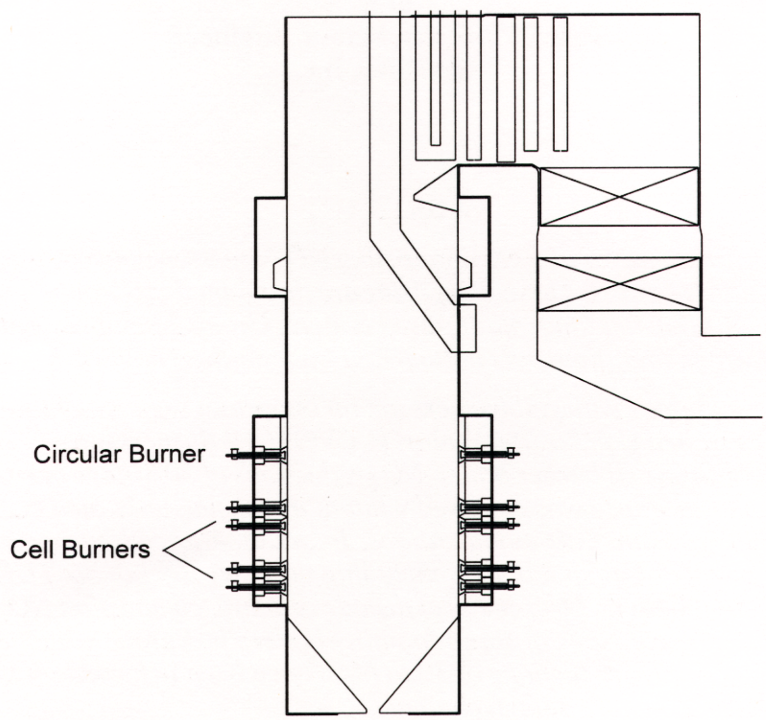

Figure 1 Muskingum River Unit 5 cell burner boiler

As shown in Figure 1, the original opposed wall firing system consisted of twenty traditional two-nozzle cell coal burners and ten conventional circular coal burners installed above the two bottom rows of cell burners. Each cell burner contains two close-coupled burner coal nozzles. The compact burner spacing combined with the relatively small furnace size (39 feet deep and 63 feet wide) promotes intense high temperature flames and correspondingly high levels of NO_x. Prior to the retrofit, reported NO_x emissions at Muskingum River were 1.2 lb/MBtu.

The Riley low-NOx retrofit involved replacement of the existing circular burners with ten DB Riley low-NOx Controlled Combustion Venturi (CCV®) Burners and replacement of the existing cell burners with DB Riley low-NO_x CCV® cell burners (40 coal nozzles).

