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Alternate Solutions for Reducing NOx Emissions from Tangentially Fired Boilers

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ABSTRACT

With the advent of the 1990 Clean Air Act Amendments, the U.S. utility industry has begun retrofitting coal, gas and oil-fired boilers with Low NO_x technologies to meet Title I and IV of the Act.

This paper discusses an alternative method for reducing NO_x emissions from a tangentially-fired steam generator. Results of retrofitting Iowa-Illinois Riverside Boiler No. 9 with a new low- NO_x combustion system will be presented.

This paper focuses on the research and development, design, and performance results achieved following the retrofit.

INTRODUCTION

Iowa-Illinois Gas & Electric is an investor-owned utility serving 600,000 people in portions of central and eastern Iowa and western Illinois. Since the passage of the 1990 Clean Air Act, Iowa-Illinois has carried out several projects to control flue gas emissions from Riverside Generating Station in Bettendorf, Iowa.

One of the major projects initiated in the spring of 1993 was to reduce NO_x emissions from the Riverside Generation Station.

The station is equipped with four boilers, three wall-fired and one tangentially-fired. All currently burn a mid-western bituminous coal. The wall-fired units were designed and built in the early 1940's. The tangential unit, which also has full load gas firing capability, was built in 1960 and has a generating capacity of 125 MW.

This paper discusses the research and development, design, installation, and performance testing of a new low-NO_x combustion system supplied by Riley Stoker Corporation retrofitted to the Riverside Generating Station Boiler No. 9. This combustion system included burner modifications, an overfire air system and control system modifications.

UNIT DESCRIPTION

The Iowa-Illinois Riverside Boiler No. 9 is a coal-fired utility boiler, originally designed and constructed by Combustion Engineering, Inc. The unit produces main steam at 860,000 lbs/hr, 1005°F/1005°F superheat and reheat temperatures at an operating pressure of 1850 psig. The furnace dimensions are 30'-3 3/4" wide x 30'-0 23/32" deep.

The unit, shown in Figure 1, was originally rated to generate 125 MW of electrical power with base loading the primary mode of operation. Since 1982, the unit has been used for either cycling or peaking duty. This operating practice determined the need for enhanced turndown capabilities and a flame safety system.

Pulverized coal is supplied by four C-E 673 Raymond Bowl Mills (vertical spindle exhauster type) with twelve inch coal piping. Each mill provides coal to four corners at one elevation. The unit was designed to fire full load on either Midwestern bituminous coal or natural gas, using four elevations of pulverized coal and three elevations of natural gas, with tilting tangential fuel and air admission assemblies in each corner. The nine individual compartments in each corner include dampers to control secondary air flow distribution at various loads and firing conditions. Twenty-eight natural gas-fired, side pilot horn type, eddy plate ignitors provide start-up ignition and low load stabilization. The original ignitor design used a Dwyer-type differential pressure switch to detect the ignitor flame.

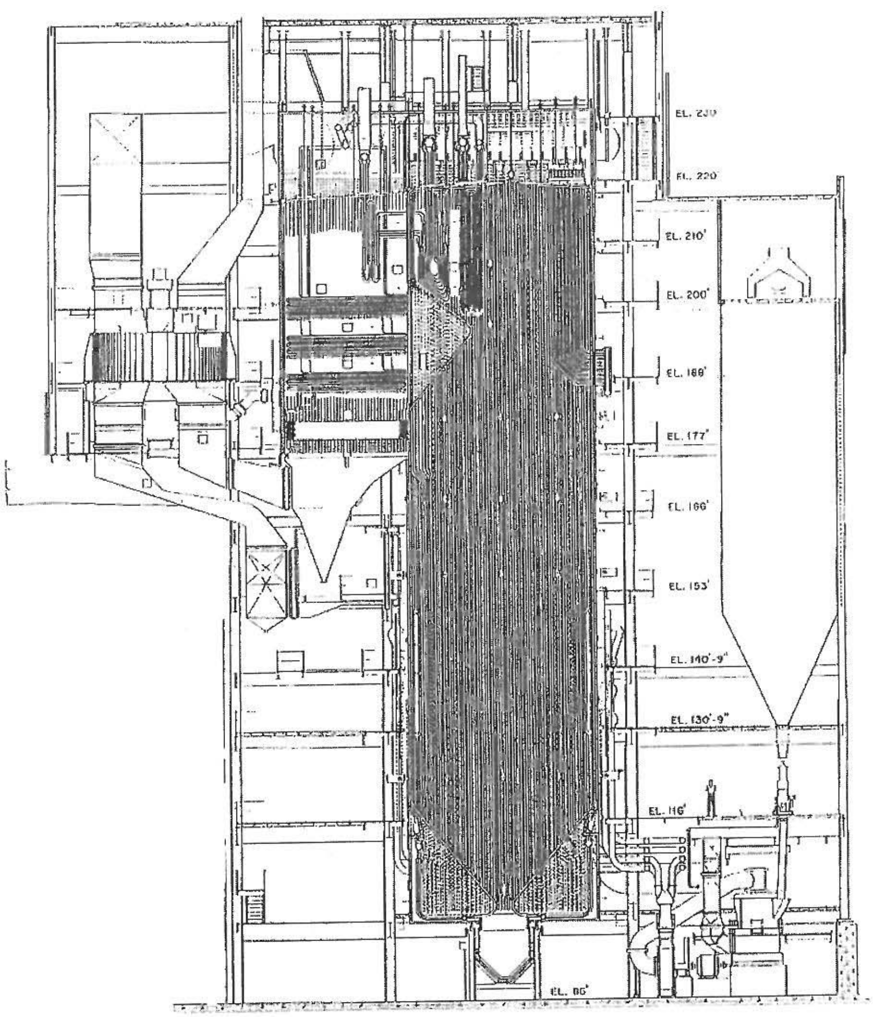

Figure 1 General Arrangement
Unit No. 9, Riverside Generating Station

RESEARCH AND DEVELOPMENT

Riley's technical approach for low-NO_x combustion in tangentially-fired boilers focused on developing a flame retention coal nozzle tip and an overfire air system to control flyash carbon loss and reduce NO_x emissions to comply with the 1990 CAAA.

