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LOW NO_X SLAG TAP FIRING FOR A LOW EMISSION BOILER SYSTEM

by

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ABSTRACT

DB Riley, Inc. was recently awarded the proof of concept phase of the U.S. Department of Energy Low Emission Boiler System (LEBS) program to develop the next major advancement in pulverized coal burning technology. The DB Riley project team has developed a 400 MWe Commercial Generating Unit (CGU) design meeting all environmental and efficiency goals. The LEBS design is based on a low-NO_x U-fired slag tap firing system. Low NO_x slag tap firing has been demonstrated in a 100 million Btu/hr (29 MW) U-fired test facility for a high sulfur, Illinois coal, and a medium sulfur Appalachian coal, at less than 0.2 lb/million Btu (0.086 g/MJ) of NO_x while converting the coal ash into a low volume, inert, and non- leachable solid. The result is an 80% reduction in NO_x emissions typical of commercial slagging boilers. We obtained this low NO_x emission firing with DB Riley's CCV® Dual Air Zone Burner in combination with either air staging alone or with coal reburning. We also tested a baseline burner that simulated burners in commercially operating slagging boilers. The baseline burner matched the trends and the absolute value of NO_x emission in the commercial boilers, validating the test facility results. The firing system and LEBS emission control components will be demonstrated in a Proof of Concept (POC) facility.

INTRODUCTION

In 1992, the U.S. Department of Energy awarded contracts to three industrial teams under the Low Emission Boiler System (LEBS) program. The overall objective is to dramatically improve the environmental performance of pulverized coal-fired boiler systems[1]. The project goals are to meet emission limits of 0.1 lb/million Btu (0.043 g/MJ) of NO_x, 0.1 lb/million Btu (0.043 g/MJ) of SO_2, and 0.01 lb/million Btu (0.004 g/MJ) of particulate. Additional objectives include improved ash disposability, reduced waste generation, reduced toxic substance emission, and increased efficiency.

The DB Riley, Inc. project team includes DB Riley Inc., Sargent & Lundy LLC, Thermo Power Corporation, the University of Utah, and Reaction Engineering International. In Phases I-III of the LEBS program, the project team developed the design for a 400 MWe class Commercial Generating Unit (CGU) to fire a high-sulfur, U.S. coal. The design concept is shown in Figure 1. The CGU design includes a supercritical Benson boiler fired with a low NO_X, slag-tap U-fired system, a regenerable flue gas desulfurization system with de-NO_X capability, advanced low-temperature heat recovery, and particulate removal. This concept, in addition to meeting all performance and emission goals, eliminates flyash and scrubber solid waste streams. It has significant benefits for local and global environmental quality because:

- The vitreous granulate produced by the slag tap boiler (in place of fly ash) is non-leachable, dust free, and has significant value as by-product;
- The sulfur in the coal is converted to one of several byproducts such as sulfur, sulfuric acid, or ammonium sulfate;
- Nitrogen oxide is controlled primarily with firing system design, allowing very low stack emissions with only moderate post-combustion treatment;
- Less carbon dioxide is emitted per MW generated due to high cycle efficiency.