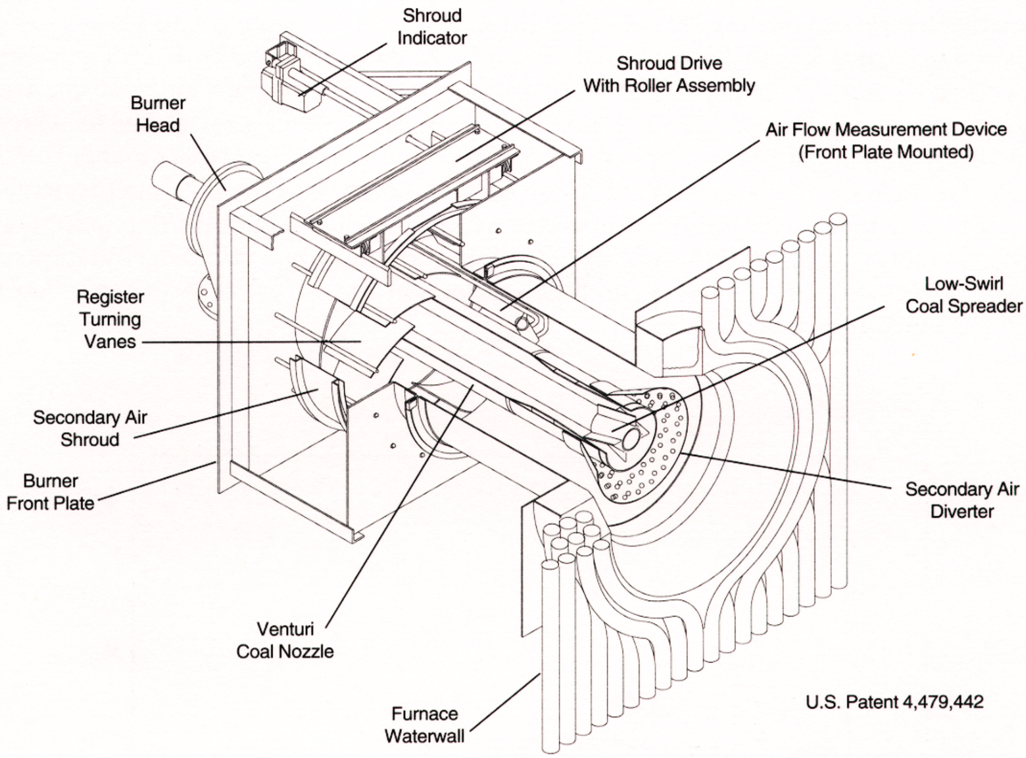

Figure 2 Riley Low-NO_x CCV® Burner

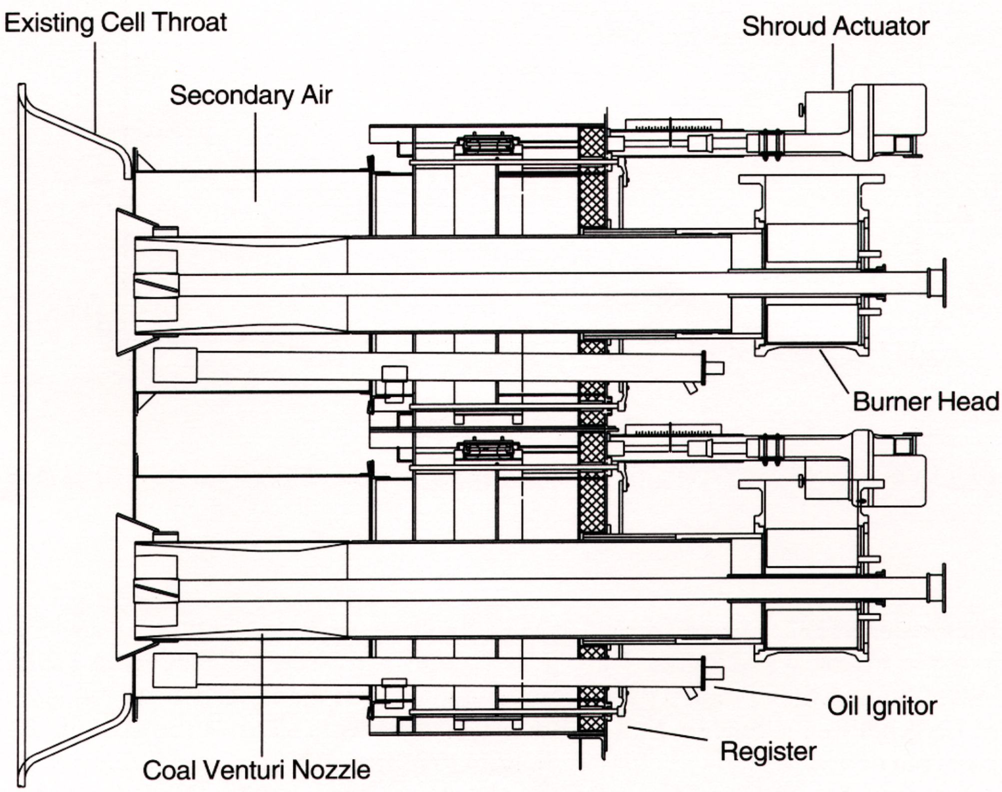

Figure 3 Riley Low-NO_x CCV® (Two Nozzle) Cell Burner

The key feature of both the low-NO_x CCV® Burner, shown in Figure 2, and low-NO_x CCV® cell burners, shown in Figure 3, is the venturi coal nozzle (U.S. Patent No. 4,479,442). The venturi acts to concentrate the coal particles in the center of each coal nozzle. A multiple vane coal spreader imparts swirl to the primary air/coal mixture, and divides the stream into distinct fuel rich and lean layers before mixing with the secondary air. Secondary air is introduced through air registers mounted on the burner front plate. Adjustable turning vanes and a sliding shroud mechanism provide independent control of secondary air swirl and flow. Retrofit of this burner system at Muskingum River required no changes to the original burner spacing, no furnace wall pressure part changes, and no changes to the existing coal feed piping arrangement. During operation little interaction was observed between adjacent flames within each CCV® Burner cell.