The Riley Flame Retention Nozzle Tip design resulted from research conducted at the Riley Research facility in Worcester, MA and was confirmed during full-scale field demonstration tests. Two years ago, Riley participated in a research project at the request of several utilities to develop a replacement coal nozzle tip that would reduce NO_x emissions. Riley engineers developed and tested a new coal nozzle tip, based on Riley's patented Controlled Combustion Venturi (CCV®) nozzle design, which could easily be retrofitted on existing burners in tangentially or corner-fired boilers. The Riley Flame Retention Nozzle Tip (patent applied for) is shown in Figure 2. Test results from the research project showed that the Riley Flame Retention Nozzle Tips provided greater flame stability and greater turndown without use of support fuel. Because the Riverside Unit was primarily used as a cycling unit and low load operation was desired, the Riley tips were provided as part of the retrofit.

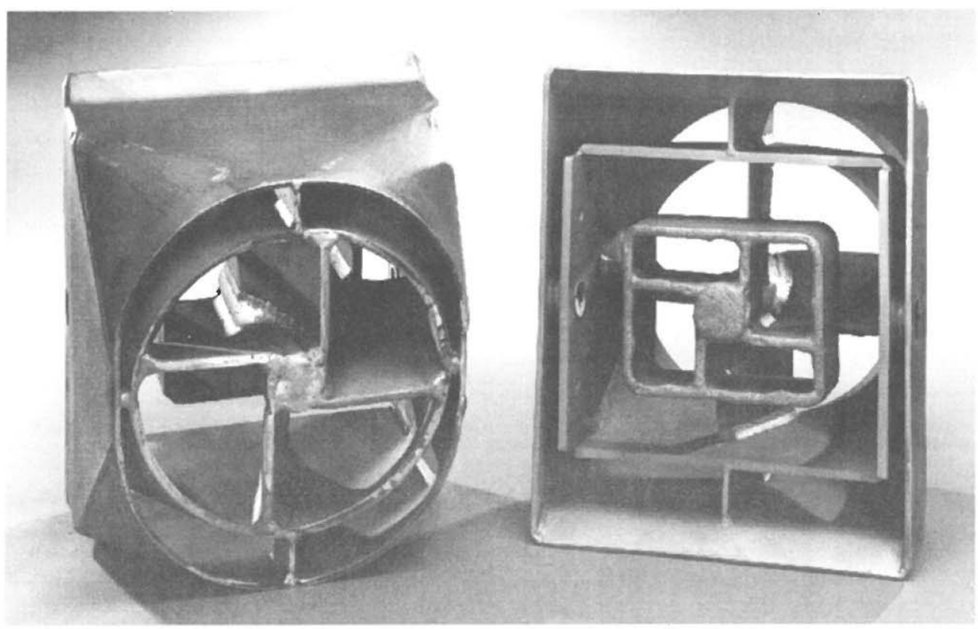

Figure 2 Riley Flame Retention Nozzle Tip

Riley's work with overfire air systems began in the 1980's, when Riley worked extensively with EPRI to develop criteria for overfire air systems. Riley used that experience and current state-of-the-art modeling techniques to locate the overfire air ports or Externally Staged Combustion System (ESCS) ports for tangentially-fired boilers. At Riley Research, physical models were constructed of a tangentially-fired boiler with various windbox configurations. The physical model was used to establish preliminary design configurations and to analyze air flow patterns through the furnace using a helium bubble/smoke medium. Figure 3 shows the flow visualization sketch. Computational fluid dynamic models were then constructed to complete the design.

Riley has also worked extensively with development of computer programs for use in analyzing boiler operations and related systems. Using this experience, Riley combined results from its own FASTFIRE program with results from the Riley-modified FLUENT program to establish optimum locations for air staging ports in various types of furnaces. Using these techniques, computational models were developed which could be used to optimize staging port location and staging port nozzle design in tangentially fired furnaces.

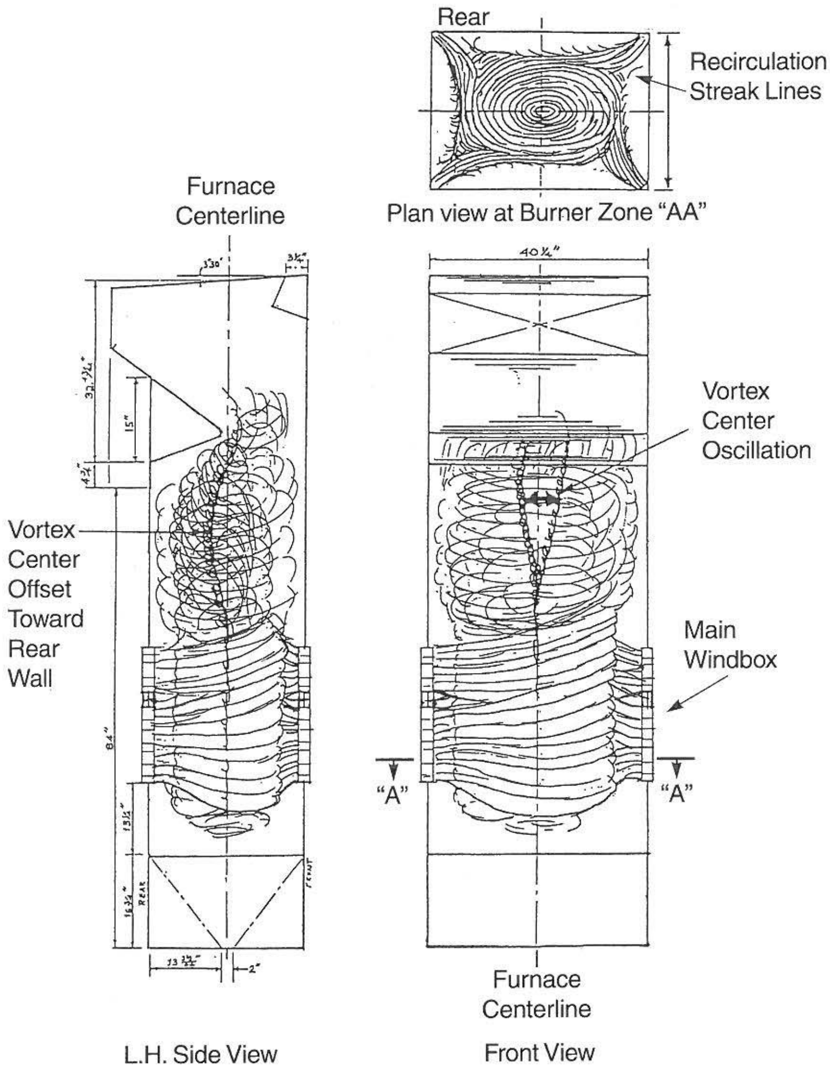

Figure 3 Helium Bubbles/Smokes Flow Visualization Flow Pattern Sketch for Standard T-Firing

LOW-NO_x COMBUSTION RETROFIT

A drawing of the complete low-NO_x combustion system retrofit, which includes burner modifications, an externally staged combustion system, controls modifications, and new scanners is shown in Figure 4. The primary equipment supplied and work performed is described below.