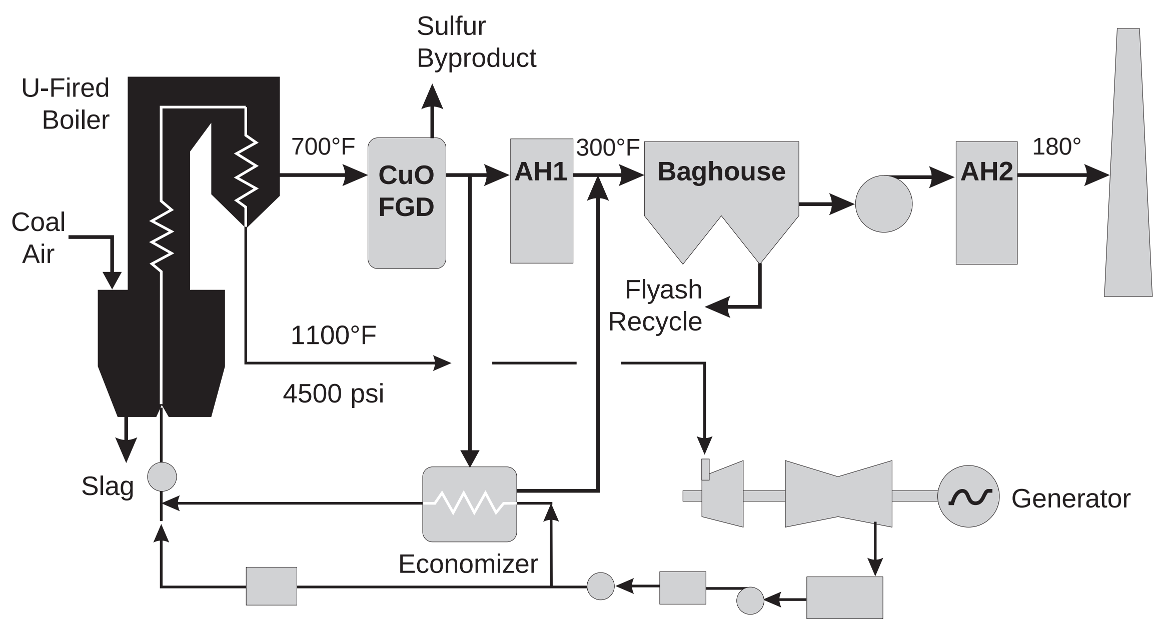

Figure 1 The DB Riley Low Emission Boiler Commercial Generating Unit Concept.

In 1997, the U.S. Department of Energy awarded Phase IV of the LEBS program to the DB Riley project team. In Phase IV, key subsystems from the CGU design will be tested in a Proof-of-Concept (POC) facility to provide the technology base for commercialization. The POC firing system design will be based on test results from a slag tap U-fired test facility firing at 100 million Btu/hr (29 MW) thermal input (equivalent to about 10 MW electric output). In this paper, we review the LEBS CGU and describe two LEBS POC options that the DB Riley team has developed. Finally, we provide the results and conclusions from the slag tap U-fired test facility work.

COMMERCIAL GENERATING UNIT COMPONENTS

Firing System

The CGU firing system is based on the well established, commercially operating U-fired slagging boiler design[2]. This firing system converts over one half of the coal ash into a low volume, inert, non-leachable solid in "once-through", or non-recycle, operation. Almost all of the coal ash can be converted by recycling the flyash back to the boiler, as is standard practice in many operating units.

With an experience list of over fifty utility scale U-fired slagging boilers, this furnace technology has demonstrated an ability to fire a wide range of coals under varying utility operating conditions. The furnace chamber design and operating conditions for producing slag are well known. This experience decreases the uncertainty in the achieving a reliably operating LEBS CGU incorporating advanced combustion controls.

In the U-fired combustion system, the fuel is fired down into a refractory chamber. Slag forms on the chamber walls and bottom, and at the slag screen at the exit of the chamber. The slag is continuously tapped from the combustion chamber, quenched, and dewatered, producing a vitreous, easy-to-handle, granulate. The hot gases then flow up and out through the slag screen, and final air is added for complete burnout.

In early U-fired slagging boilers, the high operating temperatures needed for slag production resulted in high NO_x emissions. U-fired units operating with high swirl burners produced NO_x emissions as high as 1.8 lb/million Btu (0.77g/MJ). The application of air staging and burner changes reduced this emission level to 0.8 lb/million Btu (0.34 g/MJ) for currently operating units. A major challenge for the DB Riley project team was to satisfy the LEBS emission goals and still produce slag. A goal of 0.2 lb/million Btu (0.086 g/MJ) for the U-fired combustion system was established, with the remaining amount of NO_x reduction to be accomplished by the post combustion emission control system.

DB Riley's approach for achieving the combustion system NO_x emission goal was to apply the CCV® Dual Air Zone Burner technology in combination with advanced air staging and coal reburning techniques in the U-fired combustion system. The development of the CCV® Dual Air Zone Burner and the dry-fired test results are provided in a companion paper to this conference[3].

The effects of air staging and coal reburning were investigated in parametric tests performed by the University of Utah, using a 15 million Btu/hr (4 MW_t) L1500 test furnace. The test results were used to support the 100 million Btu/hr (29 MW_t) slag tap firing tests by exploring selected variables in a smaller, more flexible system. In addition, Reaction Engineering International performed computational fluid dynamic simulations of the slag tap test facility, the POC, and the CGU. These simulations will be used to scale the test facility results to the POC and CGU designs.

Post Combustion Emission Control

The LEBS CGU design includes the Copper Oxide process to achieve the stringent sulfur dioxide (SO_2) control, waste minimization, and efficiency requirements. This post combustion emission control is a dry, regenerative process. It also provides further NO_x control by selective catalytic reduction in the copper oxide sorbent bed. Additional process advantages include the essentially complete removal of SO_3, partial removal of particulate, low parasitic power, and flexibility for sulfur, acid, or fertilizer byproduct.

In the process, a copper oxide (CuO) impregnated sorbent is used to remove sulfur dioxide from the flue gas. Contact takes place in a moving bed adsorber after the boiler economizer at about 700°F (371°C). In the adsorber, the copper oxide is converted to copper sulfate ($CuSO_4$). This compound further serves as a catalyst for reducing NO_x to nitrogen by injecting ammonia upstream of the adsorber. The sorbent moves to a regenerator unit where the sorbent laden with copper sulfate ($CuSO_4$) is regenerated by a reducing gas. The liberated SO_2 exits the regenerator in a concentrated gas stream to the byproduct recovery plant where it can be converted sulfuric acid, elemental sulfur, or ammonium sulfate.