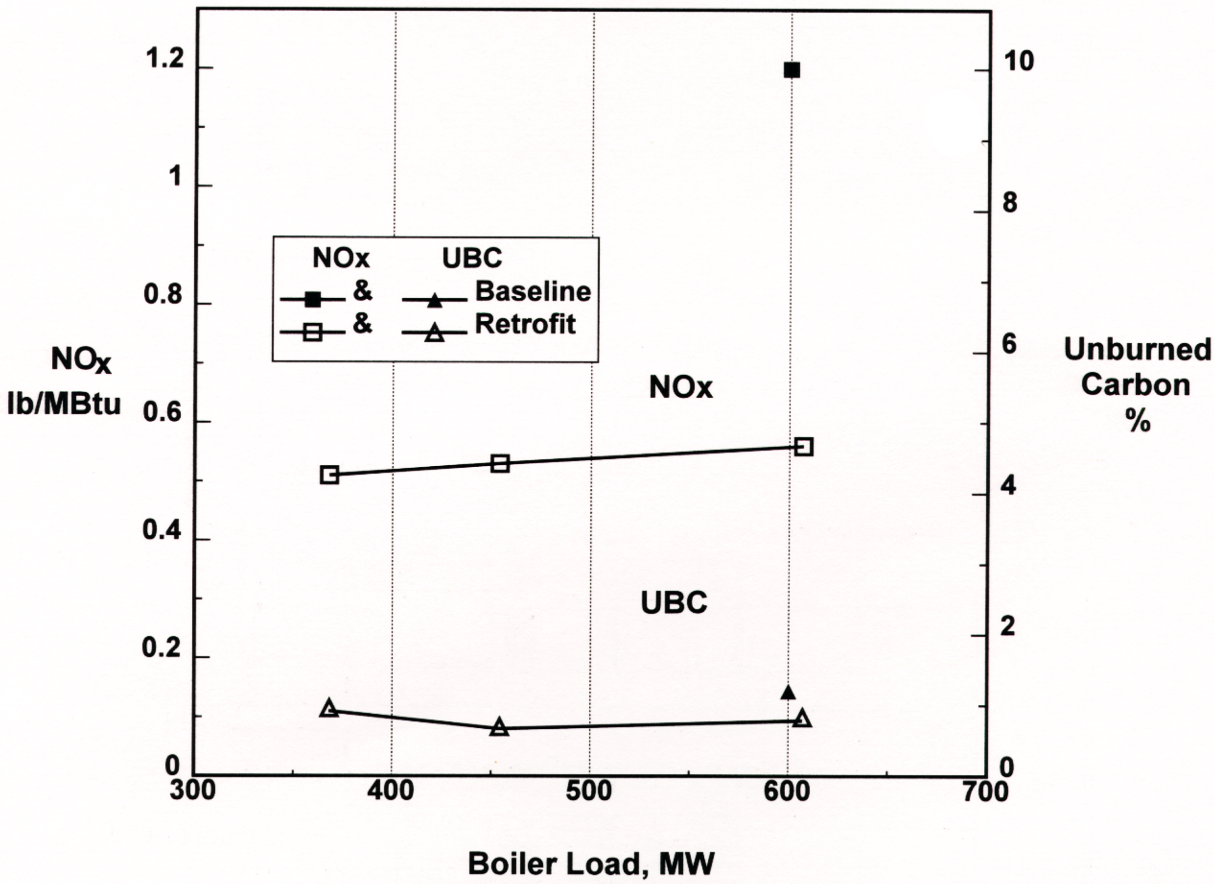

Figure 4 Low-NO_x CCV® Cell Burner Performance at Muskingum River Unit 5

Post-retrofit short-term tests were performed at Muskingum River in the summer of 1994[5]. The results are summarized in Figure 4 and Tables 1 and 2. NO_x emissions were reduced from 1.2 lb/MBtu (the pre-retrofit level) to less than 0.6 lb/MBtu. Unburned carbon in the fly ash averaged less than 1% as compared to 1.5% before the retrofit. Full load emission tests were also performed with the top row of circular burners out of service and only the two bottom rows of cell burners in service. Under these conditions, NO_x increased slightly to 0.63 lb/MBtu. Based on these results, DB Riley has developed a low-NO_x retrofit burner design for three nozzle high burner cells.

Table 1 **Muskingum River Unit 5 Low-NO_x CCV® Cell Burner Retrofit Project Test Results**

Parameter	Pre-Retrofit Baseline	Post Retrofit Optimization		
Date	9/16/93	7/6/94	7/7/94	7/7/94
Gross Generation, MW	600	607	454	368
Excess Air, %	25	22	33	40
Superheat Outlet Temp., °F	1000	994	996	993
Reheater 1 Outlet Temp., °F	1023	1010	970	937
Reheater 2 Outlet Temp., °F	1024	1003	960	917
NOx at Economizer Outlet[1], lb/MBtu	—	0.56	0.53	0.51
NOx at Stack by CEM, lb/MBtu	1.2[2]	0.59	—	—
CO at Economizer Outlet, ppm	0	1	1	1
Unburned Carbon in Ash, % wt	1.5	0.78	0.67	0.95

[1] Chemilluminescent Analysis
[2] Measured during pre-retrofit testing

Table 2 **Muskingum River Unit 5 Coal Analyses**

Proximate Analysis, wt %		*Coal Fineness*	
Moisture	6.6	% through 50 mesh	99.5
Volatile Matter	39.1	% through 100 mesh	95.5
Fixed Carbon	42.5	% through 200 mesh	79.1
Ash	11.8		
Heating Value, Btu/lb	11,660		
Ultimate Analysis, wt %, dry			
C	68.30		
H	5.00		
O	8.41		
N	0.99		
S	4.70		
Ash	12.60		

TURBO® FURNACES

Riley introduced its coal-fired dry bottom TURBO® Furnace in the early 1960's. Since then, 27 dry bottom coal-fired TURBO® Furnaces have been installed by industry and electric utilities. As shown in Figure 5, the TURBO® Furnace is characterized by upper and lower furnace zones separated by a venturi-shaped construction. Burners are mounted in the lower furnace on opposite downward facing arches. Conventional TURBO® Furnaces are equipped with Riley Directional Flame Burners. Staged combustion air can also be introduced as overfire and underfire air as illustrated in Figure 5.