Burner Modifications

As part of the overall low-NO_x combustion system retrofit provided by Riley, modifications to the existing burners were required. Sixteen new stationary coal nozzles equipped with Riley Flame Retention Nozzle Tips were installed without alterations to the existing compartments or linkages.

Besides stationary coal nozzle and coal nozzle tip replacement, air and gas nozzle tips were redesigned using the computational modeling. The modified replacement air nozzle tip provides an arrangement that offers internal main windbox air staging and maintains air penetration into the furnace when the ESCS ports are in use. Internal staging is accomplished by redesign of the air nozzle tips to increase separation of the air streams around the fuel streams entering the boiler from each burner windbox. A typical reduced free area air nozzle tip is shown in Figure 5.

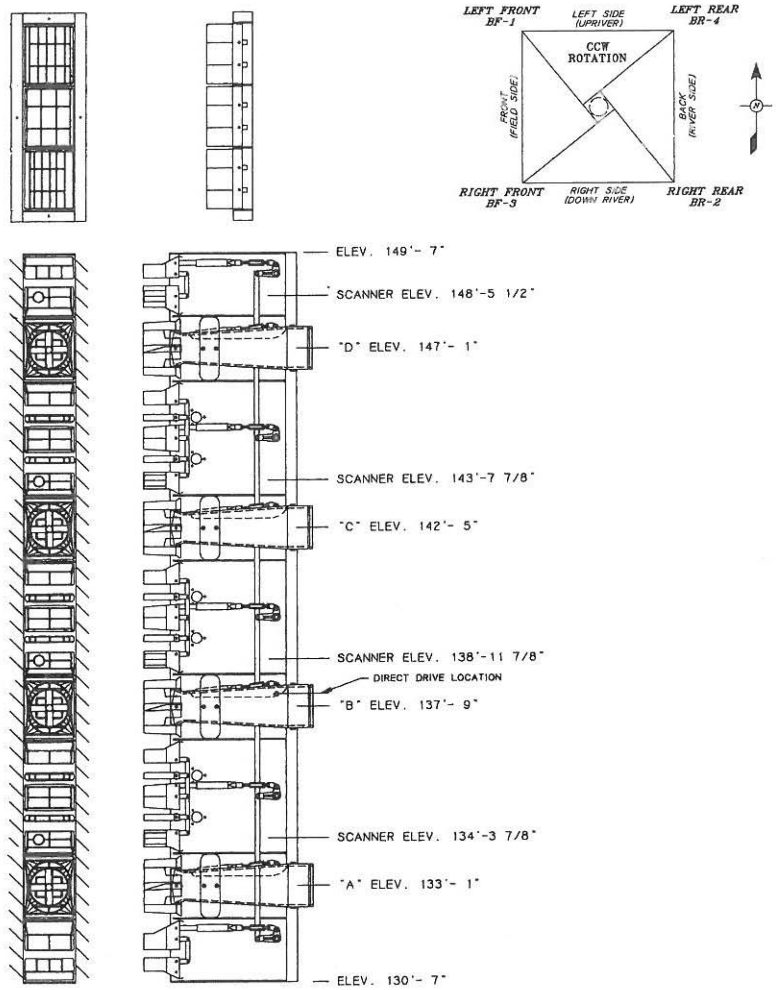

Figure 4 Low-No_x Retrofit Arrangement
Iowa-Illinois Gas and Electric Company, Riverside Unit No. 9

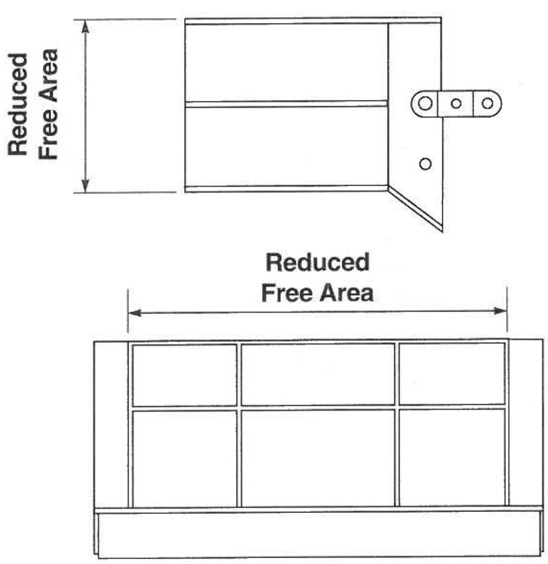

Figure 5 "Reduced Free Area"
Adjustable Air Nozzle Tips

Other burner-related modifications include replacement of burner nozzle horizontal tilt linkage and installation of electric damper drives on the secondary air dampers in the main windboxes. The addition of the electric drives on the formerly manually-operated dampers provides the ease of control necessary for maintaining low-NO_x emissions at the many load conditions required.

Externally Staged Combustion System

In Riley's design for the Riverside Unit, NO_x reduction is achieved by use of a staged combustion system. Riley provided an Externally Staged Combustion System (ESCS), more commonly known as an overfire air (OFA) system. Unique to Riley's ESCS system is the method used to find the locations for the ESCS ports in the furnace walls. Computational models were constructed of the Riverside No. 9 boiler, using the techniques developed at Riley Research. This modeling allows the critical variables to be changed and various configurations of staging port locations and sizes to be evaluated. The analysis resulted in the determination of the optimum locations for the ESCS ports to achieve the desired emissions reductions.

The application required four staging ports, two on the front wall and two on the rear wall of the boiler. The ports are shown in Figure 6. The Riley computational model optimizes the design of the ESCS nozzle tips to provide adequate penetration into the furnace. This modeling allows Riley to supply air staging ports that use linkage-free fixed nozzles, unlike other designs. The Riley system also controls air flow with the use of modulating dampers equipped with electric damper drives. In the Riverside No. 9 unit, air for the external staging ports was provided from the secondary air ducts upstream of the main burner windboxes. Since the total air flow was not changed, sufficient fan static pressure was available without adding booster fans.