The desulfurized flue gas is cleaned of particulate in a pulse jet fabric filter. The dust and acid-free gas is then further cooled in a second air heater, increasing plant efficiency. As an option for reduction of toxic substances, the fabric filter can be configured after the second air heater. Filtration of the particulate at this low temperature increases the removal of volatile species, and removal can be enhanced by addition of sorbents such as lime or active coke.

Thermo-Power Corporation is leading the development effort for the copper oxide process. They have completed bench scale tests of copper oxide sorbent reactivity directed at understanding the fundamental adsorption and regeneration chemistry and developing improved and more economical sorbent. They have also developed process models directed at process optimization and scale-up. Presently, a 3 million Btu/hr (1 MW_t) pilot scale copper oxide facility is being tested at the Illinois Coal Development Park in Carbondale, Illinois. The objective of these tests is to provide operating experience and performance data for the moving bed configuration at larger scales than previously applied. These developments are discussed in detail in a companion paper to this conference[4].

Boiler and Steam Cycle

The LEBS CGU incorporates a supercritical steam cycle with main steam conditions of 4500 psi (31 MPa) and 1100°F (590°C), and two reheats, each at 1100°F (590°C). A low temperature economizer, heating a portion of the feedwater in parallel with the first combustion air heater, reduces extraction steam consumption in the feedwater train. This allows the flue gas to be cooled to 180°F (82°C) in a second air heater, with high conversion efficiency of this low level heat. The net efficiency of the CGU design is 42.2% HHD basis, at 2.0" Hg (6.8 kPa) condenser pressure.

This supercritical cycle is proposed as a commercial system for the near term, and does not represent a maximum efficiency for the Rankine cycle. Over the longer term, continued advances in materials and boiler design are expected to yield steam plant efficiencies comparable to competing, higher risk cycles under development.

THE PROOF OF CONCEPT FACILITY

DB Riley has evaluated two options for the construction of a POC for demonstrating LEBS technology. One option is an 80 MWe mine mouth power plant at the Turris Mine in Elkhart, Illinois. A second option is the retrofit of a 40 MWe equivalent cogeneneration plant at the Savannah River Site steam generation plant near Aiken, South Carolina. Both projects would provide a LEBS reference plant which would provide significant benefits for commercialization of the technology. Both POC options include:

- A full scale, U-fired low-NO_x slag tap boiler, designed for continuous operation and capable of meeting the service life and availability demands for commercial operation.

- A 10 MW_e equivalent copper oxide Single Module Test Facility (SMTF), designed to test a single, commercial scale adsorber module in continuous operation in an operating power plant.

Current efforts are focused on the development of the Turris site as an Independent Power Project, with partial funding by the U.S. Department of Energy and the State of Illinois Department of Commerce and Community Affairs.

FIRING SYSTEM TEST PROGRAM

Test Facility

The LEBS 100 million Btu/hr (29 MW_t) U-fired slag tap test facility is located at the DB Riley Research Center in Worcester, Massachusetts. Figure 2 is an aerial view showing the coal preparation facility, the dry bottom burner test facility, office, laboratories, and equipment fabrication facilities. In addition to DB Riley burners, full-scale burners of various designs from several manufacturers from around the world have been tested in the dry-bottom furnace test facility.

Figure 2 The DB Riley Research Center in Worcester, Massachusetts.

Figure 3 is a photograph of the new U-fired slag tap test facility. It matches the residence time, or volumetric heat release, of a commercially operating U-fired slagging unit. It includes a single refractory-lined chamber fired by one full-scale burner mounted on the roof, a slag tap system, a slag screen, and an up flow section corresponding to the lower part of the radiant furnace in the commercial unit. We used the infrastructure from the existing burner test facility to supply fuel, air, water, and flue gas treatment. The total system supports firing a full-scale burner, providing a solid basis for scale-up.

The air staging and reburn system are illustrated in Figure 4. We located the first staging air level in the slag chamber and two additional levels after the slag screen. We included coal reburning ports before and after the slag screen.