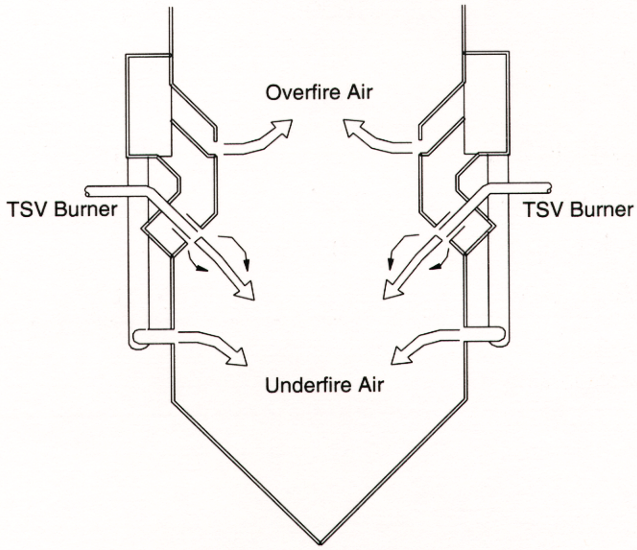

Figure 5. TURBO® Furnace low-NO_x firing system.

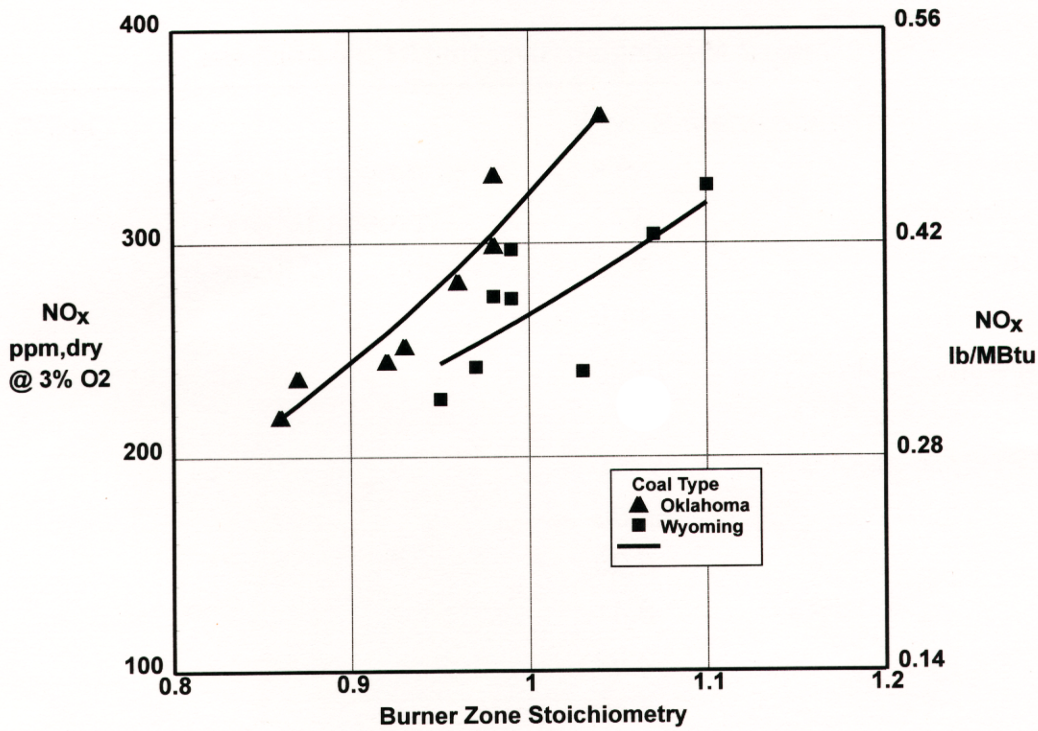

Figure 6 Industrial TURBO® Furnace NO_x Performance with Low-NO_x TSV® Burner Firing System

In 1982, Riley developed and introduced the swirl stabilized low-NO_x Tertiary Staged Venturi (TSV®) Burner as a replacement for the axial flow Directional Flame Burner. Low-NO_x TSV® Burners combined with a furnace air staging system were installed on a new 400,000 lb/hr industrial TURBO® Furnace[6]. The performance of this low-NO_x firing system for two bituminous coals is shown in Figure 6. NO_x emissions on both fuels ranged from 0.3 to 0.5 lb/MBtu depending on the level of air staging.

An updated low-NO_x TSV® burner, designed to retrofit on existing TURBO® Furnaces, is shown in Figure 7. Currently, DB Riley is designing a retrofit low-NO_x TSV® Burner and furnace air staging system for Delmarva Power and Light's 400 MW Indian River Unit 4. The existing Directional Flame Burners on Indian River Unit 4 will be replaced with 24 new low-NO_x TSV® Burners.