Controls Modifications

As part of the low-NO_x combustion system retrofit, Iowa-Illinois required an upgrade of their Flame Safety System (FSSS) to "state-of-the-art."

Riley supplied new main flame and ignitor scanners and control cabinets. Iowa-Illinois, with Westinghouse, provided the programming and main controls for the Burner Management System (BMS) and FSSS. The Iowa-Illinois bid specification required flame scanning which duplicated the

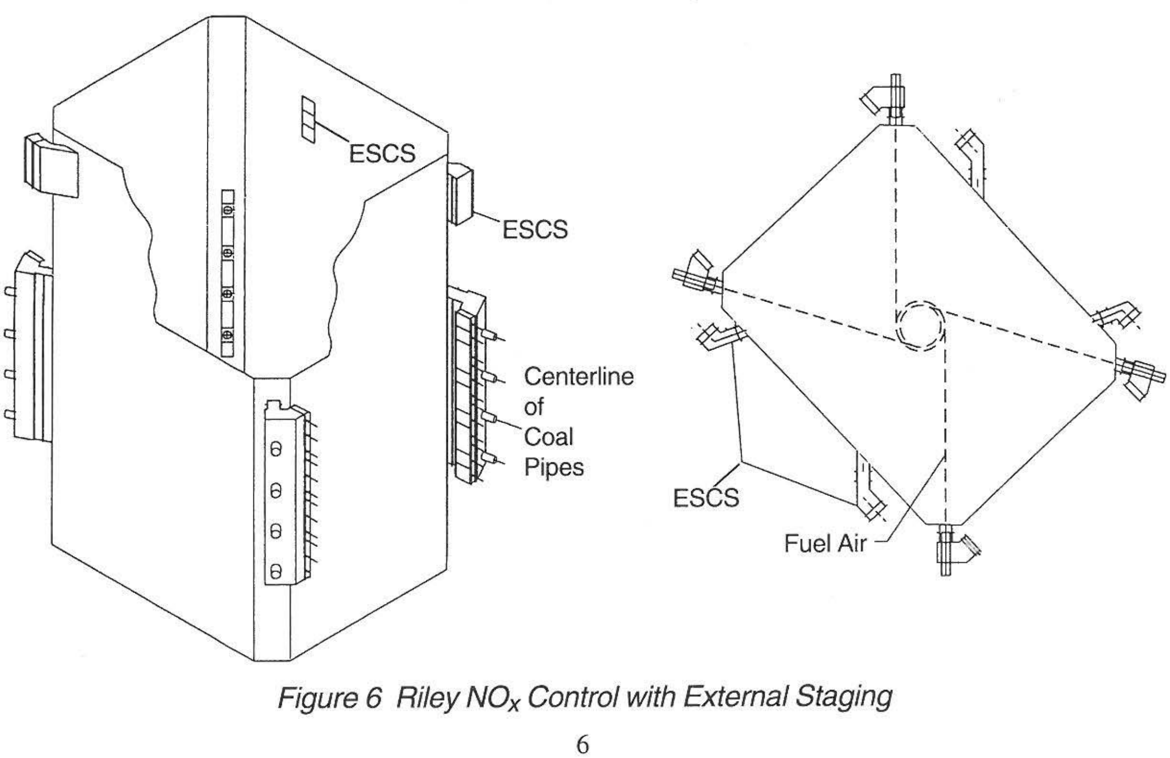

Figure 6 Riley NO_x Control with External Staging

OEM's fireball detection method for main flame scanners. Because of the multiple fuels to be fired, location of the main flame scanners was an important design consideration. Based on the scanner manufacturer's experience on similar units, the main flame scanners were located as shown in Figure 7.

Sixteen main flame and twenty-eight ignitor scanners, control cabinets, and a scanner cooling system were included in Riley's scope of supply. Since the boiler fires both coal and gas, common scanners were desired. The existing gas-fired IFM ignitors were re-used: seven ignitors per corner are used to ignite four elevations of coal and three elevations of natural gas. Riley supplied infrared (IR) type scanners with lead sulfide photoelectric cells. Since both coal and natural gas were to be scanned, a wide band IR scanner was necessary.

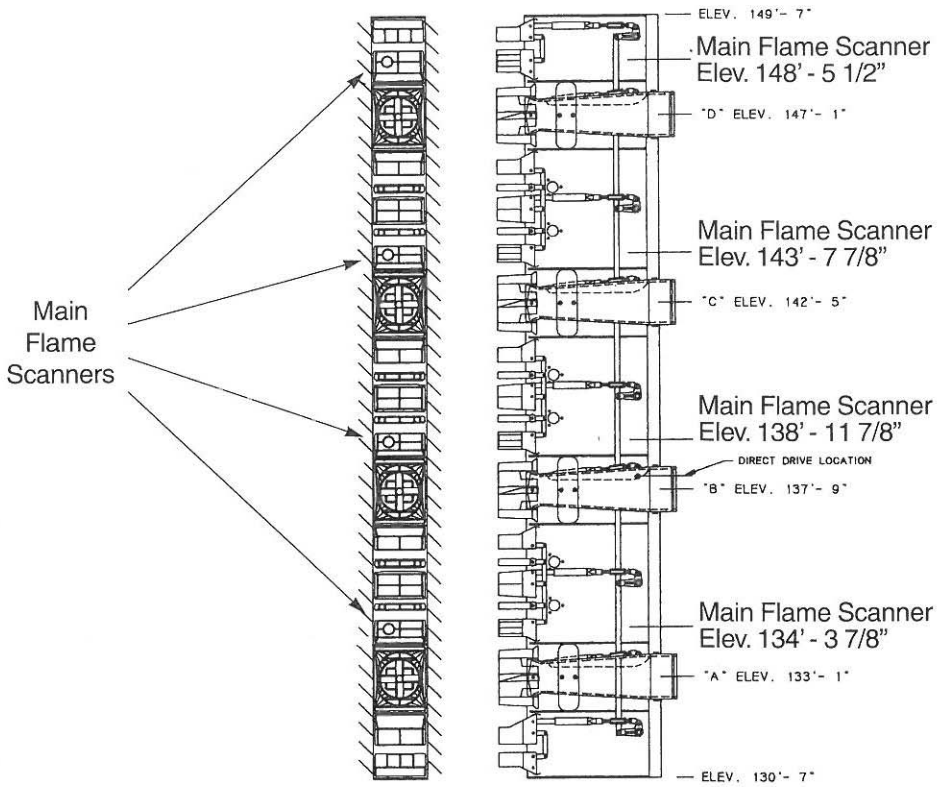

Figure 7 Coal Burner Scanners

Other Modifications

The installation of the external staging ports required the addition of new access platforms at the front and rear of the boiler and relocation of four wall blowers. Wall blower modifications included the installation of new waterwall tubing for these additional wall openings.