Figure 3 The 100 million Btu/hr (29MW$_t$) U-Fired Test Facility

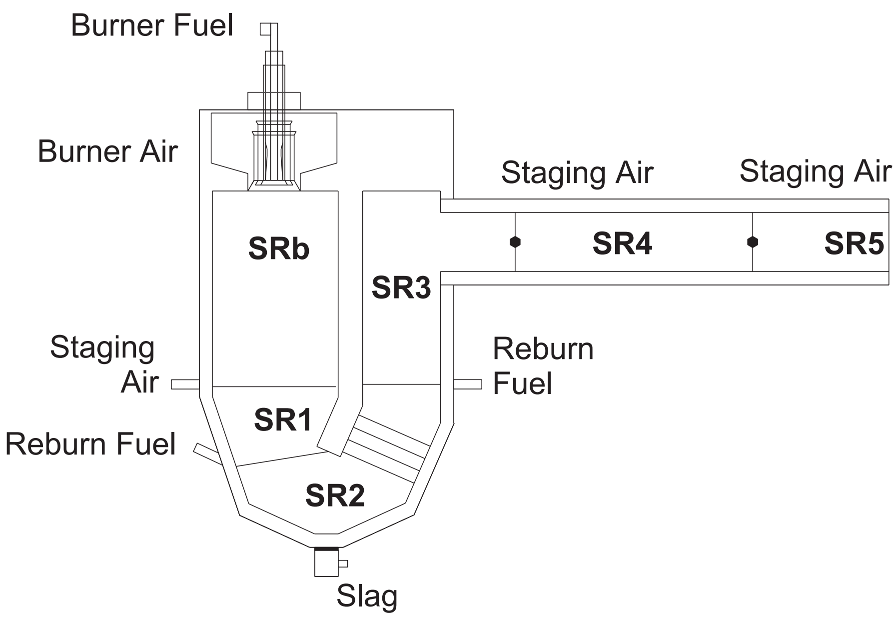

Figure 4 U-Fired Test Facility Air Staging and Coal Reburning

Test Program Overview

The combustion tests were conducted over a five month period[5]. We fired coals procured from each potential POC site. The majority of the tests were with an Illinois No. 5 coal, a high-sulfur, high volatile bituminous C produced at the Turris Mine in Elkhart, IL. This fuel is identified as "Turris coal." Selected conditions were tested with a medium sulfur, high volatile bituminous A coal blend produced by the Tom's Creek Preparation Plant in Coeburn, Virginia. This coal is blended to meet contract specifications for the Savannah River Site and is identified as "Toms Creek coal."

The Toms Creek coal is significantly lower in both sulfur and volatile matter than the Turris coal. In addition, the ash fusion temperature of the Toms Creek coal is much higher, with a calculated T_{250} of 2850°F (1566°C), compared to 2450°F (1343°C) for the Turris coal ash.

The test data reported here were for firing rates ranging from 90 to 100 million Btu/hr (26 - 29 MW) with the total excess air maintained at 15%. We completed several tests at lower loads and various excess air levels to determine the effect on NO_X emissions and slag production. Most tests were completed with the CCV® Dual Air Zone burner. Additional comparative tests were performed on a burner design installed in a commercially operating U-fired slagging boiler. This burner is identified in this paper as the baseline burner, because it was intended to provide a comparison between the test unit and existing U-fired boilers.

Burner Type and the Effect of Air Staging

Figure 5 shows the NO_X results for two burner types firing the Toms Creek coal at 100 million Btu/hr (29 MW). NO_X emissions are plotted against burner stoichiometry. In these tests, burner stoichiometry was reduced by increasing the first staging level air to maintain a constant slag tap zone stoichiometry of approximately 1.15.

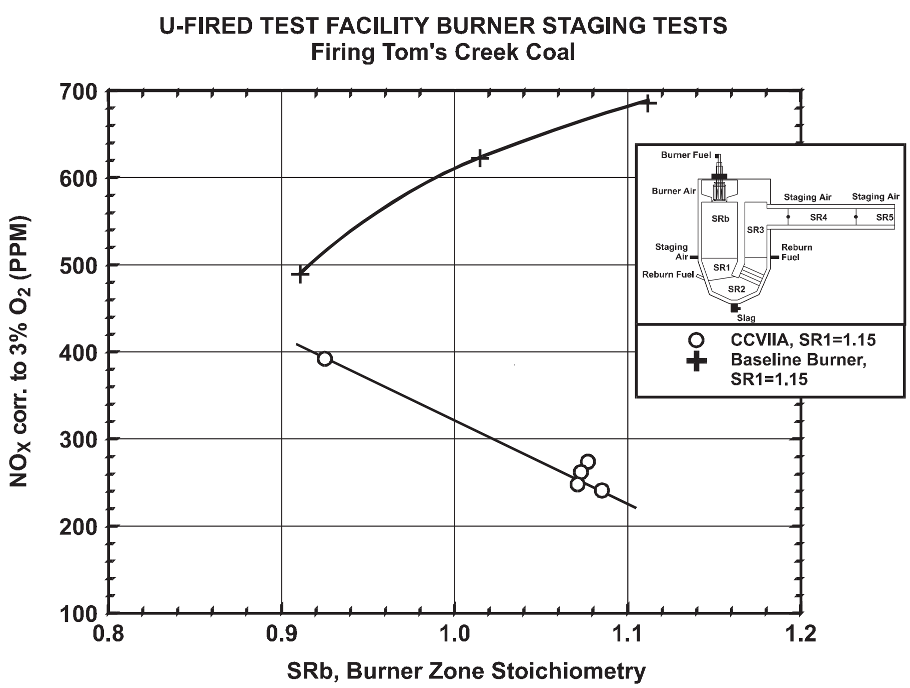

Figure 5 NO_X versus Burner Stoichiometry, Baseline and CCV® Dual Air Zone Burners