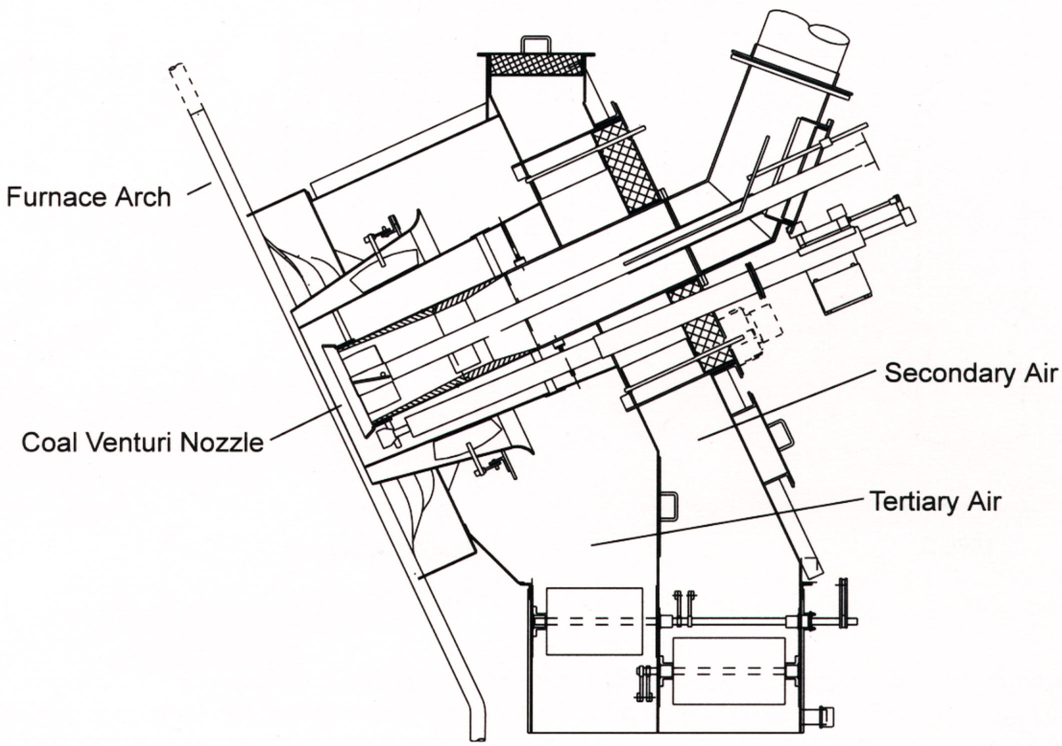

Figure 7 DB Riley Low-NO_x TSV® Burner

WET BOTTOM BOILERS

Wet bottom or slag-tap boilers require high combustion temperatures within the furnace to insure the removal of coal ash as molten slag. As a result, NO_x emissions on the order of 1.5 lb/MBtu have been measured on conventional wet bottom furnaces.

As a group, wet bottom boilers encompass a wide variety of slag-tap furnace configurations. The DB Riley TURBO® Furnace is one example. This furnace design was first introduced in the 1940's as a wet bottom furnace for difficult-to-burn low volatile fuels such as petroleum coke. Several other slag-tap furnace design configurations are illustrated in Figure 8.

Two widely utilized designs are the vertically-fired U-shaped furnace and the cyclone-fired furnace. U-fired slag-tap furnaces have been used for large steam generators in Germany since the late 1960's[7]. In the U-fired design, the burners are arrayed on the roof of the combustion chamber firing downward to produce a U-shaped flame pattern. Units of up to 350 MW have been built with two opposed slag-tap furnaces. In the late 1970's, Deutsche Babcock introduced NO_x combustion controls on U-fired slag-tap furnaces[7,8].

The following combustion modification techniques were employed on both new and existing units:

- low-NO_x burners
- furnace air staging
- flue gas recirculation through the burner
- improved coal fineness