Riley also supplied a scanner cooling air system complete with skid-mounted blower set and all necessary piping and supports.

START-UP

Modifications were completed on time during the scheduled eight week outage and the unit began operation as scheduled based on dispatch. The new burner components performed very well during start-up and optimization testing. The new scanners worked satisfactorily on coal firing, but had problems when the unit fired natural gas. Since scanner operation did not affect emissions, acceptance testing was tentatively scheduled for January 1994. The optimization and evaluation of the scanners continued based on gas firing availability of the boiler.

TEST RESULTS

As indicated earlier, the goal of the retrofit project was to reduce NO_X emissions from the Riverside No. 9 unit to guarantee levels established by Iowa-Illinois Gas & Electric. The emission limits were at or below the CAAA 1990 required limits. During baseline testing of the unit done in April 1992, uncontrolled NO_X levels measured at 100% MCR steam flow were 0.68 lbs/Mbtu. Based on this value at MCR, a reduction of approximately 50% in NO_X was required to meet the specified limits set by Iowa-Illinois Gas & Electric. Figure 8 represents the baseline NO_X emissions measured at the economizer exit versus load, the contract guarantee, and 1990 CAAA limits.

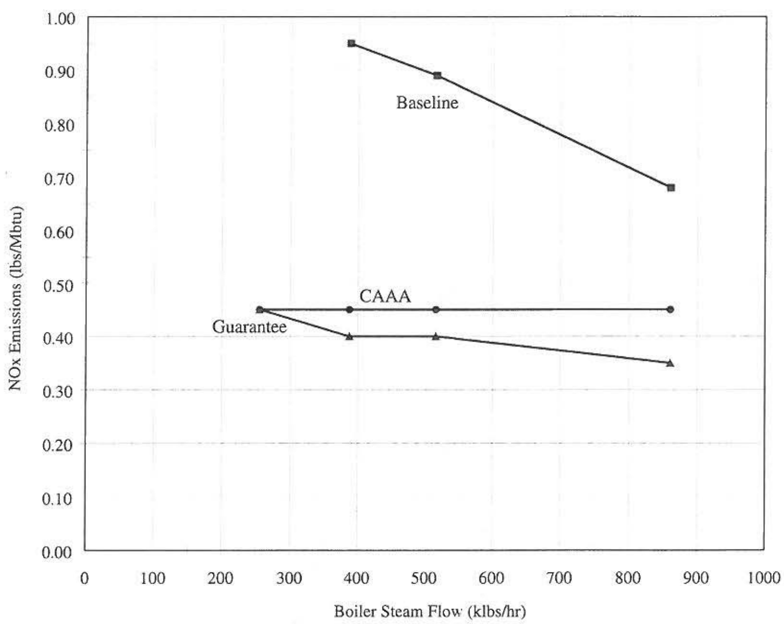

Figure 8 Baseline NO_X Emissions, Guarantee, and CAAA NO_X Emissions

The Iowa-Illinois Gas & Electric specification also required that the post-retrofit acceptance testing include nine separate firing conditions to verify compliance to the contract guarantees. The required tests duplicated six of the ten baseline tests performed. Additional tests were made at 30% MCR steam flow, a ramp test from 45 to 100% MCR steam flow, and a 100% MCR steam flow test firing 100% natural gas. A summary of these tests is shown in Figure 9.

Optimization testing was completed without any significant problems. The contract guarantees at 100% and 60% MCR were easily accomplished. Achieving the guarantee limits for NO_X at the 45% and 30% MCR load was more difficult because of the tendency of corner-fired boilers to generate greater NO_X emissions at lower loads than do similarly sized wall-fired units. Higher emissions caused by the increased excess air levels, staging levels, burner firing configuration, and burner nozzle tilt position make meeting NO_X emission limits at lower loads more difficult than meeting limits under full load (MCR) conditions. Therefore, controlling air flows to the main burners and to the external staging ports is a critical consideration when reducing NO_X. After a series of optimization tests, guarantees were finally achieved at these loads. Acceptance testing could now begin.

January 1994 Testing

Post-retrofit acceptance testing commenced in January 1994. After two days of testing, the Riverside Unit lost one mill due to a mill motor failure. Acceptance testing was stopped and was delayed until the mill motor could be repaired. A tentative date of April 1994 was targeted for renewal of acceptance testing.

Acceptance Test Number	Baseline Test Number	Load % MCR Steam Flow	Fuel	Mills/Burner Elevation in Service	Test Description
ACC-1	1	100	Coal	A,B,C,D	Standard Operation
ACC-2	4	100	Coal	A,B,C,D	-% O_2 Variation
ACC-3	5	100	Coal	A,B,C,D	+ 15° Fuel Nozzle Tilts
ACC-4	6	100	Coal	A,B,C,D	- 15° Fuel Nozzle Tilts
ACC-5	9	60	Coal	A,B,C,D	Control Load
ACC-6	10	45	Coal	B,C,D	Minimum Load
ACC-7	n/a	30	Coal	B,C	30% MCR Load
ACC-8	n/a	45 → 100	Coal	B,C,D → A,B,C,D	Ramp Test, 2 MW/minute
ACC-9	n/a	100	Nat. Gas	A,B,C	100% MCR - Gas Firing

Figure 9 Acceptance Testing Requirements

April 1994 Testing

Post-retrofit acceptance testing was again initiated during the second week of April 1994. Acceptance tests were run, firing coal at 100% MCR under four of the required boiler conditions. NO_x emissions were below 0.35 lbs/Mbtu, CO emissions were 3.0 ppm or less and flyash carbon loss averaged 1.28%. The 100% load test firing natural gas was also completed successfully with NO_x emissions at .26 lbs/Mbtu and CO at 1.5 ppm. All tests performed at 100% of MCR steam flow complied with the guarantee requirements of the customer's specification. However, at 60 and 45% MCR, NO_x emissions averaged 0.5 and .6 lbs/Mbtu respectively, above the contract requirements of <.40 lbs/Mbtu. Additionally, the emissions averaged .7 lbs/Mbtu at 30% MCR, above the guarantee level of .45 lbs/Mbtu.