The CCV® Dual Air Zone burner performance was significantly different than the baseline burner. First, the unstaged NO_X for the CCV® Dual Air Zone burner was remarkably low for slag tap operation. Second, the NO_X emissions from the CCV® Dual Air Zone burner increased with decreasing burner stoichiometry, as compared to decreased emissions for the baseline burner. This result also contrasts typical staging results and dry-fired test results of the CCV® Dual Air Zone burner. We believe the explanation for this contrast is that the first level staging air disrupted a well-defined, fuel-rich core of the flame established by the CCV® Dual Air Zone burner. When staging air was injected only downstream of the slag chamber (not shown), NO_X decreased with decreasing burner stoichiometry. It is interesting to note that the NO_X levels for the baseline burner and the CCV® Dual Air Zone burner approached the same value as we staged the burners. This result indicated that burner design effects decreased as burner staging increased.

The flame shapes and ash deposition patterns were also markedly different for the two burner types. A comparison of video camera images of the CCV® dual air zone and the baseline burner flames is shown in Figure 6. The CCV® dual air zone burner produced a much narrower, well attached flame, resulting in improved low-NO_X performance. The baseline burner produced a wider, detached flame characterized by rapid mixing, high heat release rates, and increased NO_X emissions.

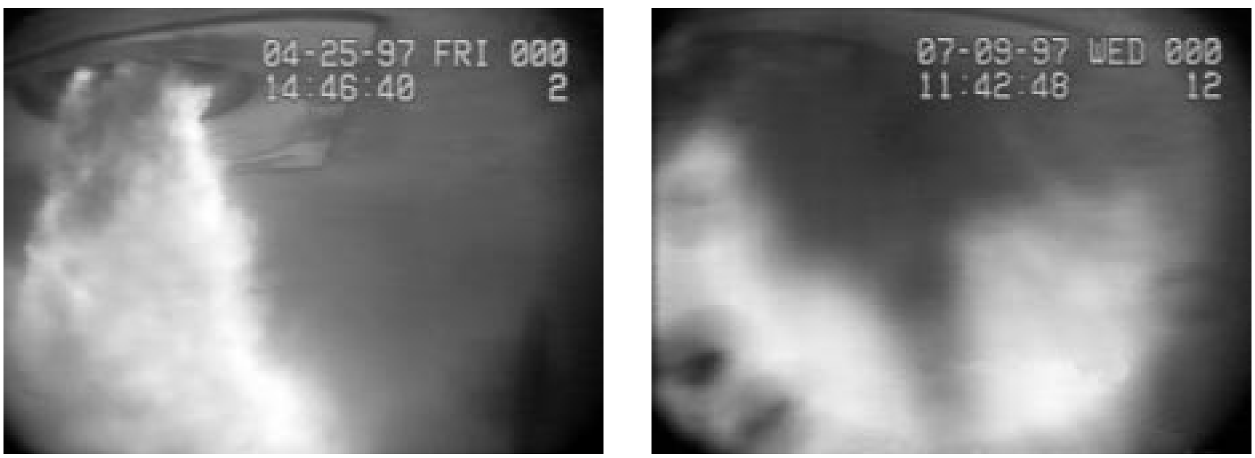

Figure 6 CCV® Dual Air Zone (left) and Baseline Burner (right) flames

Advanced Air Staging and Reburning

Figure 7 is a plot showing the effects of air staging and reburning, firing the Turris coal at a constant burner stoichiometry of 1.0. For all reburn tests shown in the figure, pulverized coal was injected upstream of the slag screen to decrease the slag tap zone stoichiometry. Similar NO_X effects were observed when injecting pulverized coal downstream of the slag screen. We increased the residence time at the plotted stoichiometry from about 1.0 seconds (open circles) to 1.5 seconds (closed squares) by changing the location of final air addition.

We observed a significant reduction of NO_X by applying reburn fuel injection. It was interesting to see a slight increase in NO_X at stoichiometries below 0.9 for a residence time of 1.0 second. We also observed a strong effect of the coal reburn residence time on NO_X

reduction. At a reburn firing rate of 10% of the total firing rate, the NO_X level fell below 150 ppm or 0.2 lb/million Btu (0.086 g/MJ) at a reburn stoichiometry of 0.9 and a residence time of 1.5 seconds.