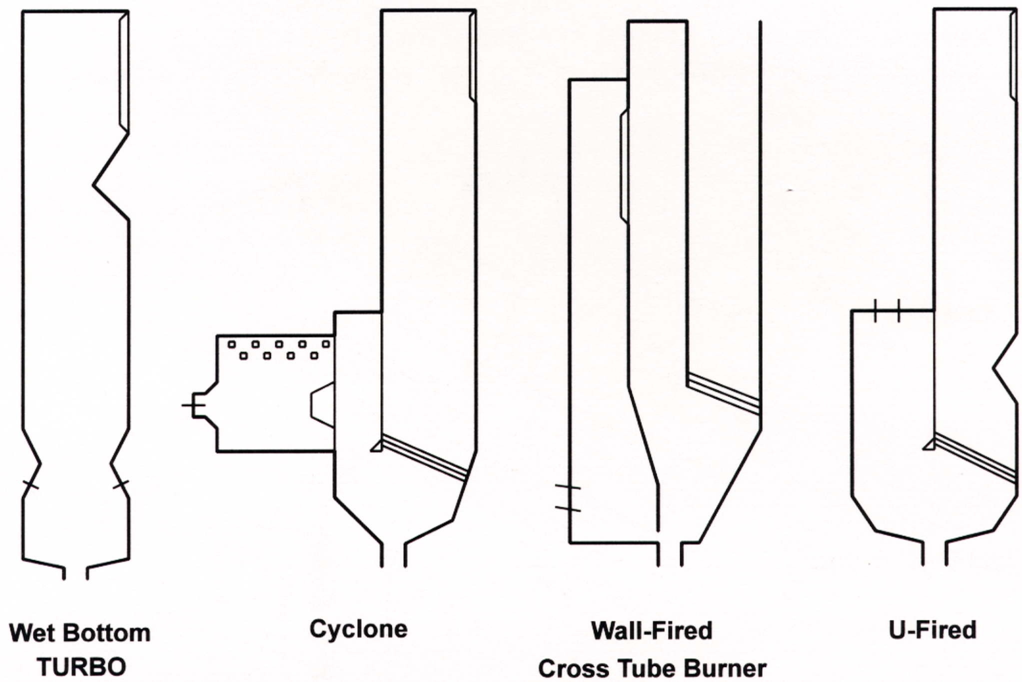

Figure 8 Slag-tap Furnace Designs

Various furnace air staging options are illustrated in Figure 9 for an opposed two chamber U-fired furnace design. Tertiary air staging ports can be installed at various locations including the firing roof, furnace wall, and downstream of the slag screen. No matter which air staging strategy is employed, furnace temperature must be controlled to ensure reliable slag-tapping.

NO_x reductions achieved for various combinations of air staging ports and flue gas recirculation for two German retrofitted 300 MW scale U-fired boilers are shown in Figure 10. The Plant No. 1 retrofit employed tertiary air nozzles located on the furnace roof with flue gas recirculation through the secondary air. Plant No. 2 employed tertiary air at locations I and II on the furnace roof and side walls. Flue gas was introduced with the primary air.

NO_x reductions of 30 to 60% were achieved on these units. Greater NO_x reductions were achieved by shifting the air staging location from the firing roof to the lower furnace walls. In each case, the combustion modifications included the addition of rotating classifiers to existing MPS pulverizers to increase coal fineness and improve distribution of fuel to individual burners. New U-fired wet- bottom boilers will employ more advanced low-NO_x burners combined with air staging ports on the furnace wall and downstream of the slag screen.

DB Riley is currently evaluating the use of air staging to reduce NO_x emissions on U.S. wet bottom boilers such as the wall-fired cross tube burner design (Figure 8). Computational fluid dynamic modeling and thermal analyses are being performed to evaluate the impact of various air staging port locations on NO_x reduction and unit performance.

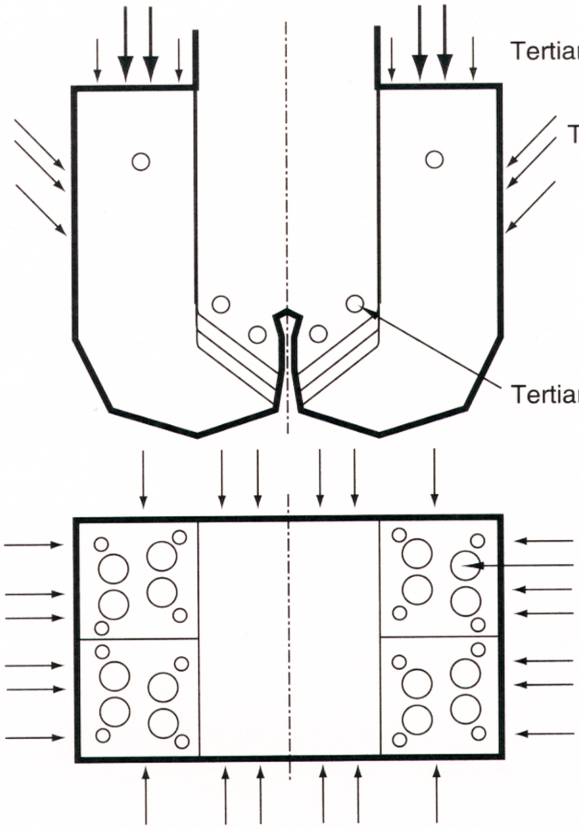

Figure 9 U-fired Furnace Air Staging System[7,8]