Acceptance testing was halted at this point since there appeared to be an anomaly in boiler performance at lower loads. The current data was compared to that collected during the initial optimization to learn the cause of the marked change in performance. Additional optimization testing was done at the lower loads using several revised settings in an attempt to regain favorable NO_x emissions. These tests did achieve emissions within the contract limits by lowering the burner nozzle tilt position, but steam temperatures were adversely affected. As a result, acceptance testing was stopped and postponed until a cause for the changes in performance at lower loads could be determined and corrected.

Design Re-evaluation and Improvement

Evaluation of the boiler and emissions performance during low load operation to determine the cause of the changes in emissions performance continued. Riley determined that there were not any significant differences in the fuels being fired in the tests of November 1993 and April 1994. Further review of the data and boiler settings used during the November 1993 optimization testing was made to find a correlation with the changes. The review included a comparison of steam temperatures and burner nozzle tilt position, fuel flow and fuel balance, furnace conditions and sootblowing sequences, total combustion air, windbox pressure and secondary air windbox damper positions. Extensive investigation revealed no obvious explanations; however, the secondary air damper positions and windbox pressure were the most likely causes for the deviation. Windbox pressure at similar damper positions showed a decrease in windbox pressure from the original optimization tests. The possibility existed that a damper blade had bound up or its shaft had slipped its connection with the electric drive. This forced a visual inspection of each secondary air windbox damper, its mechanical stops, connections to the electric drives, and an evaluation of its operational repeatability. The optimization testing also showed that the emissions were sensitive to the burner nozzle tilt position. This prompted the evaluation of the possible changes in the penetration of the staged combustion air and its residence time from the burners. The evaluation resulted in the design of a new nozzle for both the upper and middle externally staged combustion system ports.

Besides the low-load NO_x emission difficulties, the new main flame scanners did not function as expected. During initial start-up and during the November 1993 optimization testing, the scanners had worked satisfactorily when firing coal. During the April 1994 natural gas acceptance testing, the main flame scanners had difficulty scanning the gas flame. Based on the OEM's fireball scanning concept, the scanners should have worked properly. The flame pattern and furnace bulk gases rotate up and away from the downstream burner corner in a tangentially-fired furnace. (See Figures 3, 7, and 10). Because the main flame scanners were located in the compartment above the coal nozzles, it appeared that the lower elevation "A" scanners could not see flames when firing gas. The "A" elevation of main flame scanners is located below the gas burners, so they were out of the line of sight of the scanner lenses. Also, the flicker characteristic, or frequency, of the gas flame is much different from the coal flame. The off-stoichiometric firing changes these frequencies significantly. This requires low frequency sensitivity settings on scanner amplifiers to enable scanners to sense low-NO_x flames and the different frequencies the gas and coal flames produce. After running tests which evaluated different scanner lenses, Riley and Iowa-Illinois mutually decided to install additional scanners located to "see" gas flames only. A weekend outage in mid-May, 1994 was scheduled to add the additional scanners and make the adjustments necessary to achieve low-load NO_x emission levels.

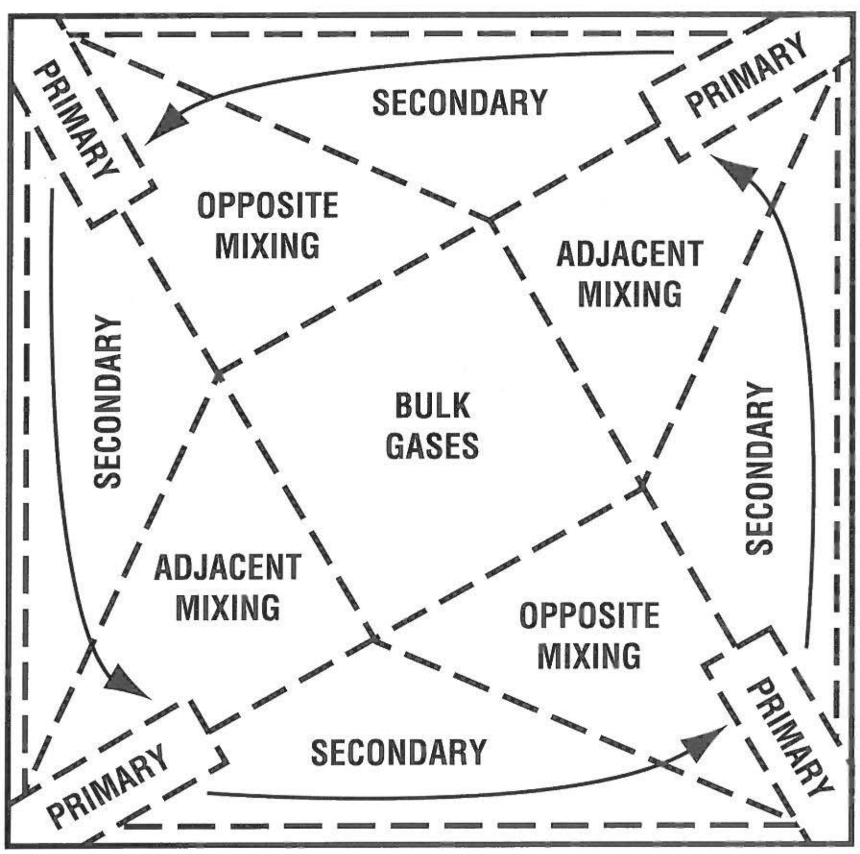

Figure 10 Mixing Zone Model for Tangential Boilers (Horizontal Section at Lowest Burner Level)

May 1994 Outage

The weekend outage began on May 19, 1994. Scanner mounting sleeves and hardware were installed just above the upper gas nozzle at each elevation. Redesigned nozzles were replaced in the upper and middle nozzle tips in each corner of the externally staged combustion system port. Inspection of the secondary air windbox dampers revealed that some dampers were not allowed to close completely because of mechanical interferences or because the damper had reached the control system closed position. In addition, some damper positions indicated by plant instrumentation did not correspond to the actual damper position. The secondary air windbox dampers and mechanical stops were reset and the damper drives were recalibrated to ensure that actual damper positions corresponded with the control room instrumentation.