Figure 7 also includes air staging data (open squares) for a constant burner stoichiometry of 1.0. This data, and data at other burner stoichiometries, showed the same NO_X versus stoichiometry relationship for either air staging or coal reburning. While comparable NO_X control can be achieved with air staging alone, this approach would require that the slag tap zone stoichiometry be reduced below 1.0 to achieve the NO_X goal for the combustion system. By using reburning, this reducing zone can be moved downstream of the slag tap allowing independent control of the slag tap stoichiometry and reducing zone stoichiometry. Independent control is an important advantage, since slag tap stoichiometry affects the temperature and viscosity of the slag. In fact, we found that slag tapping was best at a slag tap stoichiometry of 1.0, matching operating experience in commercially operating units.

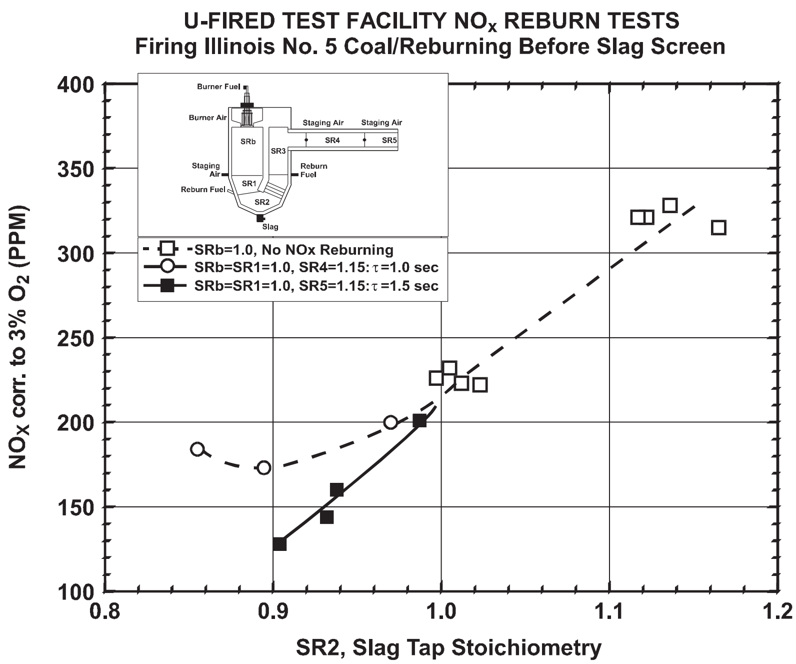

Figure 7 NO_X versus Stoichiometry, Reburning Tests at 1.0 Burner Stoichiometry

Figure 8 summarizes the NO_X emission results for the U-fired test facility firing the Toms Creek coal. The baseline burner results are compared to results for the CCV® dual air zone burner for unstaged burner operation, staging the burners alone, advanced air staging, and coal reburning. As can be seen, all staging methods provided a significant reduction of NO_X levels for the baseline burner. The combustion system NO_X emission goal was achieved with the combination of the CCV® Dual Air Zone Burner and either advanced air staging or coal reburning. The demonstrated NO_X emissions were 80% lower than the baseline burner simulating burners in a commercially operating slagging unit.

Combustion Efficiency

Slag and particulate flyash samples were analyzed for carbon content to characterize carbon burnout for the U-fired test furnace. The amount of heat lost due to unburned carbon was calculated from these sample analyses and the measured slag collection efficiency.

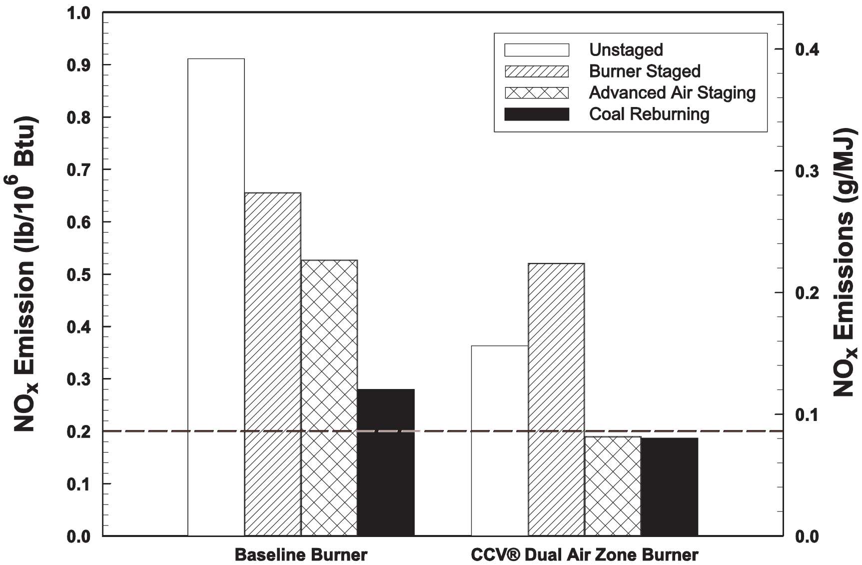

Figure 8 Baseline Burner versus the CCV® Dual Air Zone Burner

The average once-through slag collection efficiency was over 50%. The carbon in the slag averaged less than 0.5%. Since over half of the coal ash was converted into slag, the overall unburned carbon heat loss was small, averaging less than 1%. Coal reburning gave generally lower values of carbon loss than air staging for equivalent NO_X levels. Nearly all carbon loss was associated with carbon in the flyash, which was not recycled to the combustion chamber in these tests. In a commercial system, the carbon loss would be reduced even further by reinjecting the flyash back into the firing chamber.