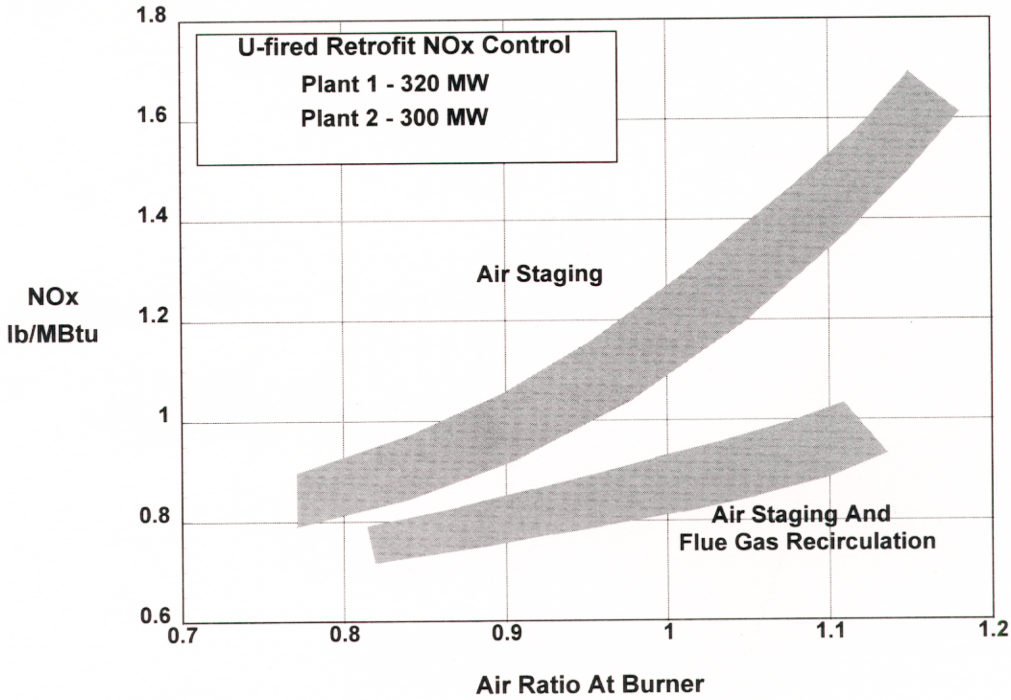

Figure 10 U-fired Wet Bottom Boiler NO_x Performance[7,8]

CYCLONE-FIRED BOILERS

There are over 100 cyclone-fired utility boilers in the U.S. representing approximately 25,000 MW of coal-fired based load capacity. Most of these boilers are located in the Midwest and are more than 20 to 30 years old. Although cyclone boilers represent about 9% of the U.S. coal-fired generation capacity, they contribute approximately 14% of the NO_x produced by U.S. utility boilers[9]. The relatively high NO_x emission levels are attributed to the high temperatures and high turbulence levels employed by cyclone combustors. Gas reburning is one of NO_x control alternatives that has been proposed for cyclone-fired boilers[9]. However, this control technology may not be economical for some cyclone boiler owners due to the cost differential between natural gas and coal.

Deutsche Babcock has built about 100 cyclone-fired boilers[10]. In 1984, the first cyclone boiler was retrofitted with an air staging system for NO_x control[8,10]. Today, more than 20 cyclone boilers in Europe are equipped with air staging systems supplied by Deutsche Babcock.

The Deutsche Babcock cyclone air staging system is illustrated in Figure 11. Air staging ports are located in the secondary screened tube combustion chamber located downstream of the cyclone outlet. Air flow modeling is used to determine the location of the air staging ports for each boiler retrofit. The air control system allows the primary cyclone air to be staged down to 80% of theoretical air. Field test results for two German cyclone installations are summarized in Figure 12. NOx reductions of 30 to 40% have been demonstrated without encountering operational problems[10].

Before such an air staging system can be applied to U.S. cyclone boilers, the influence of different coal properties and boiler design characteristics must be evaluated and taken into account. Many U.S. coals contain higher quantities of sulfur and iron than European fired coals. Also, European cyclone boilers employ different coal preparation and fuel and air delivery systems. Some of the key differences between European and U.S. cyclones include:

- coal feed size
- coal feed location
- method of combustion air control

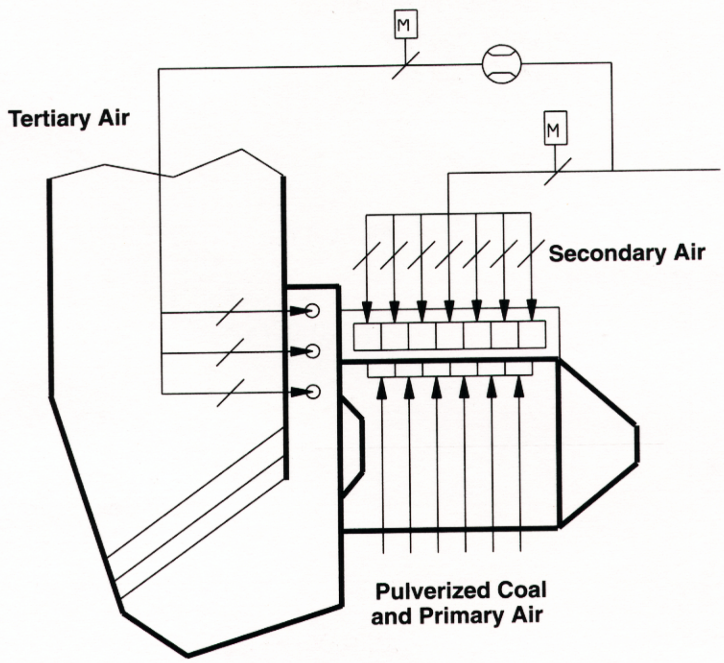

Figure 11 Cyclone Low-NOx Firing System[10].