On May 23, 1994 the unit was restarted and optimization tests were initiated. The adjustments made during the outage confirmed that actual secondary air damper positions had not previously corresponded correctly to the positions shown on the control room instrumentation. This required further optimization testing, which because of the summer peak load season, extended into June and August. The series of optimization tests were successfully performed, and the unit was scheduled for acceptance testing in September 1994.

Final Acceptance Testing - September 1994

In September 1994, Riley again began final testing of the Riverside unit. The unit had been operating almost a year since the retrofit equipment had been installed and it was functioning well. Final acceptance testing began on September 20, 1994 and was completed on September 22, 1994. Clean Air Engineering performed the emissions acceptance testing on Riverside Boiler No. 9. The testing verified that all the contract emission requirements were achieved. Figure 11 shows the NOx emissions results of this testing compared to the baseline results, the 1990 CAAA, and Contract guarantee requirements.

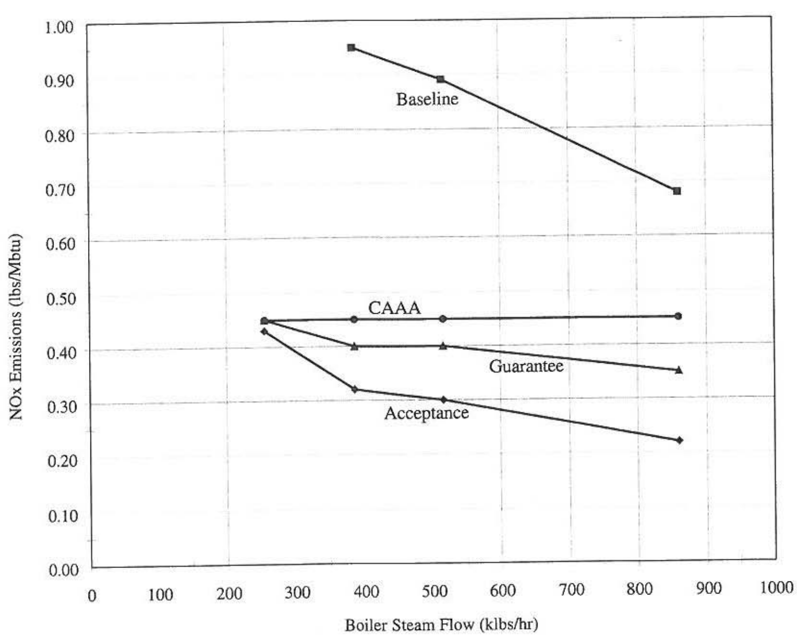

Figure 11 Acceptance and Baseline NO_x Emissions

In addition to the NO_x emissions, of particular importance were the flyash carbon loss and economizer outlet O_2 results compared to the baseline and contract guarantee requirements. This is shown in Figures 12 and 13.

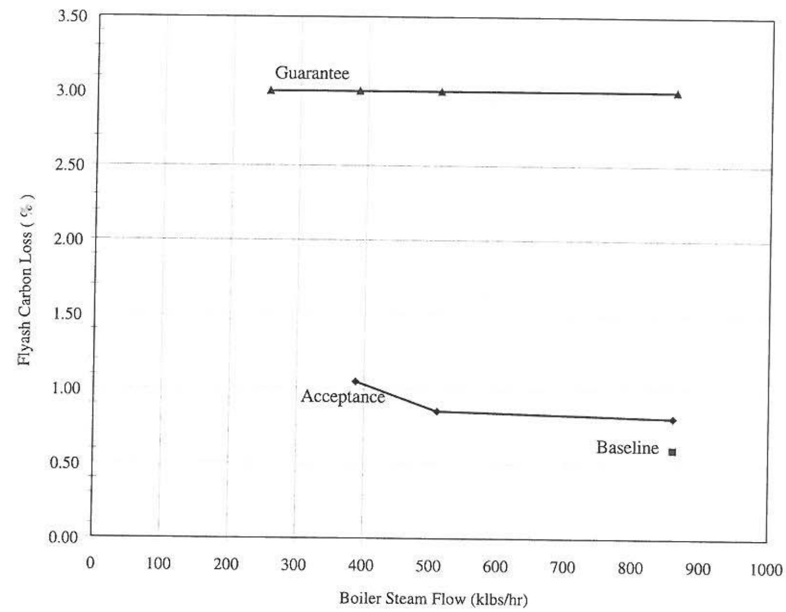

Figure 12 Acceptance and Baseline Flyash Carbon Loss

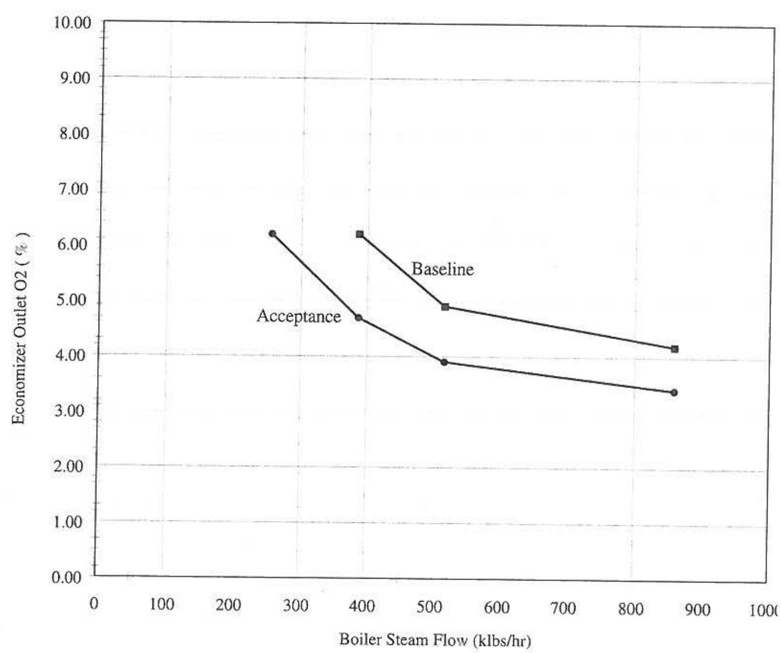

Figure 13 Acceptance and Baseline Economizer Outlet O_2 Levels

Results from other low-NO_x burner retrofits in the industry have shown that carbon loss usually increases when staged low-NO_x firing occurs. On the Riverside Boiler No. 9 retrofit, however, carbon loss levels remained almost unchanged from baseline levels. These results occurred with reduced excess air levels and with NO_x emissions below 0.30 lbs/Mbtu at 100% of MCR conditions, confirming the results obtained from the long term tests done for the coal nozzle tip research project. Riley attributes the low carbon loss values primarily to the use of the Flame Retention Nozzle Tips as part of the low-NO_x combustion system retrofit. Additionally, the reduced excess air levels did not affect the CO emissions compared to the baseline and contract guarantee limits as shown in Figure 14.