Slag Properties

We also analyzed the slag samples to evaluate physical and chemical characteristics. The material was a glassy, dust free granulate. Table 1 shows the results of a Toxicity Characteristic Leaching Procedure (TCLP) analysis of the slag. The leachable metals were well below the 1990 RCRA Toxicity Limits.

*Table 1 Average TCLP Analysis**

	Firing Coal	Coal Plus Limestone	Detection Limit	1990 RCRA Toxicity Limit
Total Arsenic as As (mg/L)	BDL	BDL	0.20	5
Total Barium as Ba (mg/L)	1.07	0.88	0.05	100
Total Cadmium as Cd (mg/L)	BDL	BDL	0.05	1
Total Chromium as Cr (mg/L)	BDL	BDL	0.05	5
Total Lead as Pb (mg/L)	0.29	0.17	0.10	5
Total Mercury as Hg (mg/L)	BDL	BDL	0.001	0.2
Total Selenium as Se (mg/L)	BDL	BDL	0.20	1
Total Silver as Ag (mg/L)	BDL	BDL	0.05	5

* UFTF slag samples. Average of 3 each with and without limestone firing Turris coal

Comparison With Commercial U-Fired Units

Very low NO_X levels were achieved with the CCV® dual air zone burner in the U- fired test facility. In order to gain confidence that this was not an artifact of the lower surface area heat release inherent in a pilot-scale test facility, the burner was substantially modified to simulate first generation low-NO_X burners operating in a commercial U-fired boiler. We compared the U-fired test facility results for this baseline burner with data from two commercial field units[2]. We compared the absolute values of NO_X from the test facility with Field Unit A equipped with the first generation low-NO_X burners. We also compared the NO_X versus stoichiometry trends for the baseline burner with Field Unit B equipped with single register, high velocity burners.

NO_X vs. Surface Area Heat Release

Field Unit A NO_X data were available over a boiler load range from half to full load permitting a comparison between the test facility and the field unit at a common surface area heat release rate. This data is plotted in Figure 9 as a function of surface area heat release rate. Uncontrolled NO_X at half-load was approximately 20% lower than full load. At half load, the Unit A heat release rate was equivalent to that of the U-fired test facility.

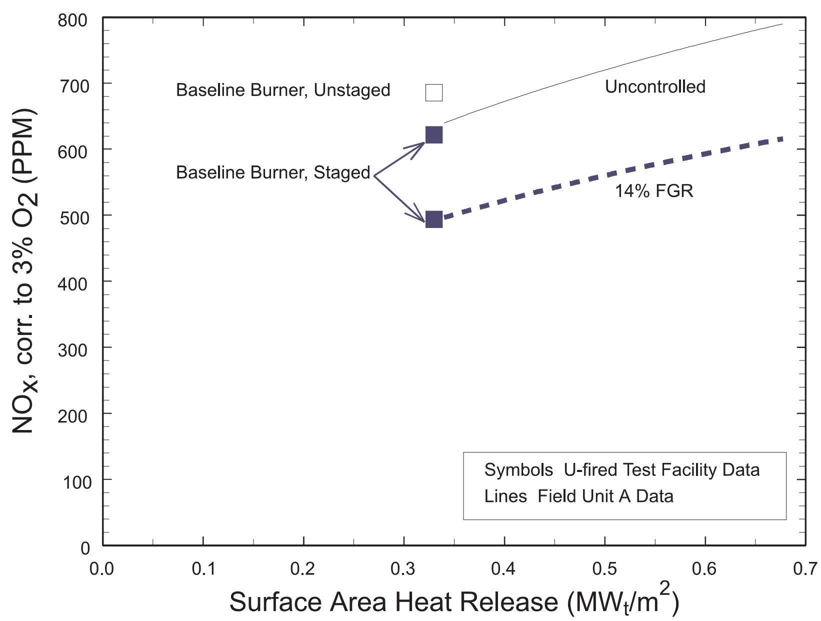

Figure 9 NO_X versus Heat Release for Field Unit A and the U-fired Test Facility

As shown in the figure, the unstaged NO_X for the baseline burner in the U-fired test facility was close to, but slightly higher than, the uncontrolled Field Unit A value at half load. Air staging in the test facility and flue gas recirculation in the field unit each gave a moderate amount of NO_X reduction with this burner type.