Most European cyclone-fired boilers utilize a finer crushed coal feed size. Also, coal and primary air are introduced through a series of injection ports along the cyclone periphery beneath the tangential secondary air inlets rather than through a burner located at the front end of the cyclone. In Europe, secondary air is supplied and controlled to each cyclone from individual air ducts rather than from a common windbox. In addition, not all U.S. cyclone boilers employ a screen furnace arrangement downstream of the cyclone exit as shown in Figure 11.

The historic concerns of all owners of cyclone boilers have been excessive refractory wear and boiler tube erosion and corrosion. Such problems have been experienced on cyclone boilers even without combustion NO_x controls. During the past 20 years, these problems on European cyclones and wet bottom boilers have largely been solved through improved air/fuel controls, and the utilization of new refractory materials and modern refractory stud welding techniques. In view of the history of U.S. cyclone boiler operational problems, such improvements must be considered in any cyclone boiler low-NO_x retrofit.

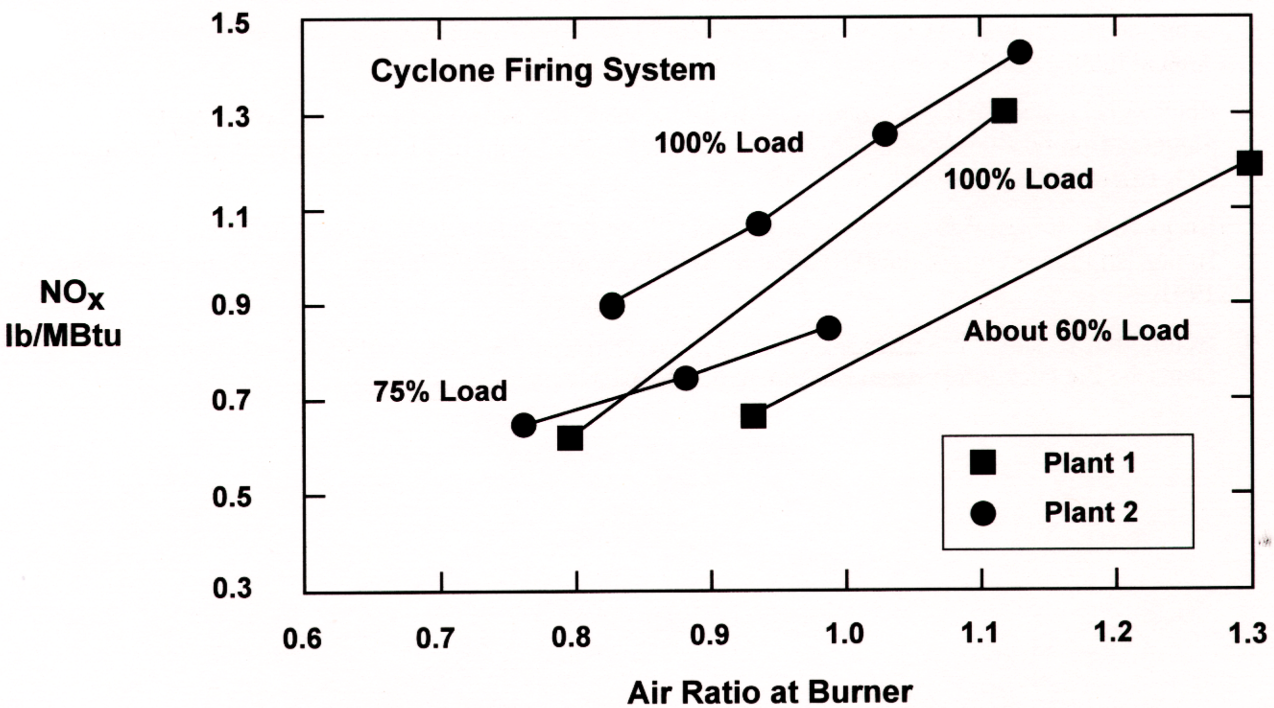

Figure 12 Cyclone-fired Boiler NO_x Reduction with Air Staging[10].

CONCLUSIONS

Combustion NO_x controls developed originally for dry bottom wall-fired pulverized coal boilers can be applied to boilers categorized by the U.S. EPA as Group 2 boilers. NO_x reductions of 50% have been achieved on a large coal-fired cell burner boiler using "plug-in" low-NO_x CCV® cell burners. Air staging has been applied successfully in Europe on wet bottom U-fired and cyclone-fired boilers without adverse operational problems. NO_x reductions of 30 to 60% have been achieved through this technique. Operational problems on slag-tap furnaces have been avoided through the use of improved air/fuel controls, upgraded refractory materials, and new refractory installation practices. Because of differences in coal properties and boiler design, NO_x combustion controls must still be demonstrated on U.S. slag-tap furnaces before achieving commercial acceptance.

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