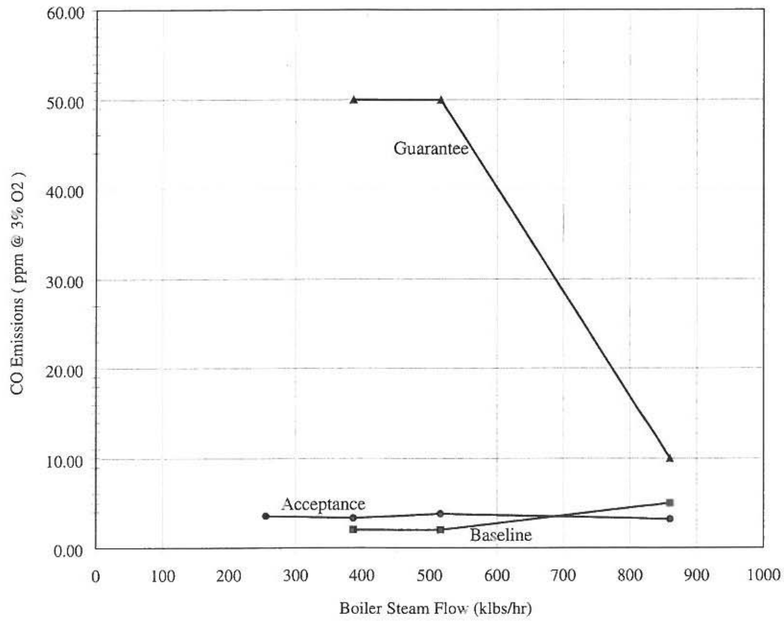

Figure 14 Acceptance and Baseline CO Emisiions

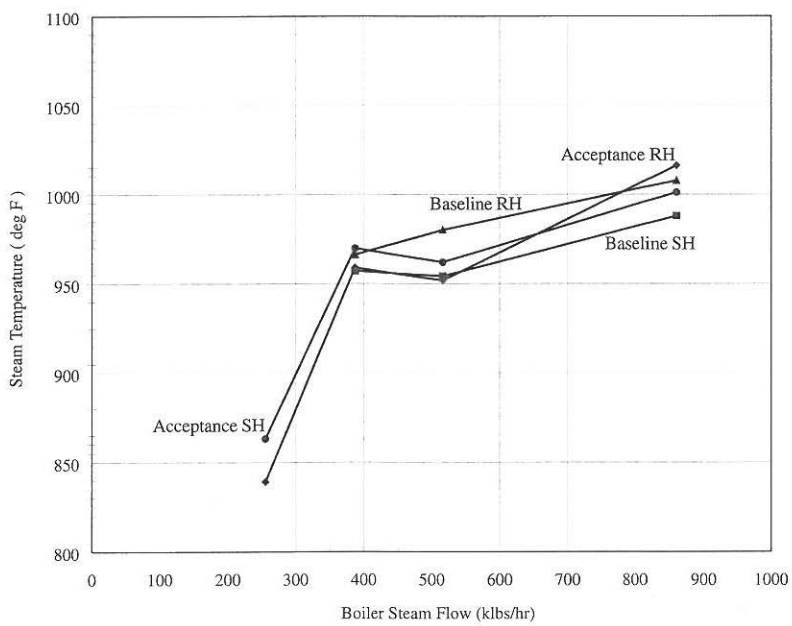

Figure 15 Acceptance and Baseline Superheat and Reheat Temperatures

The comparison of the baseline and post-retrofit main steam and reheat temperatures in Figure 15 shows that the retrofit has not impacted the heat transfer performance of the boiler.

All of the data gathered during the optimization and acceptance testing was used to create operating curves for the plant to incorporate into their control system. The data presented above shows that the contract guarantees have been successfully achieved without adverse effect to boiler performance.

EFFECTS ON BOILER OPERATION

Since the retrofit of the Riverside Boiler No. 9 to low-NO_x operation more than a year ago, the unit has not experienced significant changes in boiler operation or in slagging and fouling characteristics. The frequency of furnace sootblowing has been amended to allow achievement of higher steam temperatures at lower loads, but normal full load procedures continue to be followed. No maintenance of the new burner equipment has been required since it was put into operation. No mechanical problems with the burner or ESCS equipment have been experienced.

As part of the low-NO_x combustion system retrofit, an extensive operator training program was provided in 1993 before unit start-up. The Clean Air Act Amendment requires that utility boiler operation be more closely monitored to ensure continuing emissions compliance. For that reason, a better understanding of low-NO_x operation philosophy has resulted in improvement in Boiler No. 9 performance and NO_x emissions on a daily basis. The new burner equipment is performing as expected.

SUMMARY

Iowa-Illinois has successfully retrofitted low-NO_x combustion technology on Riverside Boiler No. 9. Of particular importance was the ability of the new combustion system to achieve NO_x emissions <0.35 lbs/10^6 Btu without degradation in boiler performance or increase in carbon loss. Improved control of the burner equipment made it possible to achieve acceptance performance. The burner tilts, secondary air dampers and ESCS dampers are all easily controlled from the control room. Boiler operation was not adversely affected with the new equipment installed and mechanical reliability has improved.

Acceptance testing verified that significant NO_x emission reductions could be achieved without the necessity of extraordinary boiler modifications.

ACKNOWLEDGEMENTS

Special thanks are extended to Iowa-Illinois Gas & Electric and Riverside Station personnel for their patience and support during the many hours of testing; to APTEC-CMSI for their material fabrication and detailing assistance; to Bob Grant, Riley Stoker's service engineer, for his significant contributions to making this retrofit project go smoothly; and to Al Spinney, RCI Construction Superintendent for accomplishing the demolition and installation of the equipment on schedule.

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