NO_X vs. Burner Stoichiometry

Figure 10 shows the effect of burner stoichiometry with two retrofit configurations in Field Unit B. In the retrofit I configuration, staging air was admitted through ports in the firing roof, parallel to the burners. In the retrofit II configuration, staging air was admitted through the firing chamber walls, perpendicular to the burners, and final combustion air was added through the walls downstream of the slag screen. In this figure, the U-fired test facility results for the baseline burner are shown for comparison.

Unstaged NO_X for the baseline burner was approximately one-half of Unit B consistent with the difference in burner design. The slope of NO_X versus stoichiometry for the U-fired test facility baseline burner is similar to the slope observed for both retrofit configurations. Furthermore, the U-fired test facility baseline burner NO_X emissions extrapolate to approximately the same level as the Unit B retrofit II NO_X levels at reduced stoichiometry. This observation can be expected since the U-fired test facility air staging for these tests was similar to the retrofit II air staging configuration.

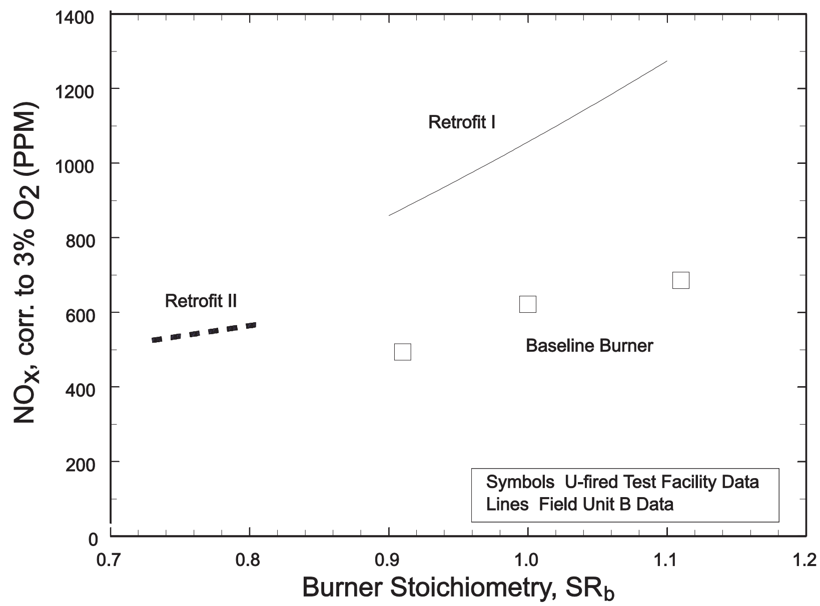

Figure 10 NO_X versus Burner Stoichiometry for Field Unit B and the U-fired Test Facility

CONCLUSIONS

We demonstrated the LEBS NO_X emission combustion system goal of 0.2 lb/million Btu (0.086 g/MJ) in a U-fired test furnace using the CCV® Dual Air Zone Burner with either advanced air staging or coal reburning. When firing the burner without these staging techniques, the NO_X levels were very low for slag tap conditions. These results were achieved while converting the coal ash into an inert, low volume, non-leachable solid. Coal reburning provided independent control of the slag tap stoichiometry and reducing zone stoichiometry. Independent control was needed to maintain conditions for good slag production and removal as found in commercially operating slag tap firing systems.

Since over half of the coal ash was converted to low carbon slag, the overall carbon loss was small (1% on a heat loss basis), even under very low NO_X firing conditions. In a commercial system, the carbon loss would be reduced even further by reinjecting the flyash back into the firing chamber.

We conclude that the test facility provided a valid simulation of the effectiveness of NO_X control measures applied to a U-fired boiler. The U-fired test facility data matched absolute values from Field Unit A operating at half load. The U-fired test facility data matched the trends observed in Field Unit B. The data from Field Unit A indicated the NO_X values would increase at most 20% for a factor of two increase in surface area heat release.

The U-fired test facility NO_X emissions with the CCV® Dual Air Zone Burner alone were 60% lower than the baseline burner. When advanced air staging or coal reburning were applied, NO_x emissions were about 80% lower than the emissions typical of slagging systems, achieving the LEBS NO_x emission goal for the combustion system. These results show that a slagging firing system consisting of the CCV® Dual Air Zone Burner with coal reburning and a regenerable desulfurization system with de-NO_x capability can meet the LEBS program emission goals of 0.1 lb/million (0.043 g/MJ) NO_x, 0.1 lb/million Btu (0.043g/MJ) SO_2, and 0.01 lb/million Btu (0.004 g/MJ) particulate. These LEBS technologies will be further tested and developed in a Proof of Concept Facility.